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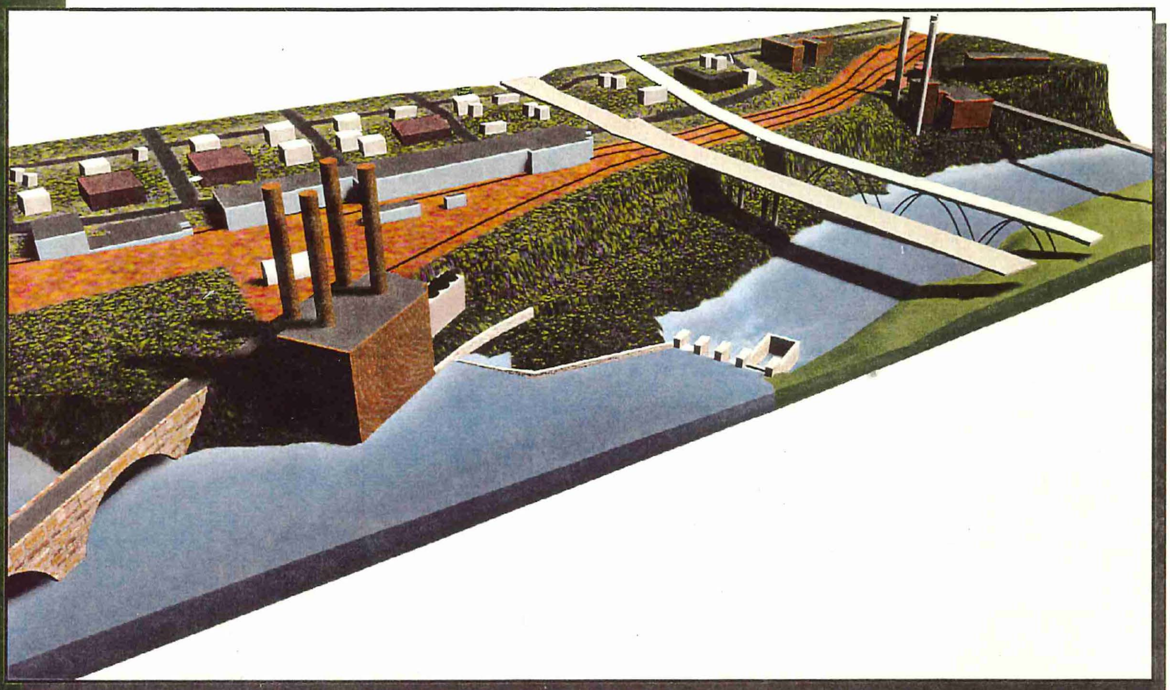

University of Minnesota Steam Service Facilities

Final EIS

COMPLETE VERSION WITH REVISIONS

September 1995

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University of Minnesota
Steam Service Facilities

Final
Environmental Impact Statement

AS REVISED BY
FINAL EIS AND FINAL EIS ADDENDUM

September 1995

Environmental Quality Board
Minnesota Planning
658 Cedar Street
St. Paul, Minnesota 55155

UNIVERSITY OF MINNESOTA STEAM SERVICE FACILITIES ENVIRONMENTAL IMPACT STATEMENT:

AS REVISED BY FINAL EIS AND EIS ADDENDUM

SEPTEMBER 1995

Additional information about this EIS can be obtained by contacting:

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ABSTRACT: The University is proposing a major renovation to its steam production facilities. The University's proposed project is defined by the 1992 construction contract between the University and Foster Wheeler, Inc. The contract includes two basic equipment options, labeled "Case A" and "Case B." Under Case A at the Minneapolis Campus, the Southeast Heating Plant would be modified, and the primarily coal-fired boilers at the Main Plant would be retired. Steam would be produced by a new circulating fluidized bed boiler with multiple-fuel capability, two new gas/oil-fired boilers, and by existing coal-fired boilers. Electricity would be cogenerated by a 15 mW non-condensing steam turbine. A range of fuels could be used at the Southeast Plant. Under Case B, the situation at the Minneapolis Campus would be similar to Case A, except that one of the gas/oil-fired boilers would be replaced with a 22 mW gas/oil combustion turbine and a waste-heat boiler, for a total of 37 mW capacity. The percentage of natural gas used would increase under Case B, compared to Case A. Under Case A and Case B (which are identical for the St. Paul Campus), the St. Paul Plant would produce steam with a new 250,000 lb/hr natural gas/No 2 fuel oil burner.

PROCESS: The Minnesota Environmental Quality Board was the responsible governmental unit (RGU) for preparation of the environmental impact statement (EIS) on the University's proposed renovation of its steam service facilities. The EQB adopted on August 19, 1993 a scoping document that the describes the issues to be addressed in the EIS. The Draft EIS was released for public comment on November 28, 1994, and a public information meeting on the Draft EIS was held on December

20, 1994. The public comment period on the Draft EIS closed on January 11, 1995. The Final EIS was noticed in the EQB Monitor on August 14, 1995, and copies of the Final EIS were mailed to all parties that had requested a copy of the Draft EIS. The public comment period on the adequacy of the Final EIS closed on September 6, 1995. The EQB found the EIS adequate on September 21, 1995.

The original Final EIS includes three volumes. The first volume consists of the changes to the Draft EIS and Responses to Comments. The second volume consists of the timely written comments received on the Draft EIS. The third volume consists of technical supporting data prepared for the Final EIS. The Final EIS also incorporates by reference the comments received, all the EIS Technical Support Documents, and the appendices prepared for the FEIS. The Draft EIS comments and Technical Appendices are available upon request.

This revised version of the Final EIS includes–for easier reading–all the changes to the Draft EIS as described in the August 1995 Final EIS, and the minor corrections included in the Final EIS Addendum of September 14, 1995. The FEIS comments and responses are also attached at the end of this revised version of the FEIS.

The FEIS also incorporates by reference Volume II and Volume III of the joint University and Foster Wheeler comments, which are available upon request. A transcript of the public information meetings on the DEIS and FEIS are also available from EQB staff upon request.

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Chapter 1. Introduction

The University of Minnesota is proposing a major renovation of its steam plants

The University of Minnesota heats its Twin City campuses with steam produced at three separate University-owned steam plants. Two of the facilities -- the Southeast Plant and the Main Plant -- serve the Minneapolis campus, and one facility -- the St. Paul Plant -- serves the St. Paul campus.

Most of the equipment in the plants was installed in the 1950's, and by 1988, a consultant's report indicated that the equipment was deteriorating. In 1992, the University Board of Regents selected a steam plant renovation project, the purpose of which was to provide reliable thermal energy to the University for the next 25 years and beyond.

The University Regents had Six Major Objectives

The University of Minnesota Regents, when selecting the proposed renovation, had five major objectives, with a sixth added later:

- Ensuring reliable steam service and supply
- Obtaining the lowest steam cost possible
- Maintaining maximum fuel price protection through fuel flexibility or pricing guarantees.
- Minimizing adverse environmental and health impacts
- Minimizing business risk to the University
- Implementing an economic electricity cogeneration system.

Major EIS Issues Include land use, coal impacts, and maximizing electricity cogeneration.

The Environmental Quality Board (EQB) is the Responsible Governmental Unit (RGU) for the Environmental Impact Statement (EIS) on this steam plant renovation project. A scoping decision outlining the major issues to be addressed in this EIS was adopted by the EQB in August, 1993. The EIS is being completed pursuant to Minnesota Rules Part 4410.2000, Subpart 3b.

Major issues identified during the scoping process include:

- Riverfront land use
- Potential negative environmental impacts of handling and burning coal compared to natural gas
- Long-term energy policy
- Maximizing the use and environmental benefits of electricity cogeneration to meet University steam demand

The Purpose of the EIS is to Disclose Information

The purpose of the EIS is to provide accurate information to governmental units, the project proposer, and the public regarding the impacts of the proposal, the feasibility and impacts of alternatives, and the potential for reducing adverse environmental effects.

EIS Technical Support Documents are Available

This EIS is largely a summary of information contained in a number of detailed reports completed for this project. The following technical support documents are available:

1. *Alternatives to the University of Minnesota's Steam Service Facilities Renovation, Screening Analysis*, March 25, 1994, by Dahlen, Berg & Company.

2. *Fuel Price Projections,* March 30, 1994, by Dahlen, Berg & Company

3. *Value of Cogenerated Electricity,* April 1, 1994, by Dahlen, Berg & Company.

4. *Financial Projections for the University of Minnesota's Steam Supply Alternatives,* July 29, 1994, by Dahlen, Berg & Co.

5. *University of Minnesota, Environmental Impact Statement, Proposed Alternatives Air Quality Analysis,* October 27, 1994, by Trinity Consultants, Inc.

6. *Soil and Groundwater Contamination Site Assessment,* October 1994, by B.A. Liesch Associates, Inc.

7. *Water Quality Study, University of Minnesota Steam Services,* September 1994, by B.A. Liesch Associates, Inc.

8. *Summary of Land Use Plans, St. Anthony Falls Riverfront, City of Minneapolis,* October 1994, by the Environmental Quality Board.

The EIS First Describes the Existing Plants, the Proposal, and Thirteen Alternatives.

Chapter 1 describes the existing steam facilities. Chapter 2 describes the University's proposal ("Case A" and "Case B"), and chapters 3 and 4 describe the alternatives developed for the EIS. The remainder of the chapters descibe potential impacts.

- Chapter 5 describes the natural environment at existing and potential steam plant sites
- Chapter 6 addresses air pollutant emissions and impacts;
- Chapter 7 addresses water quality issues in the Mississippi and

elsewhere;

- Chapter 8 addresses solid and hazardous waste;
- Chapter 9 describes land use planning efforts in the affected areas and addresses the impacts of the proposal and alternatives;
- Chapter 10 describes potential mitigation for environmental impacts, including cogeneration benefits;
- Chapter 11 addresses the economic and technical feasibility of the EIS alternatives.

Chapter 1.1. Existing Facilities: Minneapolis Campus

The University Heats its Buildings with Steam Produced at Three Separate Facilities

Two of the three existing steam plants serve the Minneapolis Campus, and one serves the St. Paul campus.

1. The Southeast Plant is located between the Mississippi River and the corner of 6th Avenue S.E. and Main Street S.E., Minneapolis, near lower St. Anthony Falls and the east end of the Stone Arch Bridge.
2. The Minneapolis Campus "Main" Heating Plant is located adjacent to the campus at 1180 Main Street S.E., near the Steel Truss Bridge, Minneapolis.
3. The St. Paul Campus Heating Plant is located at 1952 Commonwealth Avenue, Falcon Heights.

Figure 1 shows the general location of the three existing facilities on a USGS 7.5 minute, 1:24,000 scale map. See Chapter 9 for a detailed description of each site and its surrounding land uses.

The University Steam Plants are Operated by Foster Wheeler, Inc.

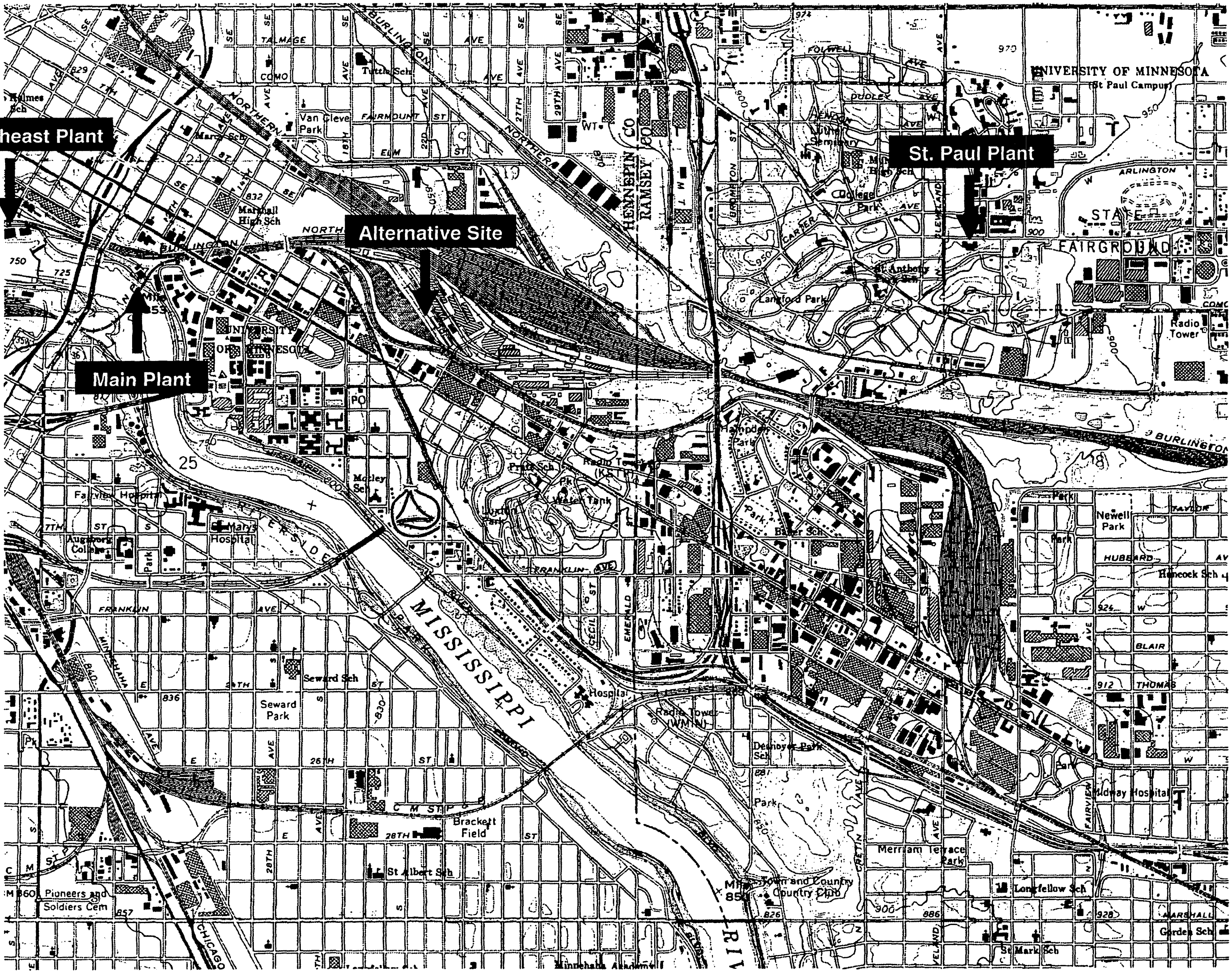
Although owned by the University, the three steam plants have been operated since 1992 by the University's steam vendor, Foster Wheeler Twin Cities, Inc.

The description of the existing facilities, the proposal, and the alternatives each contain the following informatiol:

- Steam and electrical production technology
- Boiler capacity
- Fuel mix and usage
- Material handling system

Southeast Plant has two Older Coal-Fired Boilers in Operation.

The Southeast Plant is a five story red-brick, turn-of-the-century industrial building of historical significance (see chapter 9). The Southeast Plant has two coal fired boilers in service: a pulverized coal unit, 53 years old, rated at approximately 110,000 lb/hr steam, and a spreader stoker unit, 45 years old, rated at approximately 120,000 lb/hr steam. Two additional boilers in the plant are retired. The Plant is configured for electrical generation, but it is not operational. Total plant capacity is 230,000 lb/hr.


Southeast Plant
Main Plant
Alternative Site
St. Paul Plant
UNIVERSITY OF MINNESOTA
(St Paul Campus)
UNIVERSITY OF MINNESOTA
STATE FAIRGROUND
MISSISSIPPI
HENNEPIN CO
RAMSEY CO
Van Cleve Park
Marshall High Sch
Langford Park
Hampden Park
Fairview Hospital
St Marys Hospital
Augsburg College
Seward Sch
Seward Park
Brackett Field
St Albert Sch
Pioneers and Soldiers Cem
Merriam Terrace Park
Town and Country Country Club
Longfellow Sch
St Mark Sch
Midway Hospital
Newell Park
Hancock Sch
Radio Tower
Water Tank
FRANKLIN AVE
BURLINGTON
NORTHERN
CHICAGO

Minneapolis Campus ("Main") Plant has Five Older Coal-Fired Boilers and One Newer Gas/Oil Boiler in Operation

Six existing boilers at the Main Plant burn coal, oil and natural gas. There are three coal-fired spreader stoker units, one 45 years old and rated at 60,000 lb/hr of steam, one 42 years old rated at 60,000 lb/hr of steam, and one 41 years old rated at 70,000 lb/hr of steam; two pulverized coal units, one 29 years old rated at 80,000 lb/hr of steam and one 26 years old rated at 120,000 lb/hr of steam. There is one comparatively new 23-year old oil/gas unit rated at 180,000 lb/hr of steam. A seventh boiler (a pulverized coal unit, 57 years old, capacity of approximately 100,000 lb/hr of steam) is in near-operable condition but is not currently permitted. Total plant capacity is 570,000 lb/hr.

Minneapolis Campus Steam Load is one of the Highest in Minnesota

The University's Minneapolis campus has one of the largest district heating loads in Minnesota. Steam use at the Minneapolis campus currently averages about 270,000 lb/hr. The peak winter heating demand reaches approximately 520,000 lb/hr. Summertime steam use is also high because the University cools many of its buildings with steam driven chiller units (see Chapter 10). The minimum or baseload steam demand is approximately 110,000 lb/hr. Electricity use at the Minneapolis campus is about 234,000 mw-hours annually.

Recent Minneapolis Fuel Mix: 85-90% Coal 10% Natural Gas

The current annual fuel mix on the Minneapolis campus is approximately 85-90% coal, 5%-10% natural gas, and small amounts of distillate fuel oil. Total annual coal consumption was about 150,000 tons in FY 92-93.

Coal Unloaded and Stored at Main Heating Plant

Subbituminous western coal is delivered by rail to the Minneapolis campus. The railcars are first unloaded in a shed adjacent to the Main Plant, where the coal is dropped into a small underground storage area, treated with dust suppressant, and transferred via a covered conveyor to an open storage area near the Main Plant.

Coal for the Southeast Plant is trucked from the Main Plant on a private road above the riverfront bluff. A short-term coal supply for the Southeast Plant in stored in an adjacent, uncovered outdoor bunker. See Chapter 9 for additional description of the riverfront coal handling operations.

Ash Stored Inside Before Being Trucked to Landfill

Foster Wheeler has recently changed the coal-ash handling procedures at both campuses. At the Minneapolis campus, ash is no longer temporarily stored on the ground near the Mississippi riverfront. Instead, the ash is first stored in a former incinerator building located near the Main Plant. From there, the ash from the Minneapolis plants is trucked to a licensed landfill in Madison, Wisconsin.

The MPCA has indicated that any future outdoor ash storage must be done under permit from the Solid Waste Section, using a lined site with leachate collection. The University contract includes options for upgraded outdoor ash storage facilities. The contract option does not mention lining and leachate collection, but all MPCA requirements will be met if outdoor ash storage is resumed.

Two Above Ground Fuel Oil Tanks, and Fourteen Underground Tanks at the Minneapolis Campus

An fuel oil unloading station and two above ground storage tanks, 500,000 gallons and 250,000 gallons, are located and utilized at the Main Plant. There are fourteen underground storage tanks for fuel oil at the Main Plant. There is one 10,000 gallon aboveground oil storage tank located at the Southeast Plant containing distillate fuel oil for use in boiler startup only.

Chapter 1.2. St. Paul Campus

St. Paul Plant has Six Coal-Fired Boilers and One New Gas/Oil Fired Boiler.

The St. Paul Plant has seven boilers, ranging in age from 1 to 54 years: two pulverized coal units, each 38 years old, each rated at approximately 30,000 lb/hr of steam; two oil/gas units, each 54 years old, each rated at approximately 30,000 lb/hr of steam; two coal spreader stoker units, 24 and 16 years old, each producing approximately 60,000 lb/hr of steam; and a newly installed (1991 start-up) oil/gas unit rated at approximately 80,000 lb/hr of steam. The present total capacity at the St. Paul Plant is 330,000 lb/hr of steam.

Average Annual Steam and Demand is About 90,000 lb/hr

Steam demand at the St. Paul campus currently averages about 90,000 lb/hr.. The winter heating peak demand reaches approximately 170,000 lb/hr. Electricity demand averages approximately 71,000 mw-hours annually.

Recent Fuel Mix at St. Paul:
46% Coal
48% Natural Gas
6% Fuel Oil

The annual fuel mix on the St. Paul campus in FY 1992-93, the most recent complete data available, was 46 % coal, 48 % natural gas, and 6% distillate fuel oil. The University has indicated that it keeps annual coal use at about 65% of total energy use. Total annual coal consumption was 16,000 tons coal. This fuel mix uses more natural gas than would a strictly economic dispatch fuel use.

Eastern Bituminous Coal is Delivered to St. Paul Plant by Truck and Stored in Open Area in Back.

The St. Paul Plant uses bituminous eastern coal. The coal is delivered directly from coal suppliers' docks and stored in an open coal pile to the rear of the building. The coal storage volume was recently reduced, and coal handling facilities were upgraded to include some partitioning in the coal bunkers.

Ash Stored Inside or Trucked Directly to Landfill

Ash at the St. Paul facility, previously stored outside in an open bunker, is either trucked to the incinerator building near the Minneapolis Main Plant or is trucked directly from the ash silos to a licensed landfill in Madison, Wisconsin. A detailed description of the St. Paul facility and the surrounding land uses is contained in Chapter 9. Potential material handling modifications are described in the chapter on mitigation (Chapter 10).

Fuel Oil Storage Consists of A Large Storage Tank and Two Small Tanks

The St. Paul plant has one 400,000 gallon above ground oil storage tank which is currently used for number 2 fuel oil. Also in use are two smaller underground "day tanks" of 35,000 gallons each.

Chapter 2. The Proposed Project

The University's Proposal is Defined by its Contract

The University's proposed project, including options, is defined by the 1992 construction contract between the University and Foster Wheeler. The contract includes specific renovations to the steam plants at both campuses, so the following project description and the financial evaluation includes a discussion of both campuses. Most environmental and other impacts for the two campuses, however, are addressed separately, except when describing the general terms of the University's contract and as otherwise necessary.

The Construction Contract Includes Two Major Equipment Options.

The University's contract includes two basic equipment configurations, designated as "Case A" and "Case B, which are described below. The University has not decided between these options, but it has submitted an air quality permit application to the Minnesota Pollution Control Agency only for Case A.

Contract Includes Tariff Rate for Steam Consumption.

The University's contract includes a tariff rate for steam consumption (with both fixed and variable components) and base rates for monthly operation and maintenance charges. The contract also includes base rates for steam consumption charges.

Under the University's contract, insurance, ash disposal costs, and fuel price changes pass directly through to the University. The quantity of fuel charged to the University is based on minimum efficiency guarantees in the contract. Any fuel efficiency savings above the guaranteed levels are shared by the University and its steam provider.

A copy of the tariff description is included in the *Financial Projections* report, by Dahlen, Berg & Co.

Section 2.1. Case A

Introduction

This section describes the proposed equipment configuration and the plant operation for the Case A option. The Minneapolis Campus is described first, followed by the St. Paul Campus.

Steam Would Be Produced at the Southeast Heating Plant With New Circulating Fluidized Bed Boiler and Two Conventional Gas/Oil Boilers.

Under Case A, steam would be produced at the Southeast Heating Plant. Existing boilers 3 and 4 would remain in service. All other boilers in the Southeast Heating Plant and the Main Heating Plant would be decommissioned. The total capacity of boilers 3 and 4 is 230,000 lb/hr.

Under Case A, 650,000 lb/hr of steam capacity would be added at the Southeast Heating Plant. The new capacity would be from a 200,000 lb/hr circulating fluidized bed boiler, and from conventional boilers (450,000 lb/hr). Existing coal-fired boilers 3 and 4 would be retained primarily for backup. Total steam capacity including existing boilers 3 and 4 would be 830,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 630,000 lb/hr. The fluidized bed boiler has operational and criteria pollutant emission advantages over conventional coal boilers that are briefly described in Chapter 6.

The new combustion equipment would exhaust flue gasses through the two stacks that are not currently used.

15 mW Steam Turbine Would Be Installed at Southeast Heating Plant.

A nominal 15 mW noncondensing steam turbine would be installed at the Southeast Heating Plant and would produce electricity in proportion to the Minneapolis campus steam load. Net electricity production would be approximately 50,000 mW-hours annually depending on steam load.

Southeast Heating Plant Would Be Modified, Roof Section Raised 40 Feet

The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. The weight of the new circulating fluidized bed boiler would be roof-hung and supported on new structural steel columns independent of the existing structure.

In order to accommodate the new CFB boiler, 40 feet would be added to the existing turbine hall building height. The footprint of the building would not be changed. (See Chapter 9 for building renovation description.)

Main Plant Would be Decommissioned Following Renovation

The Main Plant will be operated and maintained to provide steam service for the Minneapolis Campus during design and construction of the new facilities at the Southeast Plant. Following the beginning of commercial operation of the renovated Southeast Plant, the Main Plant would be retired.

Contract Includes Minneapolis and St. Paul Construction Options.

The University's contract includes eight construction options at additional cost for the Minneapolis campus and three construction options for the St. Paul campus. These options are discussed in more detail in Chapter 10. The University has not yet exercised any of these options, which may be described as follows.

Minneapolis Options

1. Install NO_X control equipment (Denox System) on the fluidized bed boiler.
2. Construct a wall partially to enclose the Minneapolis Campus ash pile.
3. Construct a wall partially to enclose the Main Plant coal pile.
4. Install an additional gas boiler.
5. Install an additional fluidized bed boiler.
6. Install a coal conveyor between the Main Plant and the Southeast Plant.
7. Modify the fluidized bed boiler to allow 100% natural gas firing.
8. Modify the fluidized bed boiler to allow up to 30% firing with petroleum coke.

Existing Main Plant Coal Handling Facilities Would Be Used, with Optional Use of Coal Conveyor.

The existing coal unloading and storage facilities at the Main Heating Plant would continue to be used. Coal would continue to be trucked to the Southeast Heating Plant. The contract includes an option to partially screen the coal storage area and to install a coal conveyor from the Main Heating Plant to the Southeast Heating Plant through the existing tunnel, although the University has not exercised this option.

Existing No. 2 Oil Storage Facilities in Minneapolis Would Be Used.

The two existing No. 2 oil storage tanks (500,000 gallons and 250,000 gallons) would store fuel oil for the packaged natural gas and No. 2 oil conventional boilers. An oil pipeline would be installed between the two plants. Fourteen underground storage tanks are anticipated to be retired at the closure of the Main Plant (see Chapter 8).

Economic dispatch assumes fluidized bed boiler first, followed by new gas/oil boilers and existing coal boilers as needed

The costs and emission levels for the University's proposed Case A project are based on the following least-cost fuel dispatch of steam production equipment:

- circulating fluidized bed boiler first, to meet baseload steam demand
- conventional high pressure natural gas and fuel oil boiler, second
- Southeast coal boilers number 3 and 4 third, and
- conventional medium pressure natural gas boilers last

The University has described the likely dispatch order as using the medium pressure conventional boiler before the existing coal-boilers.

Economic Fuel Mix at Minneapolis:
83% Coal
15% Natural gas
1% Fuel Oil

After the facilities were completed, the Case A FY 1998 fuel mix in Minneapolis would be approximately 83% coal, 15% natural gas, and 1% fuel oil, based on economic dispatch of the steam production facilities. The total fuel consumed in FY 1998 would be 2,728,914 MMBtu. The FY 1998 fuel mix could also include up to approximately 5.0% waste wood.

For purposes of its comments on the DEIS, the University assumed the following annual fuel mix: 70% Coal, 20% Natural Gas, 5% Fuel Oil, and 5% Waste Wood.

In addition, the University has a contract option to burn petroleum coke in the circulating fluidized bed boiler under Case A and Case B. Petroleum coke is a solid, high Btu fuel that can be efficiently burned in this type of boiler.

If the University exercises its option in the Foster Wheeler contract, the new circulating fluidized bed boiler would be physically capable of operating on 100% petroleum coke. The currently requested air emission permit limits, however, would probably restrict petroleum coke use to about 80% of total CFB capacity on an annual basis. At currently predicted steam loads, therefore, about 60% of the total annual Minneapolis campus steam load could be met with petroleum coke.

The air emission implications of petroleum coke are addressed in FEIS Chapter 6.

Steam Would Be Produced at the Existing St. Paul Heating Plant.

Under Case A, steam would be produced at the St. Paul Heating Plant. Existing primarily-coal fired boilers 1, 2, 5, 6 and 7 would remain in service and two older gas/oil boilers, 3 and 4, would be decommissioned. The total capacity of boilers 1, 2, 5, 6 and 7 is 250,000 lb/hr.

Under Case A, 250,000 lb/hr of steam capacity would be added at the St. Paul Heating Plant. The total steam capacity including existing boilers would be 500,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 250,000 lb/hr.

Case A Includes Options for St. Paul Plant.

St. Paul Options:

1. Construct ash pile storm water collection system.
2. Construct walls to partially enclose the coal pile.
3. Install a combustion turbine.

St. Paul Heating Plant Would Be Expanded for Gas/Oil, but Coal Storage Would be Retained.

The St. Paul Heating Plant would be expanded to provide space for the new production equipment. The new natural gas. fuel oil boiler would be enclosed in a pre-engineered building with metal siding. A dedicated 200-foot steel chimney will also be provided.

The existing coal unloading and storage facilities at the St. Paul Heating Plant would be retained because coal would continue to be used for backup, according to the University.

Existing No. 2 Oil Storage Facilities in St. Paul Would Be Used.

The existing No. 2 oil storage facilities would be used to supply fuel oil for the new and existing boilers.

Fuel Mix at St. Paul Would Be 92% Natural Gas 8% Fuel Oil

The University has defined the proposal as using negligible quantities of coal at the St. Paul Campus following renovation, although coal permits will be retained. After completion of the facilities in FY 1997, the Case A fuel mix in St. Paul would be approximately 92% natural gas and 8% fuel oil, based on economic boiler dispatch–and assuming no use of coal. The total fuel consumed in FY 1997 would be 932,368 MMBtu's. The fuel consumed varies with steam production, and the fuel mix remains relatively stable throughout the projections.

Section 2.2. Case B

Introduction

Case B is an option to the proposed construction contract between the University and Foster Wheeler. The contract includes the same steam consumption tariff rates and the same construction options as those contained in Case A.

Case B is Case A with 22 mW Combustion Turbine with Waste-Heat Boiler Replacing Conventional Natural Gas, Fuel Oil Boiler

For Case B, as under Case A, nominal 15 mW noncondensing steam turbine would be installed and would produce electricity in proportion to the Minneapolis campus steam load. But for Case B, a 22 mW combustion turbine, powered by natural gas and No. 2 fuel oil, would also be installed and would produce electricity to meet the Minneapolis campus electric load net of the steam turbine production.

Waste heat from the 22mW combustion turbine would be used to produce up to 60,000 lb/hr of steam in the waste heat boiler. Net combined electricity production would be about 197,000 mW-hours annually.

Steam Would Be Produced at Southeast Heating Plant With Waste-Heat Boiler, Fluidized Bed Boiler, and Gas/Oil Boiler.

Under Case B, steam would be produced at the Southeast Heating Plant. Existing boilers 3 and 4 would remain in service. All other boilers in the Southeast Heating Plant and the Main Heating Plant would be decommissioned. The total capacity of boilers 3 and 4 is 230,000 lb/hr.

Under Case B, 600,000 lb/hr of steam capacity would be added at the Southeast Heating Plant. The new capacity would be from a waste heat boiler with supplementary firing (200,000 lb/hr), a 200,000 lb/hr fluidized bed boiler, and from a conventional gas/oil boiler (200,000 lb/hr). Total steam capacity including existing boilers 3 and 4 would be 830,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 630,000 lb/hr.

The new combustion equipment would exhaust flue gasses through the two stacks that are not currently used.

Southeast Heating Plant Would Be Modified.

The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. While the conventional boiler would be installed in a building addition, the combustion turbine, waste heat boiler and fluidized bed boiler all would be installed within the Southeast Plant. An additional 40 foot height addition to the boiler hall would be required.

Existing Coal Handling Facilities in Minneapolis Would Be Used.

The existing coal unloading and storage facilities at the Main Heating Plant would continue to be used. Coal would be trucked to the Southeast Heating Plant. The contract includes an option partially to enclose the coal storage area and to install a conveyor from the Main Heating Plant to the Southeast Heating Plant through the existing tunnel, although the University has not exercised this option.

Existing No. 2 Oil Storage Facilities in Minneapolis Would Be Used.

The two existing No. 2 oil storage tanks (500,000 gallons and 250,000 gallons) would store fuel oil for the packaged natural gas and No. 2 oil boilers. An oil pipeline would be installed between the two plants.

Economic Fuel Dispatch, Would be Waste Heat for Part of Baseload, Followed by the Fluidized Bed and Gas/Oil Boilers.

At economic dispatch, the Case B boiler configuration would generally be used to meet steam requirements in the following order

- waste-heat boiler using combustion-turbine exhaust, first
- fluidized bed boiler, second, depending on steam load
- supplemental gas/oil firing of waste heat boiler, third
- conventional gas/oil boiler and existing coal boilers last

Fuel Mix at Economic Dispatch Predicted to Be
50% Coal
46% Natural Gas
4% Fuel Oil

After the facilities were completed, the Case B FY 1998 fuel mix in Minneapolis would be 50% coal, 46% natural gas, and 4% fuel oil, based on economic dispatch of the steam production facilities. The total fuel consumed in FY 1998 would be 3,712,636 MMBtu. The fuel consumed varies with steam production, and the fuel mix remains relatively stable throughout the projections.

The University, for purposes of its DEIS comments, used the following Case B fuel mix: 36.6% coal, 54.9% natural gas, 4.5% fuel oil, and 4.0% wood chips.

Since Case B also includes the installation of a new circulating fluidized bed boiler, the general description of petroleum coke capability included for Case A applies to Case B, although the maximum annual percentage of petroleum coke would be less than under Case A.

St. Paul Proposal for Case B Is the Same as for Case A.

Under Case B, equipment modifications, plant modifications, fuel handling, and fuel mix for the St. Paul facility would be the same as under Case A.

Chapter 3. Description of Alternatives

The Alternatives Chosen for Detailed Analysis Focused on Economically Reasonable, Proven Reliable Technologies.

The thirteen alternatives listed in the EIS scoping document, including off-site steam production, were quantitatively analyzed in an initial environmental and feasibility screening analysis. The results of this screening study, are described in *Alternatives to the University of Minnesota's Steam Service Facilities Renovation*, March 25, 1994, by Dahlen, Berg & Company.

Five alternatives were chosen for detailed analysis, four in Minneapolis and one in St. Paul. All are on-campus cogeneration systems that use primarily either natural gas with fuel-oil backup, or use a mixture of coal, natural gas, fuel oil. The alternatives are located either at riverfront Southeast Plant or at an alternative "23-acre" site located near Marriucci Arena and some Archer Daniel Midlands elevators. The two "No Action" alternatives (one per campus), were also carried into the next phase for comparison purposes.

The alternatives chosen for detailed analysis were based on the following criteria:

- Estimated point source emissions
- Estimated emissions adjusted for cogeneration benefits
- Cost and technical feasibility
- Potential for beneficial land use impacts
- Mix of technology, fuels, and location

Electricity Can Be Cogenerated Using either Steam or Combustion Turbines

The proposed project and most of the alternatives include an electricity cogeneration component. Cogenerating electricity with steam or hot water for heating and cooling is more energy efficient than producing electricity and thermal energy separately.

The proposed Case A cogeneration project and one EIS alternative produce electricity using a *steam turbine*. High pressure steam is first produced in boilers and then expanded through a back pressure steam turbine to produce electricity. The resulting lower pressure steam is then exported to the campus. Typically, large coal fired utility plants use steam turbines.

Most of the EIS cogeneration alternatives, however, include a natural gas or fuel oil fired *combustion turbine*. Electricity is first produced by burning liquid or gaseous fuel in the jet-engine like turbine, and the hot exhaust gases are used to make steam or hot water for heating and cooling. Plants that use both processes are sometimes called "combined cycle" facilities.

Combustion turbine cogeneration facilities produce more electricity for a given steam load than steam turbine based facilities. Less expensive solid fuels like coal or petroleum coke cannot be used in combustion turbines, although coal and biomass gasification systems are currently nearing commercial development.

Seven AlternativeDescribed

First, the alternatives analyzed in detail, as listed below, will be described.

Minneapolis Campus

Alt. No. 1	Minneapolis Deferred Construction
Alt. No. 3	Southeast Plant using Coal with Natural Gas Cogeneration
Alt. No. 4	Southeast Plant without Coal with Natural Gas Cogeneration
Alt. No. 6	New Plant at Alternative Location with Coal
Alt. No. 7	New Plant at Alternative Location without Coal

St. Paul Campus

Alt. No. 11	St. Paul Plant Deferred Construction
Alt. No. 13	St. Paul Plant without Coal

Detailed Descriptions of Alternatives Contained in Separate Report

Conceptual engineering design drawings of the alternatives chosen for detailed analysis, and the associated financial cost assumptions and calculations are described in a separate report: *Financial Projections for the University of Minnesota's Steam Supply Alternatives*, July 29, 1994, by Dahlen, Berg & Co.

Six Other Alternatives Described

Alternatives which did not survive the initial Screening Analysis are listed below. These alternatives are described in Chapter 4, along with the reasons why they were not chosen for further consideration.

Minneapolis Campus

Alt. No. 2	Southeast Plant Natural Gas and Oil
Alt. No. 5	Southeast Plant with Large Cogeneration
Alt. No. 8	Main Plant Renovation and Expansion

Combined Campuses

Alt. No. 9	Purchase Steam from Third Parties
Alt. No. 10	Interconnect Minneapolis and St. Paul Systems—New Plant

St. Paul Campus

Alt. No. 12	St. Paul Plant with Cogeneration with coal

Summary Table of Minneapolis Steam Plant Alternatives

	Location	Boilers & Economic Dispatch Order	Electrical Capacity (mW)	1998 Annual Fuel Mix	1999 Elect. Prd. (mW-hrs)	Coal Handling
Case A	Southeast Plant	1. CFB 2. Gas/Oil boilers	15 Steam Turbine	75-83% Coal 16-24% Gas 2% Oil	65,500	Existing, With Tunnel Option
Case B	Southeast Plant	1. Gas Turbine 2. CFB 3. Gas/Oil Boilers	15 Steam + 22 mW Combustion Turbine (CT)	50% Coal 46% Gas 4% Oil	223,500	Existing, With Tunnel Option
Alt. 1	Southeast & Main	Existing Coal	None	97% Coal	0	Riverfront But Enclosed
Alt. 2	Southeast	Gas/Oil Boilers	None	92% Gas 8% Oil	0	Eliminated
Alt. 3	Southeast Plant	1. Gas Turbine 2. Existing Coal 3. Gas/Oil Boilers	22.5 CT	62% Gas 32% Coal 6% Oil	187,000	Riverfront But Enclosed
Alt. 4	Southeast Plant	1. Gas Turbine 2. Gas/Oil Boilers	22.5 CT	92% Gas 8% Oil	187,000	Eliminated
Alt. 6	Off-River Site	1. CFB 2. Gas/Oil Boilers	17 Steam	76% Coal 22% Gas 2% Oil	60,000	Off-River Enclosed
Alt. 7	Off-River Site	1. Gas Turbine 2. Gas/Oil	22.5 CT	92% Gas 8% Oil	187,000	Eliminated
New Alt. 5 V Large Cogen (Minnegasco)	Probably Off-Campus	Large Gas Turbine	250+ Combustion Turbine	90% Gas 8% Oil	2 million +	Eliminated
New Alt. 9: MEC Third Party	Off-Campus Steam "Network"	New and Existing Gas/Oil Boilers + (Existing NSP Coal at St. Paul)	None	About: 72% Gas 20% Coal 8% Oil	0	Eliminated

DEIS SUMMARY

Several comments specifically addressed either the scope or content of the DEIS Summary. One revision was made to the Summary text, and a revised summary table of alternatives is provided in the FEIS Introduction.

Replace middle section on page S-10 with the following text:

Proposal and Riverfront Alternatives Compatible with Some Specific Policies and/or Goals of MNRRA

The MNRRA plan establishes a number of purpose and vision statements. Site specific issues will be addressed at the local level following plan approval based on the broad visions, general concepts, and corridor-wide policies articulated in the plan.

Different MNRRA goals and policies are advanced by both the proposed project and or the detailed alternatives. There are no specific policies in the MNRRA plan that prohibit the proposed project or alternatives.

Comment Sa

Land Use and Greenhouse Gas Impacts Should Be Emphasized

In general, the DEIS summary should expand its discussion of land use issues and emphasize the numerous local land use plans and federal and state statutes that apply to the riverfront area, and the text should be revised to indicate that the riverfront site itself is in itself an important historic, recreational, and scenic resource.(Minnegasco)

The statement in the Summary that the proposed project is compatible with MNRRA is misleading and should be changed. (National Park Service, SORC, others)

The EIS summary is deficient because it omits information about greenhouse gas emissions. (SORC, Abrahamson)

Response Sa

MNNRA Compatibility Summary Revised

The Summary text on MNRRA compatibility has been revised. Information on riverfront importance, greenhouse gas emissions, and other revisions have been made to the FEIS chapters, but no other changes were made to the summary text

Section 3.1. Alternative No. 1 Minneapolis Deferred Construction ("No Action")

Under Alternative No. 1, the Southeast Heating Plant and the Main Heating Plant would be operated in their current configurations until 2001. At that time, Southeast boilers 3 and 4 and Main boilers 1 and 2 would be retired. New coal-fired boiler capacity would be installed in the Southeast Plant.

This description of Alternative No. 1 includes the following components.

- Coal Used as the Primary Fuel
- Steam Produced at the Southeast Heating Plant
- Steam Produced at the Main Heating Plant
- Coal Storage and Handling Modified
- Southeast Heating Plant Modified
- Fuel Mix Identified

The purpose of this alternative is to provide an environmental comparison with other renovation alternatives, It represents the minimum effort required to continue to provide steam using the existing system, based on existing information. No conceptual design drawings have been made, and no permitting or other regulatory feasibility analysis has been conducted.

Coal Would Be Used as the Primary Fuel

Under Alternative No. 1, all boilers capable of burning coal would be dispatched first.

Steam Would Be Produced at the Southeast Heating Plant

Under Alternative No. 1, steam would be produced at the Southeast Heating Plant. Existing boilers 3 and 4, with a total capacity of 230,000 lb/hr, would remain in service until 2001, when 360,000 lb/hr of new coal fired capacity would be installed.

The new boilers would exhaust flue gasses through the two stacks that currently are not used. The building height above the boiler hall would be increased similar to that required for Case A and Case B.

Steam Would Be Produced at the Main Heating Plant

Under Alternative No. 1, the existing boilers at the Main Heating Plant would be used. Boilers 1 and 2 would be retired and their capacity would not be replaced.

Coal Handling Would Be Modified

The coal unloading and storage facilities at the Main Heating Plant would be modified. Coal unloading and storage would be in enclosed areas and would be transported to the Southeast Plant on a new conveyor installed in the existing tunnel.

Southeast Heating Plant Would Be Modified

The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective.

The roof would be removed to demolish existing boilers 3 and 4 and to install the new ones.

Fuel Mix Would Be 97% Coal 3% Natural Gas and Fuel Oil

The fuel mix for Alternative No. 1 in FY 2002, the first year the renovated plant would be operated, is projected to be 97% coal and 3% natural gas and fuel oil. Prior to renovation, the fuel mix for each of the alternatives is projected to be approximately 98% coal. The quantity of fuel consumed varies with the steam produced, but the fuel mix is remains stable throughout the 25-year projections.

Section 3.2. Alternative No. 3 Southeast Plant Using Coal with Natural Gas Cogeneration

Under Alternative No. 3, the Southeast Heating Plant would be modified and the Main Heating Plant would be retired. Electricity would be produced by combustion turbines and steam would be produced by waste heat boilers, by new packaged natural gas and No. 6 fuel oil boilers, and by the two existing coal-fired boilers. This description of Alternative No. 3 includes the following components.

- 22.5 mW Combustion Turbines Installed
- Electricity Distributed to East and West Bank Campuses
- Steam Produced at Southeast Heating Plant
- Coal Storage and Handling Modified
- No. 6 Oil Storage Provided
- Existing No. 2 Oil Storage Used
- Southeast Heating Plant Modified
- Fuel Mix Identified

Steam Produced at Southeast Heating Plant

Under Alternative No. 3, steam would be produced at the Southeast Heating Plant. Existing boilers 3 and 4 would remain in service. All other boilers in the Southeast Heating Plant and the Main Heating Plant would be decommissioned. The total capacity of boilers 3 and 4 is 230,000 lb/hr.

Under Alternative No. 3, 525,000 lb/hr of steam capacity would be added at the Southeast Heating Plant. The new capacity would be from waste heat boilers with supplementary firing (275,000 lb/hr) and from conventional boilers (250,000 lb/hr). Total steam capacity including existing boilers 3 and 4 would be 755,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 630,000 lb/hr.

22.5 mW Combustion Turbines Installed

22.5 mW of combustion turbines, powered by natural gas and No. 2 fuel oil, would be installed to produce electricity. The 22.5 mW total capacity would be provided by five nominal 4.5 mW units. The combustion turbines would be base loaded and would be operated 95% of the hours in a year.

Waste heat from the combustion turbines would be used to produce up to 110,000 lb/hr of steam in the waste heat boiler Electricity production would be about 187,245 mW-hour annually.

Electricity Distributed to East and West Bank Campuses

Because electricity produced under Alternative No. 3 would exceed the east bank campus load, electrical feeders to the west bank campus would be installed.

Coal and Ash Handling Would Be Modified

The coal unloading and storage facilities at the Main Heating Plant would be modified. Coal would be stored in the same area near the Main Plant, but in an enclosed structure, coal would be transported to the Southeast Heating Plant on a new conveyor installed in the existing tunnel similar to conveyor option in University contract.

The practice of temporarily storing ash on-site would be discontinued. The ash would be cooled in ash silos and then transported by truck directly to a local ash repository.

No. 6 Oil Storage Would Be Provided

350,000 gallons of new No. 6 oil storage capacity, sufficient for seven days' capacity at the full No. 6 oil-firing rate, would be added on site, either near the existing Main Plant, or near the Southeast Plant. An oil pipeline would be installed between as required.

Existing No. 2 Oil Storage Would Be Used

The two existing No. 2 oil storage tanks (500,000 gallons and 250,000 gallons) would store fuel oil for the combustion turbines and heat recovery boilers. An oil pipeline would be installed between the two plants.

Southeast Heating Plant Would Be Modified

The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. The combustion turbines, waste heat boilers and conventional boilers would be installed within the Southeast Heating Plant. The exterior of the building would remain unchanged.

At Economic Fuel Dispatch, Base-Load Gas/Oil Cogeneration first, then supplemental gas/oil firing and existing coal boilers

At economic dispatch, the boilers would be used to meet steam requirements in the following order

- waste-heat boiler using combustion turbine exhaust, first
- supplemental gas/oil firing of waste heat boiler , second
- existing coal-fired boilers No. 3 and No. 4, third
- conventional natural gas, fuel oil boiler, last

Fuel Mix Would Be 62% Natural Gas 32% Coal 6% Fuel Oil

The fuel mix for Alternative No. 3 in FY 1999, the first full year the renovated plant would be operated, is projected to be 62% natural gas, 32% coal and 6% fuel oil. Prior to renovation, the fuel mix for each of the alternatives is projected to be 98% coal. After renovation, the fuel consumed would vary with the steam produced, but the fuel mix is projected to remain stable.

Chapter 3.3. Alternative No. 4 Southeast Plant without Coal with Natural Gas

Under Alternative No. 4, the Southeast Heating Plant would be modified, and the Main Heating Plant would be retired. Electricity would be produced by combustion turbines, and steam would be produced by waste heat boilers and by new packaged natural gas and No. 6 fuel oil boilers. The existing coal boilers at the Southeast Heating Plant would be retired. This description of Alternative No. 4 includes the following components.

- 22.5 mW Combustion Turbines Installed
- Steam Produced at Southeast Heating Plant
- Coal Storage and Handling Would Stop
- No. 6 Oil Storage and Handling Would Be Provided
- Existing No. 2 Oil Storage and Handling Would Be Used
- Southeast Heating Plant Would Be Modified
- Fuel Mix Identified

Steam Produced at Southeast Heating Plant

Under Alternative No. 4, 815,000 lb/hr of steam capacity would be added at the Southeast Heating Plant. The new capacity would be from waste heat boilers with supplementary firing (275,000 lb/hr) and from conventional boilers (540,000 lb/hr). The firm capacity (the capacity with the largest unit on standby) would be 635,000 lb/hr.

The new combustion equipment would exhaust flue gasses through the existing stacks.

22.5 mW Combustion Turbines Installed

22.5 mW of combustion turbines, powered by natural gas and No. 2 fuel oil, would be installed to produce electricity. The 22.5 mW total capacity would be provided by five nominal 4.5 mW units. The combustion turbines would be base loaded and would be operated 95% of the hours in a year.

Waste heat from the combustion turbines would be used to produce up to 110,000 lb/hr of steam in the waste heat boiler. Electricity production would be about 187,245 mW-hours annually.

Coal Storage and Handling Would Stop

The existing coal unloading and storage facilities at both the Southeast Heating Plant and the Main Heating Plant would be decommissioned.

No. 6 Oil Storage Would Be Provided

760,000 gallons of new No. 6 oil storage capacity, sufficient for seven days' capacity at the full No. 6 oil-firing rate, would be added either in or near the existing Southeast Plant coal bunker, or possibly near the Main Heating Plant. An oil pipeline would be installed as necessary.

Existing No. 2 Oil Storage Would Be Used

The two existing No. 2 oil storage tanks (500,000 gallons and 250,000 gallons) would store fuel oil for the combustion turbines and heat recovery boilers. An oil pipeline would be installed between the two plants.

Southeast Heating Plant Would Be Modified

The interior of the existing Southeast Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. The combustion turbines, waste heat boilers and conventional boilers would be installed within the Southeast Heating Plant.

Economic Dispatch is Base-Load Gas/Oil Cogeneration, followed gas/oil firing.

At economic dispatch, the boilers would be used to meet steam requirements in the following order

- waste-heat boiler using combustion turbine exhaust, first
- supplemental gas/oil firing of waste heat boiler, second
- medium pressure conventional gas/oil boilers, last

Fuel Mix Would Be 92% Natural Gas 8% Fuel Oil

The fuel mix for Alternative No. 4 in FY 1999, the first full year the renovated plant would be operated, is projected to be 92% natural gas and 8% fuel oil. Prior to renovation, the fuel mix for each of the alternatives is projected to be 98% coal. After renovation, the fuel consumed would vary with the steam produced, but the fuel mix is projected to remain stable over the 25-year projections.

Section 3.4. Alternative No. 6 New Plant at Alternate Location with Coal

Under Alternative No. 6, a new plant would be constructed with an equipment configuration similar to Case A, but at an off-river site. Both the Southeast Heating Plant and the Main Heating Plant would be retired. Electricity would be produced by a noncondensing steam turbine. Steam would be produced by a circulating fluidized bed boiler and by packaged natural gas and No. 6 fuel oil boilers. This description of Alternative No. 6 includes the following components.

- 17 mW Steam Turbine Installed
- Steam Produced at Southeast Heating Plant
- 12,000 Tons of Coal Storage Would Be Provided
- 890,000 Gallons of No. 6 Fuel Oil Storage Would Be Installed
- New Building Would Be Built

17 mW Steam Turbine Installed

A nominal 17 mW noncondensing steam turbine would be installed to produce electricity. Electricity would be generated in proportion to the Minneapolis campus steam load. Electricity production is predicted to be about 60,000 mW-hours annually, but would increase as steam use increased in the future.

A New Building Would Be Built at Off-River Site

Under Alternative No. 6, 840,000 lb/hr of steam capacity would be installed at a new building at an off-river site.. The capacity would be from a circulating fluidized bed boiler (210,000 lb/hr) and from conventional boilers (630,000 lb/hr). The firm capacity (the capacity with the largest unit on standby) would be 630,000 lb/hr.

A multi-flue chimney would be constructed.

12,000 Tons of Coal Storage Would Be Provided

Coal would be delivered by rail, and 12,000 tons of coal storage would be provided in an enclosed dome-shaped coal storage and reclaim system. This would provide capacity to accept a unit train delivery plus seven days' capacity at the maximum coal-firing rate.

890,000 Gallons of No. 6 Fuel Oil Storage Would Be Provided

890,000 gallons of No. 6 fuel oil storage capacity, sufficient for seven days' capacity at the full No. 6 oil-firing rate, would be installed for the conventional boilers. The equipment and coal unloading and storage would be entirely enclosed.

Economic Dispatch uses CFB first to meet baseload steam demand–up to 200,000 lb/hr; followed by gas/oil boilers as needed.

At economic dispatch, the new boiler configuration would generally be used to meet steam requirements in the following order:

- circulating fluidized bed, first
- medium pressure gas/oil boilers, second

Fuel Mix Would Be 76% Coal 22% Natural Gas 2% Fuel Oil

The fuel mix for Alternative No. 6 in FY 1999, the first full year the renovated plant would be operated, is projected to be 76% coal, 22% natural gas, and 2% fuel oil. Prior to renovation fuel mix for each of the alternatives is projected to be 98% coal. After renovation, the fuel consumed would vary with the amount of steam produced, while the fuel mix is projected to remain stable.

Section 3.5. Alternative No. 7 New Plant at Alternate Location without Coal

Under Alternative No. 7, a new plant would be constructed, and both the Southeast Heating Plant and the Main Heating Plant would be retired. Electricity would be produced by combustion turbines and steam would be produced by waste heat boilers and by new packaged natural gas and No. 6 fuel oil boilers. This description of Alternative No. 7 includes the following components.

- 22.5 mW Combustion Turbines Installed
- Steam Produced at New Plant
- 760,000 Gallons of No. 6 Fuel Oil Storage Would Be Installed
- 580,000 Gallons of No. 2 fuel Oil Storage Would Be Installed
- New Building Would Be Built
- Fuel Mix Identified

22.5 mW Combustion Turbines Installed

22.5 mW of combustion turbines, powered by natural gas and No. 2 fuel oil, would be installed to produce electricity. The 22.5 mW total capacity would be provided by five nominal 4.5 mW units. The combustion turbines would be base loaded and would be operated 95% of the hours in a year.

Waste heat from the combustion turbines would be used to produce up to 110,000 lb/hr of steam in the waste heat boiler. Electricity production would be about 187, 245 mW-hours annually.

Steam Produced at New Plant

Under Alternative No. 7, 815,000 lb/hr of steam capacity would be installed. The new capacity would be from waste heat boilers with supplementary firing (275,000 lb/hr) and from conventional boilers (540,000 lb/hr). The firm capacity (the capacity with the largest unit on standby) would be 635,000 lb/hr.

A new multi-flue chimney would be constructed.

760,000 Gallons of No. 6 Fuel Oil Storage Would Be Installed

760,000 gallons of No. 6 fuel oil storage capacity, sufficient for seven days' capacity at the full No. 6 oil-firing rate, would be installed for the conventional boilers.

580,000 Gallons of No. 2 Fuel Oil Storage Would Be Installed

580,000 gallons of No. 2 fuel oil storage capacity, sufficient for seven days' capacity at the full No. 2 oil-firing rate, would be installed for the combustion turbines and waste heat boilers.

New Building Would Be Built

The equipment would be installed in a new multilevel structure.

Economic Dispatch is Base-Load Gas/Oil Cogeneration, followed gas/oil firing.

At economic dispatch, the boilers would be used to meet steam requirements in the following order

- waste-heat boiler using combustion turbine exhaust, first
- supplemental gas/oil firing of waste heat boiler, second
- medium pressure gas/oil, last

Fuel Mix Would Be 92% Natural Gas 8% fuel Oil

The fuel mix for Alternative No. 7 in FY 1999, the first full year the renovated plant would be operated, is projected to be 92% natural gas and 8% fuel oil. Prior to renovation, the fuel mix for each of the alternatives is projected to be 98% coal. After renovation, the fuel consumed would vary with the steam produced, but the fuel mix is projected to remain stable over the 25-year projection period.

Section 3.6. Alternative No. 11 St. Paul Deferred Construction (No Action)

Under Alternative No. 11, the St. Paul Heating Plant would be operated in its current configuration until 2001. At that time, existing boilers 3 and 4 would be retired, and a new gas/oil fired boiler installed.

This description of Alternative No. 11 includes the following components.

- Coal Used as the Primary Fuel
- Steam Produced at St. Paul Heating Plant
- Coal Storage and Handling Would Remain
- Existing No. 2 Oil Storage Would Be Used
- St. Paul Heating Plant Would Be Expanded
- Fuel Mix Identified

Coal Would Be Used as the Primary Fuel

Under economic fuel dispatch for alternative No. 11, boilers capable of using coal would be dispatched first.

Steam Would Be Produced at the Southeast Heating Plant

Under Alternative No. 11, steam would be produced at the St. Paul Heating Plant. The existing boilers would be operated until 2001. At that time, boilers 3 and 4 (total capacity of 50,000 lb/hr) would be retired, and a new 50,000 lb/hr gas/oil fired boiler would be installed. Existing boilers 1, 2, 5, 6 and 7 (total capacity of 250,000 lb/hr) would remain in service.

The total steam capacity before boiler replacement would be 300,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 220,000 lb/hr. After boiler replacement, the total and firm capacities would remain at 300,000 lb/hr and 220,000 lb/hr respectively.

A new 120 foot steel stack would be provided for the new boiler.

Existing Coal Handling Would Remain

The existing coal unloading and storage facilities at the St. Paul Heating Plant would remain.

Existing No. 2 Oil Storage Would Be Used

The existing No. 2 oil storage facilities would be used to supply fuel oil for the new and existing boilers.

St. Paul Heating Plant Would Be Expanded

The St. Paul Heating Plant would be expanded to provide space for the new production equipment.

Fuel Mix Would Be 92 % Coal 7 % Natural Gas 1 % Fuel Oil

The fuel mix for Alternative No. 11 in FY 2002, the first year the renovated plant would be operated, is projected to be 92.6% coal, 6.8% natural gas, and 0.6% fuel oil. Prior to renovation, the fuel mix for each of the St. Paul alternatives is projected to be 93% coal. After renovation, the fuel consumed would vary with the amount of steam produced, with increasing use of natural gas.

Section 3.7. Alternative No. 13 St. Paul without Coal

Under Alternative No. 13, the St. Paul Heating Plant would be modified. Coal would no longer be used. Steam would be produced by new and existing boilers. Electricity would not be produced. Alternative No. 13 is similar to the proposed project, except for the total elimination of coal storage and use, and the installation of a smaller new gas/oil conventional boiler. This description of Alternative No. 13 includes the following components.

- Steam Would Be Produced at St. Paul Heating Plant
- Coal Storage and Handling Would Be Eliminated
- Existing No. 2 Oil Storage Would Be Used
- St. Paul Heating Plant Would Be Expanded
- Fuel Mix Identified

Steam Would Be Produced at St. Paul Heating Plant

Under Alternative No. 13, steam would be produced at the St. Paul Heating Plant. Existing boilers 1, 2, 5, 6 and 7 would remain in service, and boilers 3 and 4 would be decommissioned. The total capacity of boilers 1, 2, 5, 6 and 7 is 250,000 lb/hr.

Under Alternative No. 13, 50,000 lb/hr of steam capacity would be added at the St. Paul Heating Plant. The total steam capacity including existing boilers would be 300,000 lb/hr. The firm capacity (the capacity with the largest unit on standby) would be 220,000 lb/hr.

A new 120 foot steel stack would be provided for the boiler.

Coal Storage and Handling Would Be Eliminated

The existing coal unloading and storage facilities at the St. Paul Heating Plant would be decommissioned.

Existing No. 2 Oil Storage Would Be Used

The existing No. 2 oil storage facilities would be used to supply fuel oil for the new and existing boilers.

St. Paul Heating Plant Would Be Expanded

The St. Paul Heating Plant would be expanded to provide space for the new production equipment.

Fuel Mix Would Be 92% Natural Gas 8% Fuel Oil

The fuel mix for Alternative No. 13 in FY 1998, the first full year the renovated plant would be operated, is projected to be 92% natural gas and 8% fuel oil. Prior to renovation, the fuel mix for each of the St. Paul alternatives is projected to be 93% coal. After renovation, the fuel consumed would vary with the steam produced, while the fuel mix is projected to remain stable.

Chapter 4. Alternatives Considered but Not Analyzed in Detail

Introduction: Emerging Biomass-Fired Technologies Eliminated Becauqe of Uncertain Reliability

A number of emerging power and steam production technologies were considered as part of the screening analysis, including integrated coal gassification combined cycle (IGCC), fuel cells, and biomass gassifier combined cycle (BGCC), but none were analyzed in detail.

These technologies have potentially significant environmental benefits. For example, IGCC, like the fluidized bed system proposed by the University, produces lower sulfur dioxide and nitrogen oxide emissions than conventional coal boilers, and has potentially better solid waste handling features. And a biomass gassification plant would reduce or eliminate the negative environmental and economic impacts associated with the use of fossil fuels.

These alternatives, however, have not yet had extensive operational field testing, and the reliability and costs of both are unknown. The necessity of providing reliable thermal energy to the University at a reasonably predictable cost eliminated emerging technologies.

Biofuels Derived from Many Sources

Biofuel can be derived from any renewable organic matter capable of being converted to energy. Potential sources include agricultural crops and crop residues, urban waste wood, commercial wood and logging residues, animal wastes, and even municipal solid waste. Biofuels can be solid, liquid, or gas. In addition, some of the most promising biofuel applications involve converting solid biomass into a low-Btu gas.

Locally, biofuel energy sources are getting closer to commercial development. Recent Minnesota legislation, for example, requires NSP to develop biomass-generated electric capacity. Minnesota Power has been developing a whole-tree burning pilot project. And the University of Minnesota College of Agriculture's Center for Alternative Plant and Animal Products provides research and promotes the use of crops for energy production.

Equipment Capabilities Not a Limiting Factor

The conventional fossil-fuel equipment included in the University proposal and in EIS alternatives is generally physically capable of using some form of biofuel.

Case A, Case B, and the off-river coal-based alternative, for example, include circulating fluidized bed boilers. This type of boiler has numerous operating advantages over conventional coal boilers for burning solid fuels, including solid biofuels. Consequently, a wide range of solid biofuels would be possible under the University's proposed project if the fuels were to become economically feasible and if the necessary fuel handling and delivery systems were added. Even as currently proposed, the project could provide about 5% of the University steam load from wood chips mixed with coal. Additional modifications could increase that percentage.

Exclusively natural gas/fuel oil plants could burn gaseous or liquid biofuels. Alternatives with natural gas/fuel oil boilers, for example, could fire gas or liquid biofuels if those fuels became available in quantity at competitive prices. Combustion turbines designed for natural gas can also burn biomass derived methane, if proper fuel filtering equipment were added and other modifications were made. (See Abrahamson comment letter on DEIS.)

Obstacles Include Cost, Transportation, and Storage

Since the University is in an urban area, the long transportation distances involved would increase the cost of solid and gaseous biofuels. (See DEIS, p. 6-34.) Solid biomass fuels typically have low-heating value and would require the trucking and storing of large volumes of waste wood, crops, or other fuel. On-site gassification of methane from solid biofuels would likewise require large facilities with large storage areas. Without on-site production, large-scale use of gaseous biofuels would likely require dedicated pipelines.

Detailed engineering designs for the use of biofuels were not prepared for the EIS. The uncertain economic feasibility and potential transportation and land use impacts of large scale biofuel use make these alternatives unlikely at the University for the near future.

A brief assessment of the benefits and environmental impacts of solid and gaseous biomass fuels is provided in Chapter 6.

Each alternative is described and the reasons for not studying it in detail are provided

The remainder of this chapter describes the alternatives for which the costs and impacts were quantified in a screening analysis, but that were not addressed in detail. Each alternative is described, and the reason for not addressing it further is provided.

Detailed descriptions of each alternative, and detailed information on costs and feasibility are described in detail in a separate report, *Alternatives to the University of Minnesota's Steam Service Facilities Renovation, Screening Analysis*, March 25, 1994, by Dahlen, Berg & Company. A summary of the costs of all alternatives addressed in the screening analysis is also included in Chapter 11.

Section 4.1. Alternative No. 2 Southeast Plant Natural Gas/Oil

Conventional Natural Gas, Fuel Oil Facility at Southeast Plant Without Cogeneration

Under Alternative No. 2, the Southeast Heating Plant would be modified, and the Main Heating Plant would be retired. Steam would be produced by new packaged natural gas and No. 6 fuel oil boilers. No electricity would be cogenerated. All existing coal-fired boilers would be decommissioned. This description of Alternative No. 2 includes the following components.

- Steam Would Be Produced at the Southeast Plant
- Coal Storage and Handling Would Stop
- Existing No. 2 Oil Storage Would Be Converted to No. 6
- Gallons of No. 6 Fuel Oil Storage Would Be Added to the Main Heating Plant
- Southeast Heating Plant Would Be Modified
- Two Fuel Scenarios: 92% Natural Gas/8% Fuel Oil
- 100% Natural Gas
- Alternative Rejected Because No Cogeneration

Existing No. 2 Oil Storage Would Be Converted to No. 6

The existing No. 2 oil storage facilities would be converted to No. 6, which costs less than No. 2 fuel oil. Tanks would be insulated and oil heaters and pumps would be installed. An oil pipeline would be installed between the two plants.

Alternative Rejected Because No Cogeneration and 100% Natural Gas Version Too Expensive

The costs for Alternative No. 2 were similar to the costs for Alternative No. 4, but Alternative No. 2 did not include the potentially significant environmental and energy efficiency benefits of electricity cogeneration.

The 100% natural gas version of this alternative was not considered further because the operating costs were $100 million higher than when an alternative fuel (No. 6 fuel oil) was assumed to be available.

Section 4.2. Alternative No. 5 Southeast Plant with Large Cogeneration

Under Alternative No. 5, the Southeast Heating Plant would be modified, and the Main Heating Plant would be retired. Electricity would be produced by large combustion turbines, and steam would be produced by waste heat boilers and a conventional boiler. The two existing coal-fired boilers would be converted to burn natural gas and No. 6 fuel oil. This description of Alternative No. 5 includes the following components.

- 80 mW Combustion Turbines Installed
- Cogeneration of Steam and Electricity Would be Maximized
- Steam Would Be Produced at the Southeast Heating Plant
- Coal Storage and Handling Would Stop
- No. 2 Oil Storage Would Be Increased
- Gallons of No. 6 Oil Storage Would Be Added to the Southeast Heating Plant
- Southeast Heating Plant Would Be Modified
- Fuel Mix: 92% Natural Gas, 8% Fuel Oil
- Alternative Rejected Because of Land Use Constraints and Because it is Too Expensive for the Near Future

80 mW Combustion Turbines Installed

Eighty mW of combustion turbines, powered by natural gas and No. 2 fuel oil, would be installed to produce electricity. The 80 mW total capacity would be provided by two nominal 40 mW units. The combustion turbines would provide most of the University's electrical requirements.

Alternative Rejected Because Too Expensive

Alternative No.5 was rejected because it was too expensive to justify the incremental improvement in energy efficiency ($50 million more than other cogeneration alternatives). The avoided cost paid to the University by the utility for production beyond the University's needs was not enough to compensate for the cost of production. Potentially large space needs would have required major additions to the Southeast Plant or acquisition by the University of a large adjacent property.

Defer Construction Until Large Cogeneration Alternative Feasible

Under a modified Large Cogeneration Alternative (Alternative 5a), the major capital investment in a steam plant renovation would be deferred for three or more years—until 250 mW or more of new base-load electrical capacity is needed.

In the short term, the existing University coal plants would continue to operate, with new low-cost conventional gas/oil boilers installed if necessary to maintain steam capacity and reliability.

Instead of using a heating and cooling plant with some electricity generation, this alternative is more accurately described as a base-load electricity facility, designed to meet 100% of Minneapolis campus steam requirements. The existing Southeast and Main Heating Plants would probably have to be retired because such a large cogeneration facility would require more space than available in the existing plants.

This alternative would include the following components.

Short Term

- Conventional Gas/Oil Boiler Capacity Installed In Southeast Plant or Main Plant For Backup Reliability

Three to Eight Year Term

- 250 mW or more of Combustion Turbines Installed
- 100% of University Steam from Turbine "Waste Heat"
- Coal Storage and Handling Would Stop
- Fuel Mix: 92% Natural Gas, 8% Fuel Oil
- Construction Costs Could Approach $200,000,000
- Electricity Production Exceeds University Demand
- Capacity Payments From Utility or Retail Wheeling Necessary for Economic Feasibility
- Alternative Rejected From Detailed Study Because it is Too Vague To Quantify Size, Costs, Fuel Efficiency, and Impacts in detail. Feasibility Outside of University Control

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250 mW or More of Combustion Turbines Installed

250 mW or more of total electrical capacity could be provided by 5 or more 40 to 80 mW combustion turbines. The fuel mix would be approximately 92% natural gas/8% fuel oil. Waste heat boilers could be added to capture turbine "waste heat," which would ordinarily supply 100% of the Minneapolis campus's thermal energy needs. Some conventional boiler capacity would probably be included.

Plant Located Off-Campus, Near University

Siting such a large facility within the existing steam plants or at the alternative site indicated in the EIS would be difficult and would create land use impacts from, among other things, increased traffic, fuel oil storage, and possibly noise.

The plant would likely be located on or near University property, or near other interconnected steam loads. Possible sites include the "30-acre" site that the University is in the process of acquiring or– as a tie-in to a thermal network–a site like that suggested by MEC. (See FEIS Figures 9-1a and 9-2.) The Southeast Plant site would likely require unacceptably extensive modification and large-scale expansion to accommodate a 250 mW cogeneration plant.

Short-Term Economic Feasibility Appears Favorable

Short term economic feasibility appears favorable because low-cost coal could continue to be used as the primary fuel at the Minneapolis campus. Construction costs for back-up or supplementary gas/oil boilers would be comparatively low as well. Although the existing boilers at the Minneapolis campus are old, neither the University nor its steam vendor has provided specific information indicating that, given proper maintenance, the existing coal boilers would be unable to continue operating for the near future.

Long-Term Economic Feasibility is Uncertain

Long-term economic feasibility is uncertain. To be economically feasible, a 250 mW plant would require capacity payments from NSP to the plant operator, which could be the University, an independent power producer, or NSP itself. However, the latest NSP resource plan indicates that no baseline power will be needed until 2005, although intermediate power will be needed by 2001. The economics of an intermediate load dispatchable cogeneration plant at the University are uncertain because of the University's large steam load. (The steam needs would still have to be met, of course, even when electricity wasn't needed.)

In addition, for such a large cogeneration plant, the site, and the operator granted capacity payments from the utility would likely be determined by a competitive bidding process. In this competitive process, there would be no guarantee that the chosen facility would include the University as its steam "host."

The effect that changes in wholesale or retail wheeling or other regulatory changes would have on this alternative is beyond the scope of this study. Details of who would operate the facility and how steam revenues or costs would be shared with or charged to the University are also indeterminable at this time.

Long-Term Increase in Point Source Emissions Invites Review

Short-term land use and air emission impacts would be similar to those identified under Alt. No. 1, and some emissions and land use impacts would be mitigated to the extent that new natural gas/fuel oil boilers would be installed and used (although that would increase short-term costs).

Long-term, such a large cogeneration system, while improving overall energy efficiency in the region, would increase point source emissions of some air pollutants.

Assuming that very low sulfur fuel oil (.05%) were used as the back-up fuel, SO_2 emissions would be low. In addition, air pollution dispersion modeling completed for the DEIS indicates that short term SO_2 emissions may have to be restricted. To avoid short-term ambient air quality violations, fuel oil quantity limits would likely have to be accepted, or very low sulfur fuel oil (.05%) would have to be used exclusively as the natural gas backup fuel.

NO_X emissions would present the most likely permitting and emission problem and would require Best Available Control Technology with dry, low-NO_X combustion.

Emissions of mercury and other air toxics, with the exception of formaldehyde, would be low, even for a facility of the size indicated. Depending, however, on the location of the new cogeneration facility and other factors, emission credits from the decommissioning of the existing steam plants might not be available. This could result in a lengthy "new source review" process for all criteria pollutants, although no significant regulatory or environmental issues should arise that could not be met with operating restrictions, fuel oil limits, or other controls.

Point Source Air Emissions Could Be Offset by Regional Gains in Energy Efficiency

As with all cogeneration systems, energy efficiency increases as otherwise wasted thermal energy is used for heating and cooling. Increased energy efficiency, of course, results in a concurrent reduction in fuel consumption. Assuming that nearly all the University heating needs would be met with cogenerated steam, and that the existing steam plants would be decommissioned, this alternative could result in a net improvement in regional and local air quality.

A base-load electrical facility of such a large size, however, would not be optimized for cogeneration for the University steam load. The electricity production component would often be producing more steam than the Minneapolis campus alone would require. When the steam was not used, the facility would simply act a single cycle or combined cycle electricity plant. Optimum metro-wide energy efficiency could only be developed by interconnecting with other large local steam loads. (See Chapter 10 for the benefits of a large cogeneration thermal network.)

Alternative Rejected From Detailed Study Because Timing and Specifics Difficult to Quantify

Alternative 5a was rejected for more detailed study because, without a more specific location, size, and financing structure, it is difficult to design and assess at a conceptual level. The necessary information is not available, and predicting the likely economics of such a system would depend on a large number of speculative regulatory, financial, environmental, and technical factors.

In addition, the primary purpose of the University's project is to provide reliable heating and cooling for the University's buildings. A 250+ mW power plant is not an optimized, campus-specific cogeneration plant, but a large-scale electricity production plant that would also sell steam. The long-term economic viability of such a facility depends on factors that are outside the direct control of the University of Minnesota.

Section 4.3. Alternative No. 8 Main Plant Renovation and Expansion

Under Alternative No. 8, the Main Heating Plant would be modified to fire 100% gas/oil. The Southeast Heating Plant would be retired. Steam would be produced by existing boiler 6 and by new packaged boilers. All boilers would use natural gas and No. 6 fuel oil. No electricity would be generated. All existing coal-fired boilers in both plants would be decommissioned. This description of Alternative No. 8 includes the following components.

- Steam Would Be Produced at the Main Plant
- The existing gas/oil in the Main Plant would remain in service. All other boilers in the Main Heating Plant and the Southeast Heating Plant would be decommissioned
- Coal Storage and Handling Would Stop
- No. 6 Oil Storage and Handling Would Be Added
- Main Heating Plant Would Be Modified
- Fuel Mix: 92% Natural Gas, 8% Fuel Oil Alternative Rejected Because of Lack of Space

Main Heating Plant Modified

The interior of the existing Main Heating Plant would be demolished to provide space for the new production equipment. Existing systems would be retained where necessary or cost effective. The new boilers would be installed entirely inside the Main Heating Plant.

Alternative Rejected Because of Lack of Space

Alternative No. 8 had the lowest construction cost of any alternative considered in the screening analysis, lower even than the "Deferred Construction" alternative (Alt. 1) at the Southeast Plant because of the higher capital cost of coal boilers. It also had a reasonable 25-year net present value cost, although it is 100% natural gas and fuel oil.

Alternative No. 8, however, was not analyzed in more detail because there was no room for cogeneration equipment and no room for any necessary future expansion.

Section 4.4. Alternative No. 9 Purchase Steam from Third Parties

Under Alternative No. 9, steam would be provided from the University of Minnesota heating plants and from existing third party, off-campus vendors. This description of Alternative No. 9 includes the following components.

- Steam Would Be Transmitted from a Minneapolis Site
- Steam Would Be Transmitted from a St. Paul Site
- Fuel Mix for Generated Steam Identified
- Alternative Rejected Because Too Expensive, with High Emissions

Steam would Be Transmitted from a Minneapolis Site

Under Alternative No. 9, steam would be produced at both Minneapolis heating plants. The existing heating plants would be operated in their current configuration. Minimal capital improvements would be made.

Steam also would be produced at Minneapolis heating plants such as Hennepin County Energy Center or Minneapolis Energy Center. 140,000 lb/hr would be available and would be transmitted to the west bank side of the Minneapolis campus through a 24-inch pipeline. Condensate would be returned through a 10-inch pipeline. Each pipeline would be direct buried and about 6,600 feet long.

The boiler capacity would be dispatched in the following order:

- Steam Line
- Southeast Heating Plant - Using coal fired boilers
- Main Heating Plant - Using coal fired boilers
- Main Heating Plant - Using gas/oil fired boilers

Steam would Be Transmitted from a St. Paul Site

Steam would be produced with the St. Paul Heating Plant operating in its current configuration. Minimal capital improvements would be made.

Steam also would be produced at a St. Paul plant such as NSP's High Bridge generating plant, probably using existing coal boilers that are not equipped for cogeneration currently. 150,000 lb/hr would be available and would be transmitted to the St. Paul system through a 24-inch pipeline. Condensate would be returned through a 10-inch pipeline. Each pipeline would be direct buried and about 8,000 feet long.

The boiler capacity would be dispatched in the following order:

- Steam Line
- St. Paul Heating Plant - Using coal fired boilers
- St. Paul Heating Plant - Using gas/oil fired boilers

Off Campus Fuel Mix Would be Mostly Coal

The most likely least-cost fuel for such a system would be coal, but the mix could include natural gas, fuel oil, and possibly municipal waste if a variety of steam sources were included in the "network."

Fuel Mix for On-Site Generated Steam Could Be: 100% Coal, 100% Natural Gas or a Combination

The least-cost fuel mix for the steam generated at the remaining campus plants under Alternative No. 9 is 100% coal in FY 1995. Then, natural gas and fuel oil would only be needed as backup for the coal boilers.

The total fuel consumed for on-campus steam production in FY 1995 is estimated to be 1,199,906 MMBtu's. The 100% use of natural gas for on-site production would decrease most air emissions and eliminate the fugitive dust and other problems associated with coal. 100% use of on-site natural gas instead of coal was projected to increase NPV cost by an additional 18 million dollars.

Alternative Rejected Because Too Expensive, with High Emissions

Alternative 9 was not addressed in detail because it was too expensive without necessarily adding any of the environmental benefits of cogeneration. Without cogeneration, this alternative had high emissions.

Implementation of Alternative 9 or a similar off-campus steam supply would reduce or eliminate on-campus impacts from coal dust, ash and associated land use problems. The steam lines could also be an important first step toward a metropolitan wide thermal network that includes the widespread use of cogeneration. Such a network could maximize electrical production "waste heat" to heat the University (see Chapter 10).

The feasible short-term, and likely long-term, version of this alternative, however, simply relocates the air emission source to one or more older, higher emitting facilities that are currently not technically compatible with cogeneration.

New Gas/Oil Plant Connected to Thermal Network; Existing Steam Plants Shut Down

Under a modification of Alternative 9 proposed by the Minneapolis Energy Center, the University would purchase 100% of its steam from facilities owned by a third party and located off-campus. The existing University steam plants on the Minneapolis and St. Paul campuses would be decommissioned. (See DEIS comment letter from Minneapolis Energy Center dated January 27, 1995 for details.) This variation of Alt. No. 9 includes the following components.

- 400,000 lb/hr. of New Gas/oil Capacity Installed North of Downtown for the University East Bank
- Steam lines connected to West Bank From Existing Gas/Oil Boilers
- Steam for St. Paul Transmitted from Highbridge Plant
- Existing Steam Plants at Both Campuses Decommissioned
- Alternative Feasible, but Rejected as Too Expensive

Steam Would Be Transmitted from Several Minneapolis Sites

Steam for the Minneapolis campus east bank would be provided by a new 400,000 lb/hr., gas/oil plant north of downtown Minneapolis. (See FEIS Figure 9-2). Steam lines would be connected across the river to the University distribution system, and interconnected with the existing downtown Minneapolis steam system.

Excess steam capacity from the Hennepin County Medical Center would be routed to the West Bank. A new gas/oil plant being completed for Fairview Riverside and Augsburg College would also be connected to the West Bank.

Steam for St. Paul Campus Transmitted from NSP Highbridge Plant

Steam for the St. Paul campus would be produced at the NSP Highbridge Plant and delivered through an extension of an existing steam line to a paper company located near Cretin Avenue and I-94. New natural gas and fuel oil capacity would be added to the Highbridge Plant as necessary to meet the St. Paul campus steam demand.

Fuel Mix Would be Mostly Natural Gas and Fuel Oil at Minneapolis; Mostly Coal in St. Paul

Fuel mixes would be:

Minneapolis: 90-92% natural gas, 8-10% fuel oil
St. Paul: 70% to 100% coal, up to 30% natural gas/fuel oil
Natural gas would be used for the St. Paul campus for peaking and backup purposes.

25-Year Present Value Cost is $436 Million

At the inclusive steam tariff rate of $8.90/MMBtu suggested by MEC, and using current University steam projections, the estimated present value cost of this alternative to the University is $436 million. This PV is about $70 million less than that projected for the similar alternative designed for the DEIS. It is also $20 million higher than the third party costs projected for Case A under the University contract, and it remains one of the most expensive alternatives evaluated.

Under this alternative, the University would lose direct control of its steam supply but would shift operational and fuel cost risks to the third party vendor. (Fuel costs are a pass through to the University under the existing Foster Wheeler contract.)

Eliminates On-Campus Land Use Impacts but Leaves Future of SE Plant Uncertain

Any problems from fugitive coal dust at the Minneapolis and St. Paul plants would be eliminated. In addition, the new site proposed by MEC near the Minneapolis campus does not adjoin any existing residential area. As under some other "off-river" alternatives, however, the historic Southeast Plant building is left to an uncertain future.

At the Minneapolis campus, the regional and point source air emissions impacts are generally favorable, with emissions levels similar to those in DEIS Alt. Nos. 2 and 8. As at the other natural gas based plants, emissions of mercury and SO_2 would be low.

At the St. Paul campus, however, regional emissions of SO_2 and NO_X would likely be substantially higher than under the on-campus natural gas/fuel oil plant case currently proposed by the University. This is because the St. Paul campus would be served mostly by existing, older coal boilers at the NSP Highbridge Plant. Nonetheless, no unsolvable permitting or toxic emission related problems would be anticipated.

No Cogeneration, but Steam Network Might Encourage Its Development

The MEC proposal does not include any cogeneration capacity, nor does it include the associated energy efficiency benefits.

The MEC proposal does, however, include the development of a steam "network" between the University, MEC, Augsburg, Fairview Riverside, and HCMC, and would connect an existing NSP plant to the St. Paul campus. This expanded, interconnected steam load could in the long term encourage geographically distributed cogeneration plants by providing a large, dispersed district energy system that could use the otherwise rejected thermal energy from new or existing electricity plants. A large, combustion turbine based cogeneration plant could, for example, replace the gas/oil boilers at the MEC site by early in the next decade—even though MEC has not suggested a cogeneration component in its proposal.

The probability of a cogeneration-based thermal network developing from this particular proposal is difficult to estimate. Debate continues, for example, over whether a hot water distribution system would be more likely than a steam system to lead to a large scale cogeneration thermal network.

Alternative Comparatively Expensive; Cogeneration Uncertain

The present value cost of this system—using the costs MEC presented in its comment letter—is estimated to be about $436 million, or $25 million higher than the cost of Case A under the Foster Wheeler contract. This alternative is outside the University's direct sphere of control and is therefore difficult to analyze in detail.

Overall predicted air emissions would be well below those from the existing steam plants, as under the proposed Case A and all the EIS alternatives, but this alternative does not include cogeneration. Consequently, even though the proposed steam "network" could encourage metro-wide cogeneration in the future, the associated energy efficiencies and regional emission reductions cannot currently be attributed to this alternative.

Section 4.5. Alternative No. 10 Interconnect Minneapolis/St. Paul Systems - New Plant

Under Alternative No. 10, one new plant would be constructed between the two campuses, and would provide steam for both. The Southeast Heating Plant, Main Heating Plant and St. Paul Heating Plant would be retired. Electricity would be produced by a noncondensing steam turbine. Steam would be produced by a circulating fluidized bed boiler and by packaged natural gas and No. 6 fuel oil boilers. The scenario would include the following components.

- Steam Turbine Installed
- Coal Storage and Handling Would Be Provided
- No. 6 Oil Storage and Handling Would Be Installed
- New Building Would Be Built
- Fuel Mix: 53% Coal, 43% Natural Gas, 4% Fuel Oil
- Alternative Rejected Because Too Expensive, Without Offsetting Environmental Benefits

Alternative Rejected Because Too Expensive

Construction costs for this alternative were the highest of any alternative reviewed in the screening analysis. Total costs for Alternative No. 10 were also approximately the same as for all-gas, oil facilities at both campuses, yet this alternative had higher emissions than natural gas facilities would have had.

Chapter 4.6. Alternative No. 12 St. Paul Plant with Cogeneration

Under Alternative No. 12, the St. Paul Heating Plant would be modified. Electricity would be produced by a new combustion turbine. Steam would be produced by a new waste heat boiler and the existing boilers. This description of Alternative No. 12 includes the following components:

- 4 mW Combustion Turbine Installed
- Steam Would Be Produced
- Existing Coal Boilers and Handling Facilities Would Be Used to Minimize Cost to the University.
- Existing No. 2 Oil Storage Would Be Used
- Plant Would Be Expanded
- Fuel Mix Identified
- Alternative Rejected Because of High Emissions

Alternative Rejected Because of High Emissions

Alternative No. 12, although it did include an economical cogeneration system, was rejected because of the high emissions and fugitive dust problems which resulted from using coal. Using coal also contradicted the University's public commitment to using all gas and oil at St. Paul.

Chapter 5. Natural Environment

This chapter describes the soils, hydrology, and important flora and fauna at the Riverfront, Alternative, and St. Paul Sites. A more detailed description of the geology and hydrology of the Minneapolis sites is available in a separate report, *Soil and Groundwater Contamination Site Assessments*, October 1994.

Soils and Geology of the River Flats Differ from Those atop the Bluff

The surface elevation of the Riverfront Site varies from approximately 725 feet above sea level along the Mississippi River to approximately 825 feet above sea level along the railroad tracks atop the river bluff.

Atop the bluff, varying depths of fill overlie approximately 20 feet of interbedded glacial till and alluvium, which in turn overlie limestone bedrock of the Platteville formation.

Along the river at the base of the bluff, the Platteville Limestone and underlying Glenwood Shale bedrock units have been eroded away by the river. Here, the uppermost bedrock unit, overlain by varying depths of till and weathered limestone, is the St. Peter Sandstone (See Figure 1).

Groundwater Flows toward the Mississippi

In the bluff areas of the Riverfront Site, the water table reportedly occurs in the surficial deposits (glacial drift and alluvium) at an elevation of approximately 800 feet or lower.

At the base of the bluff, the water table occurs in the St. Peter Sandstone bedrock or in the river bank sediments at the elevation of the Mississippi River. River elevation is approximately 750 feet upstream and 725 feet downstream of the lock and dam located at the western end of the site.

Groundwater flow at the site is locally influenced by the proximity of the Mississippi River and of the lock and dam at the site. Generally, groundwater flows southwest and discharges to the Mississippi River.

Two Separate Groundwater Systems Divided by Confining Layer

The groundwater system at the top of the bluff differs from the St. Peter Sandstone bedrock groundwater system below it. The two systems are separated by confining zones of low permeability soil (i.e., clay) or bedrock units (i.e., shale).

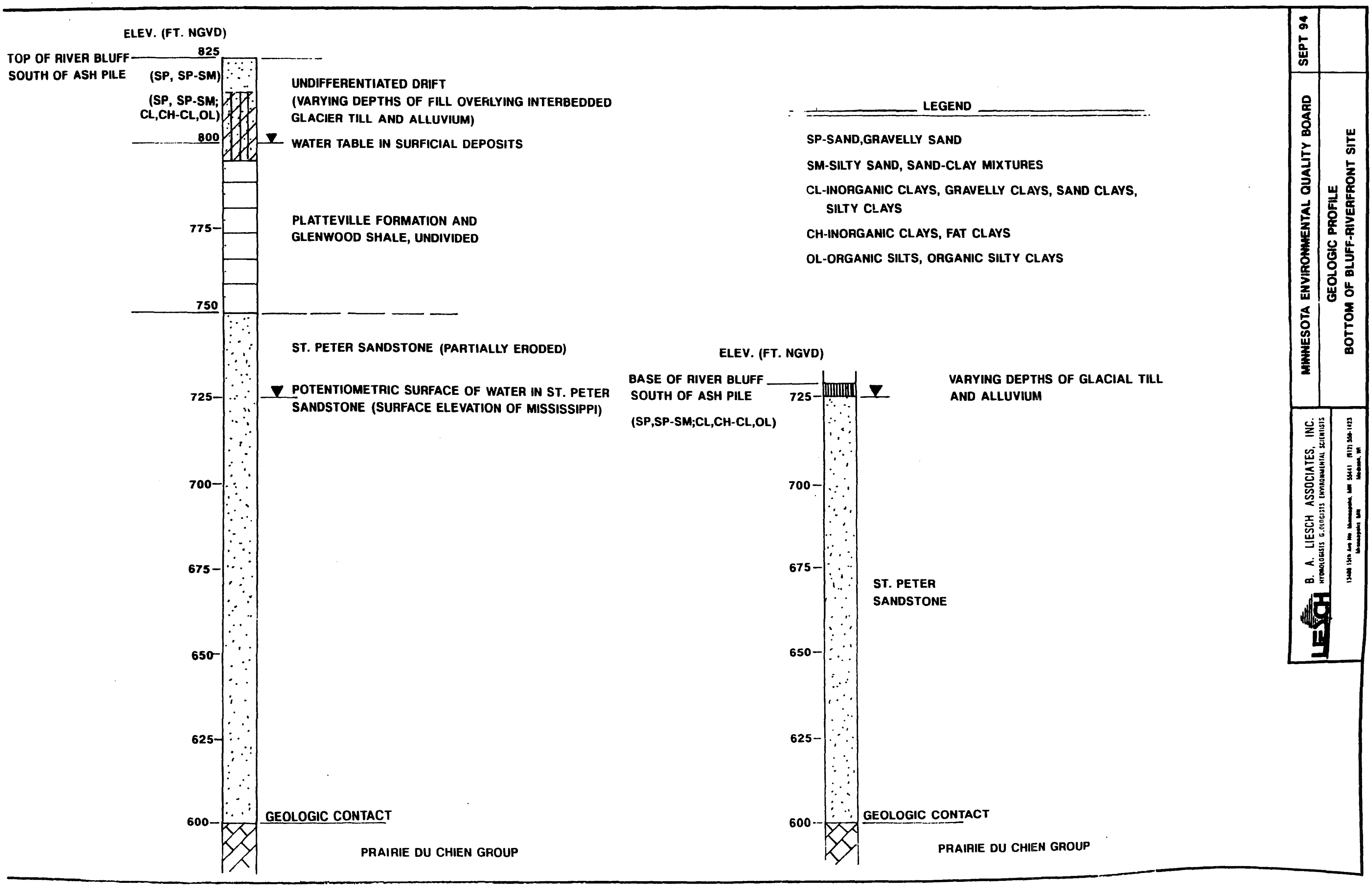

ELEV. (FT. NGVD)
825
TOP OF RIVER BLUFF SOUTH OF ASH PILE
(SP, SP-SM)
(SP, SP-SM; CL,CH-CL,OL)
UNDIFFERENTIATED DRIFT (VARYING DEPTHS OF FILL OVERLYING INTERBEDDED GLACIER TILL AND ALLUVIUM)
800
WATER TABLE IN SURFICIAL DEPOSITS
775
PLATTEVILLE FORMATION AND GLENWOOD SHALE, UNDIVIDED
750
ST. PETER SANDSTONE (PARTIALLY ERODED)
725
POTENTIOMETRIC SURFACE OF WATER IN ST. PETER SANDSTONE (SURFACE ELEVATION OF MISSISSIPPI)
700
675
650
625
600
GEOLOGIC CONTACT
PRAIRIE DU CHIEN GROUP
LEGEND
SP-SAND,GRAVELLY SAND
SM-SILTY SAND, SAND-CLAY MIXTURES
CL-INORGANIC CLAYS, GRAVELLY CLAYS, SAND CLAYS, SILTY CLAYS
CH-INORGANIC CLAYS, FAT CLAYS
OL-ORGANIC SILTS, ORGANIC SILTY CLAYS
ELEV. (FT. NGVD)
BASE OF RIVER BLUFF SOUTH OF ASH PILE
(SP,SP-SM;CL,CH-CL,OL)
725
VARYING DEPTHS OF GLACIAL TILL AND ALLUVIUM
700
675
ST. PETER SANDSTONE
650
625
600
GEOLOGIC CONTACT
PRAIRIE DU CHIEN GROUP
SEPT 94
MINNESOTA ENVIRONMENTAL QUALITY BOARD
GEOLOGIC PROFILE
BOTTOM OF BLUFF-RIVERFRONT SITE
B. A. LIESCH ASSOCIATES, INC.
HYDROLOGISTS GEOLOGISTS ENVIRONMENTAL SCIENTISTS
LIESCH

Figure 1

Groundwater in the surficial deposits at the top of the bluff eventually discharges from the bluff at the overburden/bedrock contact point and follows topography to the river as surface runoff. Surface water then either infiltrates into the river bank sediment and enters the bedrock groundwater system, or enters the Mississippi River directly.

Limited vertical recharge through the confining layers may also occur, mixing with the St. Peter water table and ultimately discharging to the Mississippi River. Limited recharge of the bedrock groundwater system by surficial runoff (or by the Mississippi during high water) probably occurs as well. Limited contamination of the bedrock aquifer by a riverfront spill or by contaminated river water is therefore possible.

Peregrine Falcons Nest within a Mile of Riverfront Site

The Department of Natural Resources (DNR) records one endangered, threatened or special concern bird species with a mile of the Riverfront Site (Peregrine falcons, Endangered) and one species of bat (Eastern Pipistrelle Bats, Special Concern). The peregrines nest on the Multifoods Tower in Downtown Minneapolis, and the bats hibernate in the Heinrich Brewery Cave downstream from the Washington Avenue Bridge.

An insect, the American Burying Beetle (Federal Endangered), has also been recorded within a mile of the site, but the records are old. In the University's 1976 Planning Base Inventory, wildlife in and near the area is noted to be song birds, gray squirrels, rabbits, and rodents.

Groundcover and Vegetation Described

The DNR records two plant species within a mile of the site: Dragon's Mouth (Special Concern) and Valerian (Threatened). DNR staff indicated to the University that these plants probably no longer occur in the area.

The general groundcover is described in the Minneapolis Critical Area Plan as natural succession woodland. The vegetation is mostly opportunistic pioneer woody trees and shrubs and herbaceous plants. Boxelder, Cottonwood, Elm, Sumac, Elder, and Riverbank Grapevine and Cocklebur are common.

Minneapolis Alternative Site Characterized

The alternative site, comprising approximately 23.8 acres of land between 17th Avenue SE on the west, 25th Avenue SE on the east, 4th Street SE on the south and the Burlington Northern railroad right of way to the north, is currently undeveloped and is overgrown with weeds. (For surrounding land use and a map of the area, see Chapter 9)

The ground surface elevation of the alternative site is approximately 840 feet, sloping gradually to the southwest. At the Site, one to five feet of till overlie approximately 40 feet of Mississippi River Terrace Deposits (sand, gravely sand, and silty sand) and glacial till, which in turn overlie the Platteville Formation, the uppermost bedrock unit beneath the site.

Bedrock occurs at an elevation of approximately 800 feet. Past investigations completed at the Alternative Site have encountered the water table at 13 to 19 feet in the Terrace Deposits. Groundwater generally flows southwest toward the Mississippi River.

St. Paul Site Characterized

The ground surface elevation of the St. Paul site is about 900 feet. The site is estimated, consistent with an urban campus site, to be approximately 75% impervious surface. Soil cover consists of up to 15 feet of silty-sand and clayey-sand fill over a layer of clay topsoil. These upper layers cover various depths of sandy and silty gravel alluvium. The water table varies from 16 to 20 feet below the surface.

Chapter 6. Air Quality Impacts

This Chapter Addresses Both Criteria and Non-Criteria Pollutants

This chapter addresses the emission rates and impacts of both criteria and non-criteria pollutants for the University of Minnesota's proposed project and alternatives.

Criteria pollutants are those for which federal ambient air standards have been established and for which a wide variety of regulatory schemes have been in place for over 20 years. Emission rates and control efficiencies for these pollutants are well documented.

Non-criteria hazardous air pollutants—or "air toxics"—are pollutants for which ambient air standards have not yet been established, but which are coming increasingly under regulatory scrutiny because of their potential for adverse effects at relatively low concentrations. Emission rates for air toxics are less well understood than for criteria pollutants, particularly for fossil-fuel fired plants.

Emissions of Five Regulated Pollutants and Twenty Air Toxics Estimated

Emissions were estimated for the following regulated criteria pollutants.

- Sulfur Dioxide (SO_2)
- Carbon Monoxide (CO)
- Particulate Matter Smaller than 10 Microns Diameter (PM_{10})
- Nitrogen Oxides (NO_X)
- Volatile Organic Compounds (VOC)

Emissions were also estimated for twenty air toxics for which reliable information could be found (emission factors for some air toxics could be found only for general categories).

SO_2 and NO_X Are Important Pollution Indicators

Criteria pollutants that do not exceed national air quality standards are classified by regulatory agencies to be "in attainment." Pollutants that exceed allowable standards are "non-attainment."

Seven counties (Hennepin, Ramsey, Washington, Anoka, Carver, Scott, and Dakota) are nonattainment for SO_2. Hennepin, Ramsey, Washington, and Anoka and portions of Carver, Scott, Dakota, and Wright are also nonattainment for CO.

A portion of Ramsey county is a nonattainment area for PM_{10}. The metropolitan area is an attainment area for NO_X and VOC.

SO_2 is currently not only a local non-attainment pollutant, but is also the primary precursor of acid precipitation. NO_X, while currently in attainment, contributes to ozone formation, a pollutant of increasing concern in the Twin Cities, and also contributes to acid precipitation.

"Potential" Emissions and "Predicted" Emissions Both Estimated

Because final permit conditions would be difficult to predict for the proposal and each of the alternatives, two methods were used to estimate annual air pollutant emission rates.

The two methods are referred to in this report as "predicted" and "potential" emissions.

Predicted emissions are those that would result from operating plant equipment to meet projected steam load, using the least-cost fuel first (economic boiler dispatch). These emissions are a best-estimate of the actual emissions that would result from facility operation.

Potential emissions are the maximum that would result from operating plant equipment all year long at rated capacity, using the highest emitting fuel. This scenario represents a "worst case"—the equipment's maximum potential to emit—not actual emissions.

Modeling of Short-term Ambient Concentrations Based on Potential Emission Rates Only

Annual average fuel estimates cannot be used to model maximum short term ambient air concentrations (24-hour, 3-hour, and 1-hour) because the short-term fuel mix varies greatly throughout the year.

Natural gas based alternatives, for example, use natural gas exclusively -- except during natural gas curtailment -- which occurs only on the coldest winter days. When natural gas is unavailable, 100% fuel oil firing at close to maximum capacity could occur. (One very cold week can account for most of the 8% annual fuel oil fraction). Therefore, only "potential" emissions were used to model maximum short term ambient concentrations.

Eventual Permit Limits Likely to Be Closer to Predicted Emissions Than Potential Emissions

Potential emissions for all alternatives are substantially higher than predicted emissions, but the difference is particularly large for gas/oil alternatives. For example, potential SO_2 emissions from gas/oil boilers are calculated by assuming 100% fuel oil firing, while predicted emissions are based on a 92% natural gas, 8% fuel oil mixture. Potential emissions, therefore, are high from gas/oil facilities not only because actual steam use is usually much less than total boiler capacity, but because fuel oil has a much higher emission factor than natural gas for most pollutants.

The current University air quality permit application to the MPCA requests annual emission limits for most criteria pollutants that are similar to or slightly higher than existing emissions. The requested permit limits for SO_2, NO_X, CO, and VOC—likely to be similar under any alternative—are based largely on restricting future emissions to levels at or near current rates, thereby ensuring no "net" reduction in air quality. (The exception is particulate emissions, which will require new source review.)

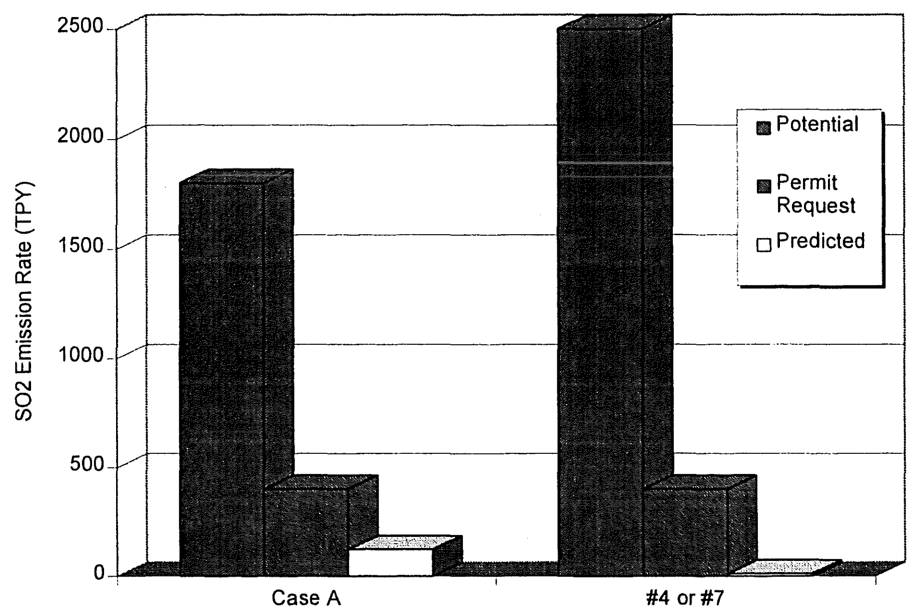
This approach is designed to avoid complicated and restrictive "new source review" regulatory requirements while still allowing maximum operational flexibility. Actual emissions following renovation will likely be significantly lower than existing emissions.

Short-term permit limits for some pollutants, and other restrictions, however, would vary between alternatives depending on the results of the detailed modeling analysis.

The permit application submitted to the MPCA is considered public information.

To illustrate the differences between the various methods of quantifying annual emission rates, Figure 6-1 shows "potential", and "predicted" SO_2 emissions for Case A and Alt. No. 4 or No. 7 for the Minneapolis campus only, compared to currently requested permit limits.

Figure 6-1. Comparison of Minneapolis campus "potential" and "predicted" SO_2 emissions: Case A and Alt. No. 4 or 7 (natural gas, fuel oil cogeneration)
Tons per Year



Predicted Emissions of Selected Pollutants Adjusted for Cogeneration Efficiency Benefits

Cogeneration of electricity and steam increases point source air emissions but reduces regional air emissions. For example, a base-load cogeneration facility at the University would, at least in the short-term, reduce base-load electricity demand at utility plants, resulting in offsetting emission reductions. Precise calculations of where or when this emission reduction occurs, however, are not possible. This chapter provides one method for quantifying the benefits of electricity cogeneration for SO_2, CO_2 and Hg.

Remainder of This Chapter in Six Sections

6.1 Major Emission Factor Assumptions
6.2 Predicted Emission Rates
6.3 Potential Emission Rates
6.4 Ambient Air Quality Modeling Results
6.5 Noise
6.6 Fugitive Dust Impact
6.7 Air Quality Regulations

Section 6.1 Major Emission Factor Assumptions

Emission Rates Depend on More Than Five Different Variables

Emission rates are calculated by multiplying the emission factors (with applicable removal efficiency) by the MMBtu heat input. Thus, emission rates depend on a number of variables, including boiler technology, fuel use assumptions, pollution control technology, emission factors, and total fuel consumption (cogeneration requires additional fuel).

The predicted emissions assume that cogeneration of electricity would be maximized (within the constraints of equipment configuration and campus load) and that lowest variable cost equipment would be operated first.

The exception is the University's proposed project (Case A) at St. Paul, where the estimates assume that no coal would be burned. The University stated that the intended mix of fuels would be about 90% natural gas and 10% fuel oil. A 91.7% natural gas, 8.3% fuel oil mix was assumed for Case A and the St. Paul alternatives.

The technological and fuel use assumptions are described in Chapters 2 through 4. Pollution control and emission factor assumptions are described below.

Criteria Pollutant Assumptions

The technologies and control efficiencies of each type of boiler for criteria pollutants are provided in Table 1 below. Control efficiencies are shown as percentages. Natural gas/fuel oil boilers and turbine emissions are uncontrolled, except for boilers firing No. 6 fuel oil, which include wet scrubbers for SO_2 control. Specific removal efficiencies are indicated where applicable.

Table 1. Summary of Major Emission Control Assumptions (Base Case)

	Particulates	SO_2	NOx	Mercury
Case A	99.25% for baghouses on CFB and Coal None for Gas/Oil	92% Limestone Injection in CFB 84.5% for Existing SE Scrubbers	CFB Low Temp; Low NOx burners for gas/oil boilers	Uncontrolled, .06 ppm Hg in Coal
Case B	Same as Case A	Same as Case A	Same as Case A, with Steam Injection for CT	Uncontrolled, .06 ppm Hg in Coal
Alt. 1	96 % for SE baghouses 99.2 & 99.4 at Main Plant	84.5% for Existing SE Scrubbers	Uncontrolled	Uncontrolled
Alt. 3	99.25% for Baghouses None on Gas/Oil Combustion Turbine	84.5% for Existing Coal Scrubbers at Southeast; New Scrubbers for #6 Fuel Oil	Low NOx burners with flue gas recirculation for pkge. boilers. Water Injection for Turbines	Uncontrolled .06 ppm Coal
Alt. 4	Uncontrolled	90% Scrubbers for #6 Fuel Oil Use Primarily Natural Gas 0.05% #2 Oil in Turbines	Same as Alt. 3	Uncontrolled
Alt. 6	99.25% for baghouse on CFB	92% Limestone Injection in CFB Scrubbers for #6 Fuel Oil	Same as Case A	Uncontrolled .06 ppm Hg in Coal
Alt. 7	Uncontrolled	Same as Alt. 4	Same as Alt. 3	Uncontrolled
Case A St. Paul	Baghouse as needed	None	Low NOx burners for gas/oil boilers	Uncontrolled
Alt. 13 St. Paul	Uncontrolled	None	Low NOx burners w/ FGR	Uncontrolled

Three Scenarios Used to Predict Criteria Pollutant Air Emissions

Predicting actual future emissions requires assumptions on future fuel mix. Case A, for example, can use a wide variety of solid, liquid, and gaseous fuels. Predicted emissions can vary widely depending on the assumed fuel mix.

Therefore, predicted emission rates of criteria pollutants are provided for the proposal and each alternative using three sets of fuel mix assumptions: a low sulfur scenario, the base case scenario, and a higher sulfur scenario.

The low-sulfur scenario assumes that very low sulfur fuel oil (0.05%) would be used during natural gas curtailment for all package boilers and combustion turbines. Solid fuel boilers use low sulfur subbituminous coal (0.3%). The fuel mix used for the proposed project is that suggested by the UofM/FW comments on the DEIS.

The base-case scenario uses the same fuel mix assumptions as for the financial projections, including 0.05% sulfur No. 2 fuel oil, and subbituminous coal with a sulfur content of no more 0.5%. This scenario assumes no petroleum coke in the circulating fluidized bed boilers.

The higher-sulfur scenario assumes uncontrolled 0.5% sulfur fuel oil, 0.5% sulfur subbituminous coal, and maximum use of petroleum coke in the circulating fluidized bed boilers. For this scenario, petroleum coke use is limited by the likely SO_2 permit limit.

The following subsections describe the assumptions for the EIS base case. Specific criteria emission factors used for each pollutant and technology are provided in FEIS Technical Appendix C.

Emission Rates from Circulating Fluidized Bed Boiler Discussed

The circulating fluidized bed boiler (CFB) is designed to fire a variety of fuels in addition to coal—up to 50% natural gas, for example—and up to about 15% wood chips mixed with the coal. Optional modifications allowing use of petroleum coke, or additional natural gas and wood firing are not included for Alt. No. 6 and are an additional cost option in Cases A and B.

SO_2 emissions from a CFB can be reduced by 92% or more using limestone injection. The SO_2 emission factor used for this study is .09 lb/MMBtu, based on 0.5% coal and 92% control.

Particulate emissions are assumed controlled at 99.6% efficiency with a baghouse.

NO_X emissions in CFBs are inherently lower than in conventional coal boilers because CFBs operate at a lower temperature. No additional control was assumed, although selectively non-catalytic reduction systems could be added to reduce emissions further (see Chapter 10).

SO_2 Emissions from Existing Boilers at Southeast Plant Controlled with Dry Scrubbers

Exiting coal-fired boilers Number 3 and Number 4 at the Southeast Plant remain in service under the proposal options Case A and Case B, and for Alternative 3. SO_2 emissions for these boilers are controlled by a dry scrubber system. Foster Wheeler, through recent improvements, has been able to achieve 90% SO_2 removal with the existing scrubbers, and based on the University permit application, an 84.5% removal efficiency was assumed for this report. Particulate controls consist of baghouses, assumed to operate at 99.6% control efficiency.

Emission Controls for Natural Gas/Fuel Oil Boilers Described

The package boilers, combustion turbine generator, and heat recovery steam generators in the proposed Case A and Case B are designed to fire both natural gas and Number 2 fuel oil. Sulfur control for these boilers consists of using primarily natural gas, which contains only negligible amounts of sulfur. SO_2 emissions are otherwise uncontrolled. SO_2 emissions from package boilers using 1.0% sulfur No. 6 fuel oil (alternatives only) are assumed to be controlled to 0.1 lb/MMBtu using wet scrubbers, based on 90% removal required by new source performance standards.

NOx emissions for Case A and Case B package boilers are controlled by low-NOx burners. NOx emissions for the alternatives are assumed to include flue-gas recirculation, even though that may not be strictly required under current regulations. The combustion turbines for the proposal and the alternatives are assumed to have steam or water injection for NOx control.

Particulates from package boilers and turbines are uncontrolled for criteria emissions. Because particulates condense near the stack exit as flue gas cools, uncontrolled particulate emission factors for package boilers are based on AP42 factors for both the filterable and condensable particulates.

Detailed Information on Criteria Emission Rates in Appendix

Criteria pollutant emission estimates may vary depending on the emission factor used. Criteria pollutant emission factors are derived from the following sources.

- *University of Minnesota Air Quality Permit Application to Minnesota Pollution Control Agency* (as of March 1, 1995) Foster Wheeler Twin Cities, Inc..
- *AIRS Facility Subsystem Source Classification Codes and Emission Factor Listing for Criteria Pollutants*, United States Environmental Protection Agency (AIRS).
- Environmental permits for the existing boilers.
- Vendor guarantees from Nebraska Boiler.
- UofM/FW Joint Comments on the DEIS

Air Toxic Emission Factor Assumptions

Four Main Factors Control Air Toxic Emission Rates

Four main factors largely control differences in air toxic emissions:

- Chemical nature of pollutant
- Primary fuel (natural gas or coal)
- Assumed pollution control efficiencies
- Total annual fuel consumption (cogeneration alternatives require additional fuel)

Large-Scale Federal Research on Air Toxics From Fossil Fuel Plants is Ongoing

Air toxic concentrations in power plant exhaust are low compared, for example, to emissions from some industrial facilities or incinerators. However, because of the large volume of fuel burned and exhaust emitted, total emissions can be significant.

Recent improvements in analytical techniques have called into question the accuracy of many fossil fuel power plant emission factors in standard EPA sources. Partly due to this uncertainty as to data quality, the Clean Air Act Amendments of 1990 mandated a comprehensive study of the air toxic emission rates and health risks associated with fossil fuel fired power plants.

The final EPA report is scheduled to be completed in late 1995 or early 1996. The report will be based on data collected by the EPA as well as recent information from the U.S. DOE (Clean Coal Research) and the Electric Power Research Institute (EPRI).

EPRI *Synthesis Report* Contains Recent, Accurate Information

EPRI has published a synthesis report based on its own research as well as data from recent DOE studies. (*Electric Utility Trace Substances Synthesis Report*, Electric Power Research Institute, November 1994) This information will likely require detailed review by EPA before its acceptance by regulatory agencies or use in the final EPA report to Congress.

However, the EIS assumes that the EPRI study provides the most current, accurate information available. For fuel oil and natural gas, the EPRI data in some cases is the only available information. EPRI data from the *Electric Utility* report is used for most of the air toxic emission estimates in the FEIS.

Until the final EPA report to Congress is completed and the results published, the emission rates and impacts of toxics from fossil fuel power plant emissions will be the subject of ongoing debate and research.

Results Described for Four Categories of Air Toxics

Air toxic emission estimates and assumptions are described in the EIS for each of four general categories of air toxics: 1) non-volatile metals, 2) volatile metals (mercury), 3) the acid gases chlorine (HCl) and fluorine (HFl), and 4) products of incomplete combustion.

Air toxic emission factors used for this report are provided in FEIS Appendix E.

Non-Volatile Metals Emissions Determined by Particulate Controls

In this report, the air toxic emission factors for non-volatile metals from coal firing are based on empirical relationships between trace metal emission rates and coal ash fraction, metal content, and particulate removal, with some exceptions (see EPRI *Synthesis Report*).

These empirical relationships were developed for individual toxics because each behaves somewhat differently, depending on volatility and other factors.

Emissions of metals for which empirical relationships were not developed by EPRI are assumed to be controlled at the same efficiency as particulates. Ash and metal content of the coal was provided by Foster Wheeler.

The empirical emission factors from the *Synthesis Report* are generally lower for both coal and fuel oil than the older EPA factors.

Trace Metal Emissions From Fuel Oil are Mostly Uncontrolled

Trace metal emissions are assumed uncontrolled for both No. 2 and No. 6 fuel oil, with 100% of fuel content released in the stack. However, since metal concentrations in fuel oil fluctuate widely depending on the source of the oil, the *Synthesis Report* recommends using its averaged data for assessing long-term impacts. That approach was adopted for this report. The same emission factor was used for No. 2 and No. 6 fuel oil because EPRI data form a composite average from facilities using both types of fuel oil.

The *Synthesis Report* emission factors for arsenic are significantly lower, and nickel emissions are significantly higher, than emission factors based on a University fuel oil sample.

Finally, since mercury is highly volatile, the comparatively low mercury fuel oil emissions at power plants are likely due, at least in part, to the metal's being emitted at the refinery, before reaching the power plant. This issue is addressed briefly in the discussion of fuel cycle impacts.

Air Toxic Emissions From Natural Gas Generally Assumed to be Negligible

Natural gas air toxic emission factors, based on currently available information, are mostly negligible The EPRI *Synthesis Report*, for example, indicates that concentrations in flue gas are usually below analytical detection limits and that they have consequently based their emission rates on natural gas content. EPRI emission factors are used in this report. Where emission factors are unavailable, emissions are assumed to be negligible.

EIS Uses High EPA Formaldehyde Emission Factor for CTs

EPA emission factors for formaldehyde from combustion turbines are high, and the *Synthesis Report*'s natural gas emissions data is largely based on gas-fired boilers. Since turbines may have combustion characteristics that produce higher emissions of products of incomplete combustion, the EPA factor for turbines is used.

Mercury Content in North American Natural Gas Reserves is Low

Although there are published reports of some extremely high mercury concentrations in natural gas reserves around the world, EPRI data and other published information indicates that North American mercury content is extremely low.

In addition, in places where mercury is discovered in natural gas, as in Southeast Asia and Europe, mercury is often removed because of its negative effect on various catalytic processes and its corrosive effect on aluminum equipment.

Petroleum Coke Has High Concentrations of Nickel and Vanadium

Petroleum coke, which can be efficiently burned in CFBs, is known to contain elevated levels of at least two metals: nickel and vanadium. One source listed a typical vanadium concentration as about 400 ppm, which is significantly higher than the concentration in coal. Information, however, on the concentrations of other trace metals in petroleum coke could not be found, so emissions from facilities with CFBs were not adjusted for the possibility. A fabric filter would effectively control nickel emissions, however.

Developing Empirical Relationships for Mercury Hampered by Variability of Data

As with other air toxics, mercury is difficult to measure in power plant exhaust because concentrations are so low, often near analytical detection limits. Recent data based on new analytical techniques indicate that mercury, unlike other trace metals, does not consistently condense or adsorb onto particulates at baghouse temperatures.

Existing emission controls removed mercury at some coal fired power plants referenced in the *Synthesis Report* but not at others. Similar results are reported elsewhere, including a draft EPA mercury report. This variability in the data prevented the development of empirical relationships for mercury similar to those for other trace metals.

Oxidized Mercury Easier to Control than Elemental Mercury

Various studies, including EPRI's, indicate that oxidized mercury is generally easier to control effectively than elemental mercury and that the oxidation rate is apparently related to the level of chlorine. (The subbituminous western coal used at the Minneapolis campus, however, generally has less chlorine than eastern coal.)

Mercury Emission Control Efficiencies Vary Widely

EPRI suggests that on average, particulate controls would remove about 30% of mercury emissions from a coal boiler and 45% in boilers with particulate controls and SO_2 scrubbers (which would apply to the SE plant existing boilers).

However, the emission control efficiencies underlying this 30% assumption vary widely between boiler types and coal types. Control efficiencies ranged from 0% to 60%, but many facilities with baghouse or FGD controls showed little or no mercury removal.

Mercury Emissions Directly Proportional to Amount in Fuel

Consequently, because information currently available is insufficient to predict specific mercury controls for the existing and proposed coal boilers at the University, this report assumes that the mercury in the fuel is 100% converted to flue gas and that zero percent of the emissions are removed by control equipment.

Optimizing mercury control at the low concentrations found in power plant exhaust gas is a relatively new research area. Advances could be expected in the near future.

The mercury concentrations in fuel-stock assumed for this analysis are listed in the table below.

EPRI and other recent data indicate that mercury content in coal is less than that listed by USGS. Researchers speculate that washing coal for use at the power plants reduces mercury concentrations. USGS coal samples were analyzed prior to washing for utility use. (What happens to the waste water from the coal washing process at the mines is not clear.)

Coal	0.06 ppm	MPCA Technical Work Paper on Mercury Emissions, 1992, and EPRI data. Generally lower than USGS data.
No. 2 and No. 6 Fuel Oil	0.009 ppm	Electric Utility Trace Substances Synthesis Report, EPRI, November 1994
Natural Gas	0.013 $\mu g/m^3$	Electric Utility Trace Substances Synthesis Report, EPRI, November 1994

Emissions of Acid Gases and Products of Incomplete Combustion Based on EPRI Study and Other Sources

Emission factors from the *Synthesis Report* were used for products of incomplete combustion. Dioxin/furan data varied considerably from site to site in the EPRI study, probably because measurements were near analytical detection limits. Dioxin/furan emissions and polycyclic aromatic hydrocarbon emissions (PAH) are expressed as 2,3,7,8 tetra-chloro-p-dioxin equivalents and benzo(a)pyrene equivalents, respectively.

Other emission factor assumptions, including those for acid gases, are taken from a variety of sources, listed below with the emission rate results. These sources include, among others, the EPA FIRE data base and Foster Wheeler. Specific emission factors used for air toxics are provided in spreadsheet form in Appendix E.

Section 6.2 Predicted Emission Rates

Predicted Criteria Emissions

Minneapolis Campus Predicted and Potential Emissions Are Estimated

Predicted emissions assume that plant equipment will operate to meet the estimated campus load, using the least cost fuel first. Table 2 below lists predicted annual criteria emissions in tons per year. The highest emitting alternative is indicated in bold for each pollutant.

Detailed emissions calculations are presented in Appendix A.

Table 2. Predicted Emission Rates at Minneapolis Facility (Tons Per Year)

Base Case
(.05% S fuel oil, 0.5% S coal, EIS fuel mix)

	Case A	**Case B**	**Alt 1**	**Alt 2**	**Alt 3**	**Alt 6**	**Alt 4&7**
Sulfur Dioxide (SO_2)	123	105	**606**	13	126	102	10
Carbon Monoxide (CO)	158	224	209	56	**309**	126	189
Particulate (PM_{10})	24	31	6	23	23	27	28
Nitrogen Oxides (NO_X)	341	378	**1440**	87	827	201	272
Volatile Organic Compounds (VOC)	17	**25**	5	2	18	17	17

Low Sulfur Scenario
(.05% S fuel oil, 0.3% S coal, UofM/FW fuel mix for Case A and B)

	Case A	Case B	Alt 1	Alt 2	**Alt 3**	**Alt 6**	**Alt 4&7**
SO_2	66	51	385	7	84	60	10
CO	133	215	209	56	309	137	189
PM_{10}	24	31	6	17	34	25	28
NO_X	292	336	1440	63	826	198	269
VOC	18	24	5	2	18	18	17

High Sulfur Scenario
(0.5% S fuel oil, 0.5% S coal, Petroleum Coke)

	Case A	Case B	Alt 1	Alt 2	Alt 3	Alt 6	Alt 4&7 (1)
SO_2	384	353	**607**	13	178	360	79
CO	84	194	**209**	56	309	91	189
PM_{10}	24	31	6	23	23	27	28
NO_X	307	348	1439	87	827	166	272
VOC	17	25	5	2	18	17	17

(1) High sulfur for the natural gas, fuel oil cogeneration alternatives (4 & 7) in Table 2 assumes 8.3% fuel oil use annually, based on natural gas interruption only. Larger percentage fuel oil use on an annual basis would probably be allowed under in the air permit, and is of course, possible for various financial or other reasons. SO_2 emissions from these plants is almost totally due to fuel oil. Therefore, for example, a 20% annual fraction of 0.5% sulfur fuel oil would result in point source emissions of about 200 tons of SO_2 per year.

Deferred Construction Alternative 1 has Highest Emissions of Most Criteria Pollutants

The "No Action" alternative (number 1) has the highest estimated emissions of SO_2, NOx, and particulates, although all renovation options are predicted to emit more VOCs.

Case A, Case B, and alternative 6 have lower sulfur emissions because of the effective limestone injection system used in fluidized bed boilers.

The lowest predicted SO_2 emissions, however, occur under the natural gas, fuel oil only alternatives. Based on the assumptions outlined above, SO_2 emissions from alternatives 4 and 7 would be about half those of that use coal. SO_2 emissions for Alternative 3 are also relatively low because that alternative uses natural gas, fuel oil turbines for the baseload steam demand, and emissions from the existing Southeast Plant coal boilers are effectively controlled with the already in place dry scrubbers.

Predicted annual NOx emissions are highest under alternative 3 because that alternative uses existing coal boilers instead of a lower-emission circulating fluidized bed boiler. As with the fluidized bed boilers, however, additional NOx controls could be retrofit on these boilers at additional cost (see Chapter 10).

Carbon Dioxide Emissions About 25% Less For Gas/Oil Alternatives

Global warming impacts can be compared by estimating carbon dioxide emissions. CO_2 emissions from 100% gas/oil alternatives are about 25 % less than for coal alternatives (see Table 3 below). On an equal Btu basis, coal produces roughly 70% more carbon dioxide than natural gas, but the gas/oil cogeneration alternatives use extra fuel for electricity production. However, cogeneration emissions would be offset by reductions from regional electrical utilities. (See section 11-3).

Table 3. Predicted Annual CO_2 Emissions Minneapolis Campus Alternatives

Alternative	Carbon Dioxide (TPY)
Case A	2.9E+5
Case B	3.4E+5
Alt 1	3.0E+5
Alt 2	1.8E+5
Alt 3	3.2E+5
Alt 4 & 7	2.5E+5
Alt 6	2.8E+5

Nitrous Oxide is also a Greenhouse Gas

N_2O is also a greenhouse gas produced by fossil fuel plants. N_2O is not readily broken down in the atmosphere and has a global warming impact per molecule 270 times that of CO_2. N_2O also acts as an ozone scavenger, thus contributing to stratospheric ozone depletion. Because of this ozone damaging impact, N_2O may be regulated in the future.

CFBs Produce Heightened Levels of N_2O

Conventional pulverized coal or spreader stoker coal boilers do not emit N_2O in large amounts. However, there is concern that CFB boilers, due to low operating temperatures, convert fuel-bound nitrogen into N_20 at rates up to ten times greater than those of conventional coal or natural gas boilers.

Foster Wheeler Will Apply Technology to Minimize This Effect

Recognizing this concern, Foster Wheeler engineers have developed a method for operating circulating fluidized bed boilers to minimize
N_2O emissions while maintaining their beneficial reductions of SO_2 and NOx. Foster Wheeler has indicated that this patented method of operation would be used for the proposed project. The precise extent to which this method reduces N2O emissions is not clear from the patent.

80% to 90% of Externality Costs From CO_2

Based on the interim PUC externality ranges on criteria pollutant emissions, predicted emission from the proposal and alternatives are provided below in Table 4. For the proposal and all alternatives, CO2 emissions accounted for 85% to 95% of calculated externatility costs. Although the dollar per ton range for CO2 is comparatively low, total emissions are high compared to the other pollutants.

Differences between alternatives is almost entirely accounted for by differences in CO2 emissions, which are higher for coal facilities (No Action), and for the larger cogeneration facilities, which require more fuel (Case B).

The Interim Externality Values Have Wide Ranges

Interim MN PUC Externality Value Range
(dollars per ton)

SO2	$0	$300
NOx	$69	$1,640
VOC	$1,180	$1,200
PM-10	$167	$2,380
CO2	$6	$14

Table 4. Criteria Pollutant Externatility Costs
($ Millions per Year)

Alternative	From	To
Case A	1.9	5.2
Case B	2.2	5.7
Alt 1	1.9	7.0
Alt 3	2.0	5.9
Alt 4	1.5	3.9
Alt 6	1.9	4.8

Case A, St. Paul Would Have Lower Local Emissions

In St. Paul, predicted emissions of most pollutants are the same because both alternatives are assumed to use natural gas and fuel oil exclusively (Table 5). NOx emissions are slightly higher for Case A (St. Paul option Case B is the same as under Case A), because additional controls are assumed for the new boiler under alternative 13 that were not assumed for Case A. The additional control (flue gas recirculation) could also be added to the Case A package boiler at additional cost.

Table 5. Predicted Criteria Emissions at St. Paul		
	Case A	Alt 13
Sulfur Dioxide (SO_2)	21 (2.5)[1]	21 (2.5)
Carbon Monoxide	20 (21.2)	20 (20)
Particulate (PM_{10})	2 (6.6)	2 (6.2)
Nitrogen Oxides (NO_X)	72 (77.1)	57 (61.2)
Volatile Organic Compounds (VOC)	1	1

[1]Emissions in parenthesis are revsions in FEIS technical appendices

Predicted Emissions of Selected Pollutants Adjusted For Cogeneration

Since various steam plant alternatives would produce differing amounts of cogenerated electricity, emission comparisons between alternatives are not straightforward.

On the one hand, cogeneration facilities produce more point source air emissions than similar facilities without cogeneration because extra fuel is required to make electricity. (Compare, for example, emissions from cogeneration Alts. No. 4 & No. 7 with steam-only Alt. No. 2.)

On the other hand, however, cogenerating electricity and steam is more energy efficient than producing each separately, as described in Section 10.2. As a result, cogeneration's higher point source emissions are offset by regional reductions in fuel consumption. Cogeneration can therefore be an effective "pollution prevention" strategy.

Consequently, predicted emissions of selected pollutants have been adjusted to reflect the area-wide benefits of cogeneration.

Quantifying the Environmental Benefits of Cogeneration is Complex

Quantifying the environmental benefits of cogeneration is complicated, particularly if the benefits accrue when electricity production is reduced at less efficient electric-only facilities. (When a new cogeneration facility is designed to meet new electricity demand, the thermal energy also put to useful work reduces or eliminates emissions from the otherwise necessary steam-only boilers—a more obvious benefit.)

In this case, neither the location nor timing of the reduced emissions can be precisely determined, and impacts on ambient air quality cannot be modeled. In addition, any emission reductions at the less efficient facilities cannot be enforced through regulatory rules or permit limits and are not normally recognized by regulatory agencies.

EIS Credits Reduction in NSP Emissions to Cogeneration Alternatives

The method used in this report to quantify cogeneration credits assumes that NSP would lower electricity production in its coal plants first in response to reduced demand (the coal plants are generally the more expensive base-load facilities). The reduced emissions from the NSP plants are then "credited" to the cogeneration alternative. (See DEIS Section 10.2.) This cogeneration adjustment in not a suggested regulatory tool but is provided to assist a planning or decision making process.

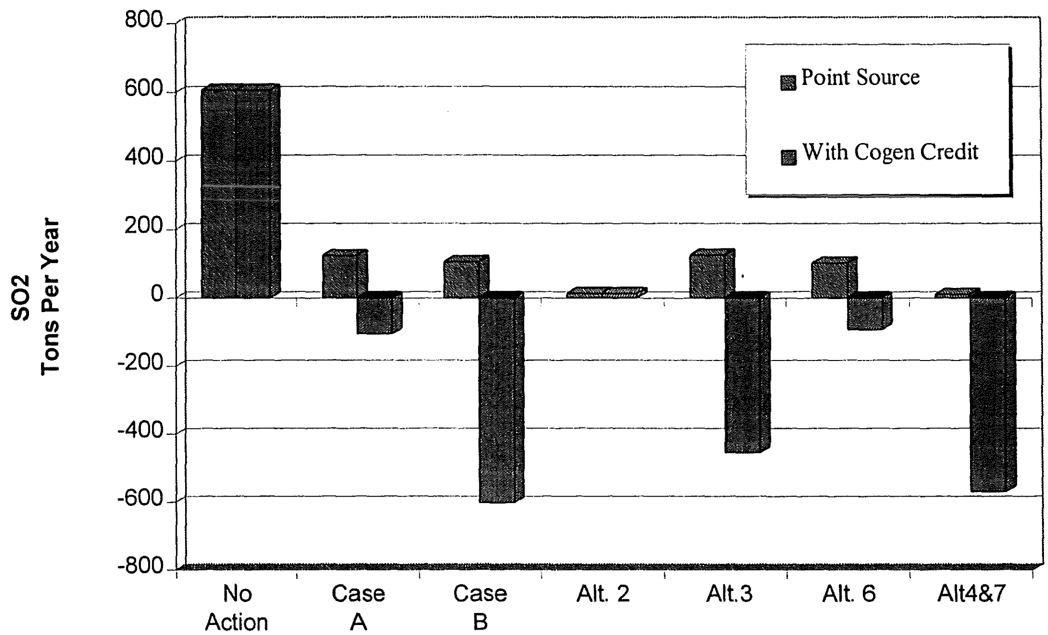
EIS Approach Logical in Intermediate Term

The EIS approach appears logical for the five to ten year period, since NSP is not currently planning on expanding its base-load capacity with new, lower emitting facilities. Nor within that time frame are any new regulatory controls likely to be installed and operational. In the longer term, this approach becomes questionable. A variety of other valid approaches are of course possible. Base Case predicted emissions adjusted for cogeneration are shown in Table 5a. The basis is described in DEIS Section 10.2 and DEIS Appendices.

Table 5a. Base-Case Predicted Emissions Adjusted for Cogeneration

	Case A	Case B	Alt 1	Alt 2	Alt 3	Alt 6	Alt's 4& 7
Sulfur Dioxide (TPY)	-105	-603	606	12	-454	-94	-570
Carbon Dioxide (TPY)	2.1E+5	8.8E+4	3.0E+5	1.8E+5	1.1E+5	2.1E+5	4.6E+4
Mercury (lb/YR)	11	-2	17	0.2	-4	10	-13

Figure 2a. Predicted Annual Emissions Rates of SO_2 , With and Without Cogeneration Adjustment (Tons Per Year)



Predicted Air Toxics Emissions

Predicted Actual Toxics Emission Rates Estimate Likely Impacts

Like SO_2, air toxic emissions not only affect local air quality, but can also affect the regional and global environment through long-range transport and deposition, and in some cases, bioaccumulation. Table 6 on the next page summarizes the predicted annual emission rates, in pounds per year, for air toxics for which reliable fossil fuel emission factors could be found or estimated.

Table 6. Predicted Annual Toxic Emissions (lb/yr)

	Case A	Case B	Alt 1	Alt 3	Alt 6	Alt 4	Alt 7	Case A St. Paul	Alt 13 St. Paul
Arsenic (1)	6	6	10	7	5	3	3	1	1
Beryllium	1	1	3	1	1	0.1	0.1	0	0
Cadmium	4	4	7	4	4	1	1	0	0
Chromium-VI	2	1	2	1	2	0	0	0	0
Chromium-tot	17	16	26	17	15	6	6	1	1
Copper	46	41	**55**	29	43	3	3	1	1
Iron	10765	9147	**12693**	6217	9679	3	3	1	1
Lead	14	13	16	11	13	4	4	1	1
Manganese	**85**	74	**103**	54	77	6	6	1	1
Mercury (2)	**16**	**14**	**19**	10	**15**	0	0	**0**	**0**
Nickel	593	644	**46**	186	661	250	250	61	62
Selenium	**33**	**28**	**38**	19	29	1	1	0	0
Vanadium	45	46	**54**	37	44	17	17	4	4
Zinc	55	51	**65**	38	51	8	8	2	2
Chlorine (3)	3798	4334	**4599**	3761	3894	2307	2307	567	575
Fluorine (3)	2189	2084	**2605**	1582	2065	468	468	115	117
Benzene (4)	10	9	**11**	8	9	3	3	1	1
2,3,7,8 Dioxin Equiv (5)	5.5E-06	7.6E-06	5.9E-06	**7.7E-06**	5.9E-06	**7.2E-06**	**7.2E-06**	1.8E-06	1.8E-06
Formaldehyde (6)	26	1718	11	2596	35	2633	2633	32	35
Benzo (a) Pyrene Eq. (7)	4.4E-03	4.3E-03	5.2E-03	3.4E-03	4.2E-03	1.3E-03	1.3E-03	3.1E-04	3.2E-04
Total (TPY) (8)	9	9	10	7	8	3	3	0	0

Table 6. Air Toxics Emission Factor Sources

(1) Non-volatile trace metals emission factors calculated from EPRI empirical relationships; metal and ash content of coal from UofM/FW permit application to MPCA. EPRI data from *Electric Utility Trace Substances Synthesis Report*, TR-104614. Vanadium, zinc, iron, and copper based on coal content and 99.25% removal as particulates

(2) Mercury assumed to be volatile; 100% conversion from fuel to flue gas, no control due to any air emission control equipment.

(3) Chlorine and Fluorine emissions based on boiler test data submitted by Foster Wheeler

(4) EPRI *Synthesis Report* data averages for coal, fuel oil, and natural gas

(5) 2,3,7,8 tetra-chloro-p-dioxin equivalents from EPRI *Synthesis Report*. No emission controls.

(6) *Electric Utility Trace Substances Synthesis Report* for coal and natural gas, fuel oil boilers, EPA FIRE database for gas/oil turbine with water injection

(7) Benzo(a)pyrene equivalents from *Synthesis Report*

(8) Total includes iron emissions, which is not on the current EPA list of Hazardous Air Pollutants

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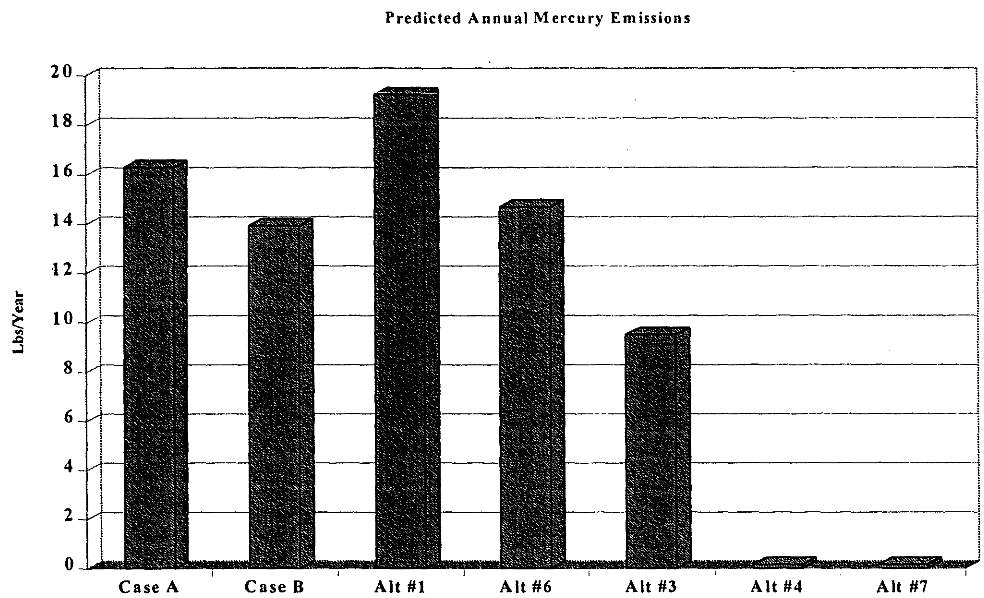
Natural Gas Has Negligible Trace Metals Content

Table 6 indicates that with the exception of two pollutants, predicted air toxic emissions are somewhat higher for coal-based facilities than for natural gas/fuel facilities. This occurs mostly because natural gas, which makes up over 90% of the fuel mix at the gas/oil facilities, contains negligible quantities of metals. The differences between alternatives, however, are mostly less than an order of magnitude because coal emissions are effectively reduced by particulate controls.

At the Minneapolis campus, the nearly all coal No Action alternative (Alt. No. 1) has the highest predicted emissions of all pollutants but dioxin and formaldehyde. Formaldehyde emissions are estimated to be highest from natural gas/fuel oil plants.

(Figure 6.2 and Figure 6.3 Were Deleted From Draft EIS)

Figure 6.4 Predicted Annual Mercury Emissions (lb/yr)



Section 6.3 Potential Emissions of Criteria and Air Toxic Pollutants

Potential Criteria Emissions

Potential Emissions at Rated Capacity are Similar for All Alternatives

Potential emissions—emissions from operating plant equipment all year long at rated capacity, using the highest emitting fuel—are shown in Table below. Potential emissions are a function of boiler type, fuel type, assumed control technology, and total installed steam capacity.

Potential emissions for most pollutants are similar for all alternatives for two primary reasons. First, the worst-case fuel for the natural gas, fuel oil boilers is fuel oil, and uncontrolled fuel oil emissions are similar to or worse than emissions from the coal boilers (depending on pollutant). Second, all the alternatives are designed to meet the University's steam demand, so all have similar installed maximum capacities.

Table 7. Potential Criteria Emission Rates (TPY)

	Case A	Case B	Alt 1	Alt 3	Alt 4	Alt 6	Alt 7
Sulfur Dioxide (SO_2)	1798	2170	1966	2005	**2462**	1855	**2462**
Carbon Monoxide (CO)	524	**882**	647	743	552	293	552
Particulate (PM_{10})	220	223	**489**	269	227	273	227
Nitrogen Oxides (NO_X)	2158	2282	**4085**	2319	1245	1245	1245
Volatile Organic Compounds (VOC)	28	**45**	20	28	24	22	26

Potential Air Toxic Emissions

Potential Emissions from Coal Higher for Mercury, Lower for Nickel

Table 8 below shows "potential" air toxic emission rates. These emissions assume maximum use of coal and fuel oil and no use of natural gas. Toxic emissions from coal and fuel oil are estimated to be similar for all but two pollutants. Coal facilities emit more mercury than fuel oil, but fuel oil facilities emit larger amounts of nickel.

Table 8. Potential Annual Air Toxic Emission Rates (lb/yr)

Constituents	Case A	Case B	Alt. 1	Alt. No. 3	Alt. No. 4	Alt. No. 6	Alt. No. 7	St. Paul Case A	Alt. No. 13
Arsenic	45	37	40	49	55	42	55	31	20
Beryllium	5	1	8	4	2	2	2	1	1
Cadmium	18	9	20	16	13	13	13	7	5
Chromium-VI	6	4	6	6	5	5	5	3	2
Chromium-tot	70	35	82	64	52	51	52	30	19
Copper	157	68	168	132	106	122	106	57	37
Iron	24310	250	34074	13911	106	11037	106	57	37
Lead	67	47	58	66	70	61	70	40	26
Manganese	260	89	304	200	130	174	130	74	47
Mercury (2)	39	40	53	24	5	20	5	3	2
Nickel	3831	4844	1599	4998	7222	4927	7222	4093	2624
Selenium	84	14	107	56	20	47	20	11	7
Vanadium	364	339	247	417	531	420	531	286	183
Zinc	256	170	227	250	266	243	266	143	92
Chlorine (3)	44673	54948	26478	52434	69208	50819	69208	39228	25145
Fluorine (3)	12259	14344	9857	12462	14042	11755	14042	7959	5102
Benzene (4)	27	28	31	19	11	17	11	6	4
2,3,7,8 Dioxin Equiv (5)	5.4E-05	6.7E-05	3.3E-05	6.3E-05	8.3E-05	6.1E-05	8.3E-05	4.7E-05	3.0E-05
Formaldehyde (6)	121	2626	65	3028	3081	144	3081	114	73
Benzo (a) Pyrene Eq. (7)	2.9E-02	3.5E-02	2.2E-02	3.2E-02	3.8E-02	3.0E-02	3.8E-02	2.2E-02	1.4E-02
Total (TPY) (8)	43	39	37	44	47	40	47	26	39

Section 6.4. Dispersion Modeling Results

Ambient Air Concentrations of SO_2, NOx, PM_{10}, and Twenty Air Toxics Modeled at Potential and Predicted Emission Rates.

Ambient concentrations of SO_2, NOx, PM_{10}, and twenty air toxics were modeled for Case A, Case B, and alternatives 3, 4, 6, 7, and 13. Stack emissions and carbon monoxide were not modeled in this analysis, although PM_{10} emissions from fugitive dust sources were modeled.

In this section, modeled annual and short-term concentrations of air toxics (based on "potential" emissions) are described first, followed by modeled annual concentrations based on the much lower (though more realistic) "predicted" emissions.

For each emission estimate, criteria modeling results are presented first, followed by air toxics modeling results.

Detailed assumptions, methodology, and results are described in a separate report, *University of Minnesota, Environmental Impact Statement, Proposed Alternatives Air Quality Analysis*, dated October 27, 1994, by Trinity Consultants.

Modeling Methodology

Ambient Air Concentrations Depend on Emissions and Dispersion

Modeled ambient air concentrations depend both on the amount of pollutant emitted and on how the pollutant is dispersed. Pollutant dispersion, in turn, depends on a number of variables, including local topography, stack height, plume rise (affected by flue gas temperature and velocity), and the effects of building "downwash," which occurs when a stack's effluent is caught in the turbulent wake of a nearby building or other structure and is pulled close to ground level, thereby increasing local ground level pollutant concentrations.

Modeling Done With EPA's ISCT2 Dispersion Model, and Five Years of Meteorological Data

Version 93109 of the ISCST2 model was used to calculate ground-level concentrations in simple terrain, since prior modeling demonstrated that ISCST2 was the dominant (conservative) dispersion model for all pollutants and all averaging periods.

Direction specific downwash parameters were calculated using U.S. EPA's BPIP downwash algorithm. Five years of surface meteorology and upper atmosphere data, from 1973 to 1977, were used to model maximum concentrations.

Averaging Periods Modeled Vary by Pollutant

The following criteria pollutants and averaging periods were modeled:

SO_2	1-hour, 3-hour, 24-hour, annual
NO_x	Annual
PM_{10}	24-hour, annual

Air Toxics Modeled by Scaling to SO_2 Emission Rate

Air toxics modeling was completed by using modeled SO_2 concentrations and "scaling" the toxic emission rate to the SO_2 emission rate. This process assumes that the dispersion characteristics of air toxics are similar to those of SO_2. This assumption is reasonable for facilities with particulate and acid gas controls such as those proposed. Air toxic concentrations could be modeled, therefore, by adjusting (or scaling) the modeled SO_2 ambient concentration by the ratio of the air toxic emission rate to that of SO_2 for each individual stack. A summary of air toxics modeling methods is provided in Appendix B.

All modeled concentrations shown represent the high modeled annual concentration and the high-second-high modeled short-term concentrations from the five-years of meteorological data used in the analysis.

Details on Methodology and Results In Separate Consultant's Report

The detailed air quality study, *University of Minnesota, Environmental Impact Statement, Proposed Alternatives Air Quality Analysis*, dated October 27, 1994, by Trinity Consultants includes details on criteria modeling assumption, a detailed explanation of air toxic modeling assumptions, and all results.

Worst-Case Criteria Concentrations

Worst-Case Annual SO_2 Concentrations are Similar for Proposal and all Alternatives.

Modeled annual average concentrations of criteria pollutants at "potential" emission rates were nearly the same for the proposal and all alternatives because potential criteria emissions are similar for all alternatives. Overall, the tall stacks at the Southeast Plant and alternatives would effectively disperse emissions, reducing local impacts. Slight differences do occur because of different dispersion characteristics.

Worst-Case modeled annual SO_2 concentrations, for example, ranged from 15 to 20 $\mu g/M^3$ for the proposal and all alternatives (the No Action alternative was not modeled).

Short-term Concentration Comparisons Significantly Different Than Annual

Short term modeling results vary between alternatives somewhat more than "worst-case" annual results because dispersion differences show up more over short-term averaging periods.

More importantly, however, short-term concentrations at potential emission rates approximate conditions that could occur during short averaging periods. Predicted annual concentrations are based on annual fuel average fuel mix. So short term maximums can be substantially different for a particular alternative, especially for 100% gas/oil facilities, for which the highest short term impacts occur during natural gas curtailment in the winter and 100% fuel oil firing. But predicted annual concentrations are calculated at the 92%/8% predicted fuel dispatch.

Table 9. Maximum Short Term Ambient Concentrations of Criteria Pollutants (µg/M3)

Pollutant	Avr. Period	Case A Mpls	Case B Mpls	Alt. #3	Alt. 4	Alt. #6	Alt. #7
PM_{10} (lb/hr)		(50)	(50)	(61)	(52)	(62)	(51)
	24-hour	22.39	20.91	21.59	24.28	18.72	24.29
SO_2 (lb/hr)		(410)	(495)	(418)	(562)	(423)	(562)
	24-hour	140.89	145	187.20	238.04	127.44	192.01
	3-hour	200.14	213	335.99	421.08	274.83	448.80
	1-hour	236.02	249	423.87	599.71	561.45	761.04

Natural Gas, Fuel Oil Alternatives Have Highest Short-Term Concentrations

100% natural gas, fuel oil alternatives have the highest short-term modeled ambient air concentrations of criteria pollutants (see Table). The highest short-term concentrations occur for alternatives 4 and 7 for a number of reasons, including higher emissions and building downwash effects. Modeled one- and three-hour SO_2 concentrations are near enough to ambient air quality standards to be of concern.

Alternatives Have Higher Short-Term Concentrations than Case A or Case B

In addition, all the EIS alternatives (3, 4, 6 and 7) have higher modeled short-term concentrations of SO_2 than Case A or Case B. This is most likely because the conventional boilers for these alternatives use Number 6 fuel oil, and are equipped with wet scrubbers for sulfur control. (Case A and Case B use low-sulfur Number 2 fuel oil, and no scrubbers.) The wet scrubbers reduce flue gas temperatures and, as a result, reduce plume rise.

Lowered Flue Gas Exit Temperatures Apparently Increase Short-Term Concentrations

Lowered flue gas exit temperatures probably increase short-term concentrations. This problem could be eliminated by reheating the flue gas after it is scrubbed in order to get proper plume rise and dispersion. Modeled short-term concentrations for all pollutants would improve for alternatives 3, 4, and 7 if this change were made.

The Highest Short-Term Concentrations Shift between Alternative 4 and 7 for Several Possible Reasons

Alternatives 4 and 7 have the highest short-term modeled concentrations. However, these alternatives as designed are exactly the same, with identical emission rates. Only the locations are different. Yet the high modeled short-term concentration shift between the two depending on averaging period. Reasons include the following.

- The polar grid modeling coordinates submitted by Foster Wheeler and used as a basis for this modeling have a higher density receptor-grid near the Southeast Plant than near the off-river Alternative 7. This increases the likelihood that a high concentration spot would be modeled for Alternative 4 in some circumstances.

- Short-term meteorological effects also increase the chance for higher modeled concentrations near the Southeast Plant because the higher receptor grid increases the chance that one receptor is affected by short-term meteorological anomalies.

- Under some circumstances, the location and height of alternative 7 at the off-river site make the plumes susceptible to building downwash, even though the stack height was increased to 200 feet from the 150 feet originally designed. Alternative 4 pollutant plumes are not downwashed.

At St. Paul Campus, Proposal Has Higher Short-Term Concentrations

At the St. Paul campus, modeled short-term concentrations are somewhat higher for the proposal than for Alternative 13 because the proposed new natural gas, fuel oil package boiler has significantly more capacity, and therefore more potential emissions, than the new boiler included in alternative 13.

Annual and 24-Hour SO2 Dispersion Modeling Pattern Mapped.

Illustrative air emission dispersion patterns are shown in the dispersion isopleth maps provided, showing annual and 24-hour concentration isopleths for Case A at the Southeast Plant and for Alternative 7 at the off-river site. Predicted concentrations are shown in the larger figure, 24-hour in the smaller. The figure demonstrates graphically how modeled concentrations drop off quickly from the high spot, which in this case occurs near the stacks, probably due to downwash effects.

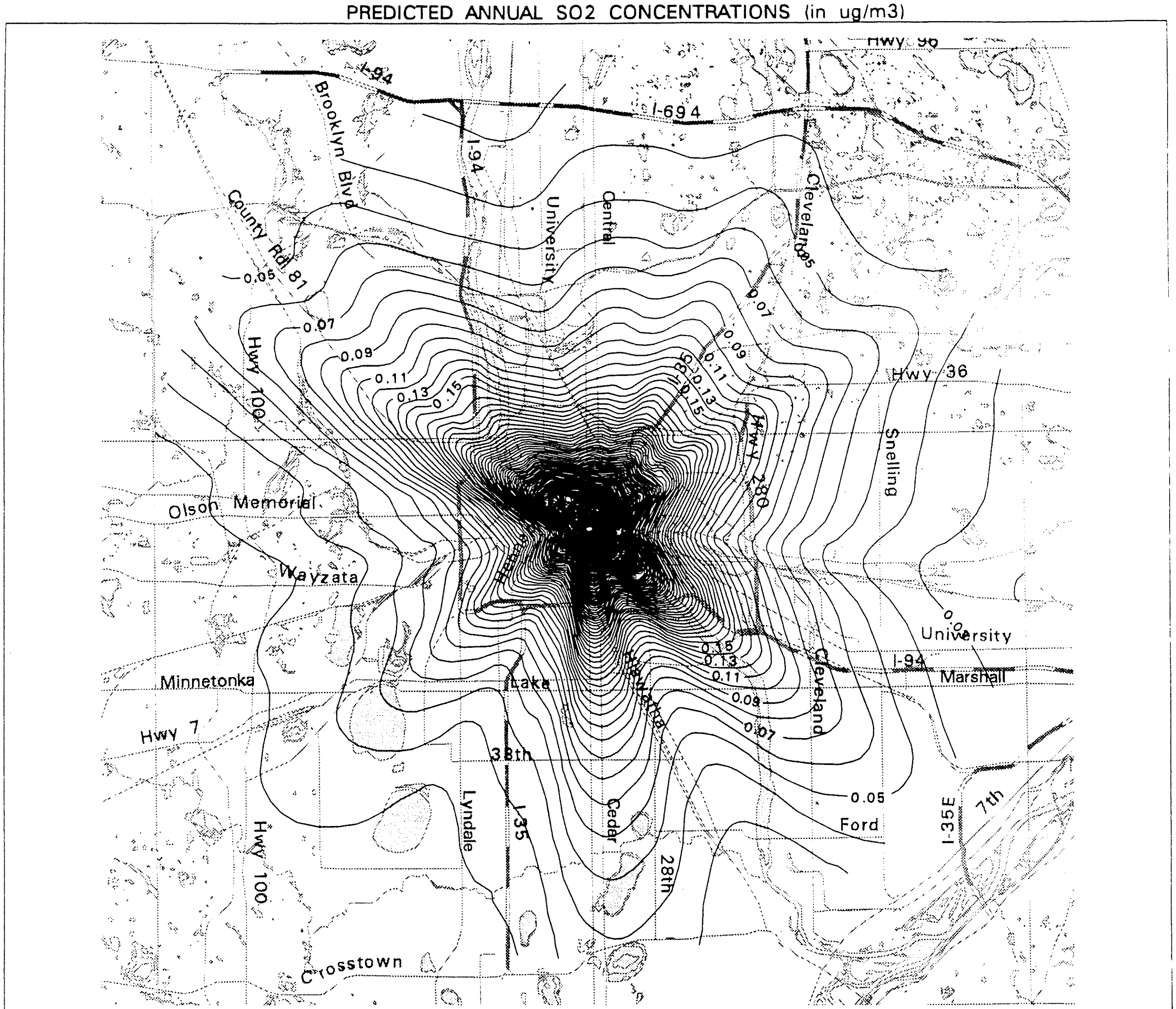
Worst Case Modeled Air Toxic Concentrations

Worst-Case Air Toxics Concentrations Similar for All Alternatives

At worst-case potential emission rates, there is little difference in modeled ambient concentrations between the proposal or any alternatives (Table 10 below). The worst-case fuel for coal boilers was assumed to be coal, and worst-case fuel for package boilers and turbines was fuel oil. For most pollutants, uncontrolled air toxic emission rates from fuel oil are similar to or only higher than emission rates from coal boilers equipped with a baghouse. Modeled concentrations for the different alternatives are within a range of plus or minus 50%, a low variability given the amount of uncertainty involved.

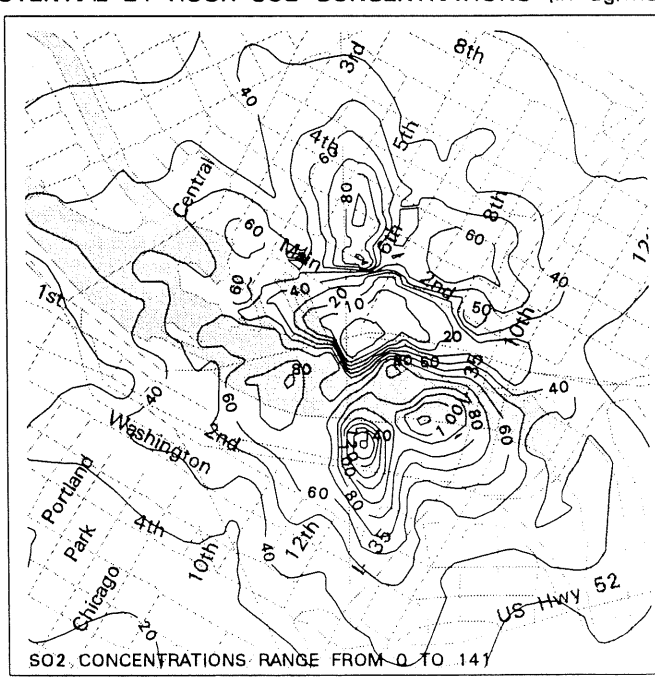
Case B does have slightly higher modeled concentrations for some pollutants because it has one of the highest total installed capacities, in part because of the cogeneration combustion turbine. Differences in dispersion characteristics are the same as that for criteria pollutants, described above.

PREDICTED ANNUAL SO_2 CONCENTRATIONS (in ug/m3)



SO2 CONCENTRATIONS RANGE FROM 0 TO 2.69

POTENTIAL 24 HOUR SO_2 CONCENTRATIONS (in ug/m3)



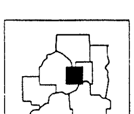
SO2 CONCENTRATIONS RANGE FROM 0 TO 141

SOUTHEAST PLANT - CASE A

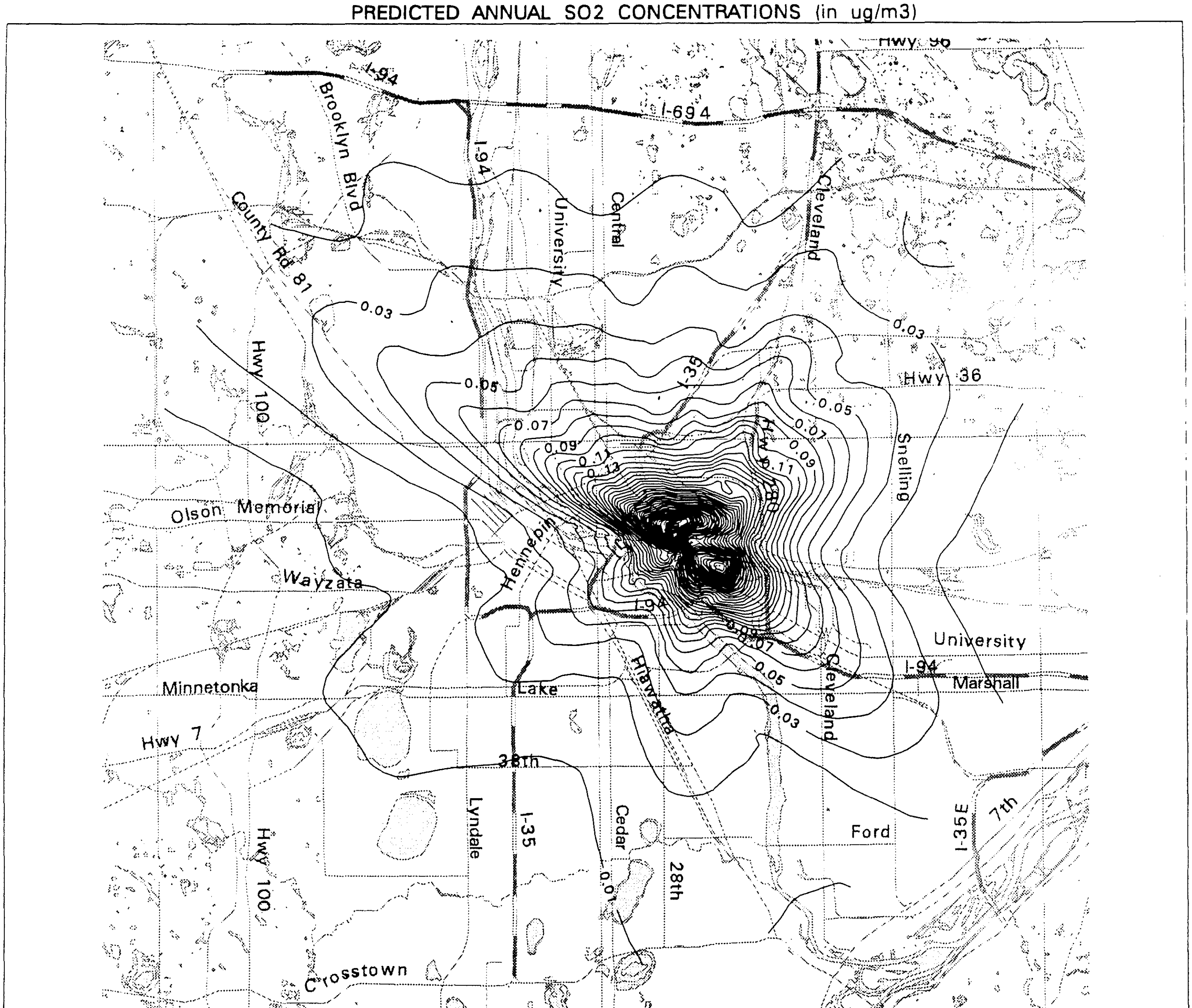
24 hour concentrations represent the worst case impact.

Analysis by Trinity Consultants, Inc., Kansas, 1994.
Further interpreted by MN Land Management Information Center.
Graphics by MN Land Management Information Center.

Map Sources:
Transportation & Hydrography from USGS Digital Line Graphs.
Shaded areas from National Wetlands Inventory, USFWS.

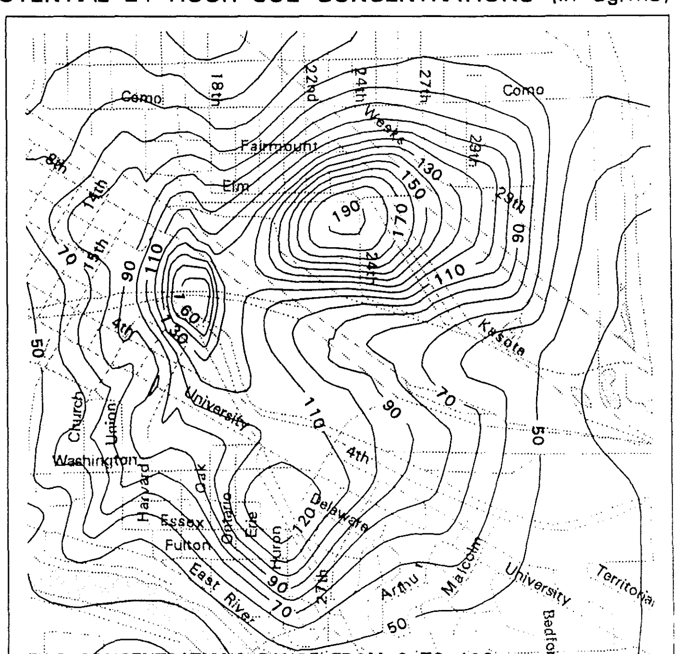


PREDICTED ANNUAL SO2 CONCENTRATIONS (in ug/m3)



SO2 CONCENTRATIONS RANGE FROM 0 TO 0.61

POTENTIAL 24 HOUR SO2 CONCENTRATIONS (in ug/m3)



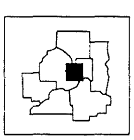
SO2 CONCENTRATIONS RANGE FROM 0 TO 192

OFF-RIVER SITE - ALTERNATIVE 7

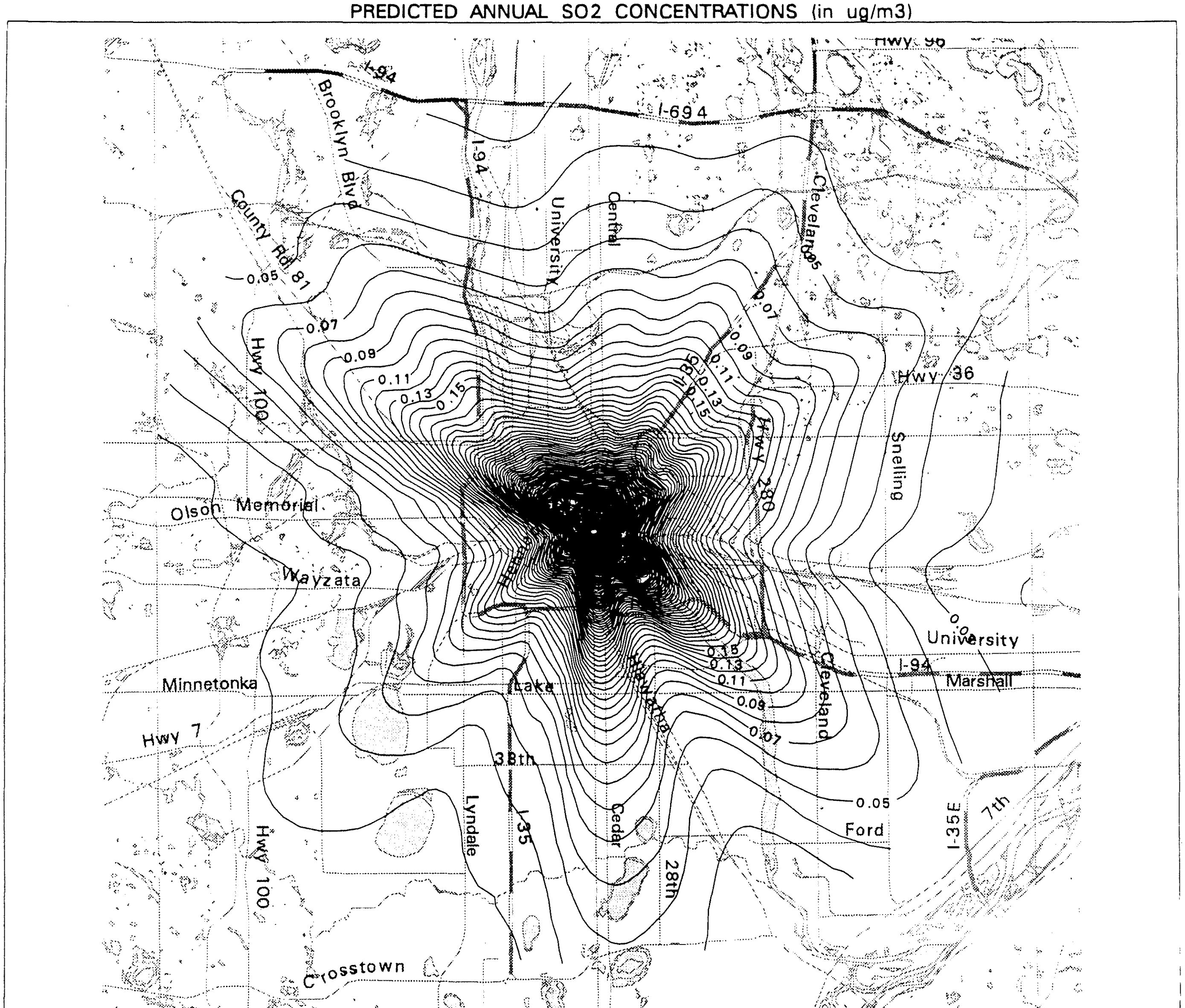
24 hour concentrations represent the worst case impact.

Analysis by Trinity Consultants, Inc., Kansas, 1994.
Further interpreted by MN Land Management Information Center.
Graphics by MN Land Management Information Center.

Map Sources:
Transportation & Hydrography from USGS Digital Line Graphs.
Shaded areas from National Wetlands Inventory, USFWS.

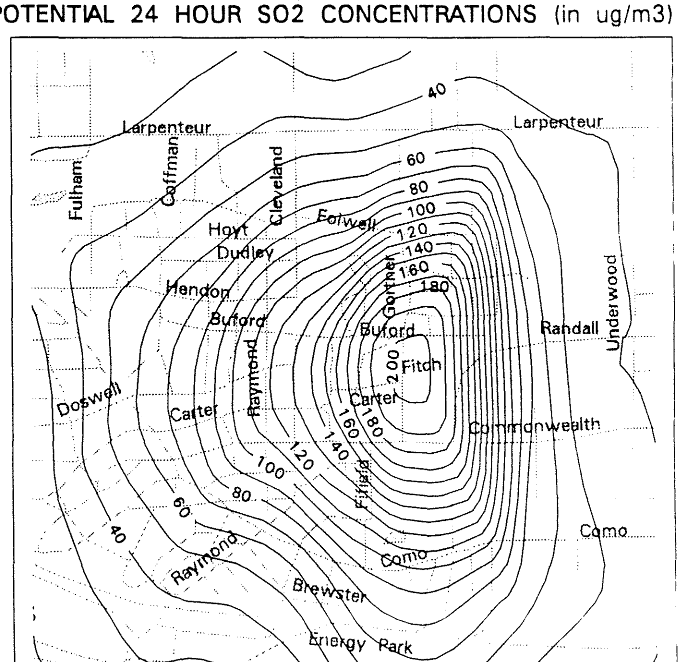


PREDICTED ANNUAL SO2 CONCENTRATIONS (in ug/m3)



SO2 CONCENTRATIONS RANGE FROM 0 TO 0.43

POTENTIAL 24 HOUR SO2 CONCENTRATIONS (in ug/m3)



SO2 CONCENTRATIONS RANGE FROM 0 TO 203

ST. PAUL PLANT

24 hour concentrations represent the worst case impact.

Analysis by Trinity Consultants, Inc., Kansas, 1994.
Further interpreted by MN Land Management Information Center.
Graphics by MN Land Management Information Center.

Map Sources:
Transportation & Hydrography from USGS Digital Line Graphs.
Shaded areas from National Wetlands Inventory, USFWS.

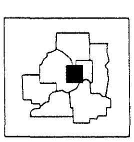


Table 10. Maximum Modeled Air Toxic Concentrations at PTE (µg/m3)

Constituents	Case A	Case B	Alt. No. 3.	Alt. No. 4.	Alt. No. 6	Alt. No. 7	Case A St. Paul	Alt. No. 13
Arsenic	2.02E-04	1.08E-04	2.55E-04	**2.94E-04**	1.66E-04	2.45E-04	2.68E-04	1.57E-04
Beryllium	2.78E-05	4.07E-06	2.01E-05	1.07E-05	7.99E-06	8.92E-06	9.76E-06	5.72E-06
Cadmium	8.97E-05	2.58E-05	7.94E-05	6.94E-05	4.51E-05	5.80E-05	6.34E-05	3.72E-05
Chromium-VI	**3.17E-05**	1.03E-05	2.86E-05	2.78E-05	1.82E-05	2.32E-05	2.54E-05	1.49E-05
Chromium-tot	**3.56E-04**	1.03E-04	3.18E-04	2.78E-04	1.79E-04	2.32E-04	2.54E-04	1.49E-04
Copper	**8.09E-04**	2.00E-04	6.51E-04	5.67E-04	4.10E-04	4.76E-04	4.90E-04	2.87E-04
Iron	**1.42E-01**	1.26E-03	5.98E-02	5.67E-04	2.36E-02	4.76E-04	4.90E-04	2.87E-04
Lead	3.15E-04	1.38E-04	3.39E-04	3.74E-04	2.26E-04	3.12E-04	3.42E-04	2.00E-04
Manganese	**1.38E-03**	2.61E-04	9.64E-04	6.94E-04	5.48E-04	5.80E-04	6.34E-04	3.72E-04
Mercury (2)	**2.24E-04**	2.24E-04	1.07E-04	2.46E-05	4.82E-05	2.05E-05	2.24E-05	1.32E-05
Nickel	1.45E-02	1.40E-02	2.73E-02	**3.84E-02**	2.04E-02	3.21E-02	3.51E-02	2.06E-02
Selenium	**4.68E-04**	4.21E-05	2.55E-04	1.07E-04	1.27E-04	8.92E-05	9.76E-05	5.72E-05
Vanadium	1.58E-03	9.82E-04	2.22E-03	**2.83E-03**	1.65E-03	2.38E-03	2.45E-03	1.44E-03
Zinc	1.22E-03	4.94E-04	**1.29E-03**	1.42E-03	8.93E-04	1.19E-03	1.23E-03	7.19E-04
Chlorine (3)	1.85E-01	1.84E-01	2.81E-01	**3.68E-01**	2.03E-01	3.08E-01	3.37E-01	1.97E-01
Fluorine (3)	5.62E-02	5.60E-02	6.49E-02	7.47E-02	4.42E-02	6.24E-02	6.83E-02	4.00E-02
Benzene (4)	**1.43E-04**	1.43E-04	9.24E-05	5.87E-05	5.09E-05	4.90E-05	5.37E-05	3.15E-05
2,3,7,8 Dioxin Equiv (5)	2.27E-10	2.25E-10	3.40E-10	**4.43E-10**	2.44E-10	3.70E-10	4.05E-10	2.37E-10
Formaldehyde (6)	4.88E-04	7.64E-03	**1.53E-02**	**1.56E-02**	5.79E-04	1.09E-02	9.76E-04	5.72E-04
Benzo (a) Pyrene Equivalents. (7)	1.32E-07	1.31E-07	1.68E-07	**2.03E-07**	1.17E-07	1.69E-07	1.85E-07	1.09E-07

Worst Case Ambient Toxic Concentrations Similar For All Alternatives

Modeled concentrations for most air toxic pollutants do not differ greatly between alternatives, as Table 10 indicates. Modeled worst-case concentrations of mercury are an order of magnitude higher for coal-based facilities than for natural gas/fuel oil facilities. Modeled worst-case concentrations of nickel and formaldehyde are highest for fuel oil facilities. Elevated modeled concentrations of formaldehyde for natural gas/fuel oil facilities are due to assuming high emissions from combustion turbines.

Modeled Concentrations at Predicted Emission Rates

Criteria Pollutants

Predicted Annual Ambient Air Concentrations of Criteria Pollutants Summarized

Annual average air concentrations of criteria pollutants for predicted emission rates generally correspond with the amount of pollutant emitted. Facilities that use coal, for instance, generally have higher modeled SO_2 concentrations. (See below)

The proposed Case A configuration had the highest predicted concentrations of SO_2.. Alternative 3 had the highest predicted NOx concentrations.

Modeled concentrations for Case A and Case B, however, are slightly higher than Alternative 6 because the forty-foot building height increase at the Southeast Plant creates downwash effects not present for other alternatives.

Modeled annual concentrations for all alternatives, however, are well below annual ambient air quality standards.

Table 11. Modeled Annual Criteria Pollutant Concentrations at Predicted Emission Rates (μg/m3)

Pollutant	Avr. Period	Alt. 3	Alt. 4	Alt. 6	Alt. 7	ase A	Case B
PM_{10} (lb/hr)	Emission	(17.1)	(1.8)	(6.8)	(1.8)	(9.95)	(8.26)
	Annual	0.66	0.07	0.16	0.05	0.61	0.49
NO_X (lb/hr)	Emission	(192.5)	(61.2)	(59.5)	(62.2)	(100.24)	(102.34)
	Annual	7.51	2.65	1.39	2.00	5.50	4.44
SO_2 (lb/hr)	Emission	(46.7)	(19.2)	(40.7)	(19.2)	(46.40)	(45.27)
	Annual	1.80	0.80	0.97	0.61	2.69	2.31

At St. Paul Campus, Predicted Annual Concentrations Affected by Stack Height

At the St. Paul campus, modeled annual concentrations at predicted operating conditions (not shown) are nearly identical for the proposal and for alternative 13, because both assume 92% natural gas, 8% fuel oil consumption. Slightly higher concentrations were modeled for the proposal (Case A and Case B are the same for the St. Paul plant) are attributable to the use of stacks with different heights.

Emissions from boiler No. 7 are routed to a 90 foot stack that is susceptible to downwash effects because it is only 40 feet above nearby buildings. Alternative 13 uses boiler No. 7 more than would be required under the proposal. Under Case A, a larger portion of the steam demand would be met with the new high capacity package boiler, which uses a new 200 foot high stack.

Predicted Air Toxic Concentrations

Predicted Emissions at Least 100 Times Less than Worst-Case Emissions

Modeled ambient air concentrations were also estimated for air toxics at "predicted" emission rates. (See FEIS Appendix F) The concentrations modeled at these more likely emission rates were about 100 times less than concentrations modeled at worst-case potential emission rates.

Modeled concentrations for most pollutants were somewhat higher for Case A compared to other alternatives, because of somewhat higher emissions due to coal-firing and because building "downwash' is projected to influence air pollutant dispersion at a renovated

Southeast Plant. Modeled concentrations for nickel and formaldehyde, however, are highest for the natural gas/fuel oil alternatives.

Compatibility of Steam Technologies with Biomass

CFB Options More Likely to Use More Biomass In Short Term

Biomass fuels are net zero emission greenhouse gas emitters. In the short-term, it is likely that the facilities that include a circulating fluidized bed boiler (CFB), like Case A, Case B, would use more biomass than 100% gas/oil facilities. CFBs are efficient at firing wood, and the base University proposal will be able to use about 7% total Btu with waste wood. or other solid biomass fuels. Modifications for additional biomass firing are also possible.

Promising long-term liquid and gas biomass fuels, such as that produced by alfalfa gassification (or other crops), could probably be filtered adequately to use in the standard combustion turbines described here. However, the gassification or other fuel conversion for such facilities usually takes place on-site with the electrical production equipment because long distance fuel distribution systems for these fuels do not exist. Siting a large scale biomass gasification plant on the University campus would present difficulties.

A gas or liquid biomass distribution system with enough capacity to supply a facility such as the University's steam plants is not likely in the short term, but a large-scale biomass gassification cogneneration heating system is possible for the long term.

Health Risk Assessment

Research on Impacts of Power Plant Emissions Continues

The Clean Air Act Amendments of 1990 triggered a number of extensive public and private research efforts on the impacts of air toxic emissions from fossil fuel plants. Much of this research attempts to obtain more accurate emission factor information, as discussed above. Other steps in the risk assessment process—pollutant dispersion, exposure, and toxicity—are also being assessed in detail.

EPRI's *Synthesis Report* a Useful Recent Study

This research has produced numerous multi-volume reports in the last year, and even a summary discussion is beyond the scope of the EIS. The results of one study, however, the Electric Power Research Institute's, *Electric Utility Trace Substances Synthesis*

Research Institute's, *Electric Utility Trace Substances Synthesis Report*, TR-104614, November 1994, are summarized below.

This study assessed the potential human health effects from over 500 fossil fuel fired power plants, using fuel mixes and emission rates projected for the year 2010, when utility compliance with CAAA regulations is expected to be complete.

Inhalation Risks Varied Widely but Were Generally Low

Maximum Exposed Individual inhalation risks estimated in the *Synthesis Report* varied widely and depended on stack height, location, and fuel type. In general, natural gas plants do not appear to be a concern, since stack emissions were in most cases below detection limits.

Of the 594 plants studied, three created carcinogenic risks to Maximally Exposed Individuals in the vicinity of the plant that exceeded one in one million. None created carcinogenic risks to Reasonably Exposed Individuals of more than one in one million.

Thirty Plants with Highest Inhalation Risks Were Mainly Coal-Fired

Of the 30 plants with the highest carcinogenic risks due to inhalation, 23 were coal-fired, 5 used multiple fuels, and 2 were oil-fired. For coal plants, arsenic was the largest contributor, followed by hexavalent chromium. For oil plants, arsenic and chromium were the largest contributors.

For non-carcinogenic inhalation risks, none of the facilities modeled had a hazard quotient over one, and the highest was 0.5. Hydrochloric acid and chromium accounted for the largest portions of the hazard index.

All Four Multi-Pathway Assessments Had Carcinogenic Risks Less than $1/10^6$

To model multi-pathway risks—including ingestion and absorption—EPRI used the Total Risk of Utility Emissions (TRUE) model for four facilities, three coal-fired facilities and one oil fired. For all sites, the dominant exposure route for carcinogenic risks were both ingestion and inhalation. For non-carcinogenic risks, inhalation was the main exposure pathway at three of the four sites.

None of the four multi-pathway assessments indicated a carcinogenic risk greater than one in one million. Arsenic was the biggest contributor to risk at the coal-fired facilities, but beryllium was the dominant contributor at the oil facility. Chlorine, mercury, and chromium were the largest contributors to non-carcinogenic risks, depending on facility location and fuel. Preliminary assessment of radionuclide emissions estimated for eight coal facilities indicates that annual individual doses were less than 25% of significance levels, although data is limited.

Inhalation Risks Modeled for Project and Alternatives

Final synthesis of the results of the extensive EPA, DOE, and EPRI research on toxic emissions and human health risks from fossil fuel plants is not scheduled for completion until late 1995. However, a screening level assessment of worst-case inhalation risks from the project and alternatives was completed based on ambient air quality modeling. The results are presented below.

Worst-Case Modeled Toxic Concentrations Below ACL's, Except Nickel

In order to assess the inhalation pathway cancer risk from steam plant emissions, Table 12 below compares the modeled maximum annual concentration for each air toxic to the current MPCA regulatory guidelines or Air Concentration Limits (ACL). For toxics without ACL's, the workplace Threshold Limit Value (TLV) divided by 1000 are also compared to the modeled maximum. The maximum concentrations in Table 12, again, assume unrestricted potential emission rates.

The far right-hand column in Table 12 is the ratio of worst-case modeled concentration to guideline criteria. The ACL's represent the annual average concentration at which the excess lifetime inhalation cancer risk is estimated to be 1 in 100,000. A ratio over 1.0, therefore, represents a modeled excess inhalation cancer risk over 1 in 100,000.

Modeled worst-case air toxic concentrations at potential emission rates are below the ACL guidelines for all listed air toxics except nickel. Modeled nickel concentrations exceed the nickel subsulfide ACL for all alternatives except Case A and Case B. Case A and Case B concentrations were slightly below the ACL. Modeled worst-case nickel concentrations exceeded the ACL at the St. Paul campus as well.

Most nickel emissions from either the proposed project or the alternatives were from fuel oil. Permit limits on annual fuel oil use could be accepted as necessary to restrict nickel emissions, because the primary fuel for the equipment is usually natural gas.

In addition, the ACL listed is for nickel subsulfide. The conservative assumption was made that all nickel emissions are as nickel subsulfide, a more toxic compound than others. Recent research on nickel speciation indicates that less than 10% of nickel emissions from fuel oil fired boilers is in the form of nickel subsulfide.

Table 12. Worst-Case Annual Toxic Concentrations Compared to ACL's

	Max Concentration (ug/m3)	ACL	TLV/1000	MAX/AAL or TLV
Arsenic	2.94E-04	2.00E-03		**0.1468**
Beryllium	2.78E-05	4.00E-03		0.0070
Cadmium	8.97E-05	6.00E-03		0.0150
Chromium-VI	3.17E-05	8.00E-04		0.0396
Chromium-tot	3.56E-04		1.00E-02	0.0356
Copper	8.09E-04		5.00E-01	0.0016
Iron	1.42E-01		2.00E-01	**0.7095**
Lead	3.74E-04	1.00E-01		0.0037
Manganese	1.38E-03	5.00E-02		0.0275
Mercury	2.24E-04	3.00E-01		0.0007
Nickel	3.84E-02	2.00E-02		**1.9218**
Selenium	4.68E-04		5.00E-02	0.0094
Vanadium	2.83E-03		2.00E-01	0.0142
Zinc	1.42E-03		5.00E-02	0.0283
Chlorine	3.68E-01	7.00E+00		0.0526
Fluorine	7.47E-02		1.50E+00	0.0498
Benzene	1.43E-04	1.00E+00		0.00014
2,3,7, 8 Dioxin Eq.	4.43E-10	8.00E-06		0.00006
Formaldehyde	1.56E-02	8.00E-01		0.0195
Benzo(a)pyrene Eq.	2.03E-07			

Ecological Risk Assessment: Mercury

Widely Dispersed Mercury Emissions Have Regional and Global Impact

Modeled ambient concentrations of air toxics are comparatively low for all alternatives, partly because high stacks improve pollutant dispersion. But widely dispersed emissions do, of course, contribute to cumulative impacts, both regionally and globally. For example, small quantities of mercury from the atmosphere have, through bioaccumulation, resulted in elevated methylmercury concentrations in fish in numerous lakes far removed from mercury emission sources. Atmospheric mercury in these remote areas is the cumulative impact of numerous regional and global air emission sources.

Mercury Currently Subject of Large-Scale Public and Private Research Efforts

Mercury's impacts and sources have been the focus of scientific research and discussion for over a decade. Numerous studies on mercury emissions, dispersion, fate and transport, and toxicity have been published within the last two years. In Minnesota, the MPCA has been a leader in mercury research and regulatory review. (See, e.g., *Technical Work Paper on Mercury Emissions From Waste combustors*, MPCA, 1992, and *Strategies For Reducing Mercury in Minnesota*, MPCA, 1994)

The 1990 Amendments to the Clean Air Act (CAAA) list mercury as one of 189 Hazardous Air Pollutants for which emission standards are to be promulgated by 2000. This provision does not currently apply to electric utility steam generating units, but could apply in the future to non-utility facilities like the University steam plants.

The CAAA of 1990 also requires EPA to prepare a study of the need to regulate mercury emissions from electric utilities, and requires the National Institute of Environmental Health Sciences to determine a "threshold level of mercury exposure below which adverse human health impacts are not expected to occur." These studies, in addition to the report on general air toxic emission risks, are scheduled to be completed in late 1995, and drafts have been released for scientific peer review.

A comprehensive review and assessment of this ongoing research is beyond the scope of this EIS.

Mercury the Focus of Potential Impacts on Ecological Resources

This section focuses on the potential impact of mercury emissions on local lakes. Local worst-case deposition is estimated, but no attempt is made to specifically quantify the relationship between mercury deposition and bioaccumulation in fish.

Mercury was chosen as the focus of the study for several reasons.

First, air quality modeling for the EIS indicates that, based on current information, local concentrations of most air toxic emissions from the proposal or any of the alternatives apparently would not, by themselves, present an inhalation-based human health risk problem, even at worst-case emission rates. Tall stacks and relatively effective control measures reduce localized impacts.

Second, emissions and modeled air toxic concentrations were similar for all alternatives, except for those of nickel, mercury, and formaldehyde. Of these, mercury is known to bioaccumulate to levels thousands of times that found in the water column. Human and ecological health risks due to mercury uptake by ingestion and other routes are at least 100 times that from inhalation alone.

Third, a percentage of mercury emissions do deposit near sources. Depending on stack height, control technology, and chemical speciation, on average, 50% of stack emissions are deposited locally or regionally (within 1000 kilometers). Approximately 10%

of emissions are deposited within 60 miles of the source. [*Mercury Atmospheric Processes: A Synthesis Report* (Expert Panel on Mercury Atmospheric Processes) March 16-18, 1994 EPRI Workshop Proceedings, EPRI/TR-104214]

Fourth, elevated concentrations of mercury have been measured in fish in Lake Calhoun, Lake Harriet and other metropolitan lakes.

Case A has the Highest Modeled Worst-Case Mercury Concentrations

The University's proposed Case A has higher potential and predicted mercury emissions than other alternatives (except the No Build Alternative) because mercury emissions are highest from coal-boilers and because the planned building height increase, according to the modeling, create "downwash" effects. The Case A worst case mercury concentration was modeled to be 2.2E-4 $\mu g/m^3$ (0.22 nanograms per cubic meter).

Ambient background mercury concentrations monitored at remote Northern Minnesota sites are 1.0 to 2.0 nanograms per cubic meter.

Mercury Deposition Calculation Indicates Worst Case Mercury Deposition Similar to Background

Mercury deposition onto nearby lakes can be estimated by multiplying the modeled air concentration by a deposition velocity, or the rate at which the mercury in the air falls to ground surfaces. The deposition velocity used for this calculation is .002 meters per second, a reasonable value for a facility with particulate and acid gas controls (MPCA personal communication).

At the worst-case annual mercury concentration modeled for Case A (2.2E-4 $\mu g/m^3$), and a deposition velocity of .002 meters per second, the calculated mercury deposition rate from Case A emissions is 14.1 $\mu g/m^2/yr$.

At predicted actual operation rates, which assume maximum use of coal, the modeled annual deposition rate is 7.1 $\mu g/m^2/yr$, about half that of worst-case emissions. In addition, worst-case modeled concentrations over nearby water bodies or wetlands are at least ten time less than the downwash related high spot, which is near the Southeast Plant. At a worst-case ambient concentration of 2.2E-5 $\mu g/m^3$ near the Minneapolis chain of lakes, the calculated annual mercury deposition rate is 1.4 $\mu g/m^2/yr$.

Published mercury deposition rates onto remote lakes are approximately 12.5 $\mu g/m^2/yr$, a rate that is similar to preliminary measurements at Minneapolis monitoring sites. The extreme worst-case modeled mercury deposition from the proposed project adds an additional 14.1 $\mu g/m^2/yr$ to this background. But at more likely

Case A emission rates, modeled mercury deposition on nearby lakes is less than 10% of background.

Mercury Bioaccumulation in Fish Proportional to Atmospheric Deposition

No attempt was made to correlate the modeled rate of mercury deposition to changes in mercury concentrations in fish. The precise mechanisms that control mercury methylation and bioaccumualtion rates in lakes remain unclear. Bioaccumulation rates are a function of a variety of water quality and sediment characteristics. A number of computer models have been developed that attempt to predict fish bioaccumulation, but none have received widespread acceptance to date. In addition, the most promising models require data which is not readily available, or would require expensive data acquisition.

However, one recently developed model was used by MPCA staff to assess the results of theoretical changes in mercury deposition on several well-studied lakes. The EPRI funded model used in this exercise is described in "Modeling the Biogeochemical Cycle of Mercury in Lakes: The Mercury Cycling Model (MCM) and its Application to the MTL Study Lakes," in *Mercury Pollution*, edited by Carl Watras and John Huckabee (Ann Arbor: Lewis, 1994), pp. 473-523.

Results indicated that the precise relationship between mercury input and fish bioaccumulation varies considerably from lake to lake. Each lake has a unique linear relationship between the amount of mercury deposited and the rate of bioaccumulation in fish; some lakes show steep linear relationships, others show flat linear relationships. In any given lake, however, an increase in mercury deposition results in a proportional increase in the mercury concentration in fish.

Hydrocarbon Vapor Emissions

Hydrocarbon vapor emissions from the fuel oil tanks for the Case A have been estimated to be 0.16 tons per year by the University in their permit application using standard EPA approved formulas and assumptions. Several EIS alternatives would require additional fuel storage, including new tanks for number 6 fuel oil (alternatives 3, 4, and 7). Vapor emissions would be up to twice as high for these alternatives, but with standard emission controls, are not expected to create a localized health risk or other environmental problem. Total emissions of volatile organic carbon from the fuel oil storage tanks are insignificant compared to stack emissions (20 to 30 TPY).

Section 6.5 Noise

State Noise Standards Described

The MPCA regulates allowable sound level for various types of receptors according to land use according to three Noise Classification Areas (NAC). NAC-1 areas include residences, mobile homes, motels, churches, camping and picnic areas. NAC-2 land use consists of retail and business services. NAC-3 areas include manufacturing and industrial facilities, water, and unused land.

The allowable sound levels for each classification are provided below.

Noise Area Classification	Daytime (1)		Nightime	
	L_{50}	L_{10}	L_{50}	L_{10}
NAC-1	60	65	50	55
NAC-2	65	70	65	70
NAC-3	75	80	75	80

(1) Daytime is 7:00 a.m. to 10:00 p.m

(2) L_{50} is the sound level, expressed in dBA, which is exceeded fifty percent of the time during a 1 hour survey

(3) L_{10} is the sound level, expressed in dBA, which is exceeded ten percent of the time during a 1 hour survey

Periodic Loud Noise From Steam Plant is Due to Steam Venting at Boiler Start-up

The state daytime L_{10} state standard is 65 decibels (The L_{10} noise level is that exceeded 10% of a given monitoring period.) Background L_{10} levels monitored in the park near the Southeast Plant are about 63 decibels. Of that background, the Southeast Plant is not the dominant noise source. The background hum of the Southeast Plant can typically be heard in the nearby park, but the louder noise in the area is from nearby grain elevators and nearby traffic. On the Dam Flats, the noise from St. Anthony Falls is louder than that from the Southeast Plant as well.

Periodically (about 10 times a year) the Southeast Plant boilers, during start-up and shut-down, produce a much louder than background noise for about 15 to 30 minutes. This loud noise is due to superheated steam that must be vented to avoid damaging plant boiler tubes.

Noise Levels at Southeast Plant Could Exceed Standards Infrequently at Boiler Start-up

L_{10} noise levels were monitored near the Southeast Plant during this start-up procedure, but because of planes and construction noise, the monitoring was not an official reading. The monitored L_{10} noise levels did, however, increase by more than 10 dBA over background (83.7 dBA), becoming the dominant noise source in the area for about 15 minutes.

The MPCA has indicated, however, that because of the infrequent nature, short duration, and location of the occurrence, the impact of the noise is minimal.

Noise Impact Considered Minimal, and Could Be Mitigated With New Equipment

This start-up noise would continue following plant renovation, but it can be minimized with the installation of mufflers and other equipment on the vent piping. This mitigation could best be done during plant renovation.

Similar noise mitigation could be installed at an alternative at the off-river site to minimize the impact of start-up noise on the surrounding area and motel. Due to this potential mitigation and the traffic noise already occurring at the alternative site, the noise impact from a new steam plant is expected to be insignificant.

The DEIS off-river "alternative" Minneapolis site is located more than 1000 feet from a residential area, but the northern and westernmost sections of the "30 Acre" site are within 300 feet of residences (see Figure 9-2).

Case B and the alternatives designed for the EIS include approximately 22 mW total capacity combustion turbines. A turbine arrangement of that size with standard noise mitigation would be expected to produce 58 dBA at 300 feet (vendor guarantee European GT). The current boiler operation at the Southeast Plant contributes to a background L_{10} of 63 dBA measured about 150 feet from the facility.

There are a wide variety of standard equipment and mufflers that can be used to effectively reduce steam plant noise, therefore the noise produced by a plant located 1000 feet from a residence would not be expected to exceed daytime or nightime standards. However extraordinary noise mitigation may have to be considered if a facility was to be located in the north or west sections of the "30-Acre" site to keep noise levels within state nightime standards.

Section 6.6 Fugitive Dust

Fugitive Dust is Created by Coal and Ash Piles

A separate fugitive dust modeling analysis was performed by Foster Wheeler and reviewed by Trinity Consultants, Inc. in order to assess the environmental impacts resulting from Case A fugitive dust emissions. Case A would produce the most fugitive dust of any renovation option. For the purposes of this analysis, fugitive dust emissions include area and point source PM_{10} emissions from all material handling and material storage operations. Table 12 summarizes the fugitive emission sources included in the analysis.

Table 13. Fugitive Dust Emission Sources

Emission Source	Plant
Coal Stockpile	Main
Coal Bunker	Southeast
Coal Bunker	Southeast
Coal Stockpile	St. Paul
Ash Pile	Southeast
Ash Pile	St. Paul
Railcar Unloading	Main
Existing Ash Silo	Southeast
New Ash Silo	Southeast
Existing Lime Silo	Southeast
New Limestone Silo	Southeast
Existing Coal Handling	Southeast
New Coal Handling	Southeast
Ash Silo	St. Paul

Modeled Particulate Concentrations From the Coal and Ash Piles Presented

The annual and 24-hour ambient ground-level PM_{10} concentrations resulting from the Southeast Heating Plant fugitive emissions are shown in Tables 13. The annual and 24-hour ambient ground-level PM_{10} concentrations resulting from the St. Paul Heating Plant fugitive dust emissions are shown in Table 14.

Table 14. Southeast Plant Fugitive Dust Concentrations Southeast Heating Plant modeled fugitive dust concentrations.

Averaging Period	Modeled Concentration (μg/m³)	UTM Location East (km)	UTM Location North (km)
Annual	0.53	483.300	4980.700
24-hour	20.76	483.300	4980.700

Table 15. St. Paul Plant Fugitive Dust Concentrations St. Paul Heating Plant modeled fugitive dust concentrations.

Averaging Period	Modeled Concentration (μg/m³)	UTM Location East (km)	UTM Location North (km)
Annual	0.003	485.640	4980.358
24-hour	0.10	485.640	4980.358

Fugitive Dust Emissions Within Regulatory Limits, But Still Create Periodic Annoyance

Results show that the annual and 24-hour fugitive dust from Southeast Plant sources are considerably higher than the concentrations that from St. Paul Plant sources: coal and ash handling quantities are lower at St. Paul, and the bituminous coal used at St. Paul is less fine-grained and dusty than the subituminous coal would be used for the Southeast Plant. In addition, the coal pile at the St. Paul Campus can be packed down tightly and remain inactive for most of the year, since the University will be using coal "primarily" for backup purposes.

Modeled particulate concentrations at both campuses are below the applicable PM_{10} standard; however, the proposed coal handling system (which is the same as existing) does appear to create aesthetic problems in the area of the Main Plant. Coal dust can be seen for some distance around the site in the winter, and some nearby residents are periodically annoyed.

Any problems at St. Paul should be eliminated by the infrequent coal handling. Without frequent use and disturbance of the coal pile, the coal dust problems would be minimal.

Construction Related Impacts Would Be Minimal

Construction at the Southeast Plant would disrupt the area near the Stone Arch Bridge for the one to two year construction period. Additional truck and other traffic would increase. Soil removal would be required for new equipment. A construction stormwater permit would likely be required, and assuming compliance with permit requirements, the impact of runoff on the Mississippi would be negligible.

Construction impacts at the alternative site are also expected to not be significant as long as the required runoff containment and other standard procedures are implemented properly. Traffic in the area of the existing parking lots could be disrupted during the construction period as well.

Section 6-7 Applicable Air Quality Regulations

Applicable air Quality Regulations

Federal and Minnesota Primary and Secondary Ambient Air Quality Standards. Minnesota and the federal government have established Ambient Air Quality Standards (AAQS) for six criteria pollutants: CO, NO_2, Ozone, TSP (Minnesota only), PM_{10} (federal only), and SO_2. Two classes of AAQS have been established: primary and secondary. The primary standards define the level of air quality necessary to protect public health. Secondary standards define levels for protecting the general welfare (soils, vegetation, and wildlife). The Minnesota and federal AAQS are summarized in Table 16.

Table 16. Ambient Air Quality Standards ($\mu g/m^3$)

		National		**State**	
Pollutant	Time	Primary	Secondary	Primary	Secondary
CO	8-hour	10,000	10,000	10,000	10,000
	1-hour	40,000	40,000	35,000	35,000
NO_2	Annual	100	100	100	100
Ozone	1-hour	235	235	235	235
TSP	Annual	-	-	75	60
	24-hour	-	-	260	150
PM_{10}	Annual	50	50	-	-
	24-hour	150	150	-	-
SO_2	Annual	80	-	80	60
	24-hour	365	-	365	365
	3-hour	-	1,300	1,300	1,300
	1-hour	-	-	1,300	-

The federal and state regulations and standard governing the proposed modifications and alternatives are listed

- Federal Prevention of Significant Deterioration (PSD) Regulations.
- The proposed project is subject to (PSD) review for TSP and PM_{10}. The proposed project is not subject to PSD review for SO_2, CO, NO_x, VOC, and lead. A PSD applicability review was not completed for each selected alternative.
- New Source Performance Standards (NSPS). NSPS are federal rules that establish requirements for emissions testing, monitoring, and reporting for specific emission units. The emission rates in the proposal must be less than the NSPS requirements. Compliance with NSPS will be demonstrated through CEMs, stack testing, fuel testing, and fuel flow monitoring.

  - Subpart D - Standards of Performance for Fossil-Fuel Fired Steam Generators for which Construction is Commenced after August 17, 1971-Subpart Db - Standards of Performance for Industrial/Commercial/Institutional Steam Generating Units
  - Subpart GG - Standards of Performance for Stationary Gas Turbines
- National Emission Standards for Hazardous Air Pollutants (NESHAPS).
- Minnesota Air Pollution Control Regulations and Minnesota Standards of Performance.
- Minnesota Acid Deposition Rule. The Minnesota acid deposition rule applies "only in sensitive areas" and only to an electric utility whose generating facilities located in Minnesota have a total combined generating capacity greater than 1,000 megawatts.
- Acid Rain - Title IV. Title IV of the Clean Air Act applies when a plant cogenerates more than 25 megawatts of electric output. In addition, a cogeneration unit that does not supply more than one-third of its potential electrical output capacity and more than 25 megawatts of electrical output to a utility power distribution system for sale is not subject to the allowance requirements of Title IV.
- Great Lake States Air Permitting Agreement. The Great Lake States Air Permitting Agreement requires, consistent with present federal and state regulatory schemes, that BACT be installed wherever possible on all new and existing sources of persistent HAPs that impact the Great

Lakes. Currently, no rules or regulations have been adopted under the agreement.

- Titles I and III of the federal Clean Air Act.

Modeled High Concentrations for Combined Campuses Are Important for Permitting

Modeled high concentrations for the combined campuses are important for permitting because the EPA has determined that although the Minneapolis and St. Paul campuses are located several miles apart, the facilities should be issued a joint air quality permit. (The permit must include all other University sources as well.) Combined modeling results for the Minneapolis and St. Paul facilities are provided in the detailed *Air Quality* report.

Pollution Dispersion from the Two Campuses Does Not Overlap Much

The EIS modeling results indicate that pollutant dispersion from the two campuses does not overlap much. At predicted emission rates, the annual average high is usually located near the Southeast Plant because emissions there are generally higher. The same is true for modeled maximum potential emissions, except with Cases A and B, for which the maximum potential emissions produced modeled highs at the St. Paul campus, probably due to downwash effects.

As described previously, some of the higher short-term modeled concentrations for alternatives at the Minneapolis campus are probably due to reduced flue gas exit temperatures from scrubbers used when firing fuel oil. The short-term modeled highs would not be reduced through annual fuel or emission permit limits

Section 6.8 Off-Site Fuel Cycle Impacts

All Fuels Have Difficult to Quantify Off-Site Fuel Cycle Impacts

Off-site air emissions and other impacts occur during the exploration, production, mining, storage, and transport of all the fuels considered for the steam plant facility. It is not possible, however, to quantify the specific off-site impacts of any individual alternative. A brief general description of various impacts due to the major fuels is provided below.

Subituminous Coal

- Fugitive dust at the open strip mines
- Methane from open coal seems
- Water pollution from mining operations and tailings runoff
- Habitat destruction due to strip mining

Fuel Oil

- Habitat destruction from exploration and production (drilling)
- Hydrocarbon emissions form fuel storage and handling in pipelines and tanker trucks; storage emissions from tanks
- Emissions of SO_2 and toxic air pollutants at the refinery

Natural Gas

- Habitat destruction during exploration and drilling
- Pipeline related destruction of habitat
- Methane release at pipeline compressor stations and other points in distribution contributes to global warming

No fuels, including natural gas and biomass fuels, are without off-site impacts; increased fuel efficiency and reduced energy consumption are likely to be more effective mitigation techniques than fuel switching to reduce these impacts.

Chapter 7. Water Quality

Sampling Completed of Wastewater, Stormwater, Coal and Ash

This chapter addresses the impacts of wastewater and stormwater discharges from the existing steam facilities and summarizes the results of sampling for trace metals in coal, ash and soil at the facilities' storage areas. Changes to the existing wastewater and stormwater system due to the proposal and alternatives are described and their potential impacts assessed. Potential mitigation measures to reduce any water quality impacts are described in Section 6.2 below. This chapter briefly summarizes this water quality report.

Detailed Results Appear in Separate Report

Details of sampling methodology, parameters, and results, along with a full discussion of water quality issues, can be found in a separate report: *Water Quality Study, University of Minnesota Steam Services*, September 1994, by B.A. Liesch Associates.

Chapter 7.1. Wastewater

Wastewater Comes from Various Sources

Sources of wastewater at steam productions facilities include 1) used boiler make-up water (condensate), which must be treated to remove metals and other corrosion-causing minerals from both the boilers and the steam distribution system. boiler make-up water release or "blowdown", 3) normal domestic sewage, 4) water from floor drains, and 5) coal pile runoff.

Wastewater Discharged into Municipal Sewer System

All three steam plants discharge wastewater into the municipal sewer system, and samples from the Southeast and St. Paul steam plants were analyzed for pH, total suspended solids, chemical oxygen demand, boron and RCRA metals.

All Samples are within Published Disposal Limits

All parameters sampled were within published limits for disposal into the Metropolitan Council Wastewater Services (MCWS) treatment system. Additionally, most of the metals not included in the published limits were either below or only slightly above method detection limits.

Proposal Would Improve the Quality of Boiler Make-up Water and of Wastewater

Installing a new demineralization package—consisting of carbon filters, cation and anion exchangers, regeneration systems, a condensate polishing system, a neutralization tank and associated instrumentation—would improve both boiler make-up water treatment and the quality of wastewater.

This system would improve the pH of the wastewater, reduce spikes of suspended solids, and eliminate the current use of lime in the process. The neutralization effluent from the Southeast Plant would combine with the rest of the process wastewater at the Southeast Plant prior to being discharged into the municipal sewer. The existing treatment system would no longer be used.

All alternatives except "No Action" assumed a similar improvement to the current water treatment system.

Permit for Entire Campus Denied

The University of Minnesota submitted a discharge application MCWS for the entire campus. MCWS staff, however, have indicated that the application was not accepted as yet because of the diverse nature of discharges from the Universities various activities, and there are apparently no applications pending.

According to the University, they have been in possession of temporary wastewater discharge permits from Metro Council Wastewater Services (MCWS) for some time, and that MCWS has never indicated that individual permits were necessary for the steam plants. The University also indicated in its comments on the draft EIS that a permit application for the St. Paul plant was submitted in January, 1995 due to recent improvements at that plant. (See UofM/FW comments on DEIS, pp. 59)

Permit and Semiannual Reporting May Be Required

The University anticipates that the Southeast Plant will discharge approximately 18.5 million gallons of process wastewater per year into the municipal sewers and that the St. Paul Plant will discharge approximately 9.5 million gallons.

Although neither Foster Wheeler Twin Cities, Inc. nor the University of Minnesota have an application currently pending, a wastewater discharge permit from MCWS may be required. Discharge amounts, wastewater testing, and discharge flow monitoring may have to be reported semiannually, depending on MCWS requirements.

Section 7.2. Stormwater

Coal and Ash Piles the Main Sources of Stormwater Runoff

The coal and ash piles at the Main, Southeast, and St. Paul plants are the main sources of potentially contaminated stormwater runoff.

The quantity and quality of stormwater runoff will not change from present levels under the proposal or any alternatives because the footprints of the plants or of the coal and ash storage areas will not change.

Runoff from the Main Plant Coal Storage Area Discharges into Main Plant and apparently into Municipal Sewer System

Runoff from the Main Plant coal pile runs below and in back of the pile into the plant—where it mixes with other process effluent—and out through a pipe in the ash unloading area on the riverfront side of the plant. The effluent, whatever its source, discharges into the sanitary sewer system, as verified by drawings supplied by Mr. George Delarche of Foster Wheeler, Twin Cities Inc.

Water from a pipe discharging into the river directly downhill from the Main Plant was tested because it appeared to be related to the coal pile effluent. Drawings supplied by Foster Wheeler clearly indicate that this effluent is stormwater from a historical stream originating in the Dinkytown area, now underground, that discharges through a pipe into the Mississippi River.

Coal, Ash, and Soil Samples Taken to Determine Impacts

Coal, ash and soil samples were collected to determine potential impacts on soil and groundwater of the earthen berms containing run-off in the storage areas. Ponded stormwater samples were collected to determine impacts on the receiving waters were the earthen berms around the ash storage areas to fail.

Coal and ash samples from the three plants were analyzed for total and TCLP extractable heavy metals and boron.

Stormwater Samples also Taken

Stormwater samples were taken at the Southeast and St. Paul Plants' ash storage areas. Because the stormwater did not breach the containment structures, samples of the ponded water were collected to assess possible impacts on receiving waters should the containment structures fail. However, because suspended solids settle in stationary water, ponded water samples do not fully identify the level of pollutants in the run-off water.

Although no water was observed breaching the earthen berms at the Minneapolis ash storage area, water was being retained in a culvert behind the fill material in the northwest corner of the storage area.

Since, according to Foster Wheeler Twin Cities, Inc., the fill is not always there, its absence would result in additional discharge, which would increase the likelihood that the berms would fail. In addition, it is likely that the collecting runoff enters the shallow groundwater system.

Samples were also taken 1) at the Main Plant near the base of the coal storage bunker and 2) from the PVC pipe below the Main Plant discharging directly to the Mississippi River. Mr. George Delarche of Foster Wheeler Twin Cities, Inc. indicated that the Main Plant coal bunker discharged into the MCWS sewer lines.

The stormwater and discharge water samples were analyzed for heavy metals, strontium, boron, total suspended solids, pH and chemical oxygen demand.

Foster Wheeler Has Suspended Old Ash Storage Procedures

Since publication of the DEIS, Foster Wheeler has changed ash storage procedures at both the Minneapolis and St. Paul facilities to eliminate potential groundwater or surface water contamination. The ash is now stored inside or shipped directly to a landfill. (See FEIS chapter 1 for description of revised ash storage and handling.) Future outdoor ash storage will require lined sites with leachate collection systems under permit from the MPCA.

Stormwater Samples also Within Regulatory Limits

Stormwater samples tested were within regulatory criteria for Class 2B waters. The only two exceptions were that the runoff from the Minneapolis ash site had a pH of 9.7 standard units (compared to a standard of 9.0 s.u.) and that the runoff from the St. Paul ash site exceeded the chronic standard for arsenic of 53 ug/l. There is, however, no readily apparent leakage into the receiving waters at the St. Paul ash storage site. Runoff from the Main Plant and samples from the discharge pipe were within regulatory discharge limits and drinking water standards.

Although the samples collected were generally within regulatory criteria, the samples collected in the ash storage areas are not representative of potential runoff. Were the current earthen berms to fail, the resulting discharge could carry ash with a concentration of suspended solids high enough possibly to exceed regulatory criteria.

Coal, Ash and Soil Samples Are Within Regulatory Limits

The toxicity characteristic leach procedure (TCLP) analysis indicated that neither coal nor ash is a hazardous waste at the University of Minnesota's storage facilities. The coal and ash samples analyzed did not approach regulatory action levels for TCLP metals—in other words, they did not have concentration levels high enough to require that regulatory agencies be notified or that the site be remediated.

Similarly, the soil sample collected at the Minneapolis Steam facility ash storage area was also well below the TCLP regulatory action levels, with only barium above the method detection limit. The low TCLP values of the soil sample suggest that the storm run-off water may not be affecting the ground water beneath the ash storage site.

The soil sample did have higher concentrations of total metals than did the ash and coal samples. This may be from the metals in the ash leaching out and concentrating in the soil. The information collected to date, however, does not permit an estimate of how long it would take for the concentrations in the soil to reach regulatory limits.

No NPDS Permit Required for Minneapolis Because There is No Discharge to Surface Water

Review of sanitary sewer pipeline drawings provided by Foster Wheeler and site inspection by MPCA staff indicates that all coal runoff at the Southeast and Main Plants is discharged into the municipal sewer system. (Ash runoff has been eliminated through changed procedures described above.)

Since no stormwater from facility operations or coal storage and handling apparently reaches the groundwater or the river–or is anticipated to following renovation–no stormwater permit is required at this time.

MPCA staff site review at the St. Paul facility indicates that some runoff from the uncovered coal pile may be entering the stormwater system through a culvert near the St. Paul Plant. Foster Wheeler indicated that it has or is planning to eliminate this potential discharge through additional berming or otherwise as necessary.

Finally, depending on the final size of the renovation project at the Minneapolis campus, a construction stormwater permit may be required.

Foster Wheeler Proposes Measures to Mitigate Ash Runoff

Although the Minneapolis ash storage area is bordered on the north by a bluff, on the south (riverside) by a concrete retaining wall, and on the east and west by earthen benns, Foster Wheeler Twin Cities, Inc. has proposed, as part of the improvements to the Southeast

Plant, an optional concrete retaining wall further to reduce the potential for stormwater runoff.

Similarly, Foster Wheeler Twin Cities, Inc. has proposed a stormwater collection and storage system to improve runoff at the St. Paul ash storage bunker. This system would not only contain runoff, but it would allow suspended solids to settle and be removed. (The University has also indicated that it will use only insignificant amounts of coal at St. Paul following renovation.)

The proposed containment facilities should adequately prevent environmental impacts. The ash samples analyzed indicate that the ash is not hazardous for metals or suspended solids.

Consequently, these efforts to contain the runoff from discharging directly into receiving waters should protect the environment from the metals and suspended solids in the ash.

Chapter 7.3. Potential Impacts from Fuel Spill

A 10,000 gallon aboveground storage tank (AST) will continue to be used at the Southeast Plant to store No. 2 fuel oil, and additional fuel oil storage would be required for riverfront alternatives 3 and 4. This AST has and will have secondary containment, but should that containment fail, and fuel oil be released, there would be several potential impacts.

A fuel oil spill would flow down the access road onto a relatively level area adjacent to the river. Depending on the quantity of the fuel oil, a portion would infiltrate into the soil, and a portion could flow into the river.

With Quick Response, Impact on Soil and Groundwater Should Be Minimal

Were the soils immediately excavated, the long-term impact on the environment would not be significant. Because bedrock lies within ten feet of the surface, excavation of the soils would be limited. Because the river—into which shallow groundwater is presumably discharged—is nearby, the impact on groundwater should be minimal.

Detailed Emergency Response Plan in Place

A detailed Emergency Spill Response Plan has been developed by Foster Wheeler and submitted to regulatory agencies as required by the EPA Spill Prevention, Control and Countermeasure regulation of 1974 (SPCC), identified in 40CFR Part 112. This plan also was prepared to comply with Chapter 115E of Minnesota Statutes, the Minnesota Spill Bill of 1991. This plan is available from EQB staff or Foster Wheeler.

Effects on River Life Would Vary with Severity of the Spill

Fuel oil released into the river would float on the river's surface until disturbed by the water passing through the downstream lock and dam. Effects on the biologic populations of the Mississippi River would depend on the amount of fuel oil released and on the timeliness of the emergency response. According to information furnished by MPCA, fuel oil toxicity is second only to that of crude oil.

An environmentally severe fuel spill would kill fish and benthic invertebra in the vicinity of the release. River life downstream would also be affected, until concentrations became sufficiently diluted to be broken down by naturally occurring bacteria.

Release at Alternative Site Could Affect Soil, Groundwater, and the River

Were a new steam facility constructed on the alternative site, that site would also have ASTs for fuel oil. A fuel oil release at this site would potentially affect the soils and, if undetected, the groundwater in the vicinity of the AST. If drainage at the site allowed a release to reach the storm sewer system, diluted fuel oil would eventually reach the Mississippi River.

Chapter 8. Solid and Hazardous Waste

Phase One Site Assessments Completed for the Two Minneapolis Sites.

Phase-one site assessments were completed for the Minneapolis Riverfront and Alternative Sites. The purpose of the assessments was to assess the potential for soil and groundwater contamination from current or historical use or storage of coal, ash, fuel oil, or other potentially hazardous substances. A detailed description of these assessments is provided in a separate technical supporting document, *Soil and Groundwater Contamination Site Assessments*, by B.A.Liesch Associates.

At Riverfront Site, Concern over Four Storage Areas

At the Riverfront Site, the four areas of primary environmental concern are 1) the aboveground storage of fuel oil at the Main and Southeast Plants, 2) the underground storage of fuel at the Main Plant, 3) the storage of coal at the Main and Southeast Plants, and 4) the temporary storage of ash from the steam plant boilers within a bermed area along the river beneath the 35W and 10th Avenue bridges.

There is no indication of site contamination or other ecological stress at Riverfront Site

Three aboveground storage tanks (ASTs) for fuel oil are currently installed on the Riverfront Site: two ASTs totaling 750,000 gallons at the Main Plant and one 10,000-gallon AST near the Southeast facility. The ASTs are registered with the MPCA Tanks and Spills Section. Although the ASTs are provided with secondary containment and there was no evidence of contaminated soil or stressed vegetation near the ASTs during Liesch's walkover of the Riverfront Site, storage of large volumes of fuel oil does represent an environmental risk.

No Evidence of Leakage from Soon-to-be-Abandoned Underground Storage Tanks

MPCA records indicate that a leaking underground storage tank was reported at the Main facility. However, a site closure letter has been issued for the site, indicating that the site has been remediated to the satisfaction of the MPCA. The University is currently in the process of tightness testing the 14 underground storage tanks at the Main Plant, prior, reportedly, to abandoning them. There is currently no evidence of leakage from these installations.

Concentrations of Metals in Coal Pile Run-off Are Within Regulatory Limits

Coal for both the Main and Southeast plants is brought by rail to the Main plant, where it is stored on the ground. Run-off from the Southeast Plant coal bunker is reportedly discharged directly to the sanitary sewer. Run-off from the coal stockpiles at the Main plant may discharge to the Mississippi River via surface run-off or infiltration to the ground water. However, laboratory analysis of seepage samples from the Main Plant coal pile indicated that concentrations of metals were within regulatory limits for drinking water.

Concentrations of Metals in Ash and Soil Are Within Regulatory Limits

Samples of ash and soil from the ash storage area were also within regulatory action limits for TCLP metals, and metals in leachate do not pose a significant risk to Mississippi River water quality.

Nearby Leaking Fuel Storage Tanks Probably Affects the Riverfront Site

Five leaking underground storage tanks have been identified immediately above or level with the Riverfront Site. Three of these sites have been closed by the MPCA. The two remaining sites are an Amoco Service Station at the intersection of University Avenue and 10th Avenue SE and the Chateau Community Housing Association at 425 13th Avenue SE.

The Amoco site should directly affect the Riverfront Site. Groundwater monitoring continues at this site, and the source of impacts has apparently not been identified. Were the fuel to continue to leak at the Chateau site, that site also would affect the Riverfront Site. The MPCA recently notified the owners of the Chateau property that the site would have to be inspected and remediated to address impacts at the site.

No Indication of Past Industrial or Other Hazardous Waste Contamination at Riverfront Site

In 1912 the Riverfront Site contained the Twin City Rapid Transit Company steam power facility (west end), the St. Anthony Falls Water Power Company and some residential units (central portion), and the University of Minnesota's New Heating Plant and Power Station (east end). At the northern border, located on the river bluff, were Chicago Great Western Railroad tracks. North of the Riverfront Site were various manufacturing and lumber companies (west end), residential units (central portion), and University of Minnesota facilities (east end).

By 1951, additional residential units had been constructed north of the site and the University of Minnesota's linear accelerator building had been constructed in the central portion of the site. Additional University buildings had been built adjacent to the east end of the site, and additional industrial development had sprung up adjacent to the west end of the site.

By 1952, the University had added a research laboratory at the site and had continued to develop the area adjacent to the east end of the site.

Ash Quantities Estimated for Proposal and Alternatives

The quantities of ash generated by the different steam plant alternatives are directly related to the amount of coal used. The 100% gas/oil plants would produce negligible amounts of solid waste. The CFB alternatives produce more ash per Btu than conventional boilers because of the limestone injected for sulfur control. The quantities of ash generated by each alternative are listed below.

Alternative	Ash Produced (TPY)	10-Ton Trucks / year
Case A	10,450	1050
Case B	8,300	830
Alternative 1	8150	820
Alternative 3	5400	540

Ash production per MMBtu of coal burned in CFB is estimated as lb/MMBtu

Ash in Coal	6.25
Reagent (limestone)	2.06
Sulfur Removal	0.30
Total residue	8.61

Some Solvents Stored on Site

The steam facilities are currently not listed as a hazardous waste generator with Hennepin County. The small amount of solvents and treatment chemical residue is stored in barrels and disposed of.

At Alternative Site, Concern Over Creosote Compounds

At the alternative site, the primary environmental concern is the appearance of creosote compounds in the soils and groundwater, at concentrations which may require remediation. These compounds are from the Republic Creosoting Company, which operated on a portion of the site in the early 1900s.

Remediation Alternative Report Currently Being Prepared

According to Dahl & Associates, Inc., a proposed remediation alternative report is currently being prepared for this site. Approximately 2,000 cubic yards of soil requiring cleanup have been identified. Groundwater will apparently not be remediated during this phase of proposed work.

Several remedial alternatives were considered for the site, and the chosen action will be presented in this report. The MPCA-VIC program is overseeing work conducted at the site. Pending

MPCA review and approval of proposed remedial actions, remediation of the site could begin in fall or winter, 1994. Dahl predicts that site soils remediation will take six weeks to complete.

Nearby Fuel Storage Tanks Could Affect Alternative Site

Five leaking underground storage tanks have been identified immediately above or level with the Alternative Site. Three of the sites have been closed by the MPCA. The two remaining sites are the Chicago & Northwestern Transportation Company (CNTC) site, and a University of Minnesota spill site.

The CNTC site is currently being remediated, but the affect on lower sites is unclear, and it could eventually affect the southern end of the Alternative Site. The location of spillage from refueling at the University of Minnesota site is unknown, although approximately 620 tons of affected soil have been removed. Because groundwater flow conditions in this area fluctuate, the University of Minnesota site could affect groundwater at the Alternative Site.

VOCs in Nearby Soils Could Affect Alternative Site

A soil sample taken from the University of Minnesota's Integrated Waste Management Facility site in 1990 was found to contain low levels of volatile and semi-volatile organic compounds. The Waste Management Facility is operates as a waste transfer site for the University.

Also in 1990, VOCs were identified in soil at the nearby Soo Line Century Mill site. Mandated remediation work was not performed, and the site was subsequently referred to the MPCA Superfund Program for further investigation. Due to lack of information regarding site conditions, potential impacts from the site cannot now be adequately evaluated.

Since 1912, Limited Development at the Alternative Site

In 1912, the Alternative Site was occupied by the Chicago Great Western Rail Yard and the Republic Creosoting Company. Various grain elevators and a linseed oil mill—reportedly built in the late 1800s and early 1900s—were located near the site. Surrounding areas to the north and west contained additional rail yards, grain elevators, and a mill, and surrounding areas to the south, southwest and west contained a bulk oil facility, grain elevators, and residential and University buildings.

By at least 1937, the Republic Creosoting Company was gone, and development since 1912 has consisted mainly of grain elevators.

Chapter 9. Land Use, Historic, Visual, and Other Socioeconomic Impacts

Chapter Contains Seven Sections.

This chapter describes impacts of the proposed steam plant renovation project and its alternatives on land use and other impacts that that are neither environmental nor economic. The sections in this chapter are the following:

9.1 Existing Land Use

9.2 Land Use Conflicts

9.3 Visual Impacts

9.4 Historic Significance

9.5 Compatibility with City of Minneapolis Land Use Plans

9.6 Special State and Federal Programs for the Riverfront

9.7 Land Use Impacts at the St. Paul Campus

This Chapter Describes Surrounding Land use and Assesses Impacts

This chapter first describes the Minneapolis riverfront area, then describes the most likely alternative Minneapolis off-river site, and finally, provides a brief description of the St. Paul campus site. The focus, however, is on the Mississippi riverfront site because of the larger public interest in that area.

Section 9.1 Existing Land Use

The land uses surrounding the riverfront site and the alternative site are illustrated on Figures 1 & 2.

The riverfront site covers about 0.5 miles of the east bank of the Mississippi River between 6th Avenue SE and 12th Avenue SE. The Main Plant occupies the east end of the site and the Southeast Plant occupies the west. The area is bounded by a railroad corridor on the north, the river on the south, the Southeast Plant and its coal bunker on the west, and the Main Plant and its associated facilities on the east.

The alternative site is a narrow, 23-acre crescent-shaped property north of University Avenue and east of Oak Street.

Figures 1 and 2 are maps depicting the nearby land uses in each area.

Figure 3 is a map of the area surrounding the St. Paul Plant

Riverfront area includes a variety of industrial, recreational, retail, and residential land uses.

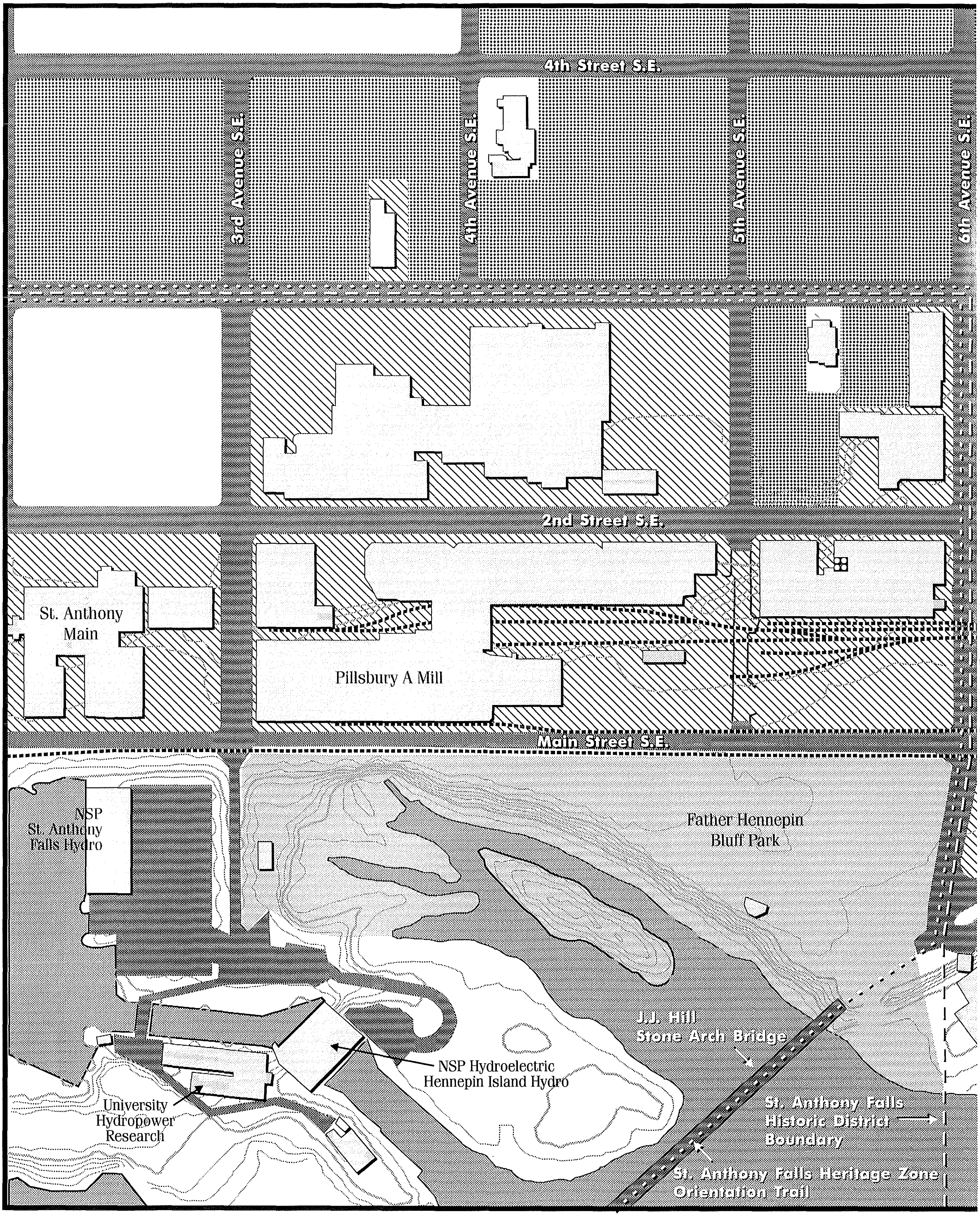
The area is bounded by a railroad corridor on the north, the river on the south, the Southeast Plant and its coal bunker on the west, and the Main Plant and its associated facilities on the east. Located near the project area are a wide variety of land uses including industry, day care facilities, parks, retail and entertainment, University facilities, and housing (Figure 9-1).

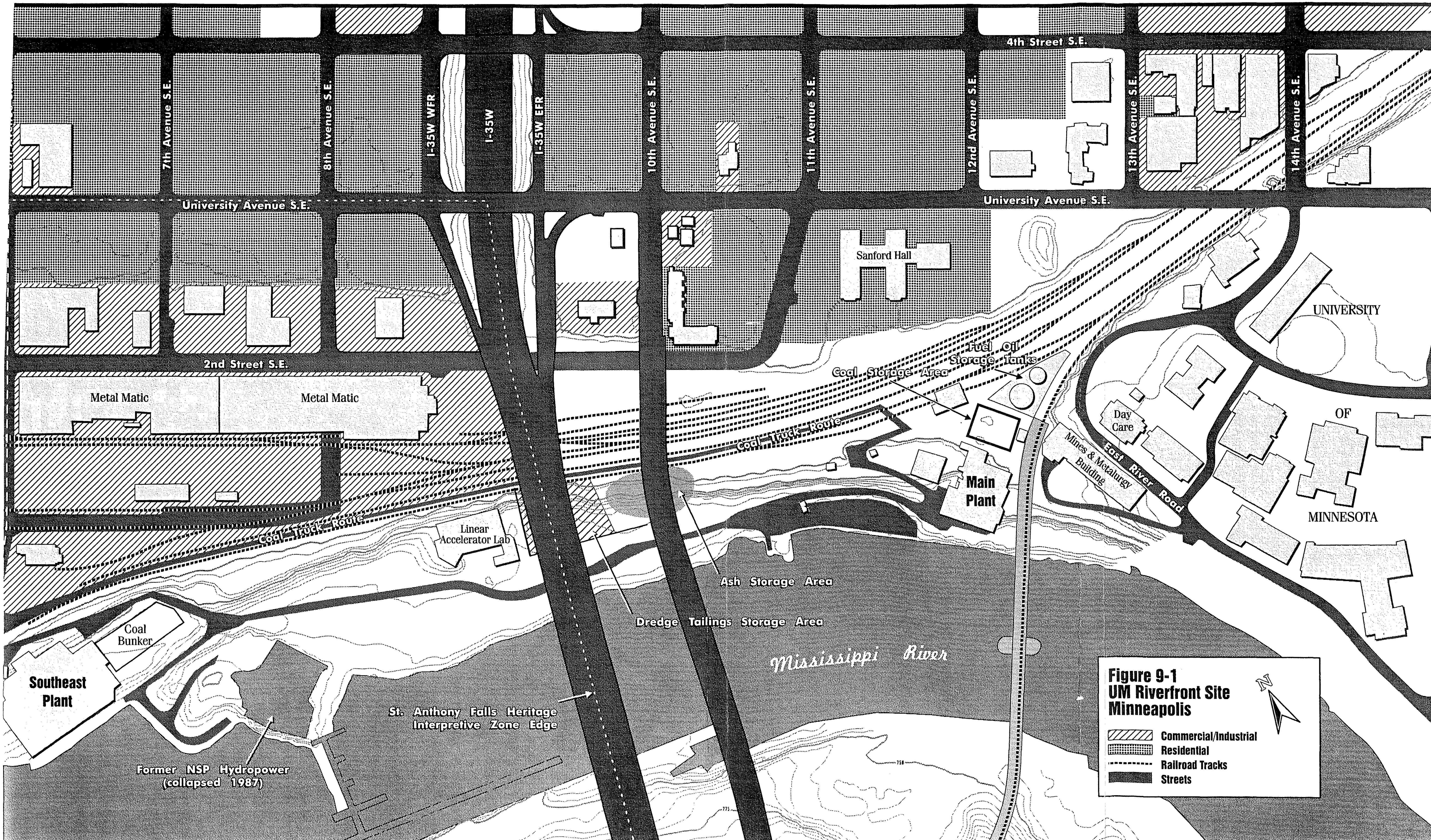
Marcy-Holmes Residential Neighborhood is Near Existing Steam Plants

The residential neighborhood closest to the steam plants, the Marcy-Holmes Neighborhood, is within 1,000 feet of the Southeast Plant (Figure 9-1). The major riverfront access route from Marcy-Holmes residential areas is along Sixth Avenue SE, which terminates at the Southeast Plant/Stone Arch Bridge. The Marcy-Holmes Neighborhood has proposed, and the City of Minneapolis has agreed to fund, a greenway connection along Sixth Avenue SE.

The Marcy-Holmes Neighborhood, according to the City of Minneapolis, has a strong and active citizens' association which struggles with issues associated with its proximity to the University, including conversion of single family dwellings to rooming houses, the accompanying parking congestion, and disinvestment. Comments on the DEIS indicate that many Marcy-Holmes residents view the riverfront as an important economic, recreational, and aesthetic resource that should be improved, and that access to the site should also be improved.

Figure 9-1a has been added to the FEIS to show the residential and other neighborhoods surrounding the University area and the


4th Street S.E.
3rd Avenue S.E.
4th Avenue S.E.
5th Avenue S.E.
6th Avenue S.E.
2nd Street S.E.
St. Anthony Main
Pillsbury A Mill
Main Street S.E.
NSP St. Anthony Falls Hydro
Father Hennepin Bluff Park
J.J. Hill Stone Arch Bridge
NSP Hydroelectric Hennepin Island Hydro
University Hydropower Research
St. Anthony Falls Historic District Boundary
St. Anthony Falls Heritage Zone Orientation Trail


4th Street S.E.
7th Avenue S.E.
8th Avenue S.E.
I-35W WFR
I-35W
I-35W EFR
10th Avenue S.E.
11th Avenue S.E.
12nd Avenue S.E.
13th Avenue S.E.
14th Avenue S.E.
University Avenue S.E.
University Avenue S.E.
Sanford Hall
UNIVERSITY
OF
MINNESOTA
2nd Street S.E.
Metal Matic
Metal Matic
Fuel Oil Storage Tanks
Coal Storage Area
Coal Truck Route
Day Care
Mines & Metalurgy Building
East River Road
Main Plant
Coal Truck Route
Linear Accelerator Lab
Ash Storage Area
Dredge Tailings Storage Area
Coal Bunker
Southeast Plant
Mississippi River
St. Anthony Falls Heritage Interpretive Zone Edge
Former NSP Hydropower (collapsed 1987)
Figure 9-1
UM Riverfront Site
Minneapolis
N
Commercial/Industrial
Residential
Railroad Tracks
Streets

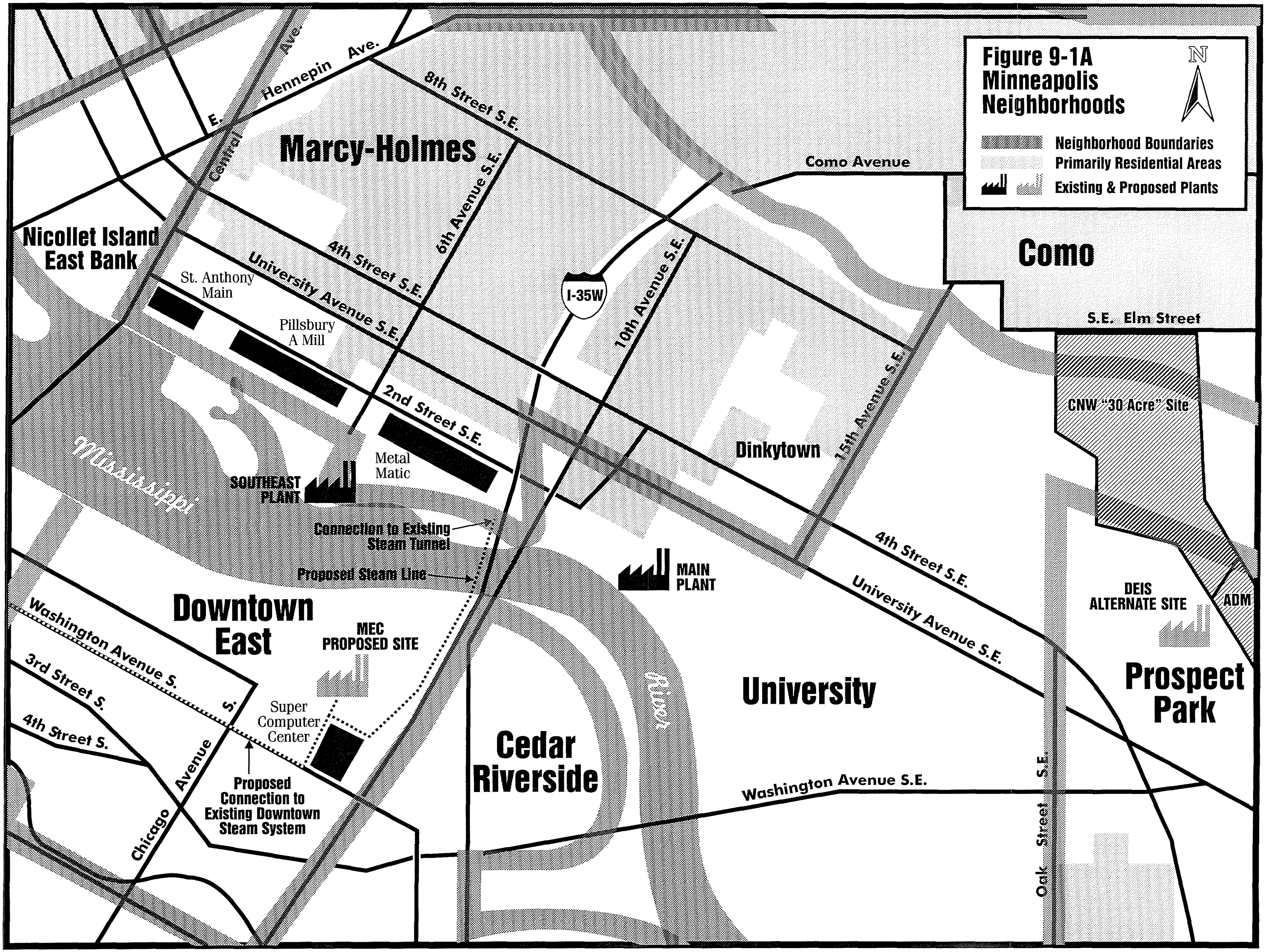


Figure 9-1A
Minneapolis
Neighborhoods
N
Neighborhood Boundaries
Primarily Residential Areas
Existing & Proposed Plants
Marcy-Holmes
Nicollet Island
East Bank
Como
Dinkytown
Downtown
East
Cedar
Riverside
University
Prospect
Park
E. Hennepin Ave.
Central Ave.
8th Street S.E.
6th Avenue S.E.
4th Street S.E.
University Avenue S.E.
2nd Street S.E.
Como Avenue
S.E. Elm Street
I-35W
10th Avenue S.E.
15th Avenue S.E.
CNW "30 Acre" Site
St. Anthony
Main
Pillsbury
A Mill
Metal
Matic
SOUTHEAST
PLANT
Mississippi
River
Connection to Existing
Steam Tunnel
Proposed Steam Line
MAIN
PLANT
DEIS
ALTERNATE SITE
ADM
MEC
PROPOSED SITE
Super
Computer
Center
Washington Avenue S.
3rd Street S.
4th Street S.
Chicago Avenue S.
Proposed
Connection to
Existing Downtown
Steam System
Washington Avenue S.E.
Oak Street S.E.

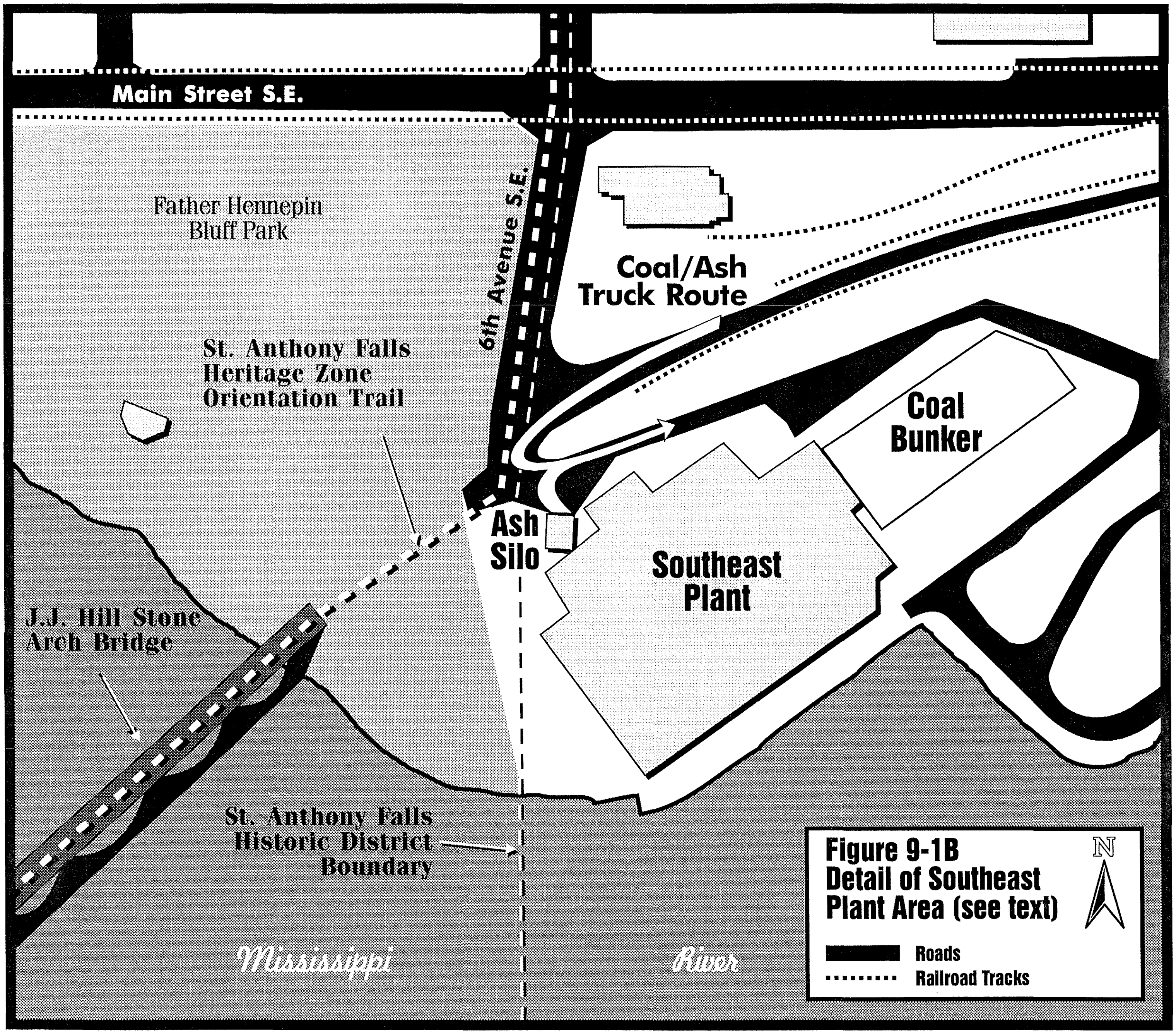


Figure 9-1B
Detail of Southeast
Plant Area (see text)

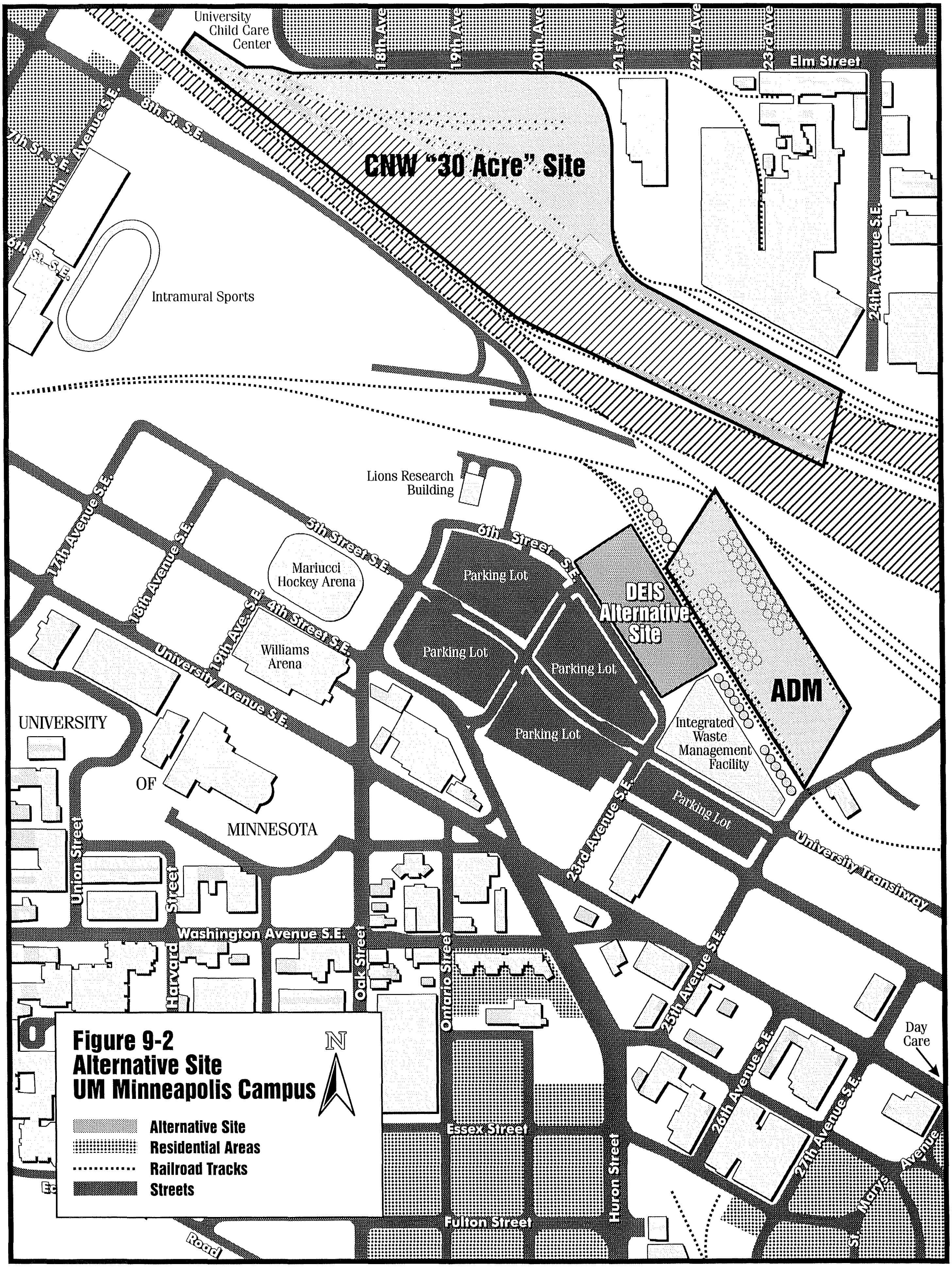


Figure 9-2
Alternative Site
UM Minneapolis Campus

N

- Alternative Site
- Residential Areas
- Railroad Tracks
- Streets

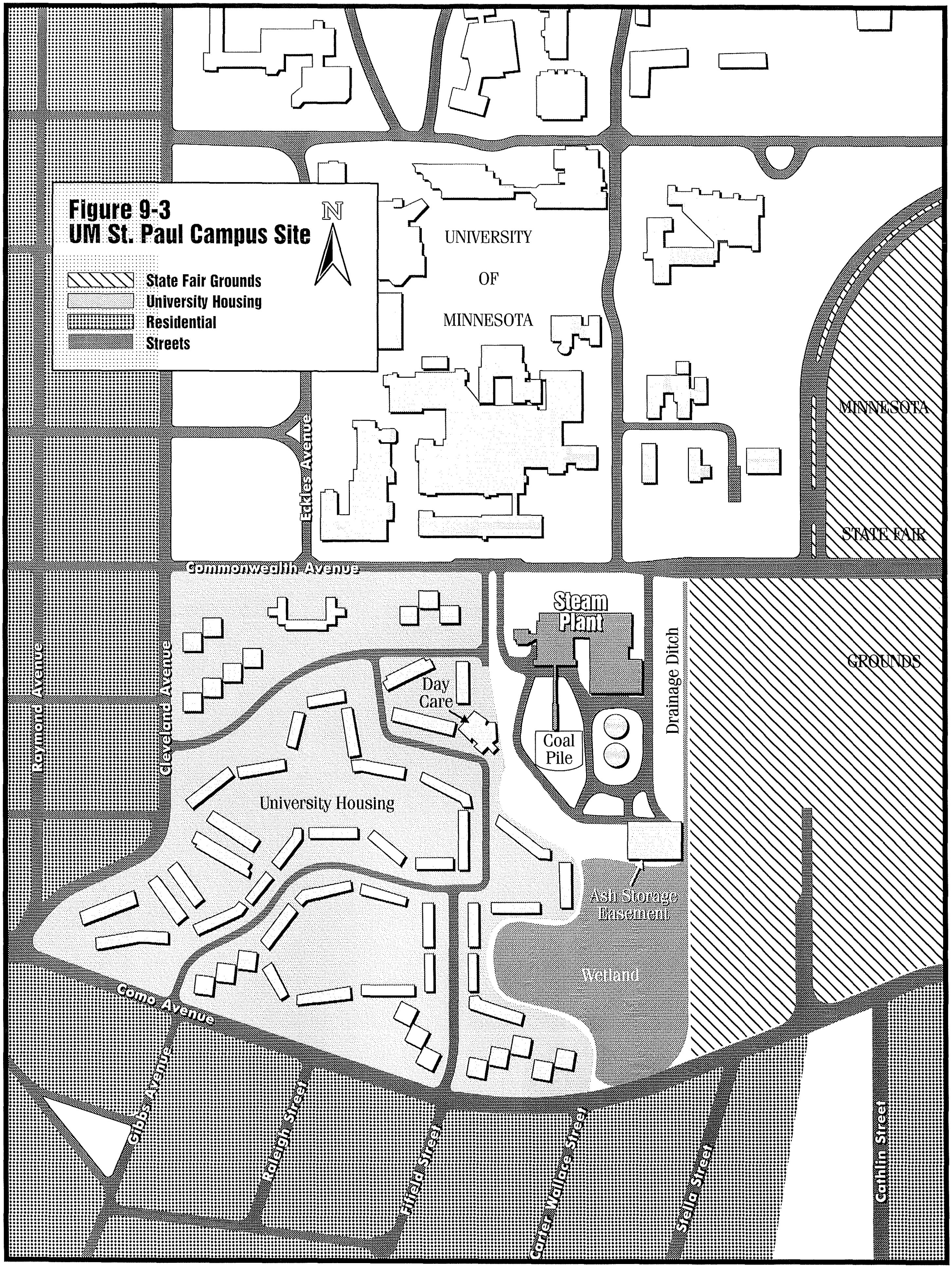


Figure 9-3
UM St. Paul Campus Site
N
State Fair Grounds
University Housing
Residential
Streets
UNIVERSITY
OF
MINNESOTA
MINNESOTA
STATE FAIR
GROUNDS
Eckles Avenue
Commonwealth Avenue
Steam Plant
Drainage Ditch
Day Care
Coal Pile
University Housing
Raymond Avenue
Cleveland Avenue
Ash Storage Easement
Wetland
Como Avenue
Gibbs Avenue
Raleigh Street
Fifield Street
Carter Wallace Street
Stella Street
Cahlin Street

locations of four potential steam plant sites: 1) the existing riverfront site, 2) the alternative site used in the DEIS, 3) the nearby "30-Acre site" being acquired by the University, and 4) the site across the Mississippi from the existing plants, proposed by the Minneapolis Energy Center.

Dam Flats are located between the Southeast Plant and the Main Plant

The Dam Flats is a level area between the river and the bluffs that extend between the Southeast Plant and the Main Plant (See Figure 4). Located within this area are the site of the former Northern States Power (NSP) hydropower facility and the access road connecting the two power plants.

The I-35W and 10th Avenue Bridges cross the Mississippi in the middle of the Flats area. Storage sites for dredged river sediment, the ash storage area, and the University's Tandem Van de Graaf Linear Accelerator Laboratory are located under the bridges, to the north of the flats and across the access road from the river.

Collapsed NSP Hydropower Facility Next To SE Plant

The hydropower facility in the Dam Flats area collapsed in 1987. NSP has no immediate plans for rebuilding this facility but is planning to make a final decision about rebuilding within the next year.

Dredged Material and Ash is Stored on Dam Flats

Under the 10th Avenue Bridge, east of the accelerator building, is an open cement bunker owned by the City of Minneapolis, into which material dredged from the river is deposited.

Ash from the steam plants is also temporarily stored under the 10th Avenue Bridge. When the ash is cooled, it is removed by truck to its final landfill destination. (See Chapter 11 for ash handling and Chapter 8 for ash disposal details). A barge slip and several small service buildings are also located on the Dam Flats.

Coal trucks deliver coal to Southeast Plant on a route above the bluff.

Above the riverfront bluff, coal is transported from the Main Plant coal receiving area to the Southeast Plant coal bunker in 10-ton trucks over an easement between the railroad tracks and the bluff face. Approximately 7500 coal trucks currently use that route each year, or an average of about 20 per day (more in winter, less in spring and fall).

Hennepin Bluffs Park Stone Arch Bridge Located Next to SE Plant

Just west along the river from the Southeast Plant is Father Hennepin Bluffs Park, which includes the site of the former hydropower tailrace outlets and a small urban park.

At the Park's eastern edge, closest to the Southeast Plant, the Stone Arch Bridge was recently renovated and reopened to pedestrian and bicycle use, thereby completing the central riverfront trail loop.

West of Father Hennepin Bluffs Park, along the river and extending onto Hennepin Island, are NSP's Hennepin Island hydroelectric facilities and the University's hydropower research facilities. Directly across Main Street, away from the River, sits the Pillsbury A Mill. The railroad corridor terminates at the Pillsbury complex.

The Area to the Immediate North is Primarily Industrial

The land north of the rail corridor from I-35W to as far west as 3rd Avenue SE is primarily industrial. Included here are Metal Matic, a large steel manufacturing facility that dominates the area, and a number of smaller manufacturing and industrial supply firms. A view of the existing Southeast Plant from the north is shown in Figure 9-4a.

Nearby Riverfront Attractions Described

Nearby riverfront attractions include a historical marker for Father Hennepin's first view of St. Anthony Falls (a few yards from the Southeast Plant), the restored Nicollet Island Inn, Riverplace, Boom Island Park, Lourdes Church, the Ard Godfrey House, East River Parkway, the Mississippi Gorge, the Whitney Hotel (opposite end of the Stone Arch Bridge), the Upper St. Anthony Falls Lock & Dam and Observation Deck, the planned public space in front of the new Federal Reserve Building, the proposed National Park Service St. Anthony Falls Center, the proposed St. Anthony Falls Heritage Board's Washburn/Crosby Complex Orientation Museum, and the proposed Mill Ruin Park.

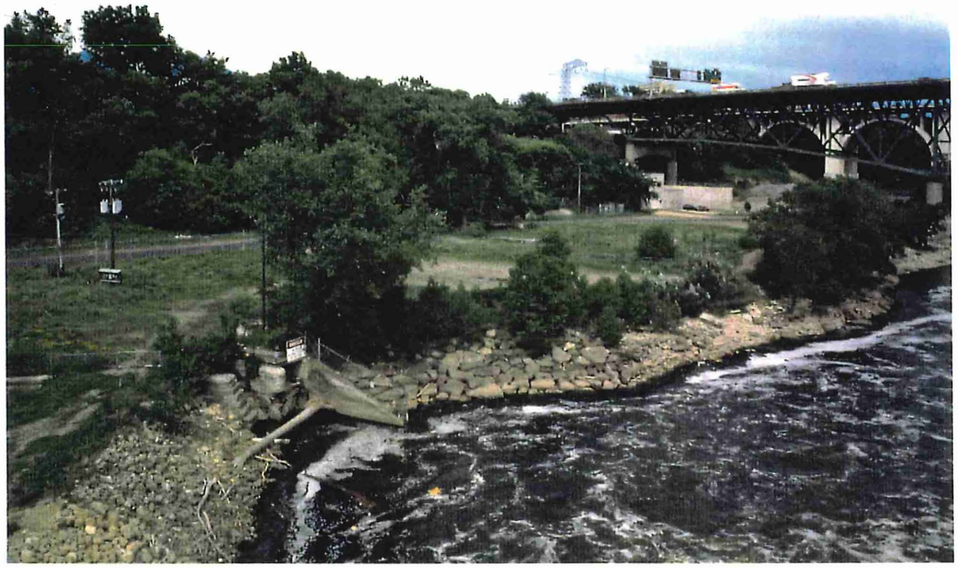
Two daycare facilities are located nearby.

There are two daycare facilities located near the riverfront steam plants. One daycare is located at 2nd Street and 8th Avenue SE. The second daycare is located across East River Road near the Main Plant. The daycare is operated by the University's Education Department.

Area Surrounding Primary Off-River Site is Mostly Industrial

The alternative site encompasses 23.8 acres between 17th Avenue SE on the west, 25th Avenue SE on the east, 4th Street SE on the south and the Burlington Northern railroad

Figure 9-4



Riverfront Dam Flats Area: Down River View From Near SE Plant

Figure 9-4a

Existing View of Southeast Plant from Sixth Avenue SE on the north. The site is currently undeveloped and overgrown with weeds.

The University Transitway forms the boundary of the site, separating it from a parking complex on the south. The new University of Minnesota Integrated Waste Management facility is located immediately east of the Alternative Site and the Modular Genetic Research facility immediately west of the site. The Williams and Mariucii Arenas are nearby. Intramural sports facilities lie just north of the Lions Research Facility (Figure 2).

Residential

There is residential development approximately 1/2 mile from the site, and a public housing project at St. Mary's Avenue and Williams Avenue. Other housing extends south from the Huron/Essex and Erie/Delaware areas.

Daycare

The Children's World Montessori school is located across University Avenue from the project area at St. Mary's Avenue.

Second Possible Off-River Alternative Site Described

The University of Minnesota has requested that an additional alternative site be addressed in the Final EIS. The site is a 30 acre area generally bounded by Elm Street SE on the north, the southerly extension of 21st Avenue SE on the east, and the southerly boundary of the Chicago and North Western railroad property to the south and west. Alternative site #2 is adjacent to the alternative site discussed in the Draft EIS. Figure 9-2 has been revised for the FEIS to include this second potential off-river site.

The site currently contains vacated railroad marshaling yards and underutilized railroad property. Several small and medium sized structures remain on the site. A large sign announcing leasing available for Phase I of the South East Minneapolis Industrial Park is located on the property near the intersection of Elm Street and 17th Avenue SE.

The University is currently seeking to acquire this site by eminent domain for general University purposes. A number of University uses, including soccer fields, married student housing, or a power plant have been suggested. If the University obtains the land, the ultimate use for the site will not be determined until the University completes its master plan for the campus.

MCDA Interested in Second Off-River Alternative Site For Industrial Park

The University's acquisition of this property has been opposed by the Minneapolis Community Development Agency (MCDA) and CSM Investors, Inc. A hearing on the matter is scheduled for July 1995.

Alternative site #2 is also identified by the City of Minneapolis as Phase I of the South East Minneapolis Industrial Area (SEMI) Redevelopment Plan. The entire SEMI area consists of approximately 300 acres of underutilized railroad yards and blighted industrial properties located in Southeast Minneapolis (extending roughly from the new alternative site southeastward to the Minneapolis city boundary). The city and MCDA have studied the potential for redevelopment of the SEMI area for several years. The city reports that many of the existing land uses in the SEMI area are obsolete and exert a blighting influence upon adjacent residential and industrial areas, and some of the current owners have indicated an interest in selling their properties.

The MCDA has been approached by a developer, the CSM Corporation, that is interested in developing alternative site #2 (SEMI Phase I). CSM has negotiated an option to purchase this property from Chicago and North Western Transportation Company. CSM proposes to build six industrial buildings on this site containing approximately 450,000 square feet of space.

A new tax increment financing district has been created for this site. Tax increment funds may be used for soil correction, pollution testing and remediation, demolition of outbuildings, asbestos removal, track removal and relocation, and the provision of public infrastructure.

Section 9.2 Land Use Conflicts

Southeast Steam Plant pre-dates many surrounding land uses.

Continued operation of the Southeast Steam Plant as described in the proposal would have no new effect on existing land use, although a number of existing land use conflicts would continue, and some would be increased. The Plant has operated nearly continuously since 1903; its operation predates many of the land uses around it; and those other operations were aware of the Plant's presence when they located in the area.

Land Use Conflicts Due to Use of Coal Most Significant

The most significant land use conflicts caused by the proposed steam plant renovation are due to coal storage, handling, transport and ash. The major impacts are the following:

- Aesthetic impacts on nearby residential areas;
- Land use conflicts between coal and ash trucks and bicyclists and pedestrians;
- Fugitive dust

Residential Buildings Overlook Main Plant Coal Facility

Across the rail corridor from the Main Plant are a dormitory (Sanford Hall) and a row of historic brownstone apartments (Florence Court). Both residences have a clear view of the coal during the winter, when the leaves are gone from the trees along the railroad tracks. Figures 4 and 5 simulate before and after view of the Main Plant area with the coal and fuel oil storage removed, as could be accomplished under Alternatives 6 and 7. Alternative 4 (gas and fuel oil) would allow for the removal of the coal storage but not the fuel oil tanks. Alternative 3 would retain the coal and oil storage, but would enclose the coal pile in some type of structure. There is an option in the University proposal to partially screen the coal pile but the screen would not block the view of the coal pile from across the railroad tracks.

Riverfront Traffic Also Created by Non-Steam Plant Land Uses

Another source of truck traffic in the area is the City of Minneapolis's Dredge Storage site, located under I-35W. Apparently, this site periodically generates a large amount of traffic on the riverfront and on access roads. In 1994, according to the University, the Corps of Engineers used a front-end loader to move about 80,000 tons of dredge material across the riverfront access road to the storage area. At the same time, much of the dredge material was hauled away by truck, requiring another 3,000 two-way truck trips past the Southeast Plant and the Stone

3,000 two-way truck trips past the Southeast Plant and the Stone Arch Bridge.

Coal Transport on Riverfront Would Increase under Proposed Project, but Decrease under Alternatives

One impact on existing land use under the proposal would be an increase in the number of coal trucks. Under the proposed project, total coal use would decrease slightly, but all the coal would be used at the Southeast Plant. The coal would continue to be received and stored at the Main Plant site, although the Main Plant itself would be retired.

Assuming economic fuel dispatch, coal use at the Southeast Plant is estimated to increase from about 71,000 tons per year currently to about 135,000 tons under Case A and about 110,000 tons per year under Case B. This would increase the number of trucks using the railroad easement from about 7500 10-ton trucks per year currently (an average of about 20 per day, more in winter, less in spring and fall) to about 13,000 per year under Case A. Alternatives 3, and the coal conveyor option in Case A and Case B, would eliminate coal truck traffic.

Coal Transport by Truck Conflicts with Bicyclists and Pedestrians.

Both the existing and the proposed facility conflicts with bicyclists using the area, particularly the easement road used by the coal trucks. The road is not a designated bicycle route, and bicyclists and pedestrians are currently discouraged from using it. However, this route is apparently often used as the most direct route between the University area and the historic, residential and retail areas. Conflicts with this use and the coal trucks would continue under the proposal without the optional conveyor systems. Moreover, as detailed in section 9.5, continued use of coal in the future constrains the planned development of new bikeways (and a planned motorway).

FEIS Figure 9-1b Shows Site of Potential Traffic Conflict at Stone Arch Bridge

Coal trucks and ash trucks from the steam plant operation also potentially conflict with pedestrians and bicyclists using the recently completed Stone Arch Bridge, which is part of the St. Anthony Falls Historic Trail. Concrete "jersey" barriers currently separate truck and automobile traffic from pedestrian traffic. Figure 9-1b has been added to the FEIS to show more clearly the location and nature of the potential traffic conflict. Other traffic accessing the riverfront, like the trucks hauling dredge tailings from the City's storage area, also contribute to this conflict.

Coal Conveyer or Off-Site Alternative Eliminates Coal Truck Traffic

The University's contract with Foster Wheeler includes an option to install a coal conveyor in the existing tunnel between the two plants that would eliminate the use of coal trucks (except when the conveyor required maintenance). This option is detailed in Chapter 10 on mitigation.

The conveyor system is also included in the design and cost of alternative 3. Alternatives 4, 6 and 7 would eliminate the use of coal on the riverfront altogether.

Ash Truck Traffic Would Increase under Proposal, Cease Along Riverfront under Some Alternatives

The number of ash trucks using the access road to and from the ash storage area would also increase, from about 800 trucks per year (from both plants), to about 1000 (Southeast Plant only). Alternatives 3, 4, 6 and 7 would eliminate ash truck traffic along the riverfront (although ash trucks would travel from the facility to a landfill under alternatives 3 and 6).

Fugitive Coal Dust Could Be Mitigated or Eliminated

Although the air quality analysis in chapter 6 indicates that fugitive coal dust levels are within regulatory limits, visual observation at the Main Plant site and anecdotal information from neighbors indicates annoyance levels of dust from the coal handling operations. Potential changes in coal use, storage, and handling would reduce these levels to varying degrees. Alternative 3 encloses all coal handling within a covered structure, and such a system could be implemented with either proposal option as well.

Trails and Parkway Conflicts Addressed in Separate Section

Other impacts of the proposal or alternatives at the riverfront site that could be classified as land use conflicts, such as conflicts with planned trails or parkways, but for the EIS are discussed under different sections of this chapter.

Alternative Site Impacts Include Large Use of Space

The coal-based alternative 6 would require a larger "footprint" than a 100% gas/oil plant because of the enclosed dome-shaped coal unloading and reclaim facility and other associated space requirements, leaving little if any space for additional future University development. Visual impacts at this site are addressed below.

Residential Areas and Child Care Center Border Alternative Site

Immediately north of the potential "30-Acre" alternative site, across Elm Street, are medium and low density residential areas in the Como Neighborhood. A University child care center is currently located adjacent to the northeast corner of the site. Light and general industry are to the east and south of the site and land owned by the University to the southwest. The site is zoned for industrial use.

Access to the site is currently provided by Elm Street. However, an additional road along the southern boundary of 30-Acre site is part of a plan by the city for new roadways to serve the entire South East Industrial Area. The city has proposed a system of new roadways to provide access to areas currently served only by rail lines.

Impacts of Steam Plant Traffic No Greater than Those from Other Industrial Uses

In general, local traffic impacts generated by a steam plant, from trucks hauling wood chips or ash, are likely to be no greater than the impacts associated with other general industrial uses. In addition, University use of the site for something other than a steam plant would likely produce similar amounts of traffic, differing only in consisting of more automobiles and fewer trucks.

However, the 30-Acre site is large and could accommodate either a primarily solid-fuel or a natural gas/fuel oil plant. Siting a power plant in the northern or northwestern part of the site without adequate buffering could create conflicts with the nearby residences and daycare facility. Detailed analysis of any potential noise, traffic, or other impacts on surrounding land uses cannot be completed without a more specific site plan indicating the location of the plant within this site.

Soil and Groundwater at Second Site are Likely to be Contaminated

A Phase I Environmental Site Assessment of Alternative Site #2 was conducted in May 1995 by a consultant for the University. This study found that there is a potential for site contamination from 1) past use and storage of hazardous substances, 2) hazardous wastes, 3) releases and spills of petroleum products, and 4) the proximity of numerous verified hazardous substance and petroleum release sites, some of which are potentially uphill from the property. The University is planning a Phase II study for the site.

A Phase I and Phase II Environmental Site Assessment report on this site has also been completed for Chicago Northwestern Railway. The railway has requested that the MPCA treat the report as non-public data.

Section 9.3 Visual Impacts

Visual Impacts Illustrated Graphically in Figures

Visual impacts at the Southeast Plant, existing, continued, and new, are illustrated in Figures 7 through 10.

Existing Plants Are Visible and Create an Industrial Atmosphere

The Main and Southeast plants are located along the river bank, and can be viewed by river travelers and local roadway traffic from downtown Minneapolis, local parks, the St. Anthony Falls Historic District and Interpretive Trail, and to a lesser extent, from areas on the Minneapolis campus (e.g. Sanford Hall) and from nearby residential areas.

The skyline near the existing plants is dominated by the steam plant stacks which are black and do not blend well with the surrounding area and by other large industrial facilities. From the nearby Hennepin Bluffs Park and other areas to the immediate north of the plant, pollution control equipment and the existing ash silo are also visible, thereby further creating an industrial atmosphere in the immediate area (Figure 4a is a picture of the "back" of the Southeast Plant).

In addition, the dust and appearance of the open coal storage areas generally reduce the aesthetic quality of the area. For example, compare the views of the Main Plant area in Figure 5 with the simulated view of the same area in Figure 6 without the coal and fuel oil storage.

View of Southeast Plant Affected by Proposed Project and Alternative 1

The proposed building-height modifications and structural improvements to the Southeast Plant will affect both the riverside view and the view from the Stone Arch Bridge. These impacts are illustrated by two computer enhanced photographs simulating the proposed height increase (Figures 8 and 10). Alternative No. 1-the "No-Action" alternative-would have a visual impact on the Southeast Plant similar to that of the proposed project, but not until the year 2001, when existing boilers would likely be replaced by two new coal-fired boilers that would require a increased roof height.

Smaller, new equipment-including an air cooler and another ash silo-would be visible from the north side of the building. Projected impacts on other parts of the riverfront area are minimal. The "back" of the Southeast Plant could be screened from view somewhat as well.

Other Alternatives would change appearance of Area Near the Main Plant.

Alternatives No. 3 and 4-the two other riverfront alternatives-would not much affect views of the Southeast Plant, but would affect views of the Main Plant asea. Alternative 3 includes an entirely covered coal unloading and storage structure. (A covered coal handling system could also be implemented as part of the proposed project at additional cost but is not presently proposed). A domed structure similar to that shown below for alternative 6 would not fit near the Main Plant, but an alternative coal silo or tent-shaped structure could be designed.

Alternative 4, which eliminates the use of coal, would allow the coal handling and storage area near the Main Plant to be decommissioned, but the existing fuel oil tanks would remain, and additional tanks in the area would probably be required.

Alternatives 6 and 7 would allow the decommissioning of coal and oil storage at both riverfront plants. In addition, the appearance of the landward side of the Southeast Plant (see Figure 4a) could potentially be enhanced by the removal of ash handling and pollution control equipment if the facility was no longer used for steam generation.

Visual impacts at Off-River Site Involve 200-Foot Stack

The area near the 23 Acre alternative site is generally industrial and of less aesthetic value than the riverfront site, so any visual impacts should be less important. The area can be seen from nearby University office buildings and research facilities, the recently completed Waste Management facility, Williams Arena, Marriucci Arena, local University offices and a hotel.

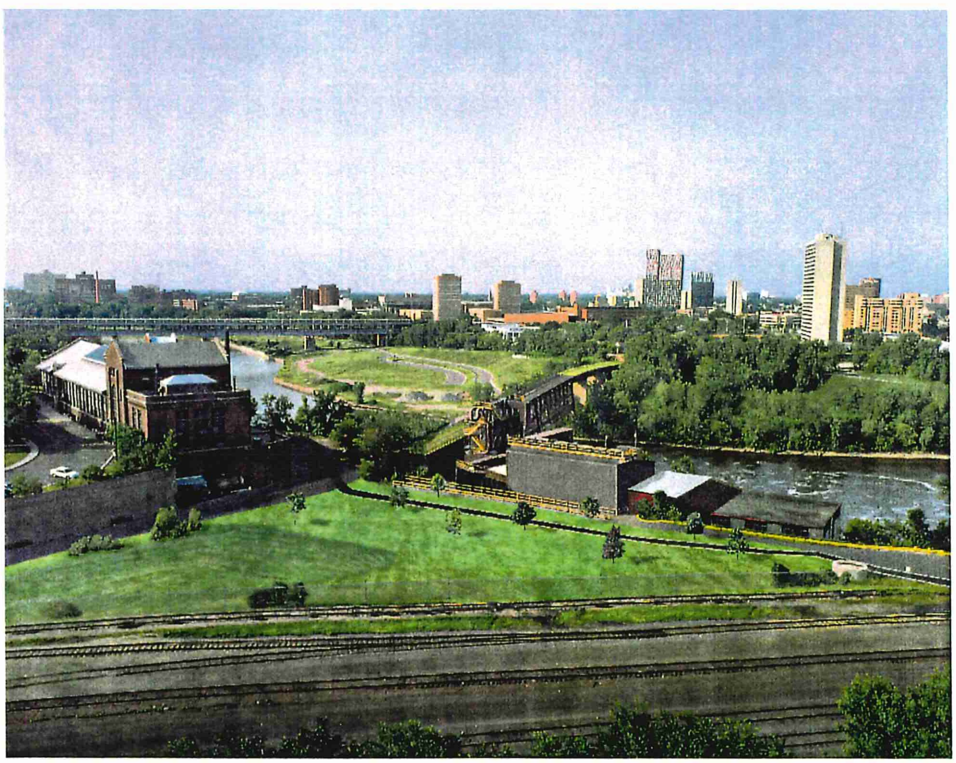
A photorealistic image of a possible version of coal and natural-gas alternatives for this site are shown in Figure 11 (existing), Figure 12 (coal, gas, fuel oil), and Figure 13 (100% gas/oil).

Air quality modeling indicates that a 200 foot high stack is likely to be required for proper air emission dispersion (see Chapter 6). The stacks of a new facility would not be higher than the nearby existing tower, but the nearby view of the existing grain elevators would be screened from the south, and the view of the Archer Daniels Midlands grain elevators, which can be seen from as far away as I-94 to the south, would be affected.

Figure 9-5

Existing View of Main Plant Coal Operations From Sanford Hall

Figure 9-6



Computer Enhanced Image of Main Plant Area:
Coal Operations and Fuel Oil Tanks Removed

Figure 9-7

Existing View of Southeast Plant From Riverfront

Figure 9-8

Computer Enhanced Image of Southeast Plant:
After Proposed Modification

Figure 9-9

Existing View of Southeast Plant From Stone Arch Bridge (Before Bridge Reconstruction)

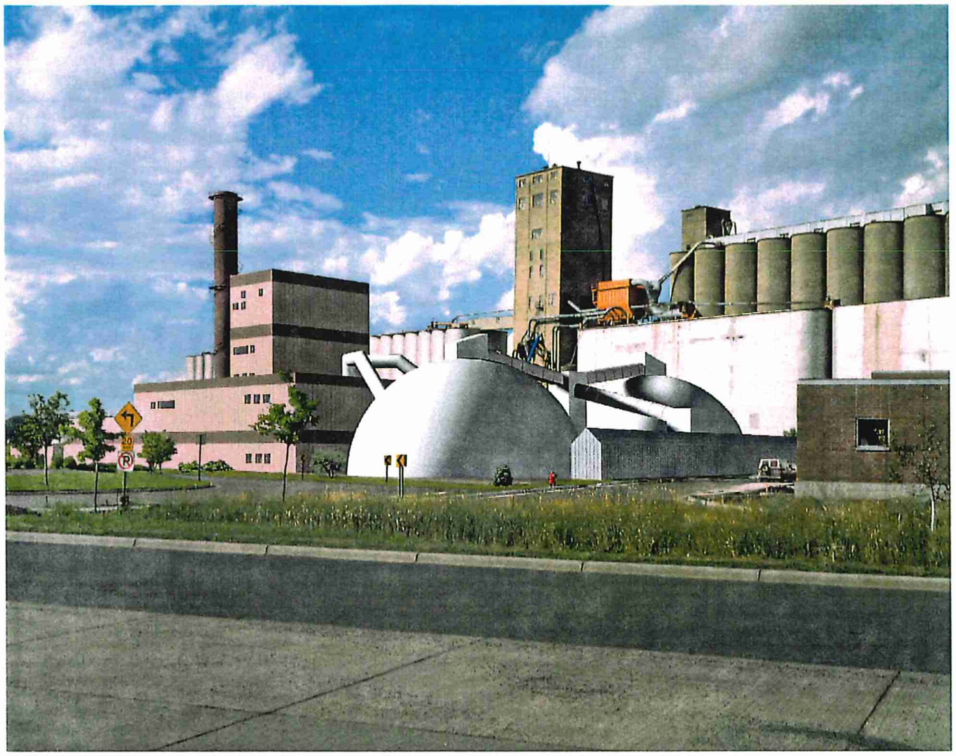
Figure 9-10

Computer Enhanced Image of Southeast Plant From Stone Arch Bridge: After Proposed Modification

Figure 9-11

Existing Alternative Site Near Stadium Village From Nearby Parking Lot

Figure 9-12



Computer Enhanced Image of Alternative Site: Coal/Oil/Natural Gas Facility

Figure 9-13

Computer Enhanced Image of Alternative Site: Natural Gas/Fuel Oil Only Facility

Section 9.4 Historic Significance

Southeast Steam Plant is Historically Significant

The Southeast Steam Plant has been proposed for inclusion on the National Register of Historic Places, and may be included on the Register by January 1995. The Southeast Steam Plant was built between 1902 and 1903 by the Twin Cities Rapid Transit Company to help meet the increased demand for electricity for its streetcars and to compensate for unpredictable interruptions in hydroelectric power. A detailed history of the Southeast Plant is available in the Minnesota Historical Society's application for the Register.

The Steam Plant incorporated a number of innovations in illumination and coal-handling, including the addition of sky lights over the engine room and light shafts over the coal bunkers. The coal bunker arrangement was described at the time as a radical change from the usual design of overhead bunkers. None of these innovative features survive today.

The Main Plant is Probably of Minor Historical Significance

The Main Plant was built in 1912-1913 and sits on a parcel of land granted to the University in the 1850's as part of the University's original land grant. Throughout the years there have been several additions to the building, all related to the operation of the Plant.

The Main Plant is not on the National Register. The State Historic Preservation Officer (SHPO) has given some minor consideration to the historic significance of the Main Plant. At this point it is not considered a historic building although the SHPO advises that a second look at the building's significance may be needed.

Main Plant Would Be Retired under Proposed Project

Under the proposed project, the Main Plant would be retired, but the site would continue to be used to receive and store coal for use at the Southeast Plant.

The University has no immediate plans for the Plant if it is retired, although they have considered demolishing it or converting it to an office building. In 1992 demolishing the plant was estimated to cost at least $1.1 million, and converting it into an office building was estimated to cost $8.5 million.

Renovation of SE Plant Should Conform With National Historic Renovation Standards.

If a planned renovation of a building on the National Register is federally funded, or if a project requires federal permits or state permits with federally delegated authority, the SHPO has authority to review proposed project for conformance with the Secretary of Interior's Standards for Rehabilitation. Federal funding is not currently being proposed for this project and it is unclear whether the federally delegated air emission permits from MPCA would trigger SHPO review.

If a renovation project is carried out by a state agency on a building on the National Register, the SHPO has authority to review such a project under state law. State law is ambiguous as to whether the University qualifies as a state agency in these situations.

Despite ambiguities in the SHPO's authority to review the proposed renovation plans, the University has voluntarily consulted and plans to comply with that agency's guidance.

Standards for Rehabilitation May Apply to Roof Height Increase

The Secretary of Interior's Standards for Rehabilitation contain guidelines for repair, maintenance and change of historic buildings. The guideline most applicable to this project involves roofs.

The Standards for Rehabilitation indicate that additions to roof should be designed so that they: (1) are inconspicuous from the public right of way; (2) do not damage or obscure character--defining features; 3) should be set back from the wall plane and as inconspicuous as possible when viewed from the street; (4) be designed to make it clear what is historic and what is new.

The proposed project will involve raising the roof 40 feet over the southeast quarter of the building, changing its appearance. The University intends to architecturally coordinate the roof addition with the red brick and arched windows of the existing facade of the building. The likely appearance of the roof height increase from two different viewpoints is simulated in Figures 6 through 9.

Alternative #1, the "no-build" option would eventually have a similar impact on the roofline of the Southeast Plant. In this alternative, new boilers would be installed in approximately 2001 and this installation would require an also required an increase in building height. The other alternatives would not alter the appearance of the building.

The St. Anthony Falls Interpretive Plan envisions trails and interpretive sites in the area.

In 1971, the St. Anthony Falls Historic District was established to help maintain the historic character of the district. In 1980, the Minneapolis Heritage Preservation Commission established regulations for the District. The Southeast Steam Plant is located on the edge of this district but is not within it.

In 1988, the St. Anthony Falls Heritage Interpretive Zone was created, and the St. Anthony Falls Heritage Board was given responsibility for developing a plan for interpreting significant historical components in the Zone. The Southeast Plant is located within the Interpretive Zone.

The St. Anthony Falls Interpretative Plan lists the Southeast Steam Plant as one of 33 major historic assets in the area, which have the potential to be integrated into the interpretive plan. Although it is identified as a major historic asset, there are no specific plans or uses mentioned for the plant.

The Interpretive Plan envisions a heritage trail system that includes an orientation trail through the Heritage Zone and five smaller trails for interpreting the area using defined themes. The orientation trail crosses the Stone Arch Bridge near the Steam Plant but then heads to Hennepin Bluff Park and northward to the Main Street area. Neither the orientation trail nor any of the smaller theme trails include the Southeast Steam Plant. The Main Plant is not within the St. Anthony Falls Historic District or the Heritage Zone.

One Interpretive Use for Southeast Plant Precluded by Case A, Case B, and Probably No Action Alternative

Interest has been shown in renovating a currently unused upper-level control room in the Southeast Plant as an interpretive viewing area. The idea is that visitors would be able to view the operation of the steam plant from this room as well as examine the historic controls once used to operate the plant. The control room could become a stop on the historic interpretive trail network in the St. Anthony Falls Heritage Interpretive Zone.

In the proposed steam plant renovation, however, the control room is likely to be demolished for installation the new fluidized bed boiler. Even if this control room remained, the view of the plant floor would be blocked. The same result would occur under the Alternative 1, although not until 2001. Alternatives 3 and 4 would probably not conflict with this interpretive use. The off-river alternatives (6 and 7) would obviously not physically preclude the renovation of the control room as an interpretive site, however, if the Southeast Plant is retired as an active steam plant it is problematic whether the building could be kept open for interpretive use unless a viable use is found for the building as a whole.

Alternative Site Borders Archer Daniels Midland Grain Elevator

A turn-of-century Archer Daniel Midlands grain elevator is located adjacent to the 23-Acre industrial site, but no other buildings have not been identified for any particular historic significance. (See section 9.3 for visual impacts of alternatives at this site). It is possible that these grain elevators along the railroad corridor near the alternative site may be of historic significance. The SHPO has not evaluated the elevators. The elevators are located across railroad tracks or otherwise separated from the alternative site and it is unlikely that development of the alternative site would significantly affect the historic value, if there is any.

Section 9. 5 Compatibility with City of Minneapolis Land Use Plans

Riverfront Area Has Been Subject of Many City Plans

The riverfront area in Minneapolis, which includes the Southeast Steam Plant and the Main Plant, holds special interest due primarily to the area's history and location, its recreational and scenic values, and its role in the preservation and restoration of the Mississippi River corridor. This special interest has led the City of Minneapolis, the University of Minnesota, the State of Minnesota, the federal government, and others to develop these numerous plans or programs for the area.

Many of the official riverfront plans and regulations published during the last twenty-five years were examined as part of the EIS study and are summarized in a separate report, *Summary of Land Use Plans, St. Anthony Falls Riverfront Area*, dated October, 1994.

Common Themes of Plans Include Open Space, Access, Preservation, Some Industry

The following City of Minneapolis plans were examined to develop the include the following list of "common themes" described below, upon which the evaluation in this section is based.

- Mississippi/Minneapolis (1972)
- The Mississippi River in Minneapolis (1975).Report of the Long Range Regional River Development and Acquisition Committee to the Minneapolis Park and Recreation Board (1976)
- Southeast Minneapolis Riverfront Plan (1976)
- Central Riverfront Open Space Master Plan (1977)
- Central Riverfront Development (1977)
- Central Riverfront Regional Park: Recreation Areas, Specifics of Development, Capacities, Estimated Costs
- Central Riverfront Urban Design Guidelines (1981)
- Metro 2000 Plan (1988)

Common Themes of City Plans for Riverfront Listed

The following themes for the riverfront emerge from the plans developed by the City of Minneapolis:

1. The City originated at the river but has since "turned its back" on it. Redevelopment of the riverfront will allow a valuable natural and historic resource to be more fully used.
2. An open space/greenway corridor, including pedestrian and bicycle paths, should follow both sides of the river. Public access to the river (often called "windows to the river") and activity nodes along the river are to be developed.

3. Preferred land uses are open space and residential. Any land uses, including industry, that do not need river access should be phased out. Industry that requires access to the river can be a desirable and compatible use. Such industry can offer interest to the riverfront.
4. Railroad tracks in the area that don't serve river terminals should be phased out.
5. Historic buildings should be preserved.

The following sections of the EIS discuss the compatibility of the proposed project and the alternatives with each of these themes.

University Has Unique Legal Status

The University of Minnesota was established in 1851 by an act of the Territory of Minnesota. The State of Minnesota was created about seven years later. Under the State constitution, the University is a constitutional arm of the state government and occupies a unique position. Its governing body, the Board of Regents, is generally free of legislative, executive, or judicial interference as long as it properly executes its duties.

Due to this status, it is not clear whether the plans, zoning and ordinances of Minneapolis and other entities are legally applicable to University land. However, regardless of its legal status, the proposal's compatibility with ordinances and land use plans for the surrounding community need to be examined to determine its potential impact on proposed land use.

Theme 1: Redevelopment of the Riverfront as a Natural and Historic Resource

Private and Public Funds have Been Expended Redeveloping the Nearby Riverfront Area.

Not only has much planning been done about recapturing the natural and historic values of the riverfront for public use, but also a substantial amount of public and funds have been spent in redeveloping the central riverfront area. The Minneapolis Community Development Agency (MCDA) reports that over 61 million dollars net have been spent by the City of Minneapolis and the MCDA on 13 projects in the central riverfront area. Another nearly 500 million dollars of money has been invested in these projects. The Minneapolis Park Board has invested 40 million dollars in development of the Central Riverfront Park.

Limited Funding Options Currently Available for the Conversion of the Southeast Steam Plant

If the Southeast Steam Plant were to be used for some use other than power generation, there would not be any currently budgeted source of funds for its purchase or conversion. The 1994-98 proposed capital improvement program of the Minneapolis Park Board does not include any capital expenditures in this portion of the riverfront. If this property did become available for purchase, the Minneapolis Park Board could seek funds from a variety of sources, including reprioritizing their own budget, special funds from the State Legislature, or potential grants through MNRRA.

The Southeast Steam Plant is currently proposed for inclusion on the National Register of Historic Places. Inclusion of the plant on the National Register will not make it eligible for any special funding for renovation. Investment tax credits are available for some historic rehabilitation but tax credits would be no advantage to the University.

Off-River Plant Opens Riverfront, but Eliminates Possible Innovative Coexistence Design

Moving the steam plant off-river would require construction of a new plant on property that the University currently plans to use for other purposes. In addition, it is possible that a creative riverfront design could successfully and creatively resolve these conflicts and integrate riverfront redevelopment plans with the continued industrial use of the Southeast Plant.

Several Plans Specifically Mention Southeast Plant

In 1972, the Mississippi/Minneapolis plan predicted that the Southeast Plant, which was then owned by NSP and used as a reserve power source, would cease operation and suggested that it could be used as an ecology center, museum or community facility.

In 1976, the Southeast Minneapolis Riverfront Plan suggested that the Southeast Plant building, which was not then in use, could be a river aquarium, a greenhouse, or headquarters for the Park and Recreation Board.

Also in 1976, the Central Riverfront Open Space Master Plan hoped to include the Southeast Plant in a historical interpretive network to portray the generation of power and steam from coal.

Theme 2: Riverfront Open Space, Greenways, Trails and Parkways

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All Plans Envision a Park or Greenway along the River

All the plans reviewed envision a park or greenway along the riverfront. Most plans call for continuous parkway in the Minneapolis central riverfront and St. Anthony Falls area, linking points of interest and connecting into other parkway systems.

The Minneapolis Critical Area Plan calls for a continuous trail corridor for motorists, bicyclists, and pedestrians along both sides of the river.

The Mississippi National River and Recreation Area Plan envisions a pedestrian/bicycle route along the entire 72 miles of river in the metropolitan area. This federal plan is discussed in Section 9.6.

City Must Acquire Land or Contract with Owners

To build a continuous parkway, the City must either acquire land along the riverfront or reach a cooperative agreement with the property owners. Riverfront property between the Southeast Plant and the Main Plant is owned primarily by the University of Minnesota and by Northern States Power.

University Is Predisposed to Cooperate With Trail Plans

The University's Critical Area Plan shows most of the Dam Flats area as recreation area or open space. The plan also states that the University encourages the establishment of a system of regional trails and notes a willingness to allow pedestrian access to the riverfront, except when it interferes with specific University needs or operations.

Operation of Southeast Plant Itself Does not Present Land Use Conflicts

Since the Southeast Plant operation in the building itself would not increase the land used for the plant, it is not in direct conflict with the goal of developing greenway, except to the extent that it would continue an existing industrial use.

The most notable conflict with greenway development is that the existing plants and coal handling operations constrain the improvement of access to and through the area as outlined in the following section. Plans for the area for the area do not require removal of the Southeast Plant, or that it cease to function as a steam production facility, provided that the operation could be made consistent with an open space or green space concept. As an historic building, the Southeast Plant is considered an asset to the area.

The Southeast Plant is located within the Central Mississippi Riverfront Regional Park. The boundaries of the park extend from the Plymouth Avenue bridge downstream to the I-35W bridge. Downriver from this point to the Ford bridge, both sides of the river are within another regional park, Mississippi River Gorge Regional Park. Not all of the land within the boundaries of these parks has been acquired.

Although the Southeast Plant and the Main Plant were excluded from acquisition plans in 1977, their existence and future operation could affect the Central Mississippi Riverfront Regional Park.

Feasibility of Proposed Trails

Proposed Motorway, Bikeways, and Pedestrian Pathways Evaluated; Constraints Identified

This section will discuss the compatibility of the project and alternatives with plans for motorway, bikeway, and pedestrian trail alignments shown in the various plans for the area. Several of the City of Minneapolis plans generally suggest the need for trails through the area, while others recommend specific alignments.

A feasibility analysis of the proposed trail alignments was completed by a registered landscape architect, Mr. James Robin as part of the EIS studies. The results are shown in Figure 14, and are available as a separate report. The following discussion relies on the accompanying Figure 14.

The Mississippi River below St. Anthony Falls is a gorge from fifty to one-hundred feet deep. The cliffs and bluffs bar access to the water, even though the bluffs have been substantially altered over the last century.

The trailway and access analysis, therefore, addresses the feasibility of proposed trail alignments based not only on the operation and location of the steam facilities, but also on other constraints, most notably the topography of the area, but also property ownership, current land use, and public health and safety considerations.

Without Major Construction, Main Plant Coal Operations Preclude Motorway Development

Plans propose an extension of East River Road to Main Street. These plans call for an at-grade roadway crossing through the area occupied by the existing coal and fuel oil storage area near the Main Plant. Barring the following changes, the continued operation of the Main Plant and the existing coal handling would preclude development of the proposed at-grade roadway.

Steam Facilities Modifications:

- Relocating existing Main Plant Coal operations
- Realigning or abandoning coal haul road

Other Modifications

- Widening the access road below the Mineral Resources Research Building, which could involve razing the building.
- Negotiating easements with the railroads and reconfiguring track alignments
- Reconciling the at-grade intersection with a future potential use of the Northern Pacific Bridge.

Alternatives 4, 6, and 7 Allow at-grade Motorway

These modifications would only be possible under Alternatives 4, 6, and 7. Alternative 3, although enclosing the coal operations, does not allow room for an at-grade motorway or trailway.

Other Solutions Are Possible, Including Bridge or Underground Space

Alternatively, a bridged parkway route over the coal/fuel facility may be feasible, but such an alternative would require civil and transportation engineering feasibility studies prior to implementation -- and a multi-million dollar capital investment--if the concept proved feasible.

A third possible solution involves using "cut and cover" construction to develop underground space for coal delivery, storage, and transport (coal transport from the Main Plant area to the Southeast Plant would be in the existing tunnel). This approach would allow the proposed at-grade motorway, and would also provide riverfront access for residents of nearby Sanford Hall and Dinkytown. The use of underground space, while technically feasible, would probably require such a gradual slope to accommodate the heavy coal-trains that the cut

UNIVERSITY of MINNESOTA STEAM FACILITIES E.I.S.

Minnesota Environmental Quality Board
658 Cedar Street, Saint Paul, Minnesota 55155

PROPOSED BIKEWAY

Suggested and/or shown in:

- Minneapolis Park and Recreation Board Heating Plant Area Study, 1993
- Minneapolis Mississippi River Corridor Critical Area Plan, July, 1989
- Central Riverfront Open Space Master Plan, 1977

Feasibility:
An at grade Bikeway as shown in the sudies above is not feasible unless the following conditions are resolved or a different alignment is proposed which avoids the main steam plant and avoids the ramp adjacent to the Southeast Plant

2a. Resolve the direct conflict ith the coal unloading structures, equipment and open storage adjacent to the Main Steam Plant
2b. Resolve the at grade intersection with the rail spurs
2c. Resolve safety problems on steep switchback ramp
2d. Resolve conflicts with existing and future coal handling at the Southeast Steam Plant
2e. Resolve the lack of visibility and conflict with cars at the blind corner adjacent to the coal bunker.
2f. Consider an alternate alignment with a raised parkway bridge.
2g. Consider an alternatge ramp structure
2h. Remove the Main Steam Plant building only which would allow ramp access from the upper level to the river edge.

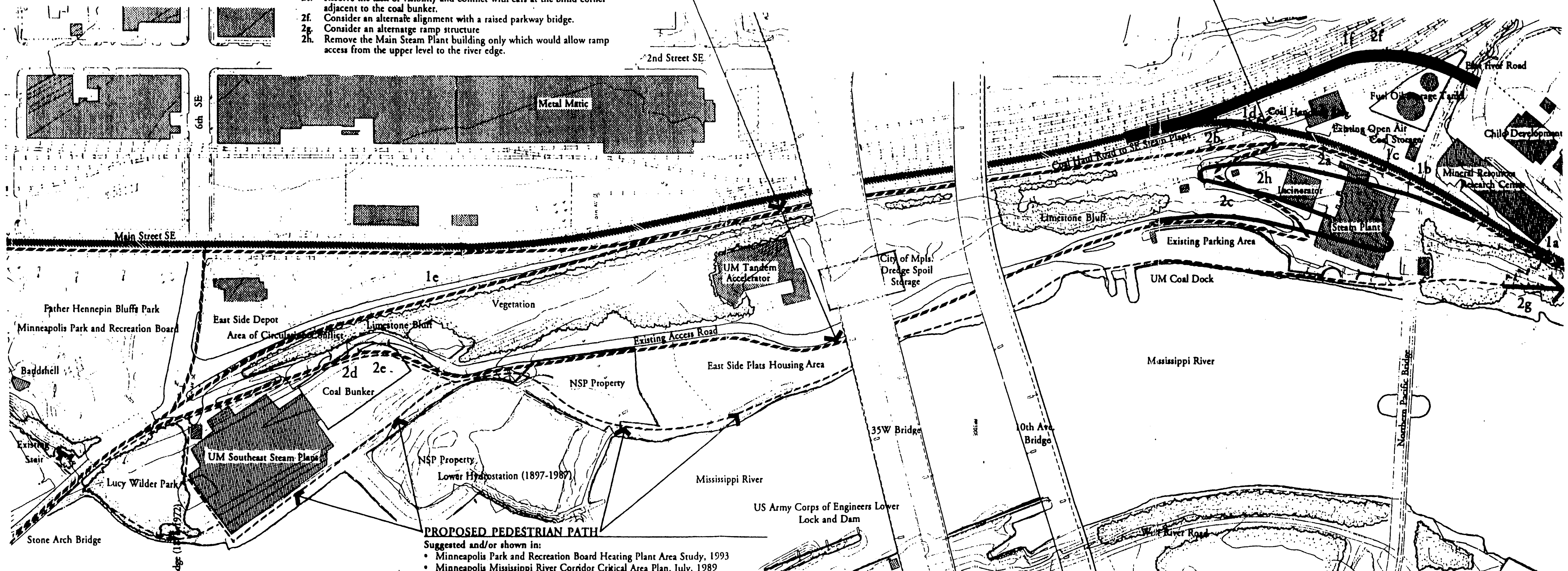
PROPOSED MOTORWAY

Suggested and/or shown in:

- Minneapolis Park and Recreation Board Heating Plant Area Study, 1993
- Central Riverfront Open Space Master Plan, 1977

Feasibility:
An at grade Park Motorway as shown in the studies above and consistent with Minneapolis Parkway Reconstructions is not feasible unless the following conditions are resolved or an alternate route to avoid between East River Road on the University Campus and SE Main Street is proposed:

1a. Resolve lack of space at corner of the Mineral Resources Research Bldg.
1b. Resolve at grade intersection with rail corridor
1c. Resolve direct conflicts with coal handling and storage
1d. Resolve at grade intersections with rail spurs
1e. Resolve conflict with coal haul road
1f. Consider an alternative route around and over the conflict area.



PROPOSED PEDESTRIAN PATH

Suggested and/or shown in:

- Minneapolis Park and Recreation Board Heating Plant Area Study, 1993
- Minneapolis Mississippi River Corridor Critical Area Plan, July, 1989
- Central Riverfront Urban Design Guidelines, August 1981
- University of Minnesota Mississippi River Corridor Critical Area, Sept. 1979
- Central Riverfront Open Space Master Plan, 1977
- Southeast Minneapolis Riverfront Plan, May 1976
- Mississippi/Minneapolis - A Plan for Riverfront Development, 1972

Feasibility:
The development of a pedestrian path as shown in the studies above is feasible and would not require any alteration of the existing steam production facilities.

The development of a pedestrian path would require the following action:

- a significant stairway would need to be constructed to connect the path vertically from below the Mineral Resources Research Building to East River Road.
- a walk along the river side and stair connection along West side of the Southeast Plant
- the path would not be entirely ADA accessible with stairs

LEGEND

- Proposed Motorway
- Proposed Bikeway
- Proposed Pedestrian Path
- Alternate Raised Parkway
- Alternate Bicycle Ramp

E W S

Scale: 0 100'

James Robin
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55331
612 / 474-3946

I hereby certify that this plan, specification or report was prepared by me or under my direct supervision and that I am a duly Registered Landscape Architect under the laws of the State of Minnesota.

Name: [signature]

Registration No. 12207 Date: 26-AUG-94

TRAIL and MOTORWAY FEASIBILITY ASSESSMENT

26 August, 1994

section would have to begin 2,500 feet or more back to the east. There are also numerous underground pipelines, tunnels, and lines in the area that would create difficult conflicts to resolve.

If feasible technically and financially, both the bridge and the trench concepts for crossing the coal/oil storage area would be possible under any of the alternatives or the proposed project.

Barring Changes, Main Steam Plant Coal Storage Operation Precludes Most Bikeway Development

The plans propose two bikeways along the riverfront between the two steam plants. An upper bikeway would follow the existing coal hauling road along the top of the bluff. A lower bikeway would follow the alignment of the existing access road through the Dam Flats area.

Barring changes, the continued operation of the Main Steam Plant and of the existing coal storage and handling facilities would preclude development of both "upper" and "lower" bikeways.

Dinkytown Bypass Could Link University Campus with Downtown Minneapolis

The Dinkytown bypass is a proposed commuter bikeway linking the University campus with downtown Minneapolis (see FEIS MAP 4 in Response to Comments). The University and the Minneapolis Public Works Department have requested federal funding for construction of this bikepath. The project would be completed in three phases.

In Phase 1, a paved bike path from Energy Park Drive to Oak Street would be constructed. Detailed design for this portion has been completed, and the project is scheduled for construction during the summer of 1995.

In Phase 2, a bike path along 5th Street from Oak Street to Central Avenue would be marked off. This phase involves no construction and is anticipated to be completed in 1996.

In Phase 3, a bike path along the railroad corridor from Oak Street to the Stone Arch Bridge would be built. This portion might also connect to East River Road and the existing bikeway system. Currently, only schematic plans for Phase 3 exist. The City of Minneapolis is responsible for developing detailed plans but is not expected to do so for another year or more. The University has indicated that it might have to exercise its power of eminent domain to obtain the necessary right-of-way from Burlington Northern Railroad.

As proposed, this bikeway would provide a commuter link from the University to downtown Minneapolis and Central Avenue (and possibly to East River Road, if a connection could be designed and implemented). This bikeway could be an important connection to a riverfront bikeway system but is not a substitute for a riverfront system.

Major Modifications Required for "Lower" Bikeway Route Under Any Alternative

Both bikeways would be possible if a connection to the University via East River Road were located along the lower access road alignment of the Mineral Resources Research Building. The proposed upper bikeway alignment, however, goes directly through the current coal handling and storage areas and would not be feasible if the coal handling and storage facilities were to remain in the current location. Bikes could then use existing road alignments as shown in Figure 14. And, as described below, expensive modifications would likely be required near both the Main Plant and Southeast Plant in order to make the "lower" route safe for bicycle traffic -- whether the coal handling remained in its existing location or not.

Modifications necessary to make the bikeways possible include:

SteamFacility Modifications

- Relocating or eliminating Main Plant coal unloading and storage area;
- For "lower" bike trail, expensively modifying or demolishing Southeast Plant coal bunker to provide safe line-of-sight on the trail alignment, given that continued vehicle access to the Tandem Accelerator Facility (and, if necessary, to the ash storage area) would be required;
- Redesigning or eliminating coal truck operations so as not to conflict with safe bikeway alignment.

Other Modifications

- Acquiring easements from the University and the railroad
- Resolving conflict with future potential use of the Northern Pacific Railroad Bridge
- Even with coal handling removed, the existing road from the Main Plant to the riverfront is too steep to be safe for bicycle use. Significant modifications of the lower alignment along the bluff would be required to improve safety. (See Figure 9-15, a photograph of the existing Main Plant access ramp to the riverfront.)

Alternatives 4, 6 & 7 Eliminate Coal and Allow Proposed Bikeway

The listed modifications would only be possible under Alternatives 4, 6, and 7.

Alternative 3 includes the use of coal, but uses a totally enclosed above-ground coal unloading, storage, and delivery system. Although this design would minimize the "footprint" necessary for coal storage, the analysis completed for this report indicates that space limitations would still preclude an at-grade motorway or bikeway through the existing coal handling area. Therefore, while enclosed coal handling facilities would eliminate fugitive dust problems, they would still preclude the "upper" access routes because of lack of space.

Alternative 4 would require the fuel oil tanks to remain in their existing location. No other sites for the tanks were found during the concept level assessment completed for this report. (Additional tanks for number 6 fuel oil would also be required. These tanks could be located near or within the Southeast Plant coal bunker.) Leaving the existing fuel tanks, but removing the coal handling, would provide room for bikeways and pedestrian paths, but the fuel tanks could still diminish the overall aesthetics of the trailway.

An alternative Lower Bikeway is Possible if Main Plant Removed.

Demolishing and removing the Main Plant and incinerator facilities (which is possible under both proposal options and all alternatives) could allow construction of the alternate "lower" route bike ramp shown, but that would require significant funding. The impact of the continued use of the Southeast Steam Plant itself on a lower bikeway is primarily confined to the line-of-sight conflict at the coal bunker.

Steam Plant Operations Do Not Affect Proposed Pedestrian Pathway

The proposed pedestrian pathway could be developed without altering existing steam plant operations and is therefore compatible with all options, but a significant investment would be required to overcome the topographical obstacles posed by the bluffs.

A steep stairway would be required to connect the path vertically from below the Mineral Resources Research Building to East River Road and a walkway along the river side and stair connection along west side of Southeast Plant would have to be constructed. The path would not be entirely ADA accessible. Easements from the University and NSP would be needed.

Theme 3: Preferred Land Uses Discourage Industry

Plans Agree that Industry not Dependent on River Location Should Move

The plans generally agree that industry that may be harmful to the river or is not dependent upon a river location should be phased out of the area. The *Mississippi River in Minneapolis* report, for example, stated that any facilities which did not require a location near the river should not be permitted to occupy valuable river frontage.

The *Mississippi/Minneapolis Plan* (1972) noted that industry should be phased out except for hydropower and "high employment" industry that offered a large number of jobs to nearby residents.

The *Minneapolis Critical Area Plan* (1989) recommended that the City establish a special riverfront-related land use category that would include industries providing strong tax revenues and requiring a riverfront location.

Steam Plants Not Dependent on River Location

Since their coal supply no longer arrives by barge but comes exclusively by rail, neither the Southeast Plant nor the Main Plant is dependent on a river location. Nor does either plant provide large numbers of jobs to area residents or high tax revenues. By these criteria, the continued use of the steam plants is not compatible with City of Minneapolis plans for the riverfront area. However, some specific plan provisions contradict this general conclusion.

Metro 2000 Plan Excepts Power Plants

For example, while the Metro 2000 plan lists open space as the priority for the riverfront, with residential second and nonresidential uses subordinate. it states that exceptions to this are the "powerhouses" (presumably NSP, the Southeast Plant, and perhaps the Main Plant), the Post Office, Mill Place, Riverplace, and St. Anthony Main.)

It is possible that the continued operation of the Southeast Plant could enhance the character and experience of the riverfront if conflicts can be resolved through creative solutions. Despite the many plans for the riverfront, there have been few feasible proposals for the joint use of the Southeast Plant facility, except the control room interpretive site concept described earlier.

Theme 4: Remove Railroad Tracks Where Possible

Plans Anticipate Removal of Railroad Tracks

The plans also anticipate that railroad tracks in the area would eventually be removed. The Mississippi/Minneapolis plan notes that all railroad tracks are expected to be removed from the area as industrial activity is reduced, except for the tracks leading to the Stone Arch Bridge and the Burlington Northern railroad bridge south of 10th Ave. The City's Critical Area Plan states that railroad spurs that don't serve river terminals should be eliminated and landscaped.

At this point, Burlington Northern does not plan to discontinue service on the rail corridor behind the project site as long as businesses in the area need rail service. The rail line serves Pillsbury and the University power plants. The rail line terminates at the Pillsbury mill.

Section 9.6 Special State and Federal Programs for the Riverfront

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Compatability with Critical Area Plans

State Critical Areas Act Program Enacted To Protect Areas of State-Wide Value

In 1973 the Minnesota Legislature passed the Critical Areas Act to protect areas possessing greater than local significance from being damaged by development.

If the governor, acting on the recommendation of the Environmental Quality Board (EQB), designates a critical area, local governments with jurisdiction in that area must make their own plans and official controls consistent with regional objectives and with the provisions of the designation order.

The Mississippi River corridor from Ramsey to south of Hastings is one of only two designated Critical Areas.

Since both the University of Minnesota and the City of Minneapolis are governmental units under the Act, each has adopted Critical Area Plans.

University Plan States Plants Planned for Continued Power Use

The University's Critical Area Plan designates the Southeast Steam Plant and Main Plant sites for power/heat generation. Most of the Dam Flats area is shown as recreation/open space (excluding the physics lab).

University Critical Area Requires Additional Review of Developments

The University's Critical Area Plan establishes special site plan requirements which include: (1) site plans should maximize opportunities for open space and public viewing of the river; (2) site plans should contain conditions for buffering, landscaping, and revegetation; and (3) locations of improvements should be sensitive to riverland and bluff disruption and interference with views.

Project Will Meet Some of Critical Area Site Plan Requirements

Comparing the steam plant renovation project to these three requirements, it can be concluded that while the proposal is not specifically in conflict with any of them, it does little to further their goals. There are no specific plans in the proposed project to maximize opportunities for open space and public viewing of the river. The plans are considering some buffering but generally little of the vegetation and landscaping around the plants will change from current conditions.

The plans include no additional bluff disruption and the proposed addition to the Southeast Plant's roof will have little interference on river views. Regarding the first requirement especially, some of the alternatives would create more opportunities for public viewing of the river and for riverfront recreation, as discussed in previous sections of this chapter.

Project Does Not Encourage Use of Identified Scenic Viewing Spot

The transportation policy in the plan states that "access will be made available where appropriate for the construction of scenic overlooks and/or to encourage public access to riverfront lands." The Open Space and Recreation Plan section identifies scenic viewing spots and proposed and existing trailways. Good distance views are identified from the southwest corner of the Southeast Plant building and from the Dam Flats area between the former NSP plant and the I-35W bridge. The plan states that such views should be preserved and their utilization encouraged. While the current proposed project does not destroy these view sites, it also does not meet the goal of encouraging the use of these sites.

The Open Space and Recreation map in the plan shows a trail extending from Main Street across the railroad tracks under I-35W and 10th Avenue bridges and down to the river's edge at the Main Plant. The feasibility of this trail is discussed above in section 9.5.

Project Conforms with Minneapolis Critical Area Plan for Bluff Protect and Greenway Window

The City of Minneapolis Critical Area Plan identifies St. Anthony Falls as the focus of the City's efforts to rediscover and redevelop the riverfront.

The Plan includes policies to maintain water flow at the falls and to protect the bluffs and vegetation. Since the proposed renovation to the Southeast Plant would not change the footprint of the building, the renovation should have no new effect on the bluffs or vegetation. Any changes to access routes or storage facilities would have to be designed to conform to these policies.

The plan also provides that, wherever feasible, lateral access routes or greenway windows to the river should be provided. This would include a greenway window along 6th Avenue SE to a scenic observation area on the north side of the Stone Arch Bridge. The operation of the Southeast Plant would not interfere with the development of this window, although the presence of the Southeast Plant directly at the foot of 6th Avenue SE detracts from the view of the river along the approach to the viewing area.

The Minneapolis Critical Area Plan, which includes a larger planning area than the Central Riverfront or St. Anthony Falls Plans, calls for a continuous trail corridor for motorists, pedestrians and bicyclists along both sides of the Mississippi River. These aspects of the Minneapolis Critical Area Plan is discussed in section 9.5.

Industry in Riverfront Must Need River Location

The plan recommends that the City should establish a special "Riverfront Related" land use category. Among the activities that would be appropriate within this category is industry that provides a large amount of tax dollars, enhances the riverfront amenities, and requires river water for its industrial activities. As discussed earlier, the Southeast Steam Plant and Main Plant use coal delivered by rail exclusively and do not require the river for their industrial activities.

Compatibility with Mississippi National River Recreation Area Plan (MNRRA)

MNRRA Goal to Preserve and Enhance Significant Resources

In 1988, Congress created the Mississippi National River and Recreation Area (MNRRA) for the 72 miles of Mississippi River and four miles of Minnesota River in five Minnesota counties from Ramsey to Hastings. as a unit of the national park system. MNRRA identified a national interest in protecting and enhancing the historical, recreational, scenic, cultural, natural, economic, and scientific resources of the Mississippi River corridor in the Twin Cities.

The MNRRA plan establishes conceptual policies concentrating on corridor-wide issues. With the exception of National Park Service development, the plan does not address site specific issues.

MNRRA Plan Finalized

The MNRRA Plan has been finalized and has been approved by both Governor Carlson and the Secretary of the Interior.

NPS Has Addressed Compatibility of Project and Alternatives with MNRRA Policies

Now that the Plan has been approved, site-specific issues will be addressed at the local level based on the broad visions, general concepts, and corridor-wide policies articulated in the Plan.

A number of purpose and vision statements are offered in the Plan. Those relating to the riverfront sites include: 1) preserve significant historic, ethnographic and archaeological resources of the corridor, 2) enhance opportunities for public outdoor recreation, education, and scenic enjoyment and provide access to the entire length of the corridor by foot and bicycle (although the Plan recognizes that it is not feasible during the 10-15 year life of the Plan to acquire continuous public open space along the river), and 3) provide for continued economic activity and development, including multiple uses consistent with wise land use management principles.

The National Park Service (Dept of Interior), in its comments on the DEIS, summarizes a number of MNRRA policies and assesses the compatibility of the alternatives with those policies.

Several Policies Apply to Renovation of Southeast Plant

The MNRRA plan concentrates on new development in the corridor. Existing development is not expected to be substantially changed by this plan, and the plan would not discourage existing land uses in the corridor from expanding existing facilities if the expansion were consistent with resource protection policies and site development policies.

Policies that might apply to the renovation of the Southeast Plant include:

Provide uninterrupted vegetated shorelines where practical except for downtown areas and existing commercial and industrial areas.

Since the Southeast Plant is in a downtown location, the requirement for uninterrupted shoreline would not necessarily apply. In addition, the proposed project would not expand industrial use along the shoreline beyond that already existing. However, the MNRRA plan stresses consistency with local plans, and local plans for the area around the Plant and the Dam Flats generally indicate park usage.

When expanding existing uses located in the shoreline and 40 feet back from the river, expansions should be located as far back from the shoreline as practical and consistent with existing uses.

The expansion to the Southeast Plant will be upward and does not violate this policy.

To reduce visual impacts and protect views of the river, buildings within 200 feet of the river should be no higher than 30 feet. However building heights are set in local critical area plans and they would be higher in downtown areas.

The proposed renovation of the roofline of the Southeast Plant exceeds this height guideline. However, due to its location in a downtown area, the guideline may not be applicable.

Continue the historic use of historic properties, particularly where interpretation of history themes is planned, in preference to changing the use, even though the change might be compatible with the historic character of the resource.

The proposed renovation of the Southeast Plant is compatible with this.

Rehabilitate historic structures and landscapes for contemporary uses if they cannot adequately serve in the current condition, and if rehabilitation would not alter integrity or character.

The project proposes to renovate an historic structure. The University has already begun discussions with the State Historic Preservation Office to develop a design that will minimize alterations to the integrity of the existing building. Some of the alternatives (3,4,6, and 7), however, would avoid the need to alter the historical building.

Compatibility with Further Policies Discussed Elsewhere

Further policies include providing bicycle and pedestrian trails to connect the river with downtown, encouraging compliance with air quality standards, and reducing runoff. These issues are discussed in section 9.5.

Compatibility with Shoreland and Floodplain Ordinances

University's Critical Area Plan Requires Consistency with Floodplain Policies

Due to the University's unique status within the state (see discussion above), it is not clear whether the shoreland and floodplain ordinances applicable to the surrounding area affect properties owned by the University. The University reports that in the past it has not sought state or local shoreland and floodplain permits for University projects.

However, the University's Critical Area Plan states that for floodplain areas the University's development policies will be consistent with city and state floodplain management policies and that all city, state, and federal standards in force for construction in floodplains and floodways will be observed.

Proposed Project Complies with Some of Floodplain Guidelines

Alterations or additions to existing buildings or structures may be permitted if such will:

- Decrease the flood damage potential of the structure
- Not increase the obstruction to flood flows
- Provide for adequate protection to flood protection elevations (one foot above the regional flood)
- Not endanger human life

A portion of the Southeast Plant is in the 100 year floodplain. The project does not alter the footprint of the building and will not increase the obstruction to flood flows.

The proposal does not include any specific measures to decrease the flood damage potential of the structure.

Actions taken previously may provide for adequate protection to flood protection elevations. The Southeast Plant is located between two sets of dams and locks which are part of the St. Anthony Falls Upper Harbor Project. The pool between these two sets of dams and locks is maintained at a near constant level by the U.S. Army Corps of Engineers. Even at the peak of the 1993 flood, the pool remained within its usual limits. High river flows alone do not present a problem.

Proposed Renovations to Southeast Plant Subject to Floodplain Standards

Based on comments received from the Minnesota Dept of Natural Resources, the proposed Southeast Plant Renovation is apparently subject to both state and federal floodplain standards. If the cost of renovating a non-residential structure within a floodplain exceeds fifty percent of the value of the structure at the time the City adopted the floodplain ordinance, state rules require floodproofing of all parts of the building (including the addition). Federal Emergency Management Act rules require floodproofing of any addition.

Dry floodproofing involves elevating the lowest floor above the base flood level or insuring that the structure below the base flood level is watertight. For the lowest floor of the Southeast Plant to be used after renovation, that portion of the building would have to be made watertight. None of the government agencies or private contractors contacted could estimate the cost of the dry floodproofing without an in-depth, on-site study of the facility.

Steam Plants a Conditional Use by Shoreland Standards

The Southeast Plant is also within the Shoreland Zoning District. The Shoreland Management law and regulations establish standards for land use in the shorelands of public waters of the state. Local governments are required to adopt shoreland management controls that include the state standards.

Applicable standards include:

- Prevention of erosion or other pollution during and after construction

During construction of the proposed project, a number of existing river intake and discharge conduits, which are no longer in use, will be permanently sealed off. A discussion of runoff from the plant and air quality is included in Chapters 6 and 7.

- Limiting visibility of structures from the water

The Southeast Plant is already fully visible from the river, although the increased roof height of the proposed project (and Alternative 1) would create an even larger structure visible from the river.

- Adequacy of water supply and on-site sewage treatment

Since the Southeast Plant is an established operation in an urbanized area, on-site sewage treatment and water supply are not issues.

Section 9.7 ST. PAUL CAMPUS

Existing Land Use Includes Daycare, Student Housing, University Campus

Current land use around the St. Paul Plant includes student housing to the west and southwest of the plant and a daycare center adjacent to the southwest corner of the steam plant property. The University Physical Plant Building is immediately to the east of the steam plant, and the Minnesota State Fairgrounds lie east of that. On the north across Commonwealth Avenue are various University buildings such as the Veterinarian Diagnostic Laboratory and Veterinarian Services Building. (See Figure 3).

Daycare and Housing Most Likely To Be Impacted

The land use impact of the proposal and alternatives on the St. Paul campus is minimal. No superior alternative sites have been identified, and the only alternative that might eliminate the requirement of any on-campus steam plant is the purchase of steam from an off-campus facility. This alternative was not studied in detail because of cost and potential environmental problems.

Therefore, the only major impacts at the St. Paul facility are environmental. The main impact from the plant in this area is from fugitive coal dust on the nearby daycare (see Figure 16). Other potential impacts include degradation of water quality in the nearby drainage ditch and wetland from ash runoff or grounwater contamination.

Although the coal pile was reduced recently and dust levels are apparently within regulatory limits, residents of the adjacent housing and daycare employees did complain about recent annoying coal dust problems.

However, as proposed, the University would primarily use existing coal boilers for backup use only, and it is therefore expected that coal use, coal dust, and ash related impacts at this plant would be substantially reduced compared to current conditions. Since the coal pile would not require frequent working , the amount of coal dust generated could probably be controlled adequately by compaction and spraying.

Another possible resolution to the conflict between the day care location and the steam plant would be to relocate the day care somewhere else within the student housing complex. Alternative 13, which eliminates even the storage of coal on-site, would eliminate all impacts associated with coal dust, coal handling, and any impacts due to runoff.

Another potential impact to surrounding land uses is noise from the plant's operation. Electrical cogeneration is not proposed currently for this campus, and high pressure at startup was found to be the largest source of noise during recent monitoring at the Southeast Plant (See Chapter 6).

Falcon Heights Has No Regulatory Authority Over University

The St. Paul Plant is located within the City of Falcon Heights. Approximately two-thirds of the total area of Falcon Heights is comprised of University of Minnesota lands and the Minnesota State Fairgrounds. Falcon Heights' Comprehensive Plan states that "Though it is within the City's limits, the University is autonomous." The city has no regulatory authority over the University's land so long as the land is used for its intended public purposes.

While the city has no direct authority over the University, its plan indicates a wish to influence future institutional policy directions of the University to reflect the city's best interests. The city's land use plan shows the power plant site and the University area surrounding it as "Institutional" usage. The plan sets a policy to work with the University to keep informed of any significant changes to long range development plans and encourage the University to expand its physical plant south of rather than in open land.

University's Plan Shows Plant Remaining

The University of Minnesota's Long Range Development Plan for the St. Paul Campus was adopted in December 1971 and revised in June 1972. This plan shows the heating plant and physical plant management buildings remaining in their current location. The area around these two uses is identified as suitable for academic, housing or commercial uses (to the south, east and west) and housing academic, commercial or transportation to the north. The plan also identifies a narrow band of natural area and wildlife habitat to the east of the site (east of the physical plant) connecting to wetlands south of the site.

The University's plan suggests "zoning" the area for plant services. The plan also states that consolidating plant services at this location should be considered as permanent (suggested zoning for some other land uses are considered more flexible). The ten-year framework plan shows what appears to be some buffering to be built around the existing plant.

Chapter 10. Mitigation

Introduction

Three categories of mitigation and control measures that may lessen environmental, land use, or socioeconomic impacts of the proposed project or its reasonable alternatives are described and analyzed in the following sections.

- Section 1. Demand and energy reduction
- Section 2. Cogeneration
- Section 3. Environmental
- Section 4. Foster Wheeler contract options

Section 10.1. Demand and Energy Reduction

In 1989 the University Building Energy Efficiency Project (UBEEP) was initiated by the Minnesota Building Research Center. The objective of this program was to lower current and future energy use by managing and coordinating campus-wide energy conservation efforts. The Board of Regents approved the initial 5 year plan and startup funding. The goal of the UBEEP was to initiate programs that would result in a savings of 30% in energy consumption. It is anticipated that savings of 30% in energy consumption would translate to approximately a 15% savings in energy demand. Reduced energy consumption lowers fuel costs and other variable operation and maintenance costs. Reduced peak demand delays the need capital required for new capacity.

The following are energy conservation projects initiated by UBEEP to date:

- Steam trap and radiator valve repair/replacement
- Fluorescent lamp replacement
- Fan operation strategies in multi-use buildings

The University estimates that they have reached approximately one-half of the 30% energy savings goal.

UBEEP Responsibilities Moved to Facilities Management

In July, 1994, the University administration reorganized the University Building Energy Efficiency Project (UBEEP), and shifted the energy conservation program from UBEEP, directed by David Grimsrud, to the Facilities Management Department. According to the university, the reorganization was undertaken to reduce overhead and speed program implementation. Mr. Grimsrud and two full-time employees continue work in the UBEEP program, but with responsibilities that are primarily persuasive and promotional.

In Facilities Management, seven full-time employees oversee a large number of energy control projects. These projects are primarily low-capital-cost efforts such as replacing incandescent lighting and monitoring and repairing thermostats and weather stripping. In approximately four years, once the less capital intensive energy control strategies have been implemented, the University expects to return to renovating building infrastructures more extensively to improve energy efficiency.

Resultant University of Minnesota Energy Use Consistent With Other Institutions

As a result of the UBEEP effort steam consumption has been significantly reduced from an estimated 142 pounds per square foot in FY 1990. Steam consumption is now more consistent with other institutions.

The steam consumption for the Minneapolis campus was calculated at 108 pounds of steam per square foot and 146.9 pounds per square foot for the St. Paul campus by OSM for the University of Minnesota in their December 6, 1993 *Energy Benchmark Study*. The study included the University, and the following unidentified institutions; one medical complex, two industrial facilities, and three post secondary educational institutions. The thermal energy benchmark (average of steam consumption from the benchmark institutions) was calculated to be 106.8 pounds of steam per square foot. Thus, OSM claims that the average steam consumption for heating the Minneapolis campus (at 108 pounds per square foot) is about 2% above the thermal energy benchmark and the steam consumption for heating the St. Paul campus (146.9 pounds per square foot) is about 38% above the thermal benchmark of the study. OSM suggests that steam consumption for greenhouses located on the St. Paul campus partially explains the significant difference between the St. Paul campus and the Minneapolis campus. As an institution, the University's steam consumption is 115.2 pounds per square foot or approximately 8% higher than the study thermal energy benchmark according to the OSM study.

Projected University Conservation Would Reduce PV Operation and Maintenance Cost of Project and Alternatives

The University is projecting additional conservation results from continuing UBEEP and other efforts. The University projects their steam load to decrease during FY95 by 6.06% and during FY 96 by 6.54% as a result of their conservation efforts. However the University has not quantified the investment required to accomplish the projected reductions.

If these conservation efforts are unsuccessful, the present value operations and maintenance costs (25 years, 6% discount rate) for the proposed project and alternatives would be higher than under the University load projection. Table 1 ~~**Error! Reference source not found.**~~ below identifies the present value operations and maintenance costs for the project and each combination of alternatives for the planned conservation and no conservation scenarios. The costs shown include fuel and are net of cogenerated electric value. The supporting documentation for this table is contained in the Dahlen, Berg & Co. July 29, 1994 report *Financial Projections for the University of Minnesota's Steam Supply Alternatives*

Cost Reductions Due to Energy Conservation Greatest For Alternatives With High Marginal Costs of Steam

As discussed in Section 11.3, three steam load scenarios were assessed for the EIS. The University's current projections, called the base case in Table 1, include a moderate level of conservation and a 220,000 Mlb. drop in FY 1998 load because contracts with current steam customers will not be renewed. The high conservation scenario is the University's projection with double the conservation projected in the base case. The no conservation scenario is the base case without any assumed energy conservation.

Table 1 illustrates potential cost reductions due to energy conservation at the Minneapolis campus. In general, the larger the incremental cost of steam, the greater the financial incentive for reducing energy consumption.

The present value difference in operation and maintenance costs between the University's projected load and a no conservation projected load is highest for Case A because Case A has the highest marginal cost for steam. Also, natural gas alternatives have higher marginal steam costs than coal-based alternatives because natural gas is more expensive, and the incremental costs of steam are largely due to fuel costs. Cases A and B, although they will use coal, also have high marginal costs of steam because under the University's contract with Foster Wheeler, operating charges include a rate paid per Mlb. of steam in addition to incremental fuel costs. Under the other alternatives, only incremental costs for fuel, ash disposal, and other operating costs are incurred.

Table 1. 25-Year Present Value Operation and Maintenance Costs ($ in Millions)

	No Conservation	Base Case Conservation	High Conservation	$ Loss No Conservation	$ Savings High Conservation
Alt. Nos. 1 & 11	281.3	270.6	254.3	-10.7	16.3
Alt. Nos. 3 & 13	319.1	298.5	273.3	-20.6	25.2
Alt. Nos. 4 & 13	348.2	324.5	294.4	-23.7	30.1
Alt. Nos. 6 & 13	285.6	266.1	240.1	-19.5	26
Alt. Nos. 7 & 13	348.1	324.4	294.3	-23.7	30.1
Case A	350.6	323.4	294.9	-27.2	28.5
Case B	342.4	316.4	28.7	-26	28.7

Replacement of Existing Building Absorption Chillers with New Central Steam Chilled Water Production Units Has Benefits

Absorption chillers were installed in many buildings constructed in the early 1960's. Many of these absorption units are nearing the end of their effective lives and are inefficient. Other university electric chillers use CFC-11 or CFC-12 and may soon need to be replaced. It is likely that the older chillers will be replaced by more energy efficient centralized units. However, the continued use of steam rather than electricity for chilled water production is necessary to reduce electricity use. Use of steam chilled water production has a direct relationship to the amount of cogenerated electricity. Combining more efficient steam chilled water production units with a district cooling system also has several benefits. A February 22, 1993 study by Ellerbe Becket, Inc *Recommendations for the East Bank Chilled Water System Planning Process* recommended that interconnecting piping with the addition of capacity via a central or satellite plants would appear to be the best means of minimizing capital, maintenance, and energy costs.

The University is planning to interconnect buildings with absorption chillers in a chilled water piping loop although no current construction has been authorized. This allows the equipment to be used more effectively since peak cooling needs for buildings may not occur at the same time. Energy consumption for chilled water auxiliaries, pumping and cooling tower fans, would be reduced.

Conversion to a Hot Water Distribution System Would Conserve Energy and Could Facilitate a Large Metro Thermal Network

Implementing central chilled water production and distribution systems would facilitate converting the campus steam distribution system to hot water since steam would no longer be required at each building.

Further environmental and socioeconomic benefits may result from converting the campus piping system that distributes steam to the various buildings for heating from steam to hot water

Most buildings constructed in the United States after the 1960's utilize hot water rather than steam to distribute heat within a building. Hot water building systems can be more precisely controlled than steam systems and thus save energy. Converting a building from steam to hot water involves improvements to the entire heating system. Experience in Minnesota has demonstrated 20-40 percent savings resulting from converting building heating systems from steam to hot water. The University of Minnesota has minimized the number of buildings that still use building steam heating systems. There are approximately 225 buildings in the University Campus that are heated and maintained for human occupancy. Only a few of these still use steam heating systems.

The next logical step would be to convert the existing steam distribution system which delivers energy to each building to a hot water distribution system.

Hot water distribution systems are generally a more efficient delivery system than steam distribution systems. The International District Energy Association September 1994 *Member Profile Study* indicates that for large district heating systems with a total output of 1,500,000 MMBTU or more hot water systems average 98.3% return compared to 52.9% return

for steam systems. District Energy St. Paul, Inc is a successful hot water distribution system which serves downtown St. Paul.

A hot water distribution system would also have the socioeconomic advantage of the facilitation of a large metro hot water thermal network. Hot water energy can be transported over much greater distances for less cost than steam. Further, greater electricity production is possible from cogeneration plants producing hot water than cogeneration plants producing steam. Producing hot water from cogeneration plant would have a significant environmental benefit as discussed in Section 2. This large metro thermal network could ultimately provide the heat sink for distributed cogeneration plants burning a variety of fuels. It could also incorporate existing production facilities such as the University's. This large hot water thermal network was originally proposed in *Feasibility of a Large Scale Cogeneration/Hot Water District Heating System in the Twin Cities*, a 1979 study funded by the Oak Ridge National Laboratory. Conversion of the University's distribution system to hot water would be an important step to accomplishing a large scale hot water thermal network.

Section 10.2. Cogeneration

As discussed in Section 2., the University can have an important role in the further development of cogeneration in the Twin Cities. Cogeneration would reduce area-wide air pollution emissions because it would use less fuel to produce the same quantities of thermal and electric energy than would separate facilities operating independently. In cogeneration, thermal energy and electrical energy are sequentially produced from a single fuel source. Energy rejected from one process is used as an energy input to a subsequent process.

The ratio of useful energy output—power plus thermal energy minus in-plant use—to total fuel input is called efficiency.

Cogeneration Plants Would Be Less Efficient Than Thermal-Only Plants But More Efficient Than Electric-Only Plants

The cogeneration plants considered for the University would be less efficient than the thermal-only plants because under cogeneration some energy is consumed when electricity is produced. The generation of electricity is an inefficient energy conversion process. Less than 40% of the total energy input into an electric generation plant is converted to usable electricity energy.

The University's cogeneration plants would, however, be more efficient than NSP electric-only plants because the cogeneration plants would still use most of the waste heat from generating electricity to generate thermal energy. Unlike an electric-only plant, it would not simply reject this extra heat energy into the atmosphere through the use of cooling towers.

The cogeneration plants would have efficiencies ranging from 69% to 75%, and the thermal-only plants would have efficiencies ranging from 77% to 80%. In contrast, NSP's coal-fired electric generation plants have efficiencies ranging from 29% to 36%.

Combined Efficiency of a Cogeneration Plant and an NSP Plant Would Be Greater than the Combined Efficiency of a Thermal-Only Plant and an NSP Plant

The combined efficiency of a University cogeneration plant and an NSP plant used together to meet the University's total energy requirements—both thermal and electric—would be greater than the combined efficiency of a thermal-only plant and an NSP plant.

Table 2 below lists for each campus the plant, NSP and combined efficiency for Case A, Case B, and each alternative. The combined efficiency is the efficiency that would result if the total campus energy requirements were provided by combining the plant and NSP output for each alternative. (For Minneapolis Case B, the combined efficiency would be the same as the individual plant efficiency because Case B would produce all of the Minneapolis campus energy requirements).

Table 2. Plant Efficiency and Combined Efficiency

	Type of Plant	Plant Efficiency (1)	NSP Efficiency (2)	Combined Efficiency (3)
Minneapolis Campus				
Alternative 1	Thermal	77.4	36	59.4
Alternative 3	Cogeneration	68.7	36	66.5
Alternative 4	Cogeneration	70.9	36	68.5
Alternative 6	Cogeneration	81.3	36	65.5
Alternative 7	Cogeneration	70.9	36	68.5
Case A	Cogeneration	82.9	36	67.0
Case B	Cogeneration	74.5	36	74.5
St. Paul Campus (4)				
Alternative 11	Thermal	77.7		
Alternative 13	Thermal	79.1		
Case A	Thermal	78.4		

(1)

Plant performance data is based on fiscal year 1999 as presented in Finanial Projections for the University of Minnesota's Steam Supply Alternatives, dated July 29, 1994, except for Alternative 6, Case A, and Case B. Alternative 6 is based on revised projections dated May 11, 1995. Case A and Case B are based on contractual guarantees.

NSP plant performance is based on the Allen S. King plant, one of NSP's more efficient non-nuclear plants. (2)

Combined efficiency is the efficiency that would result if the total Minneapolis campus energy requirements, including electricity, were provided by combining the output from an alternative with the output from an NSP plant (3)

Combined efficiencies are not presented for the St. Paul campus alternatives because none of the alternatives would produce electricity. (4)

Case B Has the Highest Combined Efficiency

As shown in the above table, Case B has the highest combined efficiency. This occurs because Case B has the most cogenerated electricity, providing all of the Minneapolis campus energy requirements. Alternative 1 has the lowest combined efficiency because it has no cogenerated electricity. Increased fuel efficiency mans reduced fuel burned and less air pollution emissions.

Cogeneration at the University Would Result in Decreased Emissions Elsewhere

Cogenerated electricity produced and used by the University would lower regional base-load electricity demand. In response, NSP would most likely lower production at its older coal-fired plants, which are currently its most expensive facilities.

It is, therefore, reasonable to estimate net emissions from cogeneration facilities by subtracting a "cogeneration credit" from predicted point source emissions. This credit is an estimate of the emissions that would have otherwise been produced by the utility plants. The adjustments are not only due to the efficiency benefits of cogeneration, but also due to the lower emissions of new proposed equipment at the University.

The credit given an individual alternative is determined by the amount of projected electricity production and the emission rate assumed for NSP facilities, a number that in turn depends on which NSP plants are assumed to reduce production first. If estimated NSP emissions are reduced, the "credit" given a cogeneration facility would also be reduced.

While estimated emissions can be adjusted for cogeneration, it in not possible to model the effect on ambient air concentrations. Furthermore, there are not any existing mechanisms for enforcing such cogeneration "offsets."

Cogeneration Credits Estimated for SO_2, CO_2, and Hg

Table 3 below shows "predicted" emissions (see Chapter 6) of SO_2, CO_2, and mercury adjusted for NSP generation displaced by cogeneration. NSP generation considered in this analysis included power plants in the seven county metropolitan area and Sherburne County. Results are in tons per year for SO_2, thousands of tons per year for CO_2, and in pounds per year for mercury.

The credit was estimated based on pollutant emissions and electric generation associated with area-wide NSP power plants. The calculation of the cogeneration credit is presented in DEIS Appendix A.

Table 3 Predicted Emissions Adjusted For Cogeneration [1]

	Case A	Case B	Alt 1	Alt 3	Alt 4	Alt 6	Alt 7
Sulfur Dioxide (TPY)	-105	-603	606	-454	-570	-94	-570
Carbon Dioxide (1000s TPY)	210	88	300	110	46	210	46
Mercury (lb/YR)	11	-2	17	-4	-13	10	-13

[1] revised calculations from FEIS Technical Appendices

Mercury Emissions Used as Example of Cogeneration Credit Emission Adjustment

Mercury is a pollutant of particular concern because of its ability to bioaccumulate in the food chain. A number of recent studies have indicated that long-range atmospheric transport and deposition of mercury is largely responsible for the elevated concentrations in fish throughout the upper midwest. Therefore, mercury is used here as a "cogeneration credit" example. Cogeneration credits for other air toxics would be a function of the amount of electricity cogenerated and the emission rate estimated for turned-down NSP plants; however, the resulting net emission estimates would vary significantly depending on each alternative's point-source emissions.

The adjusted mercury emissions shown were calculated using a mercury emission factor of 7.0E-5 lb-Hg/megawatt-hour, based on the following assumptions:

- .06 ppm mercury concentration in utility coal
- 10,440 Btu per kwh
- (Assuming .593 tons coal used per mwh, from 1994-2005 NSP Resource Plan filed with PUC as quoted in *University of Minnesota Evaluation of Steam Service Agreements, 1992*, and 8800 btu/lb low sulfur western coal)

100% Gas/Oil Cogeneration Facilities Have Lowest Net Mercury Emissions

Case B has the largest cogeneration credit applied to it because it is projected to produce the most electricity. This electricity production reduces its direct mercury emissions by 15 pounds, to a net of about minus two pounds per year.

Alternatives No. 3, No. 4, and No. 7, which are base-load natural gas facilities, are given credits of approximately 13 lb per year. As a result, mercury emissions from alternative No. 3, which uses existing coal boilers for auxiliary units, are reduced to about negative three pounds per year. The gas/oil only facilities, which have negligible point-source emissions, have net emissions of minus 12 to 13 pounds per year.

Cogeneration credits for the lower electricity production of Case A and alternative No. 6 offset predicted emissions by about 5 pounds.

Results Mostly a Function of Assumed Mercury Concentration in Coal

Note that the same mercury concentration was assumed for utility plants and University coal boilers. Therefore the higher the mercury concentration assumed in coal, the higher the emissions from coal alternatives, the larger the cogeneration credit, and the larger the difference between the coal and natural/gas primary facilities. And conversely, the lower the mercury emissions assumed from coal boilers, the smaller the cogeneration credit.

Section 10.3. Environmental

In this section, we discuss how fugitive dust emissions would be controlled under Alternatives 3 and 6 and how Alternative 3's NO_X emissions could be reduced further, if additional reductions were needed.

Alternatives 3 and 6 Include Coal And Ash Handling Systems Which Would Mitigate Fugitive Dust Emissions

The conceptual designs of the coal burning Alternatives 3 and 6 include $7,000,000 for coal and ash handling systems. Included in the $7,000,000 are three methods that would reduce fugitive dust emissions.

Store coal in enclosures
Transport coal in covered conveyors
Haul ash directly to the landfill instead of storing it on the ground

<u>Store coal in enclosures</u>
Under Alternatives 3 and 6, coal would be stored inside totally covered enclosures instead of in open piles on the ground. By enclosing and covering the coal pile, dust generated during handling would be contained and not released to the environment.

<u>Transport coal in covered conveyors</u>
Coal would be transported in covered conveyors under both Alternative 3 and Alternative 6. Under Alternative 3, which would use some of the existing coal handling equipment, coal would be transported to the Southeast Heating Plant on a new belt conveyor installed in the existing tunnel between the Main Heating Plant and the Southeast Heating Plant. (This would be similar to the $2,400,000 Foster Wheeler contract option which we discuss in Section 5.)

By transporting coal in covered conveyors, the current practice of trucking coal from the Main Heating Plant to the Southeast Heating Plant could almost be eliminated. (Some coal might have to be trucked to the Southeast Heating Plant during extended conveyor outages). Dust generated during conveying by truck would be collected and not released to the environment.

<u>Haul ash directly to the landfill instead of storing it on the ground</u>
Under Alternatives 3 and 6, ash would be loaded once into trucks and transported directly to a landfill. By hauling the ash directly to the landfill instead of the current practice of dumping it on the ground prior to landfill disposal, the ash would be handled less and reduce dust.

Alternative 3's NO_X Emissions Could be Reduced With Additional Controls

Alternative 3's NO_X emissions could be reduced by installing additional controls on the existing coal fired boilers at the Southeast Heating Plant. SO_2 emissions from the existing boilers would be effectively controlled by the existing scrubbers.

We focus our discussion on Alternative 3 because Alternative 3's local NO_X emissions were estimated to be greater than any of the other alternatives and Case A. Alternative 3's NO_X emissions could be reduced over 400 tons per year, by installing selective non-catalytic reduction (SNCR) control systems on each of the two existing Southeast Heating Plant boilers. The installation would cost about $1 million to install and about $191,000 per year to supply the necessary chemicals. Existing burners could be replaced with low NO_X burners to reduce NO_X, however the reduction would not be a effective as with the SNCR control system.

Section 10.4. Foster Wheeler Contract Options

The Foster-Wheeler contract includes six mitigation options:

- Install NO_X control equipment (Denox System on the fluidized bed boiler).
- Construct a wall to partially enclose the Minneapolis Campus ash pile.
- Construct a wall to partially enclose the Main Heating Plant coal pile.
- Install a coal conveyor between the Main Heating Plant and the Southeast Heating Plant.
- Construct ash pile storm water collection system at St. Paul.
- Construct walls to partially enclose the coal pile at St. Paul.

Each option is further described and analyzed below.

The NO_X Reduction System Option Could Reduce NO_X Emissions by 88 Tons per Year

With the NO_X reduction system, Foster Wheeler would inject chemicals into the boiler furnace to react with nitrogen oxides (NO_X) to form nitrogen (N_2), carbon dioxide (CO_2), and water vapor (H_2O).

By exercising the NO_X reduction system option, the University could reduce the fluidized bed boiler NO_X emissions. With an uncontrolled emission rate of 220 tons per year, 88 fewer tons of NO_X would be emitted based on 40% NO_X removal efficiency.

The total owning and operating costs would include not only the $1,170,000 equipment price listed in the *Design and Construction Agreement* (escalated according to the agreement's terms), but also the cost of chemicals and maintenance.

The Minneapolis Ash Screen-Wall Option Would Partially Hide the Pile, and Could Contain Some Runoff, But Would Not Stop Wind-borne Dust

With the Minneapolis ash screen-wall option, Foster Wheeler would construct three walls each 9 feet tall which would partially enclose an area 110 feet long by 110 feet wide. Foster Wheeler would use the adjacent ground embankment for one wall and construct two walls each 110 feet long. The forth wall would be 30 feet long. The 80-foot length without a wall would allow personnel access to load and unload the ash.

The screen wall would partially hide the ash pile from view and could contain some of the stormwater runoff more efficiently than the existing earth berms; however, the walls would not stop wind-borne dust because the proposed ash handling method—

transporting ash in trucks, dumping the ash on the ground to cool, reloading the ash into trucks, and trucking the ash away—would require that the ash be handled too many times.

The primary cost associated with the ash screen-wall would be the construction price listed as $226,000 in the *Design and Construction Agreement.* Of course, the listed price would be subject to escalation according to the agreement's terms.

The Minneapolis Coal Pile Screen-wall Option Would Partially Hide the Pile But Would Not Stop Wind-borne Dust

With the Minneapolis coal pile screen wall, Foster Wheeler would provide two 60-foot tall walls that would form a right angle. One wall would be 90 feet long and the other wall would be 110 feet long.

Although the screen wall would partially hide the pile from view, the walls would not stop coal dust from being blown from the site because dust would still be generated outside of the partial enclosure when coal was transferred between conveyors.

The primary cost associated with the coal screen-wall would be the $624,000 construction price listed in the *Design and Construction Agreement.* Like the other options, the listed price would be subject to escalation according to the agreement's terms.

The Coal Conveyor Option Would Reduce Truck Traffic and Wind-borne Dust

With the coal conveyor option, Foster Wheeler would construct a conveyor in the existing tunnel between the Main Heating Plant and the Southeast Heating Plant.

The coal conveyor option would reduce both truck traffic and wind-borne dust. With the conveyor in place, the current practice of trucking coal from the Main Heating Plant to the Southeast Heating Plant could almost be eliminated. (Some coal might have to be trucked to the Southeast Heating Plant during extended conveyor outages). Not only would this option reduce truck traffic, but this option would also reduce the dusting associated with loading and emptying the trucks. Presumably, dust control measures would be provided with the conveyor to control dusting during conveying operations.

The construction price, subject to escalation, is listed in the *Design and Construction Agreement* as $2,400,000. The total owning and operating costs would include not only the construction price but also the cost of maintaining the conveyor.

However, the current labor and maintenance costs associated with operating and maintaining the coal trucks would be avoided in the future if the coal conveyor option were exercised.

The Ash Pile Storm Water Collection Option Would Reduce Water Pollution at the St. Paul Campus

With the ash pile storm water collection option, Foster Wheeler would provide a system to direct ash pile runoff to a 2,550 gallon fiberglass underground storage tank.

The collection system option would allow solids to settle out and thus would reduce surface water pollution.

The construction price, subject to escalation, is listed in the *Design and Construction Agreement* as $135,000.

The St. Paul Coal Pile Screen-wall Option Would Not Improve Dust Control but Would Partially Hide the Pile

With the St. Paul coal pile screen wall, Foster Wheeler would provide two walls, one 150 feet long and the other 60 feet long. Both walls would slope from 20 feet tall to 10 feet tall. A 60-foot opening would be provided between the two walls to gain access to the coal pile. A cable supported tarpaulin would be provided to cover the opening.

Although the screen-wall would not provide a significant benefit in controlling coal dust, the wall would at least partially hide the pile. At the St. Paul plant, the University intends to burn coal only during emergencies and thus coal would not be handled very often. Because the coal handling system would be effectively shut down, there would be less opportunity for coal dust to be picked up by the wind.

Chapter 11. Economic Feasibility Analysis

After Initial Screening, Five Alternatives Selected for Further Study

The results of an economic feasibility analysis of alternatives to the University's proposed project are described in this chapter. All the technologies used in these alternatives are technically feasible.

The first step in the feasibility analysis was a screening level economic assessment completed on thirteen conceptual level designs (see Chapter 3 for detailed descriptions). On the basis of the screening work, five alternatives were selected for further study. The screening level No Action alternative was also carried into the next phase for comparison purposes.

Purpose of the Projections is to Assess Economic Feasibility of Selected Alternatives

The purpose of the financial projections is to evaluate the economic feasibility of the alternatives using consistent assumptions and methodologies for steam loads, fuel prices, escalation rates, and other key variables and sensitivities. Actual prices will inevitably differ from long-range projections. Because of this uncertainty, the projections should only be used for evaluating alternatives to the University's proposed project.

Alternatives Compared to University's Project, as Defined by Detailed Contract

The University's proposed project is defined by a complex contract for steam and electricity that contains detailed designs and technology-specific construction costs, and that defines fixed and variable operating and maintenance rates. In EIS section 11-3, the estimated costs of the alternatives—constructed and operated by the University—are compared to the costs of the University's proposed Case A and Case B under its vendor contract. This comparison provides one benchmark for assessing the economic feasibility of the alternatives designed for the EIS.

Details of Economic Analysis Available in four Separate Reports

The detailed economic analysis of the selected alternatives is contained in the report, *Financial Projections for the University of Minnesota's Steam Supply Alternatives, Screening Analysis,* March 25, 1994, by Dahlen, Berg & Co. Other detailed assumptions are contained in the following three reports prepared by Dahlen, Berg & Co. for this EIS:

Fuel Price Projections, dated March 30, 1994

Value of Cogenerated Electricity, dated April 1, 1994

Alternatives to the University of Minnesota's Proposed Steam Service Facilities Renovation, *Screening Analysis*, dated March 25, 1994.

Economic Feasibility of Cogeneration Controversial.

The University's proposal and all EIS alternatives (except the "No Action" alternative) include some form of electricity cogeneration. The economics of electricity cogeneration at the Minneapolis campus was controversial during the EIS scoping process as well during the University's internal selection process. Therefore, electricity cogeneration is an important part of this economic analysis.

Economic Analysis Presented into Four Sections

This chapter is divided into the following sections.

- Section 1 Summary of Screening Analysis
- Section 2 Additional Work Completed for Phase II Analysis
- Section 3 Present Value Cost Comparison
- Section 4 Fuel Price Projections
- Section 5 Value of Cogenerated Electricity

Section 11.1. Summary of Screening Analysis

Thirteen Alternatives Evaluated in an Initial Screening Analysis

The following thirteen steam production alternatives to the University's proposed project were identified, defined, and evaluated in the *Screening Analysis*.

Minneapolis Campus

Alt. 1a Minneapolis Deferred Construction, Coal Primary
Alt 1b Minneapolis Deferred Construction, Gas and Oil Only
Alt 2b Southeast Plant Natural Gas and Oil
Alt. 2c Southeast Plant 100% Natural Gas
Alt 3 Southeast Plant using Coal with Natural Gas Cogeneration
Alt 4 Southeast Plant without Coal with Nat. Gas Cogenereation
Alt 5 Southeast Plant with Large Cogeneration
Alt 6 New Plant at Alternative Location with Coal
Alt 7 New Plant at Alternative Location without Coal
Alt 8 Main Plant Renovation and Expansion

Combined Campus

Alt 9 Purchase Steam from Third Parties
Alt 10 Interconnect Minneapolis & St. Paul Systems - New Plant

St. Paul Campus

Alt 11 St. Paul Plant Deferred Construction
Alt 12 St. Paul Plant with Cogeneration with Coal
Alt 13 St. Paul Plant without Coal

These alternatives are described in EIS Chapters 3 and 4, and detailed descriptions, including construction cost estimates and operating cost projections, are contained in the appendices to the *Screening Analysis* report. In addition, although it was not considered as a steam production alternative in the *Screening Analysis*, hydroelectric power was discussed as a power production alternative.

25-Year Construction and Operating Costs were Estimated for Thirteen Alternatives

Construction costs were estimated by John R. Brady and Associates, a professional construction cost estimator based on the descriptions of alternatives in the *Screening Analysis*. The construction cost estimates are expressed in 1994 dollars. Terminal values were not estimated. However, alternatives with larger construction costs are likely to have higher terminal values than alternatives with smaller construction plans

Operating costs (including fuel) were estimated for each alternative. Operating costs include:

- Fuel
- Labor
- Maintenance
- Insurance
- Water and sewer

Construction Costs High for Coal Plants, Operating Costs High for Natural Gas Plants

The table below shows a comparison of the costs of the alternatives as determined in the screening analysis. The present value costs include construction and operating costs over the period July 1, 1994 through June 30, 2019 discounted at 6% to January 1, 1994.

Alternatives No. 1, 2, and 11 include different fuel scenarios. The "a" designation indicates coal as a primary fuel. The "b" designation indicates natural gas as a primary fuel. The "c" designation indicates all natural gas.

TABLE 1. SCREENING ANALYSIS PRESENT VALUE COSTS

	Construction Costs ($ in Millions)	Net Operating Costs ($ in Millions)	Present Value Costs ($ in Millions)
Minneapolis Campus			
Alt. No. 1a	35.1	182.8	217.9
Alt. No. 1b	35.1	278.8	313.9
Alt. No. 2b	37.3	236.7	274.0
Alt. No. 2c	37.3	366.4	403.7
Alt. No. 3	42.0	193.8	235.8
Alt. No. 4	53.9	221.3	275.2
Alt. No. 5	85.5	237.7	323.2
Alt. No. 6	82.1	162.3	244.4
Alt. No. 7	63.9	219.5	283.4
Alt. No. 8	29.9	237.1	267.0
Combined Campus			
Alt. No. 9	-	505.2	505.2
Alt. No. 10	126.7	246.6	373.3
St. Paul Campus			
Alt. No. 11a	2.1	76.2	78.3
Alt. No. 11b	2.1	110.9	113.0
Alt. No. 12	6.5	81.5	88.0
Alt. No. 13	2.5	103.3	105.8

Minneapolis and St. Paul Costs Must Be Added to Compare to Combined Alternatives

Because some combined alternatives include costs for the both campuses, the costs of the Minneapolis alternatives must be added to those of the St. Paul alternatives, as presented in the following table.

TABLE 2. PRESENT VALUE COMBINED ALTERNATIVES
($ in Millions)

	w/ Alt. No. 11a	w/Alt. No. 11b	w/ Alt. No. 12	w/ Alt. No. 13
Alt. No. 1a	296.2	330.9	305.9	323.7
Alt. No. 1b	392.2	426.9	401.9	419.7
Alt. No. 2a	352.3	387.0	362.0	379.8
Alt. No. 2b	482.0	516.7	491.7	509.5
Alt. No. 3	314.1	348.8	323.8	341.6
Alt. No. 4	353.5	388.2	363.2	381.0
Alt. No. 5	401.5	436.2	411.2	429.0
Alt. No. 6	322.7	357.4	332.4	350.2
Alt. No. 7	361.7	396.4	371.4	389.2
Alt. No. 8	345.3	380.0	355.0	372.8
Combined Campuses				
Alt. No. 9	505.2	505.2	505.2	505.2
Alt. No. 10	373.3	373.3	373.3	373.3

Construction Costs for Alternative 9 Part of Cost of Steam

The $56 million estimated construction cost for connecting the Minneapolis and St. Paul campuses with third party suppliers was assumed to be included in the price of the purchases steam. Although a construction cost estimate was prepared for the screening analysis, the operating cost projection for alternative 9 assumes a market rate for and no capital expenditures.

This cost estimate assumes that peak steam demand would be still be met by an on-campus coal-fired steam plant. The use of natural gas instead as a primary fuel would be significantly more expensive.

Cogeneration Increases Fuel Costs, But Decreases Electricity Costs

Cogeneration of steam and electricity increases the quantity of fuel required and, therefore, the present value cost of fuel. Electrical cogeneration, however, results in an offsetting benefit of decreasing electricity purchases from the local utility. As a result, the *Screening Analysis* estimated that the 25-year total cost of a natural gas, fuel oil cogeneration system that would meet baseload steam demand with turbine "waste heat" (alternative 4) is about equal to a gas, fuel oil plant without cogeneration capability (alternative 2).

Natural Gas without a Backup Fuel is Costly

If a plant were to use only natural gas, the local natural gas distribution company (LDC) would have to reserve capacity on its distribution system and the interstate pipeline (firm transportation) for the plant's total natural gas requirements. Minnegasco's current firm transportation rate is more than five times as much as its interruptible rate. Reliable steam supply can be accomplished using interruptible transportation, if an alternative fuel can be used when interruptions occur.

Screening Economic Analysis Summarized

The following other general observations can be made based on the results of the screening analysis:

- New plants had the highest estimated construction costs
- Fuel costs had the largest effects on operating cost projections. For alternatives with cogeneration, the value of electricity is the second largest factor
- Alternative 3, a baseload gas/oil cogeneration alternative that uses existing coal boilers as secondary units, had the lowest present value cost of any EIS alternative besides the "No Action"
- The St. Paul campus alternatives that use coal are less expensive than those without coal
- The combined campus alternatives cost more than the separate campus alternatives

Minneapolis Alternatives 1, 3, 4, 6, and 7, and St. Paul Alternatives 11 and 13 Studied in Detail in Phase II.

The three lowest cost alternatives (besides the "No Action" alternative) were alternative 3, 6, and 8. Alternative 8, however, was replaced with Alternatives 4 and 7, which, because they include cogeneration, were projected to be environmentally superior to Alternative 8. The Deferred Construction, or "No Action" Alternative Nos. 1 and 11, were also both included in the Phase II analysis.

Section 11.2. Additional Work Completed for Phase II Analysis

For the Phase II financial projections, the consultants analyzed the University's costs to make them more current than those in previous studies. This section describes the additional work performed for the Phase II analysis.

- More Detailed Construction Costs Prepared
- Operating Cost Projections Reflect Construction Schedule
- Fuel Prices Projected
- Electric Prices Projected
- Operating Cost Categories Expanded
- Sensitivity Analyses Performed

More Detailed Construction Costs Prepared

More detailed construction cost estimates were prepared for each alternative. The estimates were based on conceptual level designs and equipment lists, and on conceptual plant layout and construction drawings which were also prepared for each Phase II alternative. The construction cost estimates also include the University's structuring costs and other contingencies identified by the University.

The professional construction cost estimator retained for the EIS, John R. Brady & Associates, has indicated these construction estimates, which are based on the DEIS conceptual level designs, to be accurate to within plus or minus 20%.

Operating Cost Projections Reflect Construction Schedule

In Phase II, the operating cost projections reflect the construction schedule for new facilities in each alternative. In Phase I, operating cost projections were based on new facilities for the entire projection period.

Fuel Prices Projected

Fuel prices and escalation rates were projected in a separate EQB report, *Fuel Price Projections*, dated March 30, 1994. Fuel projections were prepared so costs for each alternative would reflect the latest information. Accurate fuel costs are important because fuel costs and escalation rates determine 50% to 70% of the total present value cost of each alternative.

Electric Prices Projected

Electric prices and values were also projected in a separate EQB report, *Value of Cogenerated Electricity*, dated April 1, 1994. That projection was prepared because five of the seven alternatives and Cases A and B include cogeneration.

Operating Cost Categories Expanded

A review of historical University operating costs resulted in two additional operating cost categories: Administrative & General and Supplies. These costs were added to the operating costs of each of the seven University alternatives.

Sensitivity Analyses Performed

Seven different present value cost scenarios were developed to test the sensitivity of the cost projections to changes in key assumptions (see section 4, below).

Section 11.3. Present Value Cost Comparison

Costs to University for Cases A and B Are Based on University Contracts

In this section, the present value costs of the conceptual level alternative designs developed for the EIS are compared to the University contract options, Cases A and B.

The present value costs to the University for Cases A and B are based on the University's contract for steam supply, which contains detailed designs The University's contract contains technology-specific construction costs and operating and maintenance rates that were designed and negotiated specifically for the construction and operations contemplated under Cases A and B.

Costs for EIS Alternatives Based on the University's Constructing and Operating the Plants

The present value cost projections for the EIS alternatives are based on the University's constructing and operating the plants. The University's contract was not applied to the EIS alternatives because the contract is technology-specific to Cases A and B. Under the contract and most of the alternatives, however, the University would pay the construction costs.

Construction Costs for Cases A and B Based on University's Contract

The construction costs for the proposed Cases A and B are based on the detailed University contract. The construction costs for the alternatives are professional cost estimates based on conceptual-level designs completed for the DEIS. The engineering designs prepared for the contract are more detailed than the conceptual-level designs prepared for the DEIS alternatives. The construction costs of the alternatives also assume that the University would construct the plant without a "turn-key" contractor.

Construction Costs for EIS Alternatives are for Comparative Purposes Only

The construction costs for the EIS alternatives are intended to provide a consistent basis for evaluating the economic feasibility of potential alternatives to the proposed project. They are not intended to provide detailed, final design-and-build cost estimates for those alternatives.

Non-fuel Operating Costs for Alternatives Assume Efficient Plant Operation

The non-fuel operating costs of the University's project are based on the fixed and variable rates in the contract. The non-fuel operating costs for the alternatives assume that the University would operate the facilities efficiently.

Different Fuel Use and Electric Production Assumptions for Proposed Project and Alternatives

The fuel price assumptions are identical for the proposed project and alternatives; however, the assumptions used to calculate fuel use and electrical production are different. Although the University pays its own fuel costs under the contract, the contract does include various fuel efficiency and electrical production guarantees. For the EIS alternatives, fuel consumption and electricity production are not based on the contract but on engineering calculations and vendor guarantees.

All of the present value costs , for the University's alternatives, and for Cases A and B, are based on the same steam loads, fuel prices, escalation rates, and scenarios of changes in key assumptions.

Present value analyses show the total costs of alternatives at a common point in time, even while capital investments, operating costs, and operating savings may occur at different times under different alternatives. In this analysis, the present value costs are shown as of January, 1994.

Detailed engineering drawings, construction costs, and financial assumptions are contained in *Financial Projections for the University of Minnesota's Steam Supply Alternatives*, dated July 29, by Dahlen, Berg & Co.

This report contains the following conclusions:

- All University alternatives have lower present value costs than Case A
- All University alternatives have lower present value costs than Case A under each scenario
- Variability of results under the scenarios is larger for some alternatives than it is for others

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Costs Projected for Minneapolis Alternatives, St. Paul Alternatives, and Cases A and B

Construction costs and twenty-five years' operating costs were projected for each alternative, including Cases A and B. The alternatives can be grouped in three categories: Minneapolis campus alternatives, St. Paul campus alternatives, and combined Minneapolis and St. Paul campus alternatives. Table 3 shows the projected present value of operating and construction costs for each of the alternatives.

TABLE 3. PRESENT VALUE COSTS OF UNIVERSITY STEAM SUPPLY ALTERNATIVES
5% Electricity Escalation Rate
PV 1994 ($ in Millions)

	Fuel Costs	Non-Fuel Operating	Construction Costs	Value of Electricity	Total Costs
Minneapolis Campus					
Alt. No. 1	85.5	108.7	51.2	0.0	245.4
Alt. No. 3	209.8	100.6	56.2	-110.0	256.6
Alt. No. 4	246.0	90.7	59.2	-110.0	285.9
Alt. No. 6	111.3	91.1	95.9	-34.1	264.2
Alt. No. 7	246.0	90.7	71.9	-110.0	298.6
St. Paul Campus					
Alt. No. 11	32.8	43.7	4.1	0.0	80.6
Alt. No. 13	62.5	35.3	4.4	0.0	102.2
Combined Campuses					
Case A	171.7	185.4	87.8	-33.7	411.2
Case B	246.8	193.7	109.8	-124.1	426.2

Cases A and B Include Minneapolis and St. Paul Operations

The University's Case A and B projects include construction and operating costs for both the Minneapolis and St. Paul Campuses. Although some costs, like the fuel charge and ash disposal charge, can be separated by campus, other costs, like the monthly operating and maintenance charge, cover both campuses. .

All Combinations of University Alternatives Have Lower Costs Than Cases A and B

Since each of the Minneapolis alternatives can be combined with each of the St. Paul alternatives, ten combinations of Minneapolis and St. Paul alternatives can be made from the five Minneapolis alternatives and the two St. Paul alternatives.

All ten combinations of the University's alternatives have lower projected present value costs than the University's proposed Case A or Case B.

Table 4 and Figure 1 below shows the projected present value costs for the ten combinations of alternatives and for Cases A and B.

TABLE 4a. PRESENT VALUE OF COMBINED ALTERNATIVES
Revised Financial Projections 6/95
PV 1/1/94 ($ in Millions)

	Minneapolis	St. Paul	Total
Alt. Nos. 1 & 11	245.3	80.6	325.9
Alt. Nos. 1 & 13	245.3	102.2	347.5
Alt. Nos. 3 & 11	256.6	80.6	337.1
Alt. Nos. 3 & 13	256.6	102.2	358.8
Alt. Nos. 4 & 11	285.9	80.6	366.4
Alt. Nos. 4 & 13	285.9	102.2	388.1
Alt. Nos. 6 & 11	264.2	80.6	344.7
Alt. Nos. 6 & 13	264.2	102.2	366.4
Alt. Nos. 7 & 11	298.5	80.6	379.1
Alt. Nos. 7 & 13	298.5	102.2	400.7
Case A			411.2
Case B			426.2

TABLE 4b. PRESENT VALUE OF COMBINED ALTERNATIVES
3.37% Electricity Escalation Rate
PV 1/1/94 ($ in Millions)

	Minneapolis	St. Paul	Total
Alt. Nos. 1 & 11	242.0	80.6	322.6
Alt. Nos. 1 & 13	242.0	102.2	344.2
Alt. Nos. 3 & 11	272.8	80.6	353.4
Alt. Nos. 3 & 13	272.8	102.2	375.1
Alt. Nos. 4 & 11	302.2	80.6	382.8
Alt. Nos. 4 & 13	302.2	102.2	404.4
Alt. Nos. 6 & 11	267.1	80.6	347.7
Alt. Nos. 6 & 13	267.1	102.2	369.3
Alt. Nos. 7 & 11	314.8	80.6	395.4
Alt. Nos. 7 & 13	314.8	102.2	417.1
Case A			417.5
Case B			448.8

Coal Use Results in Lower PV Costs

The combination of Deferred Construction Alternative Nos. 1 and 11 has the lowest projected present value cost; however, detailed designs were not completed for this combination because it is projected to have two or more times higher emissions of most air pollutants than Case A or any other EIS alternative.

The combination of Alternative Nos. 3 and 13 has the lowest projected present value cost of the alternatives that do not use coal at the St. Paul campus. This combination is projected to cogenerate approximately three times more electricity than would be cogenerated under Case A but slightly less than would be generated under Case B. Construction and operating costs for this combination are low because the Minneapolis campus alternative uses the existing Southeast Plant coal boilers (see Chapter 3).

Comparative Cost Rankings Don't Change Under Most Sensitivity Scenarios

Eight different cost scenarios were prepared to test each alternative's sensitivity to changes in key assumptions. Under each scenario, all combinations of the University's alternatives have lower projected present value costs than Case A. The eight scenarios were based on changes in the following key assumptions:

- Price escalation rates: plus and minus 1%
- Discount rate: plus and minus 1%
- Steam loads: high conservation and no conservation
- Decrease in the spread between the escalation rates for fuel and electricity
- Decrease in escalation rate of electricity from 5.0% to 3.37%, as suggested by NSP Comment on DEIS

Case B is the most expensive alternative under all but one of the scenarios; when the difference between fuel and electricity escalation rates is decreased by 1%, Case A is the most expensive alternative. This occurs because, as the relative value of electricity increases compared to the cost of fuel, cogeneration becomes more valuable, and Case B produces the most electricity of all the facilities assessed.

Under the scenario that lowers the electricity escalation rate from 5% to 3.37%, the projected costs of the natural-gas-based off-river cogeneration plant (Alt. No. 7) are essentially equal to the costs of Case A, including the value of Foster Wheeler operations and guarantees under the contract.

Also, under the 3.37% electricity escalation scenario, the off-river coal-based facility (Alt. No. 6) replaces the on-river natural-gas-based cogeneration plant with coal backup (Alt. No. 3) as the lowest cost "build" alternative.

These results occur because, the lower the assumed retail rate for electricity, the less valuable cogenerated electricity is for offsetting retail purchases. Therefore, alternatives that cogenerate more electricity—like Alt. Nos. 3 or 7—become more expensive compared to alternatives that cogenerate less—like Case A or Alt. No. 6.

The seven original scenarios and the base case set of assumptions applied to each of the ten combinations of the University's alternatives and to Cases A and B, produced a total of 96 different results. A table showing the original 96 results for the DEIS is contained in Appendix B of the report, *Financial Projections for the University of Minnesota's Steam Supply Alternatives*, dated July 29, 1994. The revised 108 results for the FEIS are shown in FEIS Technical Appendix A.

In Scenarios, Low Variability of Results Preferable to High Variability of Results

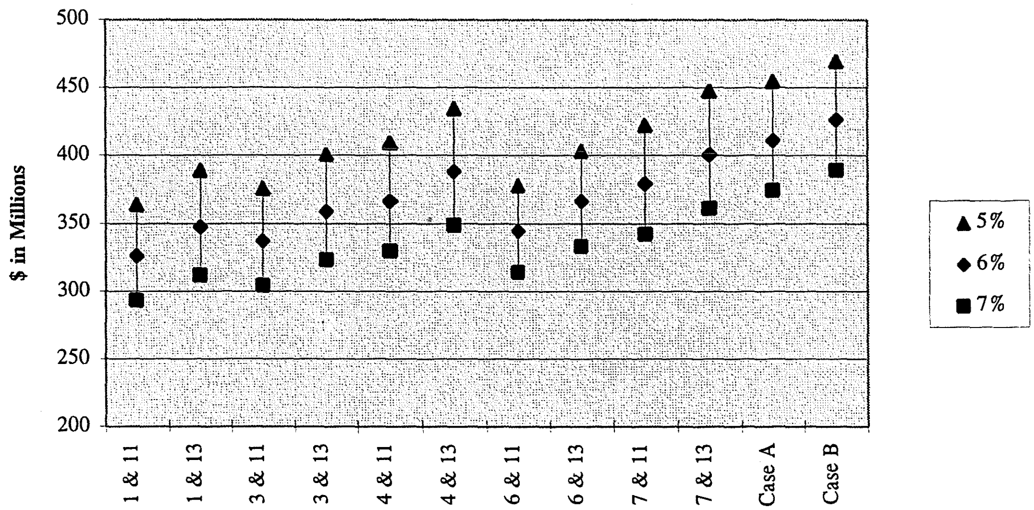
The variability of results under scenarios shows how sensitive the alternatives are to changes in key assumptions. One alternative is preferable to another if its costs remain stable under various scenarios, while the costs of the other alternative fluctuate widely under the same scenarios. In this scenario analysis, key assumptions are changed to show how sensitive each alternative is to that assumption.

The remainder of this section discusses and shows graphically the variability of results under each scenario for all of the University alternatives and Cases A and B.

Changing the Discount Rate Does Not Change the Ranking of the Alternatives

Changing the discount rate in the present value analysis from 6% per year to either 5% or 7% per year does not change the relative ranking of the alternatives. Further, the following graph shows that the variability of results is similar for all of the alternatives under different discount rates.

Scenario 1: Discount Rate

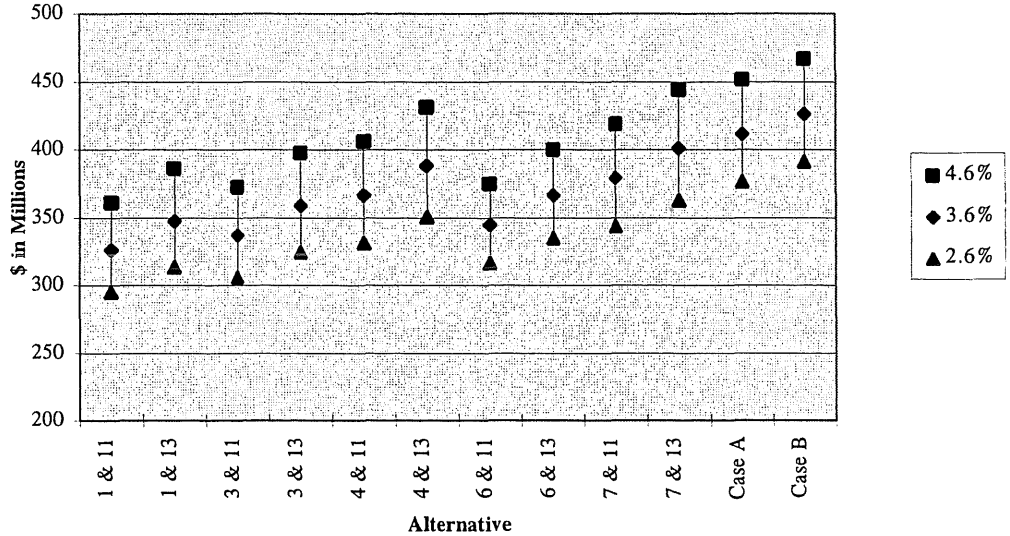


Because the cash flow patterns of the alternatives and Cases A and B are similar, changing the discount rate affects neither the ranking of the alternatives nor the relative variability of the results.

Changing Price Escalation Rates Has Similar Effects on Alternatives

Changing price escalation rates has a similar effect on all of the University's alternatives and Cases A and B. The following graph shows the present value cost projections prepared with a general price escalation rate of 3.6%, plus or minus 1%.

Scenario 2: General Price Escalation Rate



Fuel is the single largest cost in each of the alternatives. Because the fuel prices and escalation rate assumptions are the same in each alternative and in Cases A and B (fuel is a pass-through cost to the University in the contract), changing the escalation rates has a similar effect on each alternative and Cases A and B.

Changing the Steam Load Affects High Marginal Cost Alternatives More Than Others

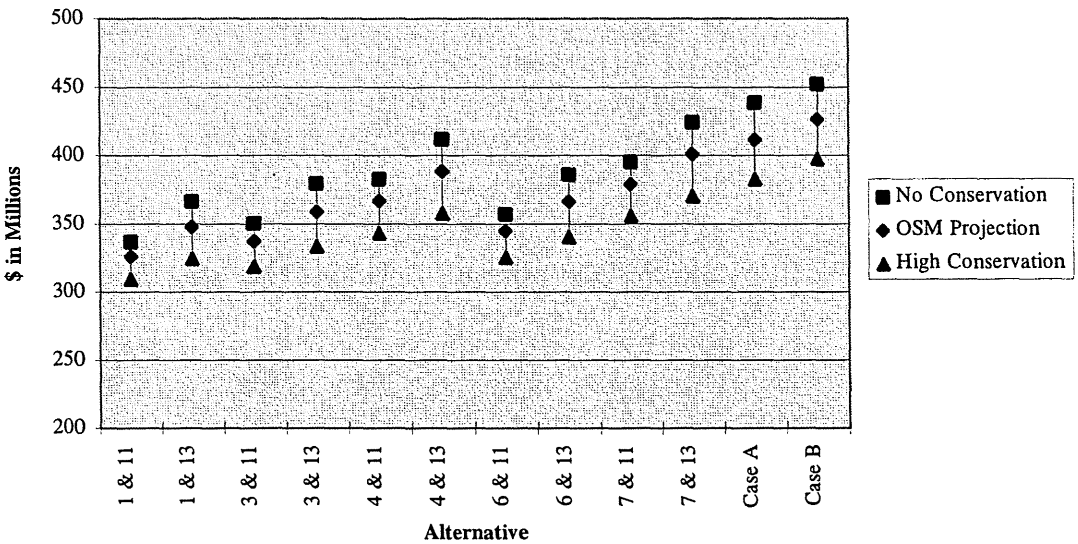
Changing the steam load assumptions affects the alternatives with high marginal costs for steam more than the alternatives with low marginal costs for steam. The marginal cost is the cost for each incremental Mlb of steam. Therefore, increasing or decreasing steam loads causes larger swings in the total costs of high marginal cost alternatives than in the total costs of low marginal cost alternatives. Or, from an energy planning viewpoint, the higher the marginal cost of steam, the greater the financial incentive to reduce demand.

Three steam load scenarios were used in this analysis. The steam load projection used in the base case set of assumptions was prepared by University's consultants, Orr Schelen Mayeron & Associates (OSM), in February 1994. OSM's projection includes a moderate level of conservation and also assumes that in FY 1998 the University's steam load would decline by 220,000 Mlbs because the University's contracts to supply steam to third party customers would expire and would not be renewed.

The high conservation steam load case is OSM's projection with double the conservation projected by OSM in its base case. The no conservation steam load case is OSM's projection without the conservation projected by OSM in its base case.

The following graph shows the variability of results under the different steam load scenarios.

Scenario 3: Steam Load



Changing the steam load has a relatively small effect on Alternative Nos. 1 and 11 because, with coal as their primary fuel, the marginal cost of production is low. The low marginal cost of production is also reflected in the relatively small cost changes occurring when other alternatives are combined with either Alternative No. 1 or Alternative No. 11.

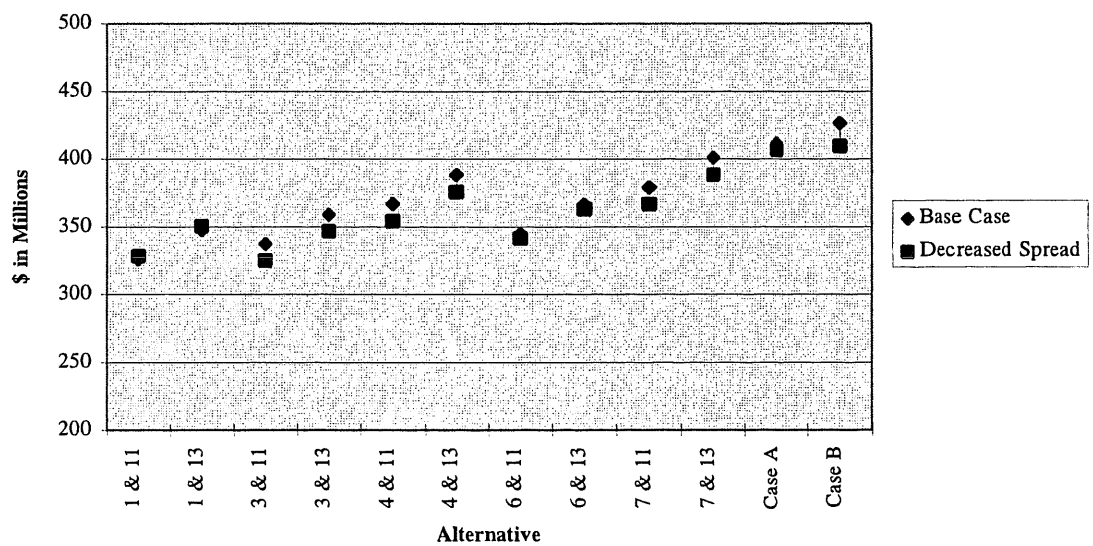
The figure above indicates that Cases A and B have larger ranges of results than do the other alternatives. The larger ranges are a result of Case A's and Case B's higher marginal costs of steam, which include a rate paid per Mlb of steam in addition to incremental fuel costs. Under the other alternatives, no rate per Mlb of steam is paid; only incremental costs for fuel, ash disposal costs, and other operating costs are incurred. Natural gas based alternatives have higher marginal steam costs than primarily coal facilities.

Decreased Spread in Fuel and Electricity Escalation Rates Makes Cogeneration More Valuable

Decreasing the spread between the escalation rates for fuel and electricity makes cogeneration more valuable. In the base case analyses, we used a 2% spread between the escalation rates of fuel and electricity. Because fuel costs are a large part of electric costs and because Northern States Power Company's costs could increase more rapidly than projected, a second scenario was prepared where the spread between the escalation rates of fuel and electricity was decreased to 1%.

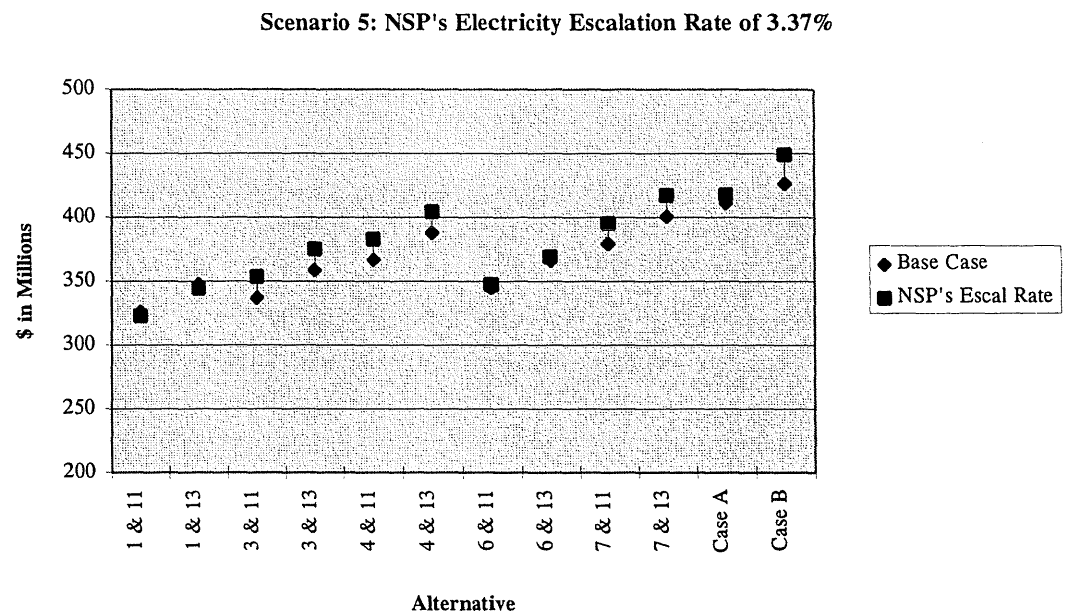
Decreasing the spread between the escalation rates for fuel and electricity makes the alternatives that include cogeneration relatively more attractive than those alternatives that do not include cogeneration. Also, alternatives that are projected to generate more kWhs benefit more than alternatives that are projected to generate fewer kWhs. The following graph shows the costs under the two scenarios of fuel and electricity escalation rate spreads.

Scenario 4: Decrease Spread Between Fuel and Electricity Escalation Rates by 1%



Higher Projected Electricity Values Improve Costs of Cogeneration Alternatives

The costs of alternatives that do not include cogeneration increase when the spread between the escalation rates in fuel and electricity is decreased. However, since cogenerated electricity becomes relatively more valuable when the spread is decreased, costs decline for alternatives that include cogeneration. The decline in costs is more pronounced for combinations including Alternatives No. 3, 4, and 7 and for Case B, because those alternatives are projected to generate more electricity than the other alternatives. The overall shifts, however, are small compared to other sensitivity variables.



Reducing Escalation Rates for Electricity Prices Reduces Economic Value of Cogeneration

As detailed in the EIS support document *Value of Cogenerated Electricity*, by Dahlen, Berg & Company, offsetting retail purchases from the electric utility is the most valuable way the University could use its cogenerated electricity. Hence, decreasing the assumed rate at which the retail cost of electricity escalates reduces the economic value of cogeneration.

Similarly, the PV costs of alternatives that produce larger amounts of electricity—Alt. Nos. 3, 4, 7, and Case B—are more sensitive to changes in assumed retail electrical rates than are alternatives that cogenerate little or no electricity. Alternatives that do not cogenerate electricity vary minimally with a change in assumed electricity escalation. (This scenario assumes that retail electricity rates would be less than the base case but that University fuel costs would remain the same.)

For example, detailed designs were not completed for the all natural gas, fuel oil alternative without cogeneration. However, the screening analysis (and rough estimates of updated projections by EQB staff) indicate that their NPV costs would be slightly less than those of the natural gas, fuel oil cogeneration alternatives. Lowering the value of electricity without revising fuel costs makes cogeneration relatively even more expensive. Conversely, decreasing fuel costs, particularly natural gas costs, without assuming reduced retail rates for electricity makes cogeneration relatively more financially attractive.

Section 11.4. Fuel Price Projections

Because fuel costs constitute 50% to 70% of the lifetime costs of any alternative, this section will briefly summarize the work on the fuel-cost component of operating costs. Some major assumptions used to calculate the value of cogenerated electricity are also described.

Fuel Price Projections Valid for this Study Only

Fuel prices, which dominate the operating costs of steam-generating facilities, can change rapidly, with wide swings both up and down, thereby causing tremendous uncertainty in all long-term fuel price forecasts.

The fuel price forecasts in this report were developed using a consistent methodology and reflect a common crude oil price forecast. Because of the uncertainty in long-term fuel price forecasts, however, they should only be used for evaluating alternatives to the University's proposed project. Actual prices will inevitably differ from forecast prices.

Fuel Prices Projected Over 25 Year Period

Fuel prices were projected for 25 years, 1994 through 2018, and were based on the following considerations.

- World Energy Balances
- Supply and Demand for Crude Oil
- Adjustments to Apply to Local Situation

World Energy Balances Adjusted from U.S. Government Data

World energy demand and supply forecasts were based on data supporting the Department of Energy's *International Energy Outlook (IEO) 1993*, the U. S. Government's major annual review and forecast of world energy markets.

World energy demand depends on economic growth, usually estimated as Gross Domestic Product (GDP) and energy-economic efficiency, usually expressed as the Btu's of primary energy used per real dollar of GDP. This government data was then adjusted to take into account the sensitivity of demand to changes in fuel prices, and more recent World Bank projections of world economic trends. All adjustments in government data gave results consistent with other widely accepted sources

Supply and Demand for Crude Oil Estimated

Supply and demand for crude oil was estimated, and price forecasts were checked for consistency with government and major private energy price forecasts. Prices for specific fuels usable in Minneapolis-area steam facilities were then forecast based on Refinery Acquisition Costs (RAC) crude oil prices.

Prices Adjusted to Apply to Local Situation

Price estimates based on RAC crude oil prices were adjusted to take into account local fuel price quotations, the influence of the dual fuel market, transportation rates for different fuels, possible low sulfur premiums from the Emissions Allowance Market, and gas and oil seasonality adjustments, all of which contribute to determining local burner-tip prices.

Section 11.5. Value of Cogenerated Electricity

The value of cogenerated electricity is the margin between the price of electricity and the cost of generating electricity.

The price of electricity could be either the retail price of purchases that would be offset by cogenerated electricity, or the wholesale price received were the electricity sold.

The cost of generating electricity includes fuel, capital, maintenance. The projected values of cogeneration in this analysis include the cost of backup power.

The projected value of cogenerated electricity is based on baseload operation 95% of the hours of the year.

Value of Cogenerated Electricity Is Higher When Used to Offset Retail Purchases

Since the retail price of electricity is higher than the average wholesale price, the value of cogenerated electricity is higher for the University when the electricity is used to offset retail purchases from NSP, even when adjusted for the cost of backup power.

Copies of NSP's current General Time of Day Service tariff and Standby Service Rider are contained in appendices of the separate *Value of Cogenerated Electricity* report.

Electricity Prices Assumed to Increase by 4.7% per Year

NSP's prices were assumed to increase by 4.7% per year through fiscal year 2019. This assumption is based on a general inflation rate of 3.6% per year and a fuel cost escalation rate of 6.5% per year. The 4.7% escalation assumes no change in the relationship between demand and energy charges.

Because fuel and purchased power are approximately thirty percent of NSP's total electric revenues, it was assumed that thirty percent of the price of electricity would increase at the fuel cost escalation rate and that the remaining seventy percent would increase at the general inflation rate. Any changes to the fuel cost escalation rate would also change the escalation rate of electricity prices. Frequent Rate case requests by NSP could cause a higher rate of price escalation than is assumed in this report.

Various Factors Affect Value of Cogenerated Electricity

Factors that could affect the value of cogenerated electricity may be summarized as follows.

- Spread between escalation rates of electricity prices and fuel costs affects the value of cogenerated electricity (see section 5)
- Summer production is more valuable than winter production.
- On-peak production is worth more than off-peak production.
- Higher summer steam requirements increases the value of cogeneration.
- Retail wheeling could increase the value of cogeneration.
- Minimum demand charges on remaining purchases could reduce the value of cogeneration.

For Detailed Information, See Separate Report

For detailed information on the value of cogenerated electricity, see the separate report, *Alternatives to the University of Minnesota's Projected Steam Service Facilities Renovation: Value of Cogenerated Electricity*, dated April 1, 1994.

Chapter 12. Permits Required For the Proposed Project

STATE

MPCA	Air Emissions Facility Permits	Applied For*
MPCA	Ash Storage Permits	To Be Applied For
MPCA	Stormwater Discharge Permits	To Be Applied For
MPCA	Hazardous Waste Contingency and Spill Prevention Plan	To Be Completed if Necessary
Minn Dept Labor Industry/ University	Boiler and High Pressure Piping Permits	To Be Applied For
Mn/DOT and City of Minneapolis	Utility Crossing Permits	To Be Applied For

LOCAL

MCWS	Sewer Discharge Permits	To Be Applied For
University	Critical Areas Plan Consistency	To Be Applied For*
University	Floodplain Certification of Occupancy	To Be Applied For
University	Shoreland Alternation Permit	To Be Applied For if Needed
University	Building Permit	To Be Applied For
University	Electrical Inspection	To Be Applied For
University	Liquid Storage Permits	To Be Applied For
University	Storage Tank Response Plan	To Be Developed if Needed

* Permits for which a record of decision is required pursuant to Minn. Rules pt. 4410.2100, subp. 6, item D and 4410.2900.

Chapter 1. Existing Facilities

Comments Primarily Address Hazardous Waste Practices

Chapter 1 in the DEIS describes the existing facilities at the Minneapolis and St. Paul Campuses. Comments addressed the description of the existing steam plants and current solid and hazardous waste production and disposal practices.

Ash Handling Procedures Have Been Changed

The only substantive modification to Chapter 1 is a revised description of the current ash handling procedures.

Foster Wheeler has discontinued storing coal-ash on the ground or in open bunkers as described in the DEIS and has indicated that the revised ash handling procedures will continue until the University determines whether to select ash disposal options under their contract as part of the steam plant renovation.

Chapter 1. Comments and Responses

COMMENT 1a

Solid and Hazardous Waste Descriptions are Incomplete

The description of the types, quantities, and characteristics of waste generated by the steam plants is incomplete. The description of the existing and proposed fuel delivery system for the steam facilities is incomplete. Alternative means of ash disposal are not addressed. (MPCA)

RESPONSE 1a

Response is in Five Parts

The response to Comment 1a is in five parts.

- Quantities of Hazardous Waste Are Small
- Current Minneapolis Campus Ash Production About 8,000 Tons per Year
- Ash Characteristics Summarized in DEIS and in Liesch Report
- Ash Handling Procedures Have Changed Since DEIS Was Approved
- Fuel Delivery Systems Are Described in DEIS.

Quantities of Hazardous Waste Are Small

Small quantities of hazardous waste, mainly cleaning solvents, are produced at the steam plants at both campuses. Foster Wheeler stores these solvents on-site, and the University processes it at their recently completed Integrated Waste Treatment Facility (see Figure 9-2). Hazardous waste production and processing are described in DEIS Chapter 8 and would not change significantly following steam plant renovation.

Current Minneapolis Campus Ash Production About 8,000 Tons per Year

The predominant solid waste produced by the steam facilities is coal ash. The DEIS description of ash quantities, characteristics, and handling procedures can be found in several sections of the DEIS. The ash quantities predicted at the Minneapolis campus for the proposal and the alternatives are on page 8-3 of the DEIS. The current ash production at the Minneapolis campus is similar to that indicated for Alternative 1 (No Build)—about 8,000 tons per year.

Ash Characteristics Summarized in DEIS and in Liesch Report

Trace metal concentrations and TCLP results from ash samples taken from both campus are summarized in DEIS Section 7.2 (Stormwater). Detailed sampling techniques and sampling results are available in Table 4 of the separate *Water Quality* support document by B.A. Liesch Associates.

Ash Handling Procedures Have Changed Since DEIS Was Approved

The ash handling system used when the DEIS was written is described on DEIS pages 1-6 (Minneapolis) and 1-7 (St. Paul). The locations of the former (and possibly future) ash storage sites in Minneapolis and St. Paul are shown in DEIS Figures 9-1 and 9-3 respectively.

Since the DEIS was published, however, Foster Wheeler has substantially modified the ash handling system at both the Minneapolis and St. Paul campuses. The coal ash is no longer stored in outside areas at either campus.

The coal ash is now first temporarily stored in a building near the Main Plant, and then trucked to a licensed landfill in Madison, Wisconsin. According to the MPCA, a solid waste permit for outdoor ash storage would require an impermeable lining with a leachate collection system.

Foster Wheeler, Twin Cities, Inc. is actively searching for markets for coal ash so that land fill disposal is not necessary. The alkaline ash produced in the circulating fluidized bed boiler to be installed under the proposal is well suited for use as a raw material for cement blocks or other products.

Fuel Delivery Systems Are Described in DEIS

The fuel delivery systems to the Minneapolis and St. Paul campuses are described on DEIS pages 1-5 and 1-7 respectively.

Chapter 2. The Proposed Project

Chapter 2 of the DEIS describes the equipment configurations of the University's proposed project, as defined by the University's contract with Foster Wheeler, and estimates future fuel use based on economic operating assumptions. The two basic equipment options under the contract are referred to as Case A and Case B.

Most Comments Addressed Projected Fuel Use and Fuel Mix

Comments on this chapter focused on the projected fuel use and fuel mix for the proposed project (and alternatives) because these assumptions have an important effect on both economic projections and predicted air emissions.

Some commenters suggested that petroleum coke is likely a potential fuel under the University's proposal, while the University/Foster Wheeler questioned the accuracy and consistency of fuel efficiency, fuel mix, and steam load projections.

Fuel Efficiencies, Fuel Mixes, and Air Emissions Implications Have Been Revised

In response to UofM/FW comments, the plant fuel efficiencies used to predict air emissions have been revised to reflect the guarantees in the University contract. These contract guarantees were used in the DEIS to project fuel costs. Therefore, the largest impact of this efficiency revision is a 3% to 5% reduction in predicted air emissions for Cases A and B.

The estimated percentage of coal to be used in the primarily coal-fired Case A and Alt. No. 6 has been revised, as has the description of the circulating fluidized bed boiler's petroleum coke capability. The fuel mix used by UofM/FW has also been added to the EIS text.

The air emission implications of these changes and alternative fuel mixes are described in FEIS Chapter 6.

Chapter 2 Comments and Responses

NOTE: Many comments and responses on Case A in this section also generally apply to Case B. Other revisions from changed efficiencies that are specific to Case B are reflected below in Chapters 6 (Air Emissions), 10 (Mitigation), and 11 (Economic Feasibility).

COMMENT 2a

Economic Dispatch Should Assume Petroleum Coke Capability

The project description and economic fuel dispatch should assume petroleum coke capability. Petroleum coke is currently a much lower cost fuel than even coal, and its use would be permitted under the University's current air quality permit application submitted to the MPCA. (Minnegasco, City of Minneapolis, SORC, and others)

The DEIS should not assume petroleum coke capability in the proposed project because the University has not formally exercised the option required to burn it. (UofM/FW)

RESPONSE 2a

Petroleum Coke Contains High Sulfur but is High Btu,, Abundant, and Inexpensive

Petroleum coke is a solid, high-sulfur, high-Btu by-product of certain oil-refining processes and can be efficiently used in circulating fluidized bed boilers like that proposed in Case A, Case B, and EIS Alternative 6. (Alternative 6 is similar to Case A but located off-river.) An abundant, inexpensive, supply of petroleum coke is apparently available from local refineries.

Petroleum coke-firing capability is included in the Foster Wheeler contract as an additional cost option ($339,000). The University has not yet decided whether to accept or reject this option.

Impact of Firing Petroleum Coke Should Be Evaluated in EIS

Since the capability to fire petroleum coke has, however, been included in the University's current permit application, EQB staff agrees that its emissions and other impacts should be evaluated in the EIS. If not addressed, exercising the petroleum coke option later could require a supplemental EIS.

Petroleum coke is not a "mitigation" option like other contract options, and its largest impact would be to increase sulfur emissions. (Detailed data on toxic metal concentrations in petroleum coke could not be found, other than the elevated levels of nickel and vanadium described in the DEIS).

Petroleum coke's potential impact on predicted air emissions is addressed below in FEIS Chapter 6 (Air Emissions).

COMMENT 2b

Fuel Efficiency and Contract Guarantees Questioned

The fuel efficiency assumed for the project should be no less than the fuel efficiency guarantee provided to the University by Foster Wheeler. (UofM/FW)

Any guarantees in the Foster Wheeler contract should be ignored because the contract's existence is contrary to state environmental laws. (Representative Phyllis Kahn at DEIS public meeting)

RESPONSE 2b

Quantity of Fuel Charged to University Based on Contract Guarantees

The UofM/FW suggestion that the cost of fuel projected for Case A and Case B is not in accordance with the contract is incorrect. The DEIS financial projections for Case A and Case B are based on the University's contract with Foster Wheeler. Under the contract, fuel costs are not paid by Foster Wheeler, but are a "pass through" to the University. In the DEIS, and in the FEIS revisions, the quantity of fuel charged to the University is based on the minimum efficiency guarantees in the contract.

Air Emissions Based on Actual Plant Performance

Air emissions, of course, would reflect actual plant performance, not financial guarantees. The University administration's *Evaluation of Steam Service Agreements,* dated March 2, 1992 (and the contract itself) seems to interpret the vendor's fuel efficiency guarantees as a "cap" on fuel costs, not necessarily a guarantee of actual plant efficiency. (See *Evaluation*, pages IV-14 and IV-15.)

For DEIS emission calculations, therefore, the fuel efficiencies for the proposed project were independently estimated using concept level engineering estimates, as they were for the alternatives..

Fuel Efficiency Calculations Were Reviewed

In response to the UofM/FW comments, however, the DEIS fuel efficiency calculations for the proposal and all alternatives were reviewed.

As a result, plant efficiency estimates for the high pressure boilers, which affects only Alt. No. 6 (off-river coal), have increased. And, for consistency, the emission estimates for Cases A and B have also been revised to reflect the contract guarantees, which were used for the DEIS economic projections.

Revised Fuel Efficiencies Lower Estimated Fuel Consumption

The revised plant fuel efficiencies lower estimated fuel consumption for Case A, Case B, and Alternative 6 by about 8% to 10%, and lower predicted air emissions by 3% to 5%, compared to DEIS estimates. (See FEIS Chapter 6.) This increased efficiency in the coal-fired base-load boilers reduces annual fuel consumption but results in a 1% to 2% increase in the projected annual percentage of coal used.

COMMENT 2c

Old Boilers Unlikely to be More Efficient than New Boilers

The DEIS incorrectly assumes that the old boilers at the existing plant will be more fuel efficient than the project's new boilers.

The DEIS also makes the unlikely assumption that the No Build alternative consumes fewer Btu's per pound of steam than Case A, which would have new, more efficient boilers. (UofM/FW)

RESPONSE 2c

Boiler Efficiency Should Not Be Confused with Overall Plant Efficiency

Contrary to the above comments, the DEIS assumed that the new boilers would be more efficient than the existing boilers. The boiler fuel conversion efficiencies in the DEIS are based on independent vendor information and on boiler-efficiency test results provided by Foster Wheeler. These comments, therefore, appear to confuse boiler efficiency with overall plant efficiency.

EIS Efficiency Calculations Not Based on Contract Guarantees

These comments are also confusing because they are not based on any assumptions actually used in the DEIS. Instead, they are apparently based on "back calculations" of fuel efficiency that used net-electricity guarantees in the Foster Wheeler contract as a starting point.

The DEIS, however, did not use these guarantees in its efficiency calculations other than to calculate fuel costs for Case A and Case B. The EIS efficiency estimates for the alternatives, in fact, did not attempt to divide the fuel consumption for the cogeneration alternatives into separate electrical and steam components.

For the EIS, instead, a simplified heat balance was prepared for medium and high pressure boilers to account for in-plant steam use. The same assumptions were used for similar equipment in the proposal and all alternatives.

Revised Fuel Use Calculations Improve Minneapolis, but Not St. Paul, Plant Efficiencies

As described above, these in-plant fuel use calculations for each of the alternatives and the proposal were reviewed for the FEIS. As a result, fuel use assumptions for Case A, Case B, and DEIS Alternative 6 have been revised. Minneapolis plant efficiencies are improved for Case A, Case B and Alternative 6. Case A and Case B calculations use the contract guarantee.

The St. Paul plant efficiencies under Case A and Case B, however, have decreased because the St. Paul plant fuel efficiencies assumed in the DEIS were better than those in the contract guarantee. (The proposed St. Paul campus renovation is the same under Case A or Case B.) The fuel efficiencies of the other alternatives have not been changed. See FEIS Chapter 3.

No Build Alternative is Efficient Because Thermal-Only Plants Are More Efficient than Cogeneration Plants

Electric cogeneration has efficiency losses that do not occur in thermal only plants like the "No Action" alternative. The revised efficiency calculations indicate that, because of the new boilers, Case A would be more efficient than the "No Action" alternative.

The No Build alternative, however, is still one of the more efficient alternatives, even with older, less efficient boilers. As Section 10.2 of the DEIS makes clear, the fuel efficiency advantages of cogeneration plants becomes readily apparent only when the lower efficiencies of utility electric plants are considered in the analysis.

<u>COMMENT 2d</u>

Steam Use Assumptions Should Be Consistent

The assumed steam demand should be consistent for both the project and the alternatives, so that comparisons between the two are fair ones. The DEIS does not appear to use any consistent steam demand in its comparative analyses. (UofM/FW)

<u>RESPONSE 2d</u>

Steam Use Assumptions Are Consistent

Identical steam consumption and demand data, provided by the University's consultant, was used for the proposal and for all alternatives in the DEIS. Financial projections for Case A, Case B and the alternatives are all based on these same 25-year steam load projections.

Subsequent discussions with the University's representatives indicate that this comment apparently refers to the steam consumption year used for the predicted air emission calculations.

EIS Air Emissions Projections Based on FY 1995 Steam Loads

The annual air emission projections in the DEIS for Case A, Case B and the alternatives are based on the steam loads projected by the University for FY 1995. This year was chosen because it was projected to have the highest steam load of any in the next twenty-five years. The 1995 steam use projections are also nearly identical to those projected for the final years of the 25-year period.

UofM/FW Comments Based on FY 2000, a Low Steam Year

The UofM/FW comments, on the other hand, are based on the year 2000, a low steam year the use of which could generally understate typical annual emissions. Steam loads around the year 2000 are projected to be low because, in 1996, the University will lose two current steam customers that make up about 10% of its steam production: Fairview/Riverside Medical Complex and Augsburg College.

More Conservative Estimates in EIS Are Preferable

Although the FY 95 data may overestimate the average 25-year steam load somewhat because it does not account for this upcoming drop in steam consumption, the University steam use projections also assume a 12% to 13% reduction in 1996 due to planned energy conservation programs. These conservation related reductions, however, may or may not actually occur.

In addition, the University has in the past underestimated its steam use projections (as it did for the 1992 contract evaluations).

Therefore, EQB staff believes that the higher FY 1995 steam consumption level used in the DEIS air emissions estimates is appropriate because it provides conservatively high annual emission predictions.

University 1995 Steam Projections On Target

Recent data provided by the University's consultant also indicates that the projected steam use figures for FY 1995 were reasonably accurate, and that the University's projected steam consumption remains the same as that used in the DEIS

COMMENT 2e

DEIS Incorrectly Assumes Steam Demand Will Decrease

The DEIS fuel use and emissions calculations incorrectly assume that boiler demand will decrease from the 520,000 lb./hr guaranteed by Foster Wheeler to 430,000 lb/hr. (UofM/FW)

RESPONSE 2e

EIS Uses Load Duration Curve Provided by University

Boiler demand refers to the peak steam requirements over a given time period. The 430,000 lb/hr figure referred to is not the peak one-hour demand used in the DEIS as suggested by the University, but the average steam demand during the peak 100-hour increment. 100 hour increments were used in the DEIS fuel consumption model to simplify the numerous calculations required for the multiple alternatives analyzed. Using one-hour increments for the boiler dispatch and fuel use model would have a minor effect on overall fuel use for all the alternatives.

The data used to estimate steam demand and steam consumption in the DEIS model comes from the load duration curve provided by the University. The load duration curve describes how steam demand fluctuates throughout the year. The University has not provided a revised load duration curve for use in either the draft or final EIS, so we assume we have used the best data available.

COMMENT 2f

Boiler Dispatch Order Should Reflect Factors Other than Fuel Cost

The boiler dispatch assumed for the project should reflect the age of the steam plant equipment, the fuel efficiency guarantees provided to the University, and the description of the project in the DEIS itself. The DEIS does not consider these factors, but assumes a straight "least cost" fuel dispatch.

The fuel mix assumed for the project should reflect the revised assumptions for fuel efficiency and boiler dispatch, and also reflect the expressed intentions of the University and Foster Wheeler. The DEIS ignores the fuel mix projections of the University and Foster Wheeler and assumes a far higher use of coal than is reasonable. (UofM/FW)

The University's calculations for their DEIS comments used the following identical fuel mix for the Minneapolis campus for each of the 25-years projected in the FEIS: 70% coal, 20% natural gas, 5% oil, and 5% wood chips.

RESPONSE 2f

EIS Assumes Maximum Cogeneration and that Lowest Variable Cost Equipment Would Be Used First

The DEIS's financial projections for Case A, Case B, and the alternatives for the Minneapolis Campus are based on the assumption that cogeneration of electricity would be maximized and that the lowest variable cost equipment would be operated first, within the constraints of equipment configuration and campus load.

An exception to this approach was used for the proposed project at the St. Paul Campus. For the St. Paul campus, the University provided a description of Case A and Case B that stated that coal would be used "primarily for backup purposes." The DEIS therefore assumed a 92% natural gas/8% fuel oil mix at the St. Paul Campus.

Under Contract, Foster Wheeler Guarantees to Dispatch Fuel "in Most Economic Manner"

The University did not provide the EQB with specific directions regarding fuel mix for the Minneapolis campus for Case A or Case B. EQB staff consequently assumed that the controlling language was that found in the Management, Operation and Maintenance Agreement between the University and Foster Wheeler, in which Foster Wheeler "guarantees that it shall dispatch fuel in the Steam Production Units constructed as part of the Phase I Improvements in the most economic manner possible."

University Does Not Assume Economic Fuel Dispatch

The UofM/FW comments on the DEIS, however, use a specific fuel mix as a basis for their suggested revisions. The difference between the fuel mix used in the DEIS and that used in the UofM/FW comments are due primarily to two factors.

1. The UofM/FW comments assume, for various reasons, that the existing coal boilers in the Southeast Plant would be used less often than assumed in the DEIS.

2. The UofM/FW fuel mix assumes about 5% waste wood, which is the maximum amount possible without additional physical modifications to the circulating fluidized bed boiler.

University Points Out No Physical Limitations to EIS Fuel Mix

The UofM/FW comments do not indicate that there is a limiting physical reason that would prohibit the proposed equipment from operating as described in the DEIS. (The DEIS, for example, does not assume the use of wood chips, which Foster Wheeler has pointed out as being problematic in the existing coal boilers.)

Therefore, the boiler dispatch model used in the DEIS financial projections has not been changed.

Decreased Coal Use Would Decrease Emissions of Some Pollutants but Would Increase Costs

Increased use of natural gas in the new boilers and decreased use of coal in the existing boilers would decrease the proposal's predicted emissions of some pollutants. Therefore, the fuel mix described in the University's comments is included in a "low SO_2 scenario for "predicted" emissions in FEIS Chapter 6 (Air Emissions).

Assuming more natural gas use as indicated in the UofM/FW comments, however, would also increase costs above the level estimated for the DEIS. The cost of Case A and Case B using the UofM/FW fuel mix is provided in their comments on the DEIS (about $10 million more than EIS projections).

Wood and Petroleum Coke Could Reduce Costs, but Prices Hard to Forecast

The financial estimates in the DEIS are based on the minimum cost mix of coal, natural gas, and fuel oil and did not assume any use of wood or petroleum coke. Using wood or petroleum coke would, of course, change and complicate the expected dispatch order and fuel mix.

These two alternative fuels are comparatively inexpensive, and using significant amounts of either, particularly petroleum coke, could lower fuel costs. Their prices, however, are driven largely by local fuel markets and are difficult to forecast on the same basis as those of the other fuels.

The predicted impacts of these fuels on air emissions is discussed in FEIS Chapter 6.

Chapter 3. Description of Alternatives

Chapter 3 of the DEIS describes the equipment configurations of seven alternatives to the University's proposed project and estimates fuel mix based on economic operating assumptions.

Comments Addressed Projected Efficiencies and Fuel Mixes

Comments focused on the efficiencies and fuel mixes assumed for the EIS alternatives. Other comments addressed the feasibility and location of the off-river alternatives as presented in the DEIS.

Minor Changes Made to Chapter 3

Only minor revisions have been made to the text of Chapter 3. Background information on the two basic types of cogeneration technology has been added, and the predicted fuel mix for one alternative has been revised slightly.

In the comment and response section of this chapter, general comments applying to a number of alternatives are addressed before specific comments applying to particular alternatives.

Chapter 3. Comments and Responses

COMMENT 3a

Fuel Mix for Gas/Oil Alternatives Should Be Revised

The annual fuel mix for the gas/oil alternatives should be revised from 92% gas/8% oil, to a 90% gas/10% oil mix. The 8% fuel oil mix assumed by the DEIS is too low for the following reasons.

- The natural gas supply is most likely to be interrupted during winter, when steam demand is highest.
- The actual experience of existing gas/oil plants indicates higher fuel oil use. (MEC uses about 17% fuel oil.)
- During the University's procurement process, Arkla was willing to guarantee no less than 10% oil use. (UofM/FW)

RESPONSE 3a

DEIS Assumes 8.3% Fuel Oil Use

The 1/12 fuel oil, 11/12 natural gas mix used in the DEIS assumes that fuel oil would be used as a backup during periods of natural gas curtailment only. This DEIS fuel-oil ratio equals about 8.3% annual energy use.

On Average, Natural Gas Is Only Curtailed 7 or 8 Days a Year

Information submitted by Minnegasco indicates that, on average, natural gas is curtailed only 7 or 8 days a year to Minneapolis customers. (Although natural gas was curtailed 18 days during the winter of 1993-94, the data indicates that that was an unusually cold winter.)

Minnegasco has also indicated that for the 100% gas/oil alternatives, particularly the higher gas consumption base-loaded cogeneration alternatives, the University would likely be a "transportation gas customer"—a customer who purchases gas directly from suppliers and arranges for delivery on the interstate pipeline.

According to Minnegasco, gas curtailment to transportation customers usually only occurs when there is inadequate flow on the interstate pipeline. Hence, on average, natural gas would be curtailed even fewer than 7 or 8 days per year.

Arkla and MEC Numbers Are Not Necessarily Representative

Arkla's long-term 10% fuel-oil guarantee in 1992 is likely to have included a significant safety margin. In order to guarantee that the fuel mix would include no more than 10% fuel oil for the term of the project, Arkla is likely to have assumed that the actual percentage would be less.

Minneapolis Energy Center (MEC) uses a high percentage of fuel oil for historical price and contractual reasons that are unrelated to natural gas curtailment.

EIS Continues to Assume 8.3% Annual Use of Fuel Oil

In actual operation, because of price changes or for other reasons, the University could, of course, use a higher fuel oil percentage. Since, however, the 8.3% fuel oil percentage is reasonably conservative, the 8% assumption has been retained for the EIS.

COMMENT 3b

Economic Fuel Dispatch for Oil/Gas Alternatives Should Be Revised

Since No. 6 oil has historically been cheaper than natural gas, a true "least cost" fuel dispatch for the 100% gas/oil alternatives would use No. 6 fuel oil before natural gas. (UofM/FW)

Using very low-sulfur No. 2 oil exclusively instead of No. 6 oil would be logical because it would reduce SO_2 emissions, and the alternatives as designed don't use much fuel oil in any case. (Minnegasco, PPERRIA)

RESPONSE 3b

Economic Fuel Dispatch Should Not Be Revised, for Four Reasons

The fuel dispatch for the 100% gas/oil alternatives has not been revised, for the following reasons.

- Natural gas projected to be less expensive than No. 6 fuel oil.
- No. 6 fuel oil cannot be used in combustion turbines.
- Natural gas is environmentally superior to No. 6 fuel oil.
- No. 6 fuel oil capability lowers gas rates.

Natural Gas Projected to be Less Expensive than No. 6 Fuel Oil

Although No. 6 fuel oil prices have at times been below those of natural gas, natural gas companies have recently tended to meet oil prices, and the fuel prices projected for the DEIS indicate that natural gas will remain less expensive than No. 6 fuel oil for the entire 25-year term of the project.

Also, since natural gas is easier to use than fuel oil from an operational standpoint, natural gas would generally be the preferred fuel even if prices were similar.

No. 6 Fuel Oil Cannot Be Used in Combustion Turbines

The 100% fuel oil alternatives are base-loaded cogeneration alternatives that use combustion turbines. No. 6 heavy oil cannot be used in combustion turbines.

Natural Gas is Environmentally Superior to No. 6 Fuel Oil

The EIS alternatives were designed as potentially environmentally superior alternatives that use primarily natural gas. Fuel oil storage quantities and the alternatives themselves are in general designed to use No. 6 oil in boilers during natural gas curtailment only.

No. 6 Fuel Oil Capability Lowers Gas Rates

Very low sulfur No. 2 fuel oil (0.05% sulfur) could be used exclusively in the oil/gas alternatives. The DEIS financial projections did assume that the No. 2 fuel oil would be the newer .05% sulfur variety. The base case emissions in the DEIS have been revised accordingly.

No. 6 fuel oil capability, however, has been kept for the DEIS alternatives because it helps buyers to negotiate lower natural gas rates. A very low sulfur fuel oil only scenario is included in the FEIS Chapter 6.

<u>COMMENT 3c</u>

Fuel Efficiency Assumptions for DEIS Alternatives should Be Revised

The fuel efficiencies assumed for the DEIS alternatives should be based on reasonable estimates of probable efficiencies. There is no apparent basis or consistency to the efficiencies for the alternatives assumed by the DEIS. (UofM/FW)

The DEIS used inaccurate assumptions for fuel efficiencies for the alternatives, based on past vendor guarantees during the University's procurement process. The DEIS efficiencies are based on a simple "static" model. A more reasonable revised fuel efficiency of 1417 Btu/lb should be used for all the alternatives. 1417 Btu/lb is the average of the guarantees by the Foster Wheeler (1350), Arkla (1400), and NSP (1500). (UofM/FW)

RESPONSE 3c

EIS Efficiencies Differ Because Equipment Configurations and Dispatch Assumptions Differ

The comment on inconsistent efficiencies for the alternatives is somewhat confusing because it is based on back calculations using University contract guarantees. The contract guarantees were not used to calculate efficiencies for the EIS alternatives. (See FEIS Chapter 2 regarding Case A fuel efficiency revisions.)

Also, each DEIS alternative has different equipment and dispatch assumptions, so each would be expected to have somewhat different overall plant efficiencies.

Boiler and Turbine Efficiencies Based on Consistent Methodology

The individual boiler and turbine efficiencies for the DEIS alternatives are based on vendor information and Foster Wheeler boiler test results. A simplified heat balance model was used to calculate in-plant steam use and fuel efficiencies. A consistent methodology was used for the proposal and all alternatives.

Vendor Guarantees Cited May Not Be Relevant

The comment above suggests that the DEIS should project fuel efficiencies for the alternatives using simplified assumptions that would assign plants with completely different equipment configurations identical efficiencies. The comment also suggests that the average of three vendor agreements should be used for the DEIS alternatives.

These guarantees, however, were submitted for different equipment configurations than those in the DEIS alternatives, and the guarantees were negotiated in 1992 under circumstances that may not be directly applicable today.

Review of Assumptions Reduces Fuel Use Projection for Alt. No. 6

All fuel efficiency assumptions were nevertheless reviewed again for the FEIS because of their potential impact on costs and emissions. As discussed in FEIS Chapter 2, fuel use projections have been revised downward about 9% for DEIS alternative No. 6. (Alternative 6 is similar to Case A, but located off-river).

These efficiency revisions result in lower emission predictions and lower fuel cost estimates for Alt. No. 6.

COMMENT 3d

New Deferred Construction Alternative Suggested

A deferred construction alternative should be analyzed in which the major capital investment is deferred into the next century, when the electric utility would need base-load capacity. At that time, a very large cogeneration plant would be economically competitive. (Minnegasco)

RESPONSE 3d

Version of Suggested Alternative Briefly Addressed in Chapter 4

This alternative was generally addressed in the DEIS as "Alternative 5: Southeast Plant with Large Cogeneration." Additional discussion of this alternative combined with a deferred construction scenario is provided in FEIS Chapter 4.

COMMENT 3e

Feasibility of a Coal Based Plant at the DEIS Off-River Site Questioned

Several comments addressed the feasibility and location of the off-river steam plants described in the DEIS.

1. The FEIS should state what the University intentions currently are for the Alternative Site. (SORC)
2. The DEIS states that there is limited space at the Alternative Site for some plant designs, but it should point out that the nearby parking lots could easily be relocated. (SORC)
3. Alternative 6 could not be built for the estimated cost on the seven acres available for development. The design for Alternative 6 does not consider adequate ash cooling and disposal. (U of M)
4. The steam plant should be relocated to an off-river site, but the FEIS should evaluate a somewhat different off-river site about 300 yards north-east of the site identified in the DEIS. Any facility located at or near the DEIS Alternative Site should be further evaluated so that there is adequate distance between it and the University's Hazardous Waste Facility, nearby housing, and other planned development in the area. (PPERRIA)

RESPONSE 3e

University Plans Further Research Facilities for Alternative Site

The University has indicated that additional research facilities are planned for the Alternative Site shown in the DEIS, of which the completed Lions Research Facility is the first phase. See Figure 9-2.

Alternative Site Has Adequate Space for Coal or Natural Gas Based Facility

Syska and Hennessy, the engineering firm for the EIS alternatives, have been contacted and have not revised their assessment that there is adequate space at the DEIS alternative site for either the coal or natural gas based facility shown. The UofM/FW comment provides little specific information to the contrary. The necessary ash cooling would take place in the ash silos. The ash would then be taken directly to the disposal site by truck. (See DEIS Chapter 9, and the 1994 *Financial Projections* DEIS support document, by Dahlen, Berg & Co.)

Also, as the SORC comment indicates, part of the adjacent parking lot space could be used if necessary.

University Working to Acquire Second Alternative Site

The University also has recently started eminent domain proceedings to acquire another, larger, nearby property that would easily be adequate for either type of off-river steam plant. This area appears to be near—if not identical to—the property suggested in the PPERRIA comment. This property is slightly farther from the Prospect Park neighborhood, and slightly closer to the Como neighborhood, than the site assessed in detail in the DEIS. (For further information on this new site, see FEIS Chapter 9.)

COMMENT 3f

Steam Capacity of St. Paul Campus Alternatives Lower than That in University's RFP

The FEIS should describe why the St. Paul alternatives are designed for a firm steam capacity of 220,000 lb/hr rather than the 250,000 lb/hr provided by the University's proposal. (Although either would be sufficient to meet the current peak demand of 170,000 lb/hr). (SORC, UofM)

RESPONSE 3f

St. Paul Steam Capacity Based on University Projections, not on RFP

The University's original Request For Proposals required a firm steam send-out capacity of 225,000 lb/hr for the St. Paul campus, which corresponds to a production firm capacity of about 250,000 lb/hr. As indicated by the comment, the DEIS alternatives for the St. Paul campus are designed instead for a firm production capacity of 220,000 lb/hr.

The firm steam capacity designs in the DEIS for the St. Paul campus are based not on the University's RFP, but on the steam consumption projections and demand curves provided by the University. Therefore, the DEIS steam capacities are adequate, assuming that current University projections are reasonably accurate.

Because the St. Paul campus has a large amount of space available for expansion, t he University apparently included a larger safety margin for the St. Paul campus in its RFP to potential steam vendors to account for any unforeseen growth. The DEIS, on the other hand, assumed that future steam demand and consumption will be reasonably close to that currently predicted by the University.

Chapter 4. Alternatives Considered but Not Analyzed in Detail

Comments Focus on Biomass and New Conventional Alternatives

Seventeen initial alternatives were designed and assessed for the EIS. These alternatives are described in detail in the March 25, 1994 support document *Alternatives to the University of Minnesota's Proposed Steam Service Facilities Renovation, Screening Analysis* by Dahlen, Berg & Co. All seventeen were assessed for technical feasibility, economic feasibility, and environmental impact.

Whereas Chapter 3 of the DEIS describes the alternatives selected for more detailed study, Chapter 4 describes the alternatives not addressed in detail, with the reasons for their elimination from further analysis.

Comments on these less detailed alternatives focused on two broad areas: (1) the feasibility and benefits of biomass fuels, and (2) the feasibility and benefits of two new conventional fuel alternatives.

Background Information on Biomass Added

Although a detailed assessment of the feasibility and environmental impacts of biofuel technologies is beyond the scope of this EIS, background information on biomass feasibility and the biofuel capacities of conventional boilers and turbines has been added.

Two New Alternatives Suggested For Detailed Study

Minnegasco and the Minneapolis Energy Center (MEC) each suggested review of a new conventional fuel alternative. Both alternatives are variations of ones already addressed in DEIS Chapter 4.

Minnegasco and Others Suggest 250+ mW Gas-Fired Cogeneration Plant

Minnegasco, SORC, PPERRIA, and others suggest that with the rapidly changing electricity market and dropping natural gas prices, a very large combustion-turbine cogeneration alternative could be economically feasible within a few years. The comment requests detailed review of a 250+ mW gas-fired cogeneration plant, which is five or more times larger than any cogeneration facility designed for the DEIS. Major construction would be deferred for at least three years. Short-term needs of the heating system would be met with new, low-capital-cost conventional boilers firing natural gas and fuel oil.

MEC Suggests Purchasing All Steam from Vendor with Off-Campus Plants

The Minneapolis Energy Center (MEC) suggests a revised third party purchase alternative (Alt No. 9) in which the University would purchase 100% of its steam from a vendor with plants located entirely off-campus. The alternative would not include cogeneration of electricity. The MEC proposal would provide steam to the University by connecting both campuses into a thermal "network" of other local steam producers and consumers. The proposal requires construction of a new natural gas/fuel oil plant near downtown Minneapolis. Under the MEC proposal, the existing plants at both campuses would be decommissioned. MEC also suggests a possible price of steam under this scenario.

These Two Alternatives Raise Issues Beyond the Scope of the EIS, but Descriptions of Each Have Been Added

The most important environmental considerations of these alternatives, directly or indirectly, involve the future of cogeneration, and other large-scale utility planning policy issues.

Aspects of these alternatives are largely outside the control of the University, and involve some energy policy issues beyond the scope of an EIS on a specific heating plant proposal.

The FEIS describes and analyzes each alternative, but due to the vague nature of these alternatives, the assessment is more general than that provided for other EIS alternatives.

Chapter 4 Alternatives Rejected for Variety of Reasons

The alternatives listed and described in Chapter 4 were rejected from detailed study for a variety of reasons. Some—like the combined St. Paul and Minneapolis coal-based facility (Alt. 10)—were expensive without providing offsetting environmental benefits.

Others—like the gas/oil-fired, steam-only Alt. Nos. 2 and 8—although technically, economically, and environmentally feasible, were not assessed in detail because their projected costs and impacts could be adequately assessed by detailed study of similar, more complicated cogeneration alternatives.

In other words, since the screening analysis indicated that the costs of an all natural gas/fuel oil alternative were similar to the costs of a natural gas based cogeneration alternative, the cogeneration alternative was selected for detailed study because of its additional environmental benefits.

A third group of alternatives, including those suggested by Minnegasco and MEC, was not addressed in detail not only because they either involve complicated, difficult to quantify policy issues or they would require implementation by, or close cooperation from, third parties outside the University's sphere of control.

Chapter 4. Comments and Responses

COMMENT 4a

Biomass Potential Should Be Addressed in More Detail

There should be a detailed analysis of the feasibility of a future biomass gasification gas turbine cogeneration alternative. (Abrahamson)

The use of liquid biomass fuels and synthetic gas derived from biomass should be evaluated. (SORC)

An assessment of the biomass-firing capabilities of a solid fuel boiler like that proposed by the University should be evaluated in more detail. (SORC)

The DEIS should recognize that the University's project is the only one capable of burning renewable fuels. (UofM/FW)

RESPONSE 4a

Biofuel Technology is Still Developmental and is Beyond Scope of EIS

Biomass gasification was not analyzed in detail because, although biofuel technology is developing rapidly, it is largely still in the development stage. Furthermore, detailed assessment is outside the scope of an EIS on a specific project, and background information can be found in a variety of sources, especially in proposals and research generated by Minnesota electric utilities. (Also see Abrahamson comment letter.)

Some additional information on the feasibility of biofuels and the biofuel capacity of proposed and alternative steam plant equipment has been added earlier in this chapter.

COMMENT 4b

Defer Construction of Large Gas/Oil Cogeneration Plant For 3-5 Years

The FEIS should evaluate a new alternative that defers major capital investments in a new steam plant for three to five years, until NSP is likely to need—and be willing to pay for—new baseload electric capacity. The University's immediate reliability needs could be met by installing two low-capital-cost gas/oil boilers at the Southeast Plant.

A large-scale, natural gas based electricity cogeneration plant located near the University could easily meet 100% of the University's steam needs with turbine "waste-heat" that would otherwise be rejected to the atmosphere. Recently available low-cost, long-term natural gas contracts would also lower the costs of this alternative. (Minnegasco, Nicollet Restoration, SORC)

It would be logical to optimize energy efficiency and minimize regional air emissions by deferring any major steam plant construction until such a large cogeneration system could be implemented. (Minnegasco, Nicollet Restoration, SORC)

An industrial property north and east of the University, in the area of the DEIS off-river site, will be coming available for redevelopment. This industrial development could significantly increase the size of the district heating load in the area and could therefore increase the justifiable size of the cogeneration plant. (PPERRIA)

RESPONSE 4b

80 mW Cogeneration Plant Produced More Electricity than the University Could Use

A large (80 mW) cogeneration system was evaluated in the DEIS (Alt. No. 5) and was found to be uneconomical because it produced more electricity than the University could use. The cost of producing the excess electricity would exceed the current avoided cost the University receives from the utility.

Waste Heat from Suggested New Facility Could Meet Entire Minneapolis Campus Heating Load

The suggested new alternative, however, includes an electricity generating component at least five times larger than that of any included in the DEIS. Minnegasco suggests that a new base-load electricity plant will be needed in the near future, and that that plant, located near the University, could use combustion turbine "waste heat" to meet the entire Minneapolis campus heating load. Such a facility would probably not be located at the Southeast Plant and would probably not be owned or operated by the University.

Utility Payments and Regulatory Changes Could Make Facility Competitive

However, if the utility paid enough for the new capacity, or possibly if retail wheeling of electricity were allowed, such a large cogeneration facility could be economically competitive. The University's large steam load is an attractive "steam host" for a large cogeneration system.

Optimized Cogeneration System Environmentally Beneficial

As outlined in EIS Chapter 10, there are large potential "pollution prevention" benefits of optimized cogeneration systems—assuming that the localized air pollution and land use impacts were within acceptable limits. With steam and electrical production optimized, a cogeneration facility, like the University's proposed plant and most of the EIS alternatives, would be significantly more efficient than producing heat and electricity separately.

With the much larger electrical production proposed under this alternative, essentially all of the University's thermal needs could be met from what would otherwise be an electricity plant only. Theoretically, assuming that the electricity capacity were needed and that the existing plants were shut down, the electricity and steam would be produced with a net air quality benefit.

Optimal Efficiency Attainable only through Interconnecting with Other District Heating Systems

The base-loaded cogeneration alternatives in the DEIS (Nos. 3, 4, & 7), however, are designed to efficiently match the University's electrical and thermal needs. The larger electrical plant proposed by Minnegasco would often produce more steam than the Minneapolis campus would need. Alternatively, the turbines would have to be operated at less than full capacity.

As PPERRIA suggests, optimum energy efficiency of such a large cogeneration system would only occur if the minimum (base-load) thermal sink were increased by interconnecting the large cogeneration plant with other local district heating systems, like a nearby planned industrial park, as well as with the University campus. (See FEIS Chapter 9 on the "30-acre" site.)

This Alternative Beyond Scope of EIS and Not Addressed in Detail

This alternative is essentially an electric production facility that would share or sell steam to the University, and it might not even be considered an "alternative" to a proposal, the primary purpose of which is to provide heating and cooling.

This alternative's long-term feasibility and timing depend on utility planning policy issues, such as NSP resource plans, and the future of retail wheeling in the mid-west. Some of these issues are beyond the control of the University and outside the scope of the EIS. Similarly, the details of the size and financial arrangements required for such a facility are at this time also outside the scope of the EIS.

Consequently, despite its potential environmental and energy efficiency benefits, this alternative was not addressed in detail in the EIS.

COMMENT 4c

Third Party Alternative Should Be Re-Evaluated

The DEIS addressed a third-party off-campus alternative (Alt. No. 9), but a true third party purchase alternative, in which the University would purchase 100% of its steam from facilities located off-campus, should be reevaluated. Steam for the Minneapolis campus could be provided by a new gas/oil plant north of downtown Minneapolis and by other existing or soon to be completed plants, thereby establishing an interconnected steam network. Steam for the St. Paul campus could be produced at the NSP Highbridge Plant and delivered through an extension of an existing steam line. The existing University steam plants on the Minneapolis and St. Paul campuses would be decommissioned. A likely steam tariff for this proposal would be $8.90 per MMBtu. (Minneapolis Energy Center)

RESPONSE 4c

Revised Alt. No. 9 Has Been Examined in FEIS

The 25-year present value cost of such a system has been calculated, at the projected University steam load and at the tariff rate suggested in MEC's comment, to be about $436 million.

A revised Alt. No. 9, as described in the MEC proposal, has been added to the text of the FEIS and its potential impacts and benefits have been outlined. Cogeneration is not included, but a brief discussion of the cogeneration implications of such a steam network has been included.

From Energy Policy Standpoint, MEC and Minnegasco Proposals Potentially Related

From a energy policy standpoint, this "network" based steam-only alternative is potentially related to large-scale cogeneration like that suggested by Minnegasco. Either plan would in effect delay any large capital investments until the rapidly changing economics of electricity cogeneration become more clear. Under the Minnegasco scenario, the University would continue to operate the existing steam plants for the short term, probably using mostly coal. Under the MEC scenario, MEC would build and operate one gas/oil plant at a new site, and produce steam-only until cogeneration's future in the state becomes more apparent.

Thermal Network Could Encourage Cogeneration, but Question of Steam or Hot Water Remains

As briefly discussed on p. 4-6 of the DEIS, an interconnected thermal network could encourage the development a large-scale metro-wide cogeneration system, because the thermal network suggested would have a significantly larger steam load than the Minneapolis campus by itself. Large interconnected heat sinks make it more feasible to develop large distributed electricity cogeneration projects.

The question remains, however, as to whether a steam system such as that suggested by MEC, or a hot water distribution system, would be more likely to encourage a metro-wide cogeneration network. (See Chapter 10 on mitigation.)

Chapter 5. Natural Environment

No Revisions Were Made to Chapter 5

No revisions were made to this chapter of the EIS.

Chapter 6. Air Quality Impacts

Chapter 6 of the DEIS addressed the emissions and of criteria and non-criteria air pollutants.

The chapter presented major emission factor assumptions and the results of the ambient air quality modeling and also addressed noise, fugitive dust impact, and air quality regulations.

Comments Addressed Fuel Mix Assumptions and Modeling Approaches

Most comments on this chapter addressed fuel mix assumptions and their effect on emissions. Other comments addressed the following issues: 1) emission factor assumptions, 2) the impacts of petroleum coke, 3) proposed air quality permit limits, 4) ambient air quality modeling approach, 5) the energy efficiency benefits of cogeneration, 6) the adequacy of the human and ecological health risk assessments, and 7) biomass firing capabilities and impacts.

Predicted Criteria and Non-Criteria Emissions Estimates Revised

Two major revisions were made to the air emissions analysis.

First, three new scenarios replace the single "predicted" emission rate scenario used in the DEIS. Criteria emissions are predicted for the following fuel mix assumptions:

- A low sulfur scenario
- A base-case scenario used for the financial projections
- A higher sulfur scenario

Second, air toxic emission rates and ambient air quality modeling have been revised and updated based on recently published air toxic emission factors for fossil fuel plants. The revised air toxic emission factors are lower for both coal and fuel oil, with some exceptions.

Finally, a discussion of cogeneration "credits" is included in this chapter, and fugitive dust calculations are updated. Background information on mercury emissions, controls, and impacts has also been added.

Chapter 6. Comments and Responses

COMMENT 6a

Cogeneration Benefits Important, but Not Legally Enforceable

The energy efficiency and air pollution benefits of cogeneration should be emphasized more in the FEIS. Cogeneration has the potential to be an important tool in reducing levels of criteria pollutants and air toxics that contribute to overall health risks and elevated mercury levels in fish. (MDH, City of Mpls.)

Predicted emissions of mercury adjusted for cogeneration benefits need to take into account possible lower requirements for mercury emissions in the near future. The exact amount of the reductions required is not currently known, but some limits are likely. In any case, the benefits of cogeneration are theoretical because NSP would not lower its permitted emission rates for any pollutants in response to a cogeneration project. (MPCA)

RESPONSE 6a

Discussion of Benefits of Cogeneration Has Been Expanded

An expanded discussion of the benefits of cogeneration and of the difficulties in quantifying those benefits has been added to Chapter 6.

COMMENT 6b

University Has Applied for Higher Permitted Emission Levels

The University's Air Quality Permit application seeks approval to emit higher levels of some pollutants than the plants have been emitting and higher levels than predicted in the DEIS. (Minnegasco)

The proposed project will improve emission levels. (U of M)

RESPONSE 6b

Predicted Emissions Will Be Lower than Proposed Permit Limits

In general, the predicted emissions in the DEIS are estimates of actual emissions at expected steam loads. The permit limits, on the other hand, are based on regulatory considerations, and are necessarily higher than predicted emissions. As actual emissions from the existing steam plants have been lower than current permit limits, the actual emissions following renovation will be lower than the proposed permit limits.

An expanded discussion of the relationship between permit limits and likely actual emissions has been added to Chapter 6 for the FEIS. Also, the UofM/FW comment letter describes the relationship between the permitting process and likely future emission rates.

COMMENT 6c

EIS Should Identify Impacts of Burning Petroleum Coke

The current permit application for Case A includes the ability to burn petroleum coke. Predicted least cost emission rates should therefore include the burning of petroleum coke, which is half as expensive as coal. The FEIS should identify the impacts of burning petroleum coke at levels which would be allowed under the current permit application. (Minnegasco, SORC, City of Mpls)

Emissions of other criteria pollutants, however, also must be adjusted for any assumed use of petroleum coke in the fuel mix. (UofM/FW)

RESPONSE 6c

High-Sulfur Scenario Has Been Added to Account for Use of Petroleum Coke

Petroleum coke is a locally produced, high-Btu energy resource that, including transportation, may cost less than coal. A CFB could efficiently fire petroleum coke with SO_2 control efficiencies of 95% or better. Maximum use under the proposed permit could result in SO_2 emissions at the Minneapolis campus that are about equal to that of the existing facilities.

Petroleum coke capability in the circulating fluidized bed boiler (CFB) is an option in the University's contract that has not been either selected or rejected. It has not been assumed for the "base case" fuel mix in the EIS. A high sulfur scenario for predicted emissions that estimates emissions at approximately the maximum use of petroleum coke has been added to the FEIS.

COMMENT 6d

Efficiencies and Fuel Mixes Should Be Corrected

The efficiencies and fuel mixes for the proposed project and alternatives should be corrected so that emission estimates are more accurate. (UofM/FW)

RESPONSE 6d

Fuel Mix Issue Addressed in FEIS

This issue is addressed in FEIS Chapter 2 (description of the project) and FEIS Chapter 3 (description of alternatives).

COMMENT 6e

Potential Air Pollution Emissions Should Be Based On Permit Limits

The air emission limits in the University's current permit application should be used to calculate potential emissions. (MDH, UofM)

The FEIS should analyze the environmental impacts of the levels of emissions requested in the permit. (Minnegasco)

The maximum potential emissions of criteria and air toxic pollutants and the associated modeling should be based on the University's maximum steam and electricity needs, not full boiler capacity all year long. (MPCA)

RESPONSE 6e

Maximum Potential Emissions Used in Permit Modeling

Maximum potential emissions were used in the worst-case modeling for both the EIS and the permit modeling. (The EIS modeling is partly based on that completed by Foster Wheeler.) Maximum potential emissions are standard regulatory tools used primarily to model extreme impacts. If results at this extreme assumption indicate that impacts are insignificant, further analysis is not necessary.

In this case, although specific annual emission limits are requested in the permit application, there are no restrictions on which boilers or which plants would be operating at any given time. Rather than model the numerous scenarios that would result in emissions at the permitted rate, it is far easier to model one potentially extreme emission scenario.

Finally, the mercury concentrations modeled for primarily coal alternatives at "predicted" emission rates do provide a rough estimate of mercury impacts at requested permit limits. Most of the mercury is from coal use, and the predicted emissions for Case A, Case B, and Alt. No. 6 are based on the a base-load use of coal in the circulating fluidized bed boiler.

COMMENT 6f

DEIS Emission Factors Should Be Revised

Emission factors used to determine emission rates should be revised to reflect actual vendor guarantees, EPA emission factors, and actual performance data. (UofM/FW)

The DEIS incorrectly assumed that mercury would not be captured by pollution control equipment. The FEIS should assume that the baghouse particulate control system on the Foster Wheeler CFB boiler would capture 50% of total mercury. Also, the FEIS should use a mercury concentration of .08 ppm instead of the .06 ppm used in the DEIS based on USGS data. (UofM/FW)

Emission factors used for the existing boilers in the Main Plant were not provided in backup reports. No. 6 fuel oil sulfur content was assumed to be only 1.0%, when 2% is more common. Also, New Source Performance Standards (NSPS) require 90% SO_2 removal efficiency for scrubbers, resulting in an emission factor of 0.1 lb/MMBtu for 1% sulfur No. 6 oil. (MPCA)

The Summary of Major Emission Controls in DEIS Table 1 on page 6-6 should be revised to show the existing SO_2 controls at the Southeast Plant. (MPCA)

Natural gas/fuel oil alternatives will be much cleaner than predicted in the DEIS due to the availability and use of low sulfur #2 fuel oil as a backup fuel. (Minnegasco, City of Minneapolis, SORC, PPERRIA)

RESPONSE 6f

All Emission Factors Reviewed and Some Revised

All emission factors have been reviewed, based on limits in the Foster Wheeler/UofM permit application and on other comments and sources. Some of these factors were revised. Emission factors and emission control assumptions are provided in FEIS technical Appendix C.

Insufficient Data to Revise Mercury Control Percentage

The mercury control percentage (zero) was not revised. The data from the one test sample provided in the University backup material is not sufficient to warrant an across the board emission reduction of 50%. Additional information on this issue has been added to the FEIS.

Scrubber Efficiencies Changed to 90% NSPS	The use of 1% sulfur No. 6 fuel oil was intended and was used in the financial projections as well. Lower sulfur residual oils have become more available recently. The scrubber efficiencies have been changed to the 90% NSPS, per the MPCA comment.
Low Sulfur No. 2 Oil Now Assumed for Both Financial and Emissions Estimates	Finally, very low sulfur (0.05%) was assumed for all No. 2 fuel oil in the DEIS financial analysis, but the higher sulfur fuel was assumed for the emissions estimates. The base case emission estimates have been changed to assume .05% No. 2 fuel oil for both the financial and emission estimates. The use of No. 6 fuel oil was retained for its potential financial benefits.

COMMENT 6g

Air Quality Modeling Procedures Questioned

Using a polar grid rather than a Cartesian grid resulted in wider spacing between receptors at the off-river sites and at St. Paul compared to sites near the Southeast Plant. (UofM, St. Anthony Park Association)

Modeling ground level air toxic concentrations by scaling to SO_2 emission rates may result in errors. The likely highest receptor site and maximum concentration at that site is in reality likely to be somewhat different for each pollutant. (MPCA)

Stack exit velocities for some "predicted" emission scenarios are higher than for the "potential" scenarios, which is the opposite of what would be expected because of the larger volume of air required for the larger amount of fuel used in the "potential" scenarios. (MPCA)

Multi-source SO_2 modeling for the alternatives would likely show that fuel oil restrictions are required for short term averaging periods. Therefore, emissions form all alternatives are likely to result in standard violations, contrary to the DEIS summary. (UofM/FW)

RESPONSE 6g

Polar Grid Refined Enough for EIS Purposes

The modeling was based on the polar grid developed by Foster Wheeler for the air quality permit. More refined modeling for multiple alternatives would have been costly. Redoing the grid entirely was possible, of course, but did not appear necessary for the comparative study intended for the EIS.

Scaling Air Toxics Concentrations to SO_2 Reduced Costs

Modeling of criteria pollutants was completed for each flue and stack separately for each facility to maximize accuracy. Air toxics concentrations were estimated by scaling toxic emission rates to the modeled SO_2 concentrations as a way to minimize the costs of modeling over 20 air toxic pollutants from multiple facilities and multiple alternatives. All the air quality modeling could have been scaled to "worst-case" stack parameters at one stack, but was not because the EIS modeling consultant had concerns regarding overall accuracy as well as concern regarding accurate assessment of building downwash in relationship to the multiple stack locations.

Shifts in High Receptor Locations Not Material for This Analysis

Little variation in high receptor location exists between criteria pollutants. Since the modeling for the alternatives is based on conceptual level engineering designs, minor inaccuracies due to shifts in the high receptor for specific pollutants would not be significant, given the comparative analysis intended. In addition, further detailed modeling would be required for an air quality permit should one of the alternatives be selected for implementation.

Wet Scrubbers Reduce Stack Exit Velocities

Stack exit velocities for some "potential" emissions are low because the wet scrubbers assumed for No. 6 fuel oil firing (worst-case fuel) lower exhaust gas temperature. The lower temperature also reduces gas volume.

Restrictions Do Not Imply Violations

Finally, the EIS summary states that modeled annual concentrations based on worst-case "potential" emissions were unlikely to result in standard violations. It doesn't indicate that no restrictions would be necessary. The DEIS modeling does indicate that some fuel oil restrictions or other measures could be necessary to avoid violations of short-term SO_2 standards.

COMMENT 6h

EIS Should Assume Different Air Toxic Emissions Levels for No. 2 and No. 6 Oil

The DEIS assumes that emission factors for air toxic emissions for No. 6 fuel oil with scrubbers are the same as for No. 2 fuel oil. However, EPA emission factors for some metals, in particular for mercury, indicate that emissions from No. 6 fuel oil are as high as for coal, and higher than for No. 2 fuel oil. No. 2 fuel oil firing should be assumed. (MPCA)

Trace metal emissions from petroleum coke are in the permit application, and test data should be made available or sampling should be completed. (Minnegasco)

RESPONSE 6h

Air Toxics Emission Factors from Fuel Oil Based on Recent EPRI Report

Fuel oil emission factors for air toxics have been revised to use composite average data from a recently published EPRI report. Additional data on trace metals in petroleum coke were not found, despite efforts to contact local refineries. No information was submitted in comments on the Draft EIS. Petroleum coke is known to contain high concentrations of nickel. Nickel, however, is a non-volatile metal that is effectively controlled by particulate controls.

COMMENT 6i

Scope of Air Quality Analysis should Be Expanded

Acid gases were not included in the air quality assessment in the DEIS. (MPCA)

The FEIS should include information regarding problems associated with long-range transport of mercury. The FEIS should include information that describes the reasons for the concerns over certain air pollutants. (SORC, City of Mpls)

The EIS should discuss the impact of small sources of mercury emissions on the natural environment, and a quantification of the costs of mercury pollution should be included in the analysis for each alternative. (SORC, City of Mpls., Minnegasco)

The FEIS should point out not only the annual emission differences in mercury emissions, but the 25-year total difference.

The NAAQSs should be provided on Tables 9 and 11 to compare modeled concentrations with standards. (MHD)

RESPONSE 6i

Some Requested Information Already in DEIS, Other Has Been Added

Acid gases are included in the air toxics emissions tables, listed as fluorine and chlorine.

Additional background information has been added on the impacts and general concerns regarding mercury emissions. Also, a 25-year net present value environmental cost has been calculated for each alternative using, for illustrative purposes, the interim PUC values and the MPCA recommended value for mercury emissions (see FEIS Chapter 11).

The National Ambient Air Quality Standards are provided in the DEIS on page 6-41.

COMMENT 6j

Permit Issue Involving CO Should be Examined

The EIS should reexamine the issue of whether CO emissions from Case A are subject to PSD review. (Minnegasco)

RESPONSE 6j

CO Issue Can Be Resolved in MPCA Permitting Process

The issue of whether carbon monoxide is subject to PSD review largely revolves around an apparent discrepancy between the baseline CO emissions over the last two years that were submitted by the University and those submitted by Minnegasco in their comment letter. The issue can be resolved in the MPCA permitting process.

COMMENT 6k

Greenhouse Emissions Analysis is Deficient

The DEIS is seriously deficient in its analysis of greenhouse gas emissions and climatic change impacts. (Abrahamson, SORC)

The FEIS should address the impacts of burning waste wood. (SORC)

RESPONSE 6k

Global Warming Issues Beyond Scope of EIS

The issue of the probability of global warming due to historical and continued CO_2 and other greenhouse emissions is scientifically controversial and the subject of on-going large scale research. A detailed overview of the issue is not within the scope of the EIS. An expanded assessment of the biomass firing capabilities of various steam plant equipment has been added to FEIS Chapter 4.

Waste Wood Has Some Advantages Over Coal, Some Disadvantages

A detailed study of the impacts of burning waste wood was not completed for the EIS because the proposed project includes only limited waste-wood firing capability as currently proposed. However, emission rates of criteria pollutants from waste-wood firing are shown in Technical Appendix C (low sulfur scenario for the CFB based facilities).

Wood has much lower SO_2 emissions than coal, but has higher CO and VOC emissions. In addition, EPA emission factors for dioxin are higher for wood than for coal, probably because of high chlorine content in wood. Preliminary information from ongoing research at the University of Minnesota indicates that the hard wood itself has relatively low mercury concentrations. However, wood bark and leaves may have much higher concentrations (personal communication with University researchers). Mercury emissions from wood could be considered in a different category than those from coal, however, because some fraction would inevitably volatilize back to the environment as it decomposed in compost or in nature.

COMMENT 6l

The Scoping Decision called for inclusion of a non project-specific description of fuel-cycle impacts associated with the mining and transport of coal, natural gas, and other fossil fuels. This was not in the DEIS. (SORC)

RESPONSE 6l

A brief overview of fuel cycle impacts has been added to FEIS Chapter 6.

COMMENT 6m

The DEIS assumes unreasonably high control efficiencies for fugitive dust emissions, and the St. Paul fugitive dust calculations contain other errors. (Minnegasco, PCA)

Controlling dust from the coal pile should be a permit condition. (MHD) Particulate monitoring should be done to determine the actual emissions of coal dust in the riverfront area. (Minnegasco)

Fugitive dust impacts on surrounding neighborhoods lacks detail. (MPCA)

The only evidence provided in the DEIS of a coal dust problem at the Minneapolis facilities is anecdotal reports from unnamed sources. (UofM/FW)

Coal dust and emissions are an annoyance and present a health risk at both the Minneapolis and St. Paul campuses. (Mr. Norman Kagan, St. Anthony Park Community Council)

RESPONSE 6m

EIS Fugitive Dust Modeling Has Not Been Revised

The fugitive dust modeling in the DEIS was based on modeling completed by Foster Wheeler in the permit application to the MPCA. After review of the permit by the MPCA permit engineer, the capture efficiencies of the coal handling process at the Minneapolis campus have been revised, lowering assumed capture by control equipment, and increasing emissions.

Foster Wheeler has revised its fugitive dust emissions analysis, but not the modeling, so the EIS modeling has not been revised. Additional modeling may be required for the air quality permit from the MPCA. The fugitive dust analysis at the St. Paul campus did not require revisions.

Foster Wheeler estimates the following fugitive dust emissions from coal and ash handling at the Minneapolis facilities under Case A and Case B

Predicted Fugitive Dust Emissions at Minneapolis Facilities (Tons Per Year)

Case A

	Total Particulates	PM10
Minneapolis Main	0.29	0.12
Southeast	1.06	0.41
Total Mpls	1.4	0.53

Case B

	Total Particulates	PM10
Minneapolis Main	0.24	0.10
Southeast	0.84	0.33
Total Mpls	1.1	0.43

Ambient Air Particulates Below Air Standards

Monitoring for particulates was not done for the FEIS. Coal pile size and control measures are part of the existing permit and included in the permit application.

Regarding the health threat of dust emissions, worst-case modeled air concentrations of total particulates and of PM_{10} (particulates less than 10 microns in diameter) were below ambient air standards at both the Minneapolis and St. Paul campuses.

Following renovation, dust at the St. Paul campus will be reduced significantly because the coal pile will be "worked" less often once coal use has dropped.

Fugitive Dust Emissions At Times Create a Local Annoyance

Foster Wheeler makes every attempt to keep coal dust emissions to a minimum, and most individuals who discussed this issue with EQB staff thought the situation improved after Foster Wheeler took over the facilities. Nevertheless, EQB staff observations and comments from some who live and work nearby indicate that coal dust from the steam plant operations at times creates a local annoyance. (See, for example, Mr. Kagan's comment.)

Those complaining to EQB staff include residents and custodial workers at Sanford Hall, a University dormitory located across the railroad tracks from the Main Plant, and employees at a University daycare center near the Main Plant. Employees at the daycare center near the St. Paul campus steam plant also expressed concern.

COMMENT 6n

EIS Should Deal More Fully with Coal at St. Paul Campus

The FEIS should discuss the use of coal at the St. Paul plant in greater detail, including the need for retaining a back up coal pile, the amount of coal dust anticipated, methods to eliminate coal dust, and impacts of dust and run-off. (SORC, MPCA)

The FEIS should include a description of an option to totally enclose the coal pile on the St. Paul campus. (St. Anthony Park Association)

The FEIS should state more clearly whether coal would remain at the St. Paul campus plant, and if so, why it would be retained if the University only intends to use it as backup. (SORC)

RESPONSE 6n

Complete Enclosure of Coal Storage at St. Paul Campus Probably Not Cost Effective

Chapter 2 includes the description of the proposed continued storage and use of coal at the St. Paul campus as a back-up fuel. The DEIS contains a description of coal handling at St. Paul, and the modeled concentrations of fugitive dust on page 6-39. Information on runoff at the St. Paul plant has been added to FEIS Chapter 7.

A brief description of methods to reduce fugitive dust is also described on DEIS page 6-39. The open coal pile at St. Paul, however, apparently continues to be an annoyance to nearby residents and students as indicated by the comment, as well as by other correspondence to EQB staff. (See Response 6m above).

The estimated cost of completely enclosing the coal handling system at the Minneapolis campus was \$4 to \$7 million. The University intends to use coal primarily for back-up use at the St. Paul campus, so complete enclosure of the coal pile seems cost prohibitive at St. Paul. Since coal delivery and use would occur only rarely under the proposed renovation, a different, lower cost covering could be possible.

For example, Northern States Power, in its submission to the University during the University procurement process, included a interim covered coal-delivery and unloading system at the St. Paul campus that would reduce transport related coal dust emissions. Other lower cost dust mitigation that could be considered by Foster Wheeler and the University includes simple tarps or other coverings such as packing down the coal pile. Such procedures would, of course, have to implemented as to avoid any possibility of coal pile combustion and other safety concerns.

Finally, the University is probably retaining coal capability at the St. Paul campus to reduce backup fuel costs (compared to fuel oil only backup), maintain future fuel flexibility, and to help negotiate lower prices for other fuels.

Comment 6n-2

Limited HHRA and ERA For St. Paul not Addressed

A limited HHRA and ERA for the St. Paul site were identified in the Scoping Decision but not addressed in the DEIS. (PCA)

Response 6n-2

Results of Limited Risk Assessment at St. Paul Plant Shown in Table 10

The "potential" worst-case air toxics concentrations for the St. Paul campus alternatives are shown with the Minneapolis alternatives in Table 10 of Chapter 6. The highest modeled concentrations from either the St. Paul or Minneapolis plants are compared to ACL's in Table 12. The modeled high concentrations were all near the Minneapolis facilities. The modeled maximum at 100% fuel oil use at St. Paul does exceed the MPCA ACL for nickel, as it does for alternatives at Minneapolis. St. Paul steam plant "predicted" emissions and modeled air concentrations were generally low because all alternatives assume mostly natural gas use and no coal.

COMMENT 6o

EIS Should Address Noise Standards

State noise standards may be exceeded due to coal handling operations at the Main Plant and due to venting of super-heated steam at the Southeast Plant. The EIS should discuss the environmental impacts of noise violations due to the coal handling operations. (Minnegasco)

Noise levels were not adequately measured. Applicable noise regulations were not adequately discussed. Noise impacts associated with truck traffic and facility operation were not adequately addressed. (PCA)

RESPONSE 6o

MPCA staff has indicated that while noise standards could periodically be exceeded at the Southeast Plant, the possible violation at boiler start-up occurs infrequently. Mitigation could be installed or a variance could be issued if necessary. Truck and other noise associated with the coal handling operations can be more carefully controlled to keep noise levels below the standards. Foster Wheeler has indicated that it has initiated changes to do this.

Additional information on state noise standards has been added to the FEIS Chapter 6. A brief additional analysis of potential noise issues at off-river sites has also been added.

COMMENT 6p

Multi-Pathway Human Health Risk-Assessment Not Completed

The full Human Health Risk Assessment in the Scoping Decision was not adequately addressed in the DEIS. (PCA)

RESPONSE 6p

Inhalation-Pathway Human Health Risk Assessment Has Been Added

An inhalation-pathway human health risk assessment is included in the EIS on page 6-34. The risk assessment compares worst-case air quality modeling results to current MPCA Air Concentration Limits (ACL's). Additional background information on human health risks from power plant emissions, from recently published studies, has been added to the FEIS. More background on mercury issues has also been added.

Elaborate Health Risk Analysis Originally Planned Was Not Cost Effective

The Scoping Decision did anticipate a more elaborate multi-pathway risk assessment for the proposed project and the alternatives. This larger-scope study was planned mostly to address concerns about toxic emissions from coal-fired facilities (versus natural gas/fuel oil fired facilities). There was also concern that air pollution dispersion patterns in the riverfront area could create localized impacts.

The more elaborate health risk analysis, including a multi-pathway risk assessment for all alternatives, was considered not cost effective for this EIS for several reasons:

- Modeled concentrations even at extreme worst case "potential" emission rates (significantly higher than likely permit limits) are all below the MPCA ACL's, except nickel, which for some alternatives exceeds the ACL at 100% fuel oil use.

- Modeled worst-case ambient air concentrations do not show large differences between alternatives. For most air toxics, uncontrolled emissions from fuel-oil fired boilers are similar to that from coal-fired plants with particulate controls. The exceptions are nickel and formaldehyde, which are higher from fuel oil firing, and mercury, which is higher from coal.

- Modeling indicates that air pollutant dispersion patterns at the riverfront site are not significantly different than those at the off-river sites. (There is some "downwash" at the Southeast Plant due to the building height increase)

- Existing emissions of most toxics are higher than those predicted under the proposed renovation project.

- Large-scale research is being conducted at a national level by a variety of public and private groups to help resolve many uncertainties regarding the accuracy of emission rates, and the human and ecological impacts, of toxic emissions from fossil fuel plants. The EIS used recently published results from these efforts where applicable, but final results from this research will not be available until late 1995 or early 1996.

COMMENT 6q

Ecological Risk Assessment Not Clearly Completed

It is not clear to what extent an ecological risk assessment included in the Scoping Decision was completed. (DNR, MPCA)

RESPONSE 6q

Expanded Assessment of Potential Mercury Impacts Has Been Added

An expanded assessment of the potential mercury impacts of the proposed project has been added to the FEIS. As discussed in that section, mercury emissions appear to be the most important potential impact distinguishing the various alternatives.

Foster Wheeler has modified ash handling procedures at both the Minneapolis and St. Paul facilities so that there is little possibility of runoff into the groundwater or Mississippi River at the Minneapolis facility. No other evidence indicates that runoff from coal piles or other operations is entering the river or otherwise affecting nearby ecological resources.

Chapter 7. Water Quality

Comments on this chapter focused on potential contamination of groundwater and surface water from runoff from the ash storage and coal storage areas. Further clarification of wastewater and stormwater flows at both the Minneapolis and St. Paul steam facilities was requested.

The most likely source of contamination at both the Minneapolis and St. Paul facilities was the ash storage areas. The St. Paul ash storage area was located near a small stream leading to a wetland, and the Minneapolis site was near the Mississippi River. As discussed in FEIS Chapter 1, Foster Wheeler has revised its ash handling and storage procedures.

Stormwater Sources and Destinations Clarified, Ash Handling Procedures Described

Revisions to this chapter include a brief description of the change in ash handling and storage location, as well as clarification of some uncertainties regarding the source and eventual destination of stormwater runoff at both the Minneapolis and St. Paul facilities.

Chapter 7. Comments and Responses

COMMENT 7A

Stormwater Source and Destination Not Clear

The DEIS does not clearly state whether storm water and wastewater from the facilities discharges into the Mississippi River. The FEIS should address whether the U is violating the law by not having a wastewater discharge permit. (SORC)

The DEIS does not make it clear whether wastewaters discharged from the plants goes to sanitary sewers, storm sewers or both. The removal of coal piles or additional storage requirements should noticeably improve the quality of runoff. The water quality chapter is generally too vague about the ultimate destination of stormwater runoff in the riverfront area (NPS, SORC)

Analysis of the impact of stormwater runoff from St. Paul coal and ash storage areas is not detailed enough. Because storm water runoff from the sites would likely violate water quality standards, coverage under the "NPDES Industrial Storm Water Permit" is required. The source of water discharging into the river from a pipe near the Main Plant must be identified..(MPCA).

RESPONSE 7A

NPDES Operating Permits Not Required Because Runoff Discharged Into Sewer

Review of new, additional information submitted by Foster Wheeler indicates that coal pile runoff is discharged into the municipal sewer system, not the stormwater system. Coal ash is no longer stored outside for the time being, as described in Chapter 1. Following a site visit with MPCA staff, it was determined that since there is no facility or operational discharge into surface or groundwater, no NPDES operating permit is required. The FEIS text has been revised to reflect this and other information.

COMMENT 7B

Details on Fuel Spill Impacts and Containment

Details of secondary containment of aboveground storage tanks should be provided (PCA) Information on the risks of oil spills on the riverfront should be added, and any mitigation outlined. (SORC)

RESPONSE 7B

Foster Wheeler Emergency Spill Response Plan Available for Detailed Information

According to the Emergency Spill Response Plan prepared by Foster Wheeler, and verified by review of site drawings of containment dimensions, the fuel oil containment area around the Main Plant tanks is sufficiently large to accommodate a worst case discharge from either tank (See Figure 9-5).

Foster Wheeler's Response Plan is a detailed description of all fuel oil and chemical storage tanks at the Minneapolis and St. Paul facilities. The Plan contains a description of emergency procedures and existing containment structures. The Plan is public information available upon request. Text has been added to the FEIS briefly describing this Plan.

COMMENT 7C

Identification of Two Riverfront Wells Requested

Two wells have been identified on the Riverfront site, and both are reported as being multi-aquifer wells. Consideration should be given to sealing the wells if there is any risk of contamination. (MPCA).

RESPONSE 7C

Two Riverfront Wells are NSP Water Pressure Monitors

The two wells on the riverfront are piezometers that NSP uses to monitor the stability of the berm replacement for the collapsed hydro facility near the Southeast Plant.

COMMENT 7D

Wastewater Discharge Permit Statement in DEIS Misleading

The DEIS statements on wastewater discharge are misleading. The University has temporary permits for wastewater from each campus, which include the steam plants. The MCWS has never indicated that discharge permits are necessary for the Southeast and Main Plants. The University submitted a permit application for wastewater discharge for the St. Paul Plant on January 26, 1995, due to recent modifications of its cooling system.

RESPONSE 7D

This information has been added to the text of the FEIS

Chapter 8. Solid and Hazardous Waste

No Revisions Were Made to Chapter 8

No revisions were made to this chapter of the EIS.

Chapter 9. Land Use, Historic, Visual, and Other Socioeconomic Impacts

Comments Focus on Existing and Potential Use of Riverfront Site

Land use comments addressed a wide variety of issues, reflecting the diverse, complex nature of this chapter of the DEIS. Comments focused on the following areas:

- Existing land use near the riverfront and alternative sites, and its historical and residential significance
- Potential land use conflicts between the existing steam plants and other plans for the riverfront area.
- The status and significance of national, state, and local plans for the riverfront area near the plants
- Visual impacts of the proposal and alternatives
- Socioeconomic impacts of primary fuel choice, and of continued coal use, on the Minneapolis riverfront

Information on Uses, Programs, and Options Has Been Added

Revisions to EIS text include 1) additions to the DEIS list of nearby riverfront attractions, 2) a description of the Central Riverfront Regional Park, 3) information on a new off-river site near the "alternative" site in the DEIS, 4) clarification of the MNRRA compatibility assessment, and 5) additional information on state and federal floodplain standards.

Section 9.2. Comments and Responses

COMMENT 9a

Residential Areas and Historic and Recreational Value Should Be Emphasized More

Residential areas near the Southeast Plant should be emphasized more clearly, and the map of the Alternative Site should be enlarged to depict neighboring residential areas. (Marcy-Holmes Neighborhood, Joan Leigh at public hearing, Mr. Bob Distad at public hearing, City of Mpls, James J. Marti, other individuals)

There is not enough emphasis on the great historical and recreational value of the riverfront area near the existing steam plants. (Hennepin County Commissioner Peter McLaughlin)

Nearby river attractions should be listed, to reflect the importance of the Riverfront Site. (Minnegasco, SORC, PPERRIA)

Negative impacts of continued use of the Southeast Plant should be emphasized. (Minnegasco)

RESPONSE 9a

EIS Notes Residential Development Near Southeast Plant

Residential development near the Southeast and Main plants is shown in DEIS Figure 9-1 and noted in the text on page 9-2. An additional map, Figure 9-1a, showing surrounding neighborhoods and residential areas, has been added to the FEIS. Figure 9-1a also indicates the locations of potential steam plant sites, including the existing site, the alternative site used in the DEIS, the "30-Acre" site being acquired by the University, and the site located across the Mississippi from the existing plants, proposed by the Minneapolis Energy Center.

More detail on the location and impacts of the steam facility on the Marcy-Holmes neighborhood has been added to the FEIS text on p. 9-2.

EIS Also Notes Historical and Recreational Attractions

A list of additional historical and recreational attractions located near the riverfront site has been added to p. 9-2 of the FEIS. The DEIS notes both positive and negative impacts of the various alternatives. No changes were made to emphasize the negative impacts of those alternatives.

COMMENT 9b

Map of Alternative Site Should Be Enlarged

The map of the alternative site should be enlarged to accurately depict the residential areas that could be affected. (UofM/FW)

RESPONSE 9b

DEIS Portrays Residential Areas Near Alternative Site

The residential development around the Alternative Site is shown in DEIS Figure 9-2 and is discussed in the text on page 9-5. The neighborhoods near the alternative off-river site are also shown in FEIS Figure 9-1a and Figure 9-2. (Figure 9-2 was revised for the FEIS to show the "30-Acre" site).

COMMENT 9c

EIS Should Note that Project Will Reduce Coal Truck Traffic

The EIS should note that the project will actually reduce coal truck traffic because less coal would be used than estimated in the DEIS and because 15-ton trucks would be used instead of 10-ton trucks. In addition, traffic created by trucks hauling wood and limestone for the CFB would be insignificant. (UofM/FW)

Access to the riverfront and the Stone Arch Bridge is impeded by the movement of coal and ash. (Marcy-Holmes Neighborhood Association)

RESPONSE 9c

Coal Trucks Will Continue to Conflict with Public Access

The University contends that the Southeast Plant would use less coal than estimated in the DEIS, but even the University's projections show that coal use at the Southeast Plant would increase over current levels.

The discrepancy in truck traffic numbers between the 13,000 in the DEIS and the 7,200 in the University's comments is mostly due to the University's assumption that the 10-ton coal trucks Foster Wheeler currently uses would be replaced with 15-ton trucks. Since, however, the University did not provide any specific time frame for acquiring the new trucks, the truck estimates for the EIS were not revised to reflect a shift in truck size.

Also, according to the University, trucks hauling wood chips for the proposed project would average about 100 round trips a year (2/day), and trucks hauling limestone for SO_2 control in the CFB would increase their number of round trips from 50 a year (1/week) to about 200 a year (4/week).

Overall, since the current truck traffic is approximately 7,500 10-ton trucks per year, the University's projected 7,200 15-ton trucks per year under Case A suggests that the project could have little or no impact on truck traffic. The University's possible shift to larger trucks, however, does not affect the validity of the DEIS description of the existing conflicts.

COMMENT 9d

Incremental Truck Traffic Not Large Compared to That from Other Nearby Industry

Other nearby industry adds much more traffic on Sixth Ave. SE, Second St., and other busy streets nearby than do the steam plant operations. In addition, to place the project's effects in context, the EIS should recognize all truck traffic in the area. (UofM/FW)

RESPONSE 9d

Truck Traffic from Other Nearby Industries Not Relevant

The DEIS indicates the presence of other industry in the area. This industry, in turn, can certainly generate a large amount of truck traffic on nearby streets such as University Avenue, Sixth Ave. SE, Second St., and Main St.

The discussion of conflicts between trucks and pedestrians/bicyclists (included on pages 9-8 and 9-9) does not focus on the traffic on nearby streets. Rather, the DEIS focuses on the potential conflicts of pedestrians/bicyclists with coal and ash truck traffic using 1) the access route between the Main Plant and the Southeast Plant and 2) the route along the riverfront.

Trucks serving the two University power plants make up most of the traffic along these two routes. A more detailed discussion of the truck traffic generated by surrounding industries would contribute little to a discussion of riverfront impacts.

COMMENT 9e

Conflict of Truck Traffic with Heritage Zone Could Increase

The Park and Recreation Board predicts that the Heritage Zone, when more developed, will attract 2-3 million visitors per year. Consequently, pedestrian and bicyclist traffic in the area could increase substantially. (City of Minneapolis)

If these projections are accurate, the potential for conflict with truck traffic is a great concern. The conflict between coal truck traffic and public use of the site must be resolved, preferably by installing underground coal delivery. (St. Anthony Falls Heritage Board)

The Southeast Plant is not an integral part of the St. Anthony Falls Heritage Zone. Traffic from steam plant operations will not impair development of the heritage trail system or use of the Stone Arch Bridge. (UofM/FW)

RESPONSE 9e

Close-Up of Potential Conflict Site Has Been Added

The potential conflict between steam plant traffic and the increased pedestrian use of the Stone Arch Bridge is discussed in section 9-1 of the DEIS. A close-up of the potential conflict site, Figure 9-1b, has been included in the FEIS.

Although the Stone Arch Bridge traffic and the roadway traffic are separated by concrete barriers, any increase in trucks or other vehicles, whether related to the steam plant or not, could, of course, increase the chances of an accident.

Coal Conveyor Would Mitigate Conflicts with Truck Traffic

The option of installing a coal conveyor in the existing tunnel between the two plants would eliminate most truck traffic between the plants and substantially reduce the potential conflicts between trucks serving the Southeast Plant and pedestrians and bicyclists. Trucking of ash, however, would continue, as would traffic related to the city's dredge storage area. (DEIS, page 8-3, estimates 1,050 10-ton ash truck loads per year.)

COMMENT 9f

Construction Could Disrupt Area Near Stone Arch Bridge

Disruption near the Stone Arch Bridge (from construction and truck traffic) would be particularly damaging during the next two years, when the Bridge will first be reopened to visitors. (SORC)

RESPONSE

Construction Could Disrupt Area Near Stone Arch Bridge

According to information provided by the University during the scoping process, construction at the Riverfront Site would begin with installation of the gas/oil package boiler at the Southeast Plant. Following that, the interior of the Southeast Plant would be demolished. While the interior is being demolished and the equipment is being installed—which is scheduled to take 26 months—the Southeast Plant would be out of operation.

During that period, coal truck traffic will naturally cease, but vehicles carrying construction workers and heavy trucks carrying construction materials will actually increase traffic to the site. The renovation at the Southeast Plant is expected to involve up to 225 workers, although the number employed on any given day will vary depending on the phase of the construction.

Although most of the work at the Southeast Plant is on its interior, a total of about 700 cubic yards of soil would have to be excavated to accommodate a storage tank and shelter, the package boiler, and underground piping. If a new retaining wall for ash were constructed, another 490 cubic yards of soil would have to be removed.

COMMENT 9g

City's Dredge Storage Causes Traffic Conflicts

Other land uses in the area—the City of Minneapolis's dredge spoil storage area under the I-35W bridge, for example—produce traffic conflicts along the lower riverfront that are at least as disruptive as steam plant operations. In September and October, 1994, the Corps of Engineers used a front end loader to move about 80,000 tons of dredge material across the riverfront access road to the storage area. At the same time, much of the dredge material was hauled away by truck, requiring another 3,000 two-way truck trips past the Southeast Plant and the Stone Arch Bridge.(UofM/FW)

RESPONSE 9g

City's Dredge Storage Is as Disruptive as Steam Plant Operations

Based on the large volume of dredge material stored at the City of Minneapolis storage area, this comment is accurate. The FEIS text includes an expanded description of the dredging operation.

COMMENT 9h

Project Creates No Additional Visual Impacts

The project does not create any additional visual impacts, as stated in the DEIS. (UofM/FW)

RESPONSE

Project Will Have Visual Impacts

The University and Foster Wheeler claim to concur with the DEIS that the project does not create any additional visual impacts because it does not further expand the coal storage area or increase the footprint of the Southeast Plant.

The DEIS does not, however, state that the project will create no additional visual impacts. On the contrary, it says: "The proposed building-height modifications and structural improvements to the Southeast Plant will affect both the riverside view and the view from the Stone Arch Bridge" (page 9-12). The visual impacts of the proposed project are also shown in revised DEIS Figures 9-7 and 9-8.

The latest Southeast Plant renovation plan preliminarily approved by the Historical Society is shown in the FEIS as revised Figures 9 and 10.

COMMENT 9i

Photo Enhancements of North Side of Southeast Plant Needed

The EIS should include photo enhancements of the proposed plant from the north side to reflect additional equipment. (SORC, City of Minneapolis). Also the visualization of the Main Plant without the coal facilities should omit the Main Plant stacks. (SORC)

RESPONSE 9i

Project Has Minor Visual Impact on The North Side of the Southeast Plant

The impact of the project to the north side of the Southeast Plant is discussed in the DEIS, pages 9-10 and 9-12. The most visible change to the north side of the Southeast Plant under the current proposal would be an additional ash silo on the east side of the plant.

Although the impact of the proposal is not shown, a photograph of the north side of the Southeast Plant has been added to the FEIS as Figure 9-4a. Also, revised Fig. 9-5 and 9-6 are included in the FEIS.

COMMENT 9j

EIS Should Evaluate Compliance with Preservation Guidelines

The EIS should evaluate whether the University must meet federal historic preservation guidelines and whether the proposed renovation would meet these standards. (SORC)

RESPONSE 9j

Minnesota Historical Association Addresses Federal Preservation Guidelines

When the DEIS was being prepared, the staff of the Minnesota Historical Society stated that the renovation might require review by the State Historic Preservation Officer (see DEIS, page 9-16). The Minnesota Historical Society has subsequently had an opportunity to review the design for the rooftop addition to the Southeast Plant.

In a letter dated January 27, 1995, the Minnesota Historical Society offered their preliminary comments and noted that the SHPO would have Section 106 review authority because the proposed project would require a federal EPA air emissions permit.

COMMENT 9k

Alternative Uses for Southeast Building Should Be Explored

The EIS should note that there is extraordinary potential, as yet unexplored, for alternative uses of the Southeast building. The likelihood of finding an appropriate re-use, and the costs of that re-use, should be considered. (Representative Kahn, PPERRIA, SORC, Nicollet Restoration, St. Anthony Falls Heritage Board)

The proposed renovation and continued use of the Southeast Plant is currently the only way to preserve the Southeast building. (UofM/FW)

If the Southeast Plant is retired, a viable use for the building should be determined, and the plant should not be left vacant and deteriorating. (Minnesota Historical Society)

RESPONSE 9k

Southeast Building Has Potential for Alternative Uses

The Prospect Park and East River Road Improvement Association (PPERRIA) and Nicollet Restoration have proposed a number of alternative uses for the Southeast building, including use as a museum, interpretive center, alternative energy think thank, conference center, research center, residence for visiting scholars or policy makers, or artists' studios with exhibitor sales space and a public atrium. In support of these suggestions, they cite examples of successful conversion projects in Portland, Oregon, and Seattle, Washington.

Potential re-use of the Southeast Plant is briefly discussed on pages 9-17, 9-21, and 9-28 of the DEIS.

Cost of Conversion to Other Uses Could Be High

As indicated by the UofM/FW comments, the current contract includes approximately $1 million for repair of the Southeast Plant exterior in order to comply with historical renovation standards. The Southeast Plant, of course, would remain in use as a steam plant.

If the Southeast Plant is not used for power production, its eventual fate is uncertain.

Renovation of the plant interior for other uses could require additions of whole floors because much of the existing facility is open from floor to ceiling. Additional costs include the demolition and removal of the existing equipment and the removal of asbestos. Specific reconstruction costs would vary substantially depending on the re-use intended. (As pointed out in the DEIS, NSP estimated that renovating the Main Plant into office space would cost about $8 million. On the other hand, a recent newspaper article indicated that the renovation of a waterfront power plant in Seattle cost $25 million.)

Without Funding, Further Discussion of Alternative Uses is Speculative

Other uses of the Southeast building are of course possible, but as the DEIS points out, no firm alternative funding sources for such redevelopment currently exist. Without such funding sources, discussion of redevelopment would be largely speculative. Additional detailed studies examining the potential uses, costs, and funding sources for the re-use of the Southeast Plant may be warranted, but are beyond the scope of the EIS process.

COMMENT 9l

The EIS should describe and map the location of Central Mississippi Riverfront Regional Park. (Metropolitan Council)

RESPONSE 9l

The Southeast Plant is located within the Central Mississippi Riverfront Regional Park. A description of the Park has been added to section 9-5 of the FEIS.

COMMENT 9m

Steam Facilities Preclude Some Access and Trail Options

The impact of the project and alternatives on the riverfront trailway system should be more fully evaluated in the context of MNRRA, which encourages the development of such trails. The proposal obviously restricts a transportation link between the Stone Arch Bridge and the University's east bank. (SORC, City of Minneapolis, Minneapolis Park Board, Audubon Society)

A coal-fired steam plant cannot successfully coexist with recreational uses of the site. (SORC)

The possibility of an innovative coal delivery and storage system that would allow coal operations and reduce any conflicts with trails or recreational use of the riverfront should be evaluated. (UofM/FW)

The cost of developing a trailway system should be addressed. (UofM/FW)

RESPONSE 9m

Redesign of Coal-Handling System Needed to Permit Some Trail Options

As discussed in detail in DEIS section 9-5, the continued operation of the Southeast Plant and associated coal-handling operations preclude some but not all possible trailway connections or riverfront access routes. Radical redesign of the coal-handling and storage system would be needed to allow these otherwise restricted riverfront access and trail options.

No Feasible Design as yet Put Forward

Neither the landscape architect nor the engineers retained for the EIS could readily identify or design a coal storage and delivery system that would reduce conflicts between coal operations and trails and other recreational uses. A revised, creative design is of course possible, but no one has as yet, to our knowledge, put forth a feasible design.

The entirely enclosed coal storage facilities included in the EIS riverfront coal alternatives would eliminate fugitive coal dust but would still not allow the upper trailway. The use of underground space for coal handling and storage has been suggested as another way to solve riverfront land use conflicts. Preliminary discussions with underground space experts, however, indicate that the use of underground space would not be economically feasible. (See DEIS p. 9-24.)

No Funds Have Been Set Aside for Trail Development

Finally, there are no current specific funding sources for trail development in the steam plant area of the riverfront. Minneapolis Park Board funds, for example, appear, in the short-term, to be limited. However, since the University owns much of the property, it is not surprising that other entities have not set aside funding for trail development at this time.

COMMENT 9n

Maps Do Not Show Bikeway or Motorways Proposed in DEIS

The maps contained in the City of Minneapolis's Critical Area Plan, the Park Board's Heating Plant Study, and the Central Riverfront Open Space Master Plan lacked adequate detail and did not clearly indicate the proposed bikeway or motorway routes described in the DEIS. (UofM/FW)

RESPONSE 9n

Maps Do Show Bikeway and Motorways Proposed in DEIS

The University commenters were provided with the above mentioned maps to assist them in preparing their comments. Relevant portions of the same maps are reproduced here with the bikeway and motorways pointed out (see attached maps 1, 2, and 3). As can be seen, the bikeway and motorways are plainly shown. It is not clear why the University commenters were unable to locate them.

In addition to containing the map showing the motorway route, the Central Riverfront Open Space Master Plan contains the following description of the motorway route.

"The motorway on the east bank has the potential of extending northward the existing parkway which now terminates at the University of Minnesota south of the site. Although ultimately it is desirable to bridge over the railroad tracks south of the Cedar Avenue Bridge (10th Avenue Bridge) and the I-35 Bridge, the interim plan will be to have the motorway start south of University Avenue at the intersection of 11th Avenue S.E. and 2nd Street S. E., tie into the Main Street right-of-way and continue northbound on Main Street." (Riverfront Plan, page 5)

COMMENT 9o

Upper and Lower Bikeways Too Steep to be Feasible

Upper and lower bikeways shown in the DEIS are not feasible because the projected route near the Mineral Resources Research Center is too steep. (UofM/FW)

RESPONSE 9o

Route by Mines and Metallurgy Building Could Be Used for Bikeways

The professional landscape architect retained for the EIS indicated that bicycle access to the "lower" route near the Main Plant would be difficult or expensive because it was too steep, as discussed on DEIS pp. 9-23 through 9-26, and shown in Figures 9-14 and 9-15.

However, the architect found that the ramp grade near the existing Mines and Metallurgy Building was compatible with safe use for the bikeways shown in the DEIS.

COMMENT 9p

Central Riverfront Development Plan Shows No Conflict with Bikeways

The bikeway route shown in the 1977 Central Riverfront Development Plan does not cut through the coal storage area as depicted in the DEIS. According to the Plan, neither steam plant interferes with a bikeway. (UofM/FW)

RESPONSE 9p

One Bikeway Alignment Shown in DEIS Derived from Earlier Studies

The University misleadingly claims that the bikeway shown in the 1977 Central Riverfront Development Plan does not cut through the coal storage area, as depicted in the DEIS, and claims that, according to the plan, neither steam plant interferes with the bikeway as then envisioned.

First, the DEIS Trail and Motorway Feasibility map clearly shows two possible alignments for a bikeway along the riverfront. The "upper" bikeway route shown is from the 1977 Central Riverfront Plan. The second bikeway alignment, which is closer to the river and which does cut through the coal storage area, is derived from other plans.

Second, the University cites page 7 of the 1977 Central Riverfront Plan as stating that both University power plants are compatible with the bikeway plans. However, the only power plant mentioned on page 7 of the Plan is the NSP hydro-electric plant on Hennepin Island (which is discussed as an element of a proposed interpretive system).

The Central Riverfront Plan does mention on page 9 that the UofM power plant could be used to portray the generation of power and steam from coal as part of the interpretive system. The only other power plants mentioned in this section of the plan are the NSP hydro-electric plant in Dam Flats (which collapsed in 1987) and the NSP hydro-electric plant on Hennepin Island. There is no discussion of any power plants conflicting or not conflicting with the bikeway.

COMMENT 9q

The FEIS should evaluate any potential impacts on future motorway routes by using the proposed plans for the Dinkytown Bypass extension, rather than the East River Road extension shown in the DEIS. (UofM/FW)

The Dinkytown Bypass is a theoretical plan, with no specific implementation schedule. No design work is planned or scheduled. The Bypass is not a riverfront connection. It would follow an industrial route, would not connect with the existing parkways, and would be far removed physically and aesthetically from the river. (City of Minneapolis)

RESPONSE 9q

Dinkytown Bypass Motorway Merely Conceptual

As the City of Minneapolis points out in its comments, the Dinkytown Bypass roadway (as opposed to the Dinkytown Bypass bikeway) is merely conceptual, with no design details and no plan for implementation. The Bypass has been considered as an alternative route for traffic if Light Rail Transit is located on Washington Avenue or as a route to enhance industrial development in Minneapolis.

The route would provide access to heavy commuter traffic and trucks wishing to bypass the University campus and Dinkytown. It is not currently contemplated as a riverfront connection.

The University's contention that this route is more suitable for analysis than the routes included in the DEIS is without merit.

COMMENT 9r

Dinkytown Bypass Is Appropriate Bikeway Connection

The Dinkytown bypass is the most appropriate bikeway connection between the riverfront and East River Road. (UofM/FW)

RESPONSE 9r

Dinkytown Bypass Not a Substitute for a Riverfront Bikeway System

The Dinkytown bypass is a proposal for a commuter bikeway linking the University campus with downtown Minneapolis (see map 4). The University, with the Minneapolis Public Works Department, requested federal funding for construction of this bike path.

The project is proposed for construction in three phases. Discussion of this bike path has been added to the FEIS text.

This bikeway could be an important connection to a riverfront bikeway system, but it is not meant to be a substitute for such a system. Therefore, the analysis of riverfront bikeways contained in the DEIS (pp. 9-22 to 9- 27) remains relevant.

COMMENT 9s

Critical Area Plan Requires Development of Trailway Plan with Met Council and City

The FEIS should point out that the University's Critical Area Plan encourages regional trails and pedestrian access, but with certain important safety related exceptions. Continued operation of the steam plants could justify these exceptions, so the continued operation of the plants could legitimately be used to discourage public access. The FEIS should also point out that the University's Critical Area Plan states that a river corridor trailway plan is to be developed in cooperation with the Metropolitan Council regional trail plan and the City of Minneapolis. The FEIS should report on the status of this plan and its compatibility with the proposal and alternatives. (National Park Service)

RESPONSE 9s

Regional Trail Plan Has Not Yet Been Developed

The University Critical Area Plan shows one trail through the riverfront area, discussed in the DEIS in section 9-5. The regional trail plan described in the comment has not been developed to our knowledge.

COMMENT 9t

Many Jurisdictions Committed to Mississippi Riverfront

The FEIS should emphasize the level of commitment by multiple jurisdictions to the Mississippi riverfront in general, and the downtown riverfront in particular. (City of Minneapolis)

RESPONSE 9t

DEIS Discusses a Range of Plans for the Riverfront Area

The DEIS references eight City of Minneapolis plans for the Riverfront area and reviews the Critical Area and MNRRA Plans. It also discusses the level of public and private investment in the area. (See DEIS, pages 9-19, 9-20, and 9-29 through 9-33.)

COMMENT 9u

Southeast Plant Project Not Fully Consistent with MNRRA Plans

The statement in the DEIS that the proposed project complies with MNRRA is misleading because it gives the impression that all alternatives fully satisfy all the goals of MNRRA. Some alternatives achieve these goals more than others. (National Park Service)

The Southeast Plant project is not consistent with MNRRA plans. The MNRRA plan encourages industry not requiring a riverfront location to move off-river and discourages vertical as well as horizontal building growth. (Dept. of Natural Resources)

The University's proposal is not consistent with the policies and goals of the MNRRA. (SORC)

As stated in the DEIS, the University Steam Plant project is consistent with the MNRRA plan since the Plan recognizes multiple land uses within the corridor and that the eclectic nature of the corridor is one of the assets worth protecting. (Minnesotans for the Mississippi)

The EIS process should not be used as a vehicle for groups that wish to ignore or destroy the reality of the Mississippi as a working river. (United Transportation Union)

RESPONSE 9u

Proposal and Alternatives Consistent with Some Specific Policies and Goals of MNRRA

The DEIS discusses only those MNRRA policies which might apply to the proposed project. Consequently, the statement on page S-10 of the DEIS that the proposal and alternatives appear to be consistent with MNRRA may be misleading. What that section should say is that the proposal and alternatives are consistent with some specific policies and goals of the MNRRA. The statement on p. S-10 has been revised for the FEIS. Additions to the MNRRA discussion on pages 9-32 and 9- 33 of the DEIS have also been made to the FEIS.

Alternatives Achieve Riverfront Access Goals in Varying Degrees

The National Park Service, in its comments on the DEIS, provides a summary of a number of MNRRA policies and discusses the compatibility of the alternatives with those policies.

The project and alternatives achieve Riverfront access goals in varying degrees. This comparative analysis is contained in Sections 9.2, 9.5, and 9.6 of the DEIS. For more details, see National Park Service comments on the DEIS.

COMMENT 9v

MNRRA Plan Concentrates on New Development	The statement in the DEIS that the MNRRA concentrates on new development in the river corridor is misleading. (National Park Service)

RESPONSE 9v

MNRRA Plan Concentrates on New Development	The DEIS information is based on page 22 of the MNRRA Plant: "While improvement along the riverfront is desired, this plan should concentrate on new development in the corridor. Existing development is not expected to be substantially changed by this plan."

COMMENT 9w

Proposed 40-Foot Addition Would Violate MNRRA Height Recommendation	The University's proposed 40-foot addition would contravene the MNRRA Plan's recommendations on the height of shoreline structures. The proposal is not exempt from the 30-foot limit because it is not located in a downtown area as stated in the DEIS. (SORC) Although the proposed Southeast Plant renovation will mostly increase the height of the building, the MNRRA Plan discourages vertical as well as horizontal building growth. (DNR)

RESPONSE 9w

Applicability of MNRRA Height Recommendation Is Unclear	One of the site development policies in the MNRRA Plan establishes a maximum building height of 30 feet for buildings within 100 feet of the bluff line. The MNRRA Plan notes, however, that building height limits will be set by local governments in their critical area plans and ordinances and that those limits would be higher in downtown areas. The MNRRA Plan does not specifically define "downtown area." Instead, the Minneapolis Critical Area Plan establishes three districts for the river: Urban Developed, Urban Diversified, and Urban Open Space. The Southeast Plant is in the Urban Diversified district. Therefore, it is not clear whether the 30 foot policy would apply to the Southeast Plant.

It should be noted, however, that the existing Southeast Plant already exceeds 30 feet in height.

COMMENT 9x

Impacts of Flooding Should Be Examined Further

The impacts of flooding on the Southeast Plant site should be examined. Also, the argument on the bottom of page 9-34 of the DEIS is faulty: the locks and dams are for navigation purposes and have no impact on flooding. (PPERRIA, SORC, DNR)

RESPONSE 9x

Southeast Plant Subject to Both State and Federal Floodplain Standards

Based on DEIS comments submitted by the Minnesota Dept. of Natural Resources, the Southeast Plant is subject to both state and federal floodplain standards. If the cost of renovating a non-residential structure within a floodplain exceeds fifty percent of the value of the structure at the time the City adopted the floodplain ordinance, state rules require floodproofing of all parts of the building (including the addition). Federal Emergency Management Act rules require floodproofing of the addition.

Current standards require dry floodproofing for substantial improvements. Dry floodproofing involves elevating the lowest floor above the base flood level or insuring that the structure below the base flood level is watertight. None of the government agencies or private contractors contacted could estimate the cost of the dry floodproofing without an in-depth, on-site study of the facility.

Finally, staff at the Corps of Engineers maintain that, when necessary, they do control the pool level behind the dam to avoid flooding problems at the Southeast Plant. (See also PPERRIA comment letter.)

COMMENT 9y

Fuel Choice Has Important Socioeconomic Impacts

The use of natural gas is not practical because the U.S. has only 10 to 40 years of natural gas reserves. Natural gas should be reserved for residential uses, not for utility uses. (United Transportation Union)

There is a 90 to 145 year supply of natural gas. (PPERRIA)

A guaranteed 25-year natural gas contract is available at a price lower than that in the DEIS. (Minnegasco)

Coal transport by rail produces a large economic benefit to the state by employing railroad workers and keeping costs down for crops and other commodities shipped by rail. Coal plants are less expensive than gas/oil plants in the long run in any case. (United Transportation Union)

Coal use creates many jobs and is of great economic benefit to the state. A decrease in coal use in Minnesota would affect railroad workers, railroad retirees, agricultural and industrial shippers, and people who rely on those industries. (Center for Energy and Economic Development)

RESPONSE 9y

Long-Range Policy Implications of Fuel Choice Are Beyond Scope of EIS

The financial projections prepared for the EIS indicate that a coal-based plant, in the long run, is likely to cost the University less than a gas/oil plant. For example, the costs of the coal-based off-river alternative (Alt. No. 6) are projected to be lower than a similar gas/oil only plant. (The costs of the University's primarily coal-based Case A proposal is the cost of the entire Foster Wheeler contract, with associated benefits.)

In addition, coal facilities require more labor to operate than natural gas/fuel oil facilities, as pointed out in the comment.

The broader policy issues presented by the choice between natural gas and coal as a fuel source are largely outside the scope of this EIS.

COMMENT 9z

Well-Planned Public Parks Stimulate Investment

Well planned public parks and open space often stimulate private investment in the surrounding area. Realization of these plans would generate substantial private investment. (City of Minneapolis, Hennepin County Commissioner Peter McLaughlin)

RESPONSE 9z

Socioeconomic Impacts Are Hard to Assess and Beyond Scope of EIS

A park-like riverfront connection between the University and the St. Anthony Main area and Nicollet Island could have important economic benefits throughout the area. And, of course, the extent to which continued operation of the existing plants would impose an "opportunity cost" on the surrounding areas is central to the steam plant controversy.

There is still considerable debate, however, as to the fate of the Southeast Plant and the riverfront area if the steam plant does move to another location. In addition, this type of economic impact is notoriously difficult to quantify. The studies proposed to assess this impact for the DEIS were extremely costly. Since a detailed economic impact study would be premature, expensive, and of questionable value, none was undertaken for this FEIS.

Chapter 10. Mitigation

The DEIS chapter on mitigation is divided into four sections.

- Demand and Energy Reduction
- Cogeneration
- Environmental (air emission reduction options)
- Foster Wheeler Contract Options

Comments Focused on University Energy Conservation Efforts and on Benefits of Cogeneration

Comments on mitigation focused on university energy conservation efforts, and on the energy efficiency benefits of cogeneration. The comments on energy conservation addressed three main topics: (1) the status and success of the University Building Energy Efficiency Project (UBEEP), (2) the potential benefits of coordinating steam production with centralized chillers for cooling, and (3) the potential benefits of converting the existing thermal distribution system at the university from steam to hot water.

Background Information on University Conservation Efforts and on Metro-Wide Cogeneration Has Been Added

Additional background information on energy conservation and the potential benefits of a metro-wide cogeneration thermal network has been added. Estimates of emission reductions due to cogeneration, however, have been moved to the discussion of air emissions in FEIS Chapter 6.

Tables illustrating the cost savings from energy conservation and comparing energy efficiencies have also been revised for the proposal and some alternatives.

Chapter 10. Comments and Responses

COMMENT 10a

University's Energy Conservation Program Should Be Revitalized and Evaluated More Fully

The University has cut off funding for its University Building Energy Efficiency Program (UBEEP), and the original 30% energy use reduction goal is unlikely to be reached. The FEIS should examine the impact of an restored and expanded UBEEP. (City of Minneapolis, Abrahamson at public meeting).

The FEIS should evaluate the financial savings in operation and maintenance costs of an expanded UBEEP program. The University in the past has been presented with information indicating that a 40% or even 50% energy use reduction goal would be economical. The discussion of energy conservation at the University should be expanded to include the level of investment required to reach these expanded conservation goals, and the resulting environmental benefit from such energy savings.

The University's UBEEP program should be revitalized. (PPERRIA)

UBEEP has been reorganized, and as a result has become revitalized. The University expects to reach a 30% energy cost reduction goal in the near future (UofM/FW).

RESPONSE 10a

Reorganized UBEEP Projected to Reach 30% Energy Reduction Goal

The University's UBEEP program and the associated energy conservation program have been reorganized. The reorganization is described in the FEIS text added to page 10-2.

The University, according to its current projections, is on target to meet its original goal of reducing energy use by 30% compared to the levels that would have occurred without the energy conservation efforts.

Expanded University Conservation Would Reduce Fuel Use

An expanded university conservation effort would, of course, reduce not only steam consumption, but also fuel use, air emissions, and energy costs. An estimate of the operating savings from doubling the current steam reduction efforts is included on p. 11-15 of the DEIS as a sensitivity. The related savings estimated for each of the alternatives has also been added to Table 1 of FEIS Chapter 10, above.

The major issue, however, is whether such an effort would be cost effective compared to various other possible conservation approaches and other University funding priorities.

Assessing Cost of Further Reductions in Steam Use Beyond the Scope of EIS

The University, in its comments on the DEIS, maintained that additional conservation efforts would be very difficult, if not impossible. A complete assessment of the capital costs associated with reducing campus steam consumption by 40% to 50% would involve a detailed review of the University's particular situation on almost a building by building basis. This effort is beyond the scope of the EIS.

SORC, However, Has Submitted Additional Valuable Information

Additional information on the potential for greatly expanded conservation efforts, however, can be found in material submitted by the Save Our Riverfront Coalition. This material includes a briefing memo on the issue prepared by university UBEEP staff.

<u>**COMMENT 10b**</u>

Faster Implementation of Centralized Chilled Water System Would Be Beneficial

The FEIS should evaluate the improved cogeneration potential associated with increasing summer steam demand by using central steam driven chiller units. (City of Minneapolis)

The FEIS should state that the University is planning to interconnect its chilled water system using a combination of electric and steam driven chilled water technologies, not steam driven absorption only. (UofM/FW)

The FEIS should state that the existing electric chillers use CFC or HCFC refrigerants but that the absorption chillers do not. (UofM/FW)

The DEIS suggests that an expanded centralized chilled water system and conversion to a hot water distribution system would conserve energy. Since centralized chilled water systems need medium pressure steam to drive the chiller absorption units, hot water distribution is incompatible with steam driven central chillers. (UofM/FW)

<u>**RESPONSE 10b**</u>

Existing Steam-Driven Chillers Do Not Contain CFC's

The EIS text has been revised to make it clear that the existing electric drive chillers contain CFC's, but that the existing steam driven chillers do not.

In addition, the DEIS contains a brief discussion on p. 10-4 of the environmental implications of steam chillers, as opposed to electric chillers, in a centralized chilled water system. The relationship of such a system to electricity cogeneration is also briefly discussed.

University Plans to Install Chilled Water Plant(s), but Construction Not Authorized at Time of DEIS

The cooling systems in many of the University's buildings are nearing the end of their effective lives and are being or will be replaced in the near future. Studies completed for the University by Ellerbe Becket and others recommended the installation of a central or satellite chilled water plant or plants, with individual buildings interconnected in a chilled water piping loop. The University is planning to implement such a system, but construction had not yet been authorized at the time the DEIS was released.

Choosing Steam or Electricity to Produce Chilled Water Affects Level of Cogeneration

Chilled water can be produced in centralized plants using steam or electricity. Electric chilled water facilities increase electricity use, but decrease steam demand. Steam driven centralized chiller plants, on the other hand, can encourage cogeneration. Steam driven chilled water facilities increase the steam use in the summer months, and generally increase steam consumption. The larger the campus baseload steam demand, the more electricity than can be efficiently cogenerated, resulting in higher production of electricity along with the steam.

Electricity Cheaper in Short-Run; Steam Cheaper in Long-Run

Initial costs favor electric chilled water, while overall life cycle costs are generally favorable to steam chilled water plants. The University's comment indicates that they are intending a mix of steam and electric driven chilled water plants.

Hot Water Distribution System Does Not Preclude Steam-Driven Chilled Water Plants

Finally, installing a hot water distribution system does not preclude the installation of steam-driven chilled water plants. The high pressure steam system could be retained for the chilled water plants, and possibly for hospitals or other facilities that require steam for at variety of reasons. The remaining buildings could be served with hot water using a steam to hot water heat exchange system located in the steam plant or other centralized areas. District Energy St. Paul, Inc., for example, successfully operates an efficient hot water distribution system combined with a centralized steam chilled water plant.

COMMENT 10c

Hot Water Distribution System Challenged as Problematic

The DEIS assertion that a hot water distribution system would be more efficient than the existing steam distribution system is incorrect. In addition, EIS suggests implementing both a centralized steam drive chilled water system and converting to hot water, which are incompatible, since steam would be needed to drive the chillers.

- Most of the buildings already use hot water.
- University hospitals, research facilities, and other buildings use steam for sterilization, etc. Replacing these functions with other electricity driven systems could increase electric usage beyond the capability of the existing electrical distribution system.
- The DEIS statement that more water is returned to the plant with hot water distribution systems (98%) than with steam distribution systems (53%) does not apply to the University because the University's steam system returns 90% of the steam sendout as water. (UofM/FW)

RESPONSE 10c

Facilities Requiring Steam Could Be Supplied by Existing Steam System or by Separate Steam Boilers

The DEIS acknowledges that most of the buildings use hot water. The university facilities that need steam could be supplied by retaining the existing steam system as necessary for those facilities, or by installing small separate electric steam boilers for individual buildings as suggested by University comments. Again, for example, District Energy St. Paul, Inc. successfully serves several large hospitals using a hot water distribution system.

University's Efficiency is Atypically High, and Long-Term Rate Cannot Be Addressed

Hot water distribution systems, as the DEIS points out on p. 10-5, are generally more efficient than steam systems. The university has indicated that 90% of its steam send out is returned as water, a percentage much higher than average for steam systems. The university's comment does not indicate why it achieves this higher return, so the likelihood of its continuing for the long-term cannot be addressed.

COMMENT 10d

Cogeneration and Other Environmental Mitigation Options Should Be Evaluated Further

The environmental benefits of expanded district energy and cogeneration should be described in more detail. (SORC, City of Mpls.)

The DEIS fails to evaluate the option of cogeneration at the St. Paul site. (SORC)

There is no justification provided for the statement that a hot water distribution system at the University would encourage a metro-wide cogeneration thermal network. (NPS)

RESPONSE 10d

Feasibility of Metro-Wide District Energy System with Cogeneration Has Already Been Studied

The DEIS briefly addresses on p. 10-5 the feasibility and energy efficiency benefits of incorporating the university district heating system into an expanded metro-wide district energy system combined with large-scale cogeneration. The issue is also briefly discussed in the FEIS in the context of new suggested alternatives. Several studies on the feasibility of such a large-scale cogeneration based thermal energy network in the Twin Cities were completed during the late 1970's. One of these, a 1979 study, *Feasibility of a Large Scale Cogeneration/Hot Water District Heating System in the Twin Cities*, is cited in the DEIS.

As System Expanded, Thermal Energy Needs Could Be Filled by Widely Distributed Cogeneration Plants

In theory, as a large thermal network expanded and electricity requirements increased, most of the thermal energy needed by the district heating systems could eventually be provided by widely distributed cogeneration plants with different equipment configurations, firing a variety of fuels, including natural gas, coal, wood, or non-wood biomass.

The cogeneration plants within the network could be new independent or utility-owned facilities firing primarily natural gas in combustion turbines (as suggested by Minnegasco's scenario) or could be existing plants owned by NSP, District Energy St. Paul, the University, or others, converted to cogeneration. The University itself could be either a steam provider or steam consumer in such a system.

Large-Scale Cogeneration Could Reduce Pollution in Entire Metropolitan Area

The advantages of such a system include optimizing the large-scale cogeneration of electricity and thermal energy, which would increase energy efficiency, reduce fuel consumption, and reduce related environmental impacts. In effect, large-scale cogeneration of electricity and steam could become a form of metro-wide "pollution prevention" policy.

Hot Water Distribution Would Encourage Cogeneration System Development

Hot water distribution is likely to encourage the development of such a system because more electricity can be produced in a cogeneration plant producing hot water than in one producing steam. Better cogeneration efficiencies improve the economics of such a large-scale system, and since there are no major technical feasibility issues involved, the feasibility of implementing such a system depends largely on cost. Hot water's other advantages are briefly described in Chapter 10 of the DEIS.

The thermal network suggested in the MEC comment is steam based. The issue of whether a steam or hot water thermal distribution system would be more likely to encourage a cogeneration network is somewhat controversial and outside the scope of the EIS.

Cogeneration Alternative for St. Paul Included in Screening Report for EIS

A small cogeneration option was designed for the St. Paul campus in the *Screening Report* as Alt. No. 12. This alternative was less expensive than the entirely natural gas, fuel oil Alt. No. 13, but used coal as well as natural gas fired combustion turbines. The coal use increased emissions.

Foster Wheeler's contract included an option for a steam turbine based cogeneration system at St. Paul as well.

Chapter 11. Economic Feasibility Analysis

Purpose of the Projections is to Assess the Economic Feasibility of Selected Alternatives

The purpose of the financial projections prepared for the EIS is to assess the economic feasibility of potentially environmentally superior alternatives to the University's proposed project. The financial projections include estimated construction and operating costs for each alternative. Projected operating costs include fuel, labor, maintenance, insurance, the value of cogenerated electricity, and other costs.

In the context of an EIS, the term "economic feasibility" is not specifically defined. As one benchmark for economic feasibility, the DEIS compared the projected costs of the detailed alternatives to the costs of the University's proposed project under its vendor contract.

Comments Addressed Accuracy and Completeness of Cost Projections

Comments on the DEIS economic feasibility analysis addressed the following major issues.

- Long-term contracts for natural gas are available at lower prices than that estimated in the DEIS. Natural gas alternatives would therefore actually be substantially less expensive than estimated. (Minnegasco)
- All the alternatives—particularly the off-river natural gas alternatives—would actually cost more than estimated. The financial projections underestimate construction, labor, fuel (except coal, for which the prices are too high), and other operating costs for the alternatives. (UofM/FW, labor and transportation unions)
- The value of cogenerated electricity would actually be less than suggested in the EIS because retail electricity rates will increase at less than the general inflation rate. (NSP)
- The assessment of environmental externality costs should be expanded. (City of Minneapolis, SORC, PPERRIA, Minnegasco, others)

Projections Reassessed, Revisions Made, and Background Information Added

All aspects of the financial projections were reassessed for the FEIS. Revisions have been made to some construction and operating costs and to some fuel consumption estimates.

An additional scenario has been added to the financial projections using new electricity price escalation rates suggested by NSP, and the costs of an off-campus third-party steam vendor alternative have been revised using steam rates suggested by the Minneapolis Energy Center.

Background information on the purpose and limitations of the economic feasibility analysis has also been added.

Overall Rankings of Alternatives Mostly Unchanged

The overall rankings of the costs of the alternatives compared to the costs of the proposed project did not change from that in the DEIS, with one exception.

Using the lower electricity price escalation rate suggested by NSP reduces the value of cogenerated electricity, which in turn increases the comparative costs of larger cogeneration alternatives.

Consequently, whereas under the base-case electricity escalation scenario, the Southeast Plant natural-gas based cogeneration alternative using the existing coal boilers is the lowest cost "build" option, under the low electricity escalation scenario, the off-river coal-based alternative similar to Case A becomes the lowest cost "build" option.

Details on all revised financial assumptions and calculations are available in the FEIS Technical Appendix A.

Section 11.2. Comments and Responses

COMMENT 11a

EIS Should Recognize Value of Land Used for Alternatives

The FEIS should examine the loss of use and loss of value to the University riverfront property in its economic evaluation of alternatives. (Minnegasco)

The DEIS neglected to include the land costs of the Off-River Site. The University estimates that the land at the off-river alternative site is worth $2,500,000. (UofM/FW)

RESPONSE 11a

University Already Owns Both Existing and Alternative Sites

Land values were not included because the University owns both the existing and alternative off-river site. Land values are applicable in the EIS comparison only to the extent that the value of property at one site would be substantially larger if used for some purpose other than as a power plant site.

Minnegasco's comment suggests that the riverfront property near the steam plants would be worth considerably more than $7.5 million as part of the parkway system, based on a recent award for a smaller riverfront property across the Mississippi. (See Minnegasco comment letter for details.) The University comment suggests that the land value of an off-river site is at least $2.5 million. Other commenters note that the value of the riverfront property is not just what it could be sold for, but its impact on the economy of the whole neighborhood as an aesthetic resource.

Land Value Depends on Variables Outside Scope of EIS and is a Small Portion of Total Cost for Any Alternative

The value of the riverfront property, however, not only is subject to finding an interested purchaser, but also depends on economic variables outside the scope of the EIS. Non-economic valuations of the property are largely subjective.

In addition, land value costs would be minor compared to construction and operating costs for any alternative. Detailed land valuations, therefore, were not completed. The cost estimates of the University and Minnegasco appear to be as useful as any for evaluating the current riverfront and off-river land values.

COMMENT 11b

EIS Cost Estimates Not a Fair Basis for Comparison

The cost estimates in the DEIS do not provide a fair basis for comparing the cost of the project with the costs of the alternatives because the cost estimates for the alternatives were not developed using the methods that were used in estimating Project costs, and they produced artificially low estimated costs for the Alternatives.

The estimated costs of the alternatives are inconsistent with actual experience and do not reflect "real world" costs, and the DEIS used inaccurate or inconsistent assumptions in describing the project and alternatives.

The DEIS does not account for non-quantifiable benefits. The DEIS should acknowledge that under the contract the University is protected from the risk of cost overruns and is protected from other risks by various guarantees such as for cogeneration output, steam capacity, boiler efficiency, and fuel efficiency. (UofM/FW)

RESPONSE 11b

University Participated in Process to Develop Consistent, Comparable Costs for Alternatives

The scope of the DEIS, as the University administration is aware, did not include the development of cost estimates to the same level of detail as for the project. However, the DEIS followed a process, which the University participated in, to develop consistent, comparable costs for the alternatives.

The University, in its comments, has not provided either a methodology or specific financial results which could account for the non-quantifiable benefits cited. Therefore, non-quantifiable benefits are not assessed for the project or alternatives.

COMMENT 11c

EIS Should Consider Added Weight of New Equipment

The FEIS should assess the ability of the sandstone under the Southeast site to support the added weight of the proposed new equipment. The economic risk associated with Case A and Case B should be evaluated in the event the Southeast Plant collapsed into the Mississippi River. (PPERRIA, SORC)

RESPONSE 11c

EIS Did Consider Added Weight of New Equipment

The DEIS conceptual designs completed by Syska and Henessey, did consider the added weight of the proposed new equipment at the Southeast site and its structural effect. Foster Wheeler's proposal, however, includes a larger new boiler that would be supported from new foundations and supporting steel, completely independant from the existing structure. Foster Wheeler has indicated that preliminary University soil studies did not indicate any problem and that only at a later stage would detailed geological stability tests and other analysis be completed.

COMMENT 11d

Construction Costs for Alternatives Are Too Low

The construction costs for the DEIS alternatives are too low, for the following reasons.

- The DEIS costs were lower than those submitted for similar alternatives during the University's procurement process.
- DEIS cost estimating techniques differed from those used to estimate Case A and Case B construction costs.
- The DEIS costs were lower than those of Burns and Roe, a firm hired by Foster Wheeler to perform cost estimates on the DEIS alternatives. For example, the DEIS neglected to include the $5,000,000 cost of the new steam line in a tunnel that would be required to connect a new plant at the off-river site. DEIS construction costs for the off-river natural gas cogeneration plant are low by as much as $35 million. (UofM/FW)

DEIS Capital Cost Estimating Procedure Provided Consistent, Professional Cost Estimates

The construction cost estimates were developed through a process to ensure consistent, reliable results. This process involved the development of conceptual designs for the alternatives by Syska & Hennessy, a nationally known engineering firm with specific expertise in district heating and cogeneration for colleges and universities. Construction cost estimates were provided based on the conceptual designs by a professional cost estimator, John R. Brady & Associates. John R. Brady & Associates has been in the professional estimating business for over 28 years.

Construction Costs And Reviewed, and Increased for Some Alternatives

John R. Brady & Associates reviewed the UofM/FW comments and all estimates completed for the alternatives. The construction costs have been increased for Alt. No's. 1, 3, and 4 by about $2 million.

The construction costs for the off-river alternatives No. 6 and No. 7 were increased by $8.3 million and $8.0 million, respectively. Most of these costs were for restoring the costs of the new steam line ($3.2 million), electrical duct bank (an additional $2 million), and site finishing work at the off-river location ($1.3 million). The costs of historical rehabilitation of the Southeast Plant are not included in the revised costs.

COMMENT 11e

Capital Replacement Costs Omitted from EIS

Capital replacement costs for the steam plants are funded by Foster Wheeler under the contract but would be funded by the University under the University-operated alternatives. These replacement costs, which were omitted from the costs of the DEIS alternatives, have a 25-year present value cost of about $14 million. (UofM/FW)

RESPONSE 11e

No Justification for Adding Capital Replacement Costs to EIS

The comment provides no clear justification for these replacement costs. The supporting information provided lists recent large capital expenditures by the legislature that were required for the steam plants.

The comment does not make clear who under the contract would pay for major capital replacement costs like those indicated. Nor is a new plant likely to have replacement costs similar to those of 40 year old facilities with suspect maintenance. Consequently, the capital replacement costs suggested in the comment have not been added to EIS estimates.

COMMENT 11f

EIS Should Recognize Cost of Earlier Renovation to Southeast Plant

The FEIS should recognize that the University spent $25 to $30 million to renovate the Southeast Plant after purchasing it in 1980. If the University builds a new plant at another location, it will need to recover its investment in the current building and property. (UofM/FW)

RESPONSE 11f

Earlier Renovation Costs Are Non-Recoverable Sunk Costs

The costs of renovating the Southeast Plant fifteen years ago appear to be "sunk" costs. The EIS alternatives designed for the Southeast Plant include any cost reductions associated with the use of the existing building and Southeast Plant boilers.

COMMENT 11g

EIS Fuel Cost Estimates Are Inaccurate

The price escalators used for the DEIS greatly overstate the average growth rate for coal prices and do not reflect U.S. DoE data. Natural gas based alternatives would actually cost about $63 million more than projected in the EIS. (UofM/FW)

A 25-year contract for natural gas guaranteed for the base-loaded natural gas cogeneration alternatives, Alternatives 3, 4, and 7, would save at least $46 million in present value costs compared to the DEIS estimate. (Minnegasco)

The University is likely to be able to negotiate lower fuel prices with a fuel-flexible project that can fire solid fuels as well as gas and oil. (UofM/FW)

RESPONSE 11g

Fuel Cost Escalation Rates Take Current Legislation into Account

The DEIS fuel cost escalation rates are based on forecasts provided by a professional fuel price forecasting expert. The DEIS coal forecasts are based on underlying AEO analysis forecasts for sub-regions of very-low sulfur subbituminous coal supplies. This coal is used at the University and often by NSP, and the demand for which is projected to increase faster than the average rate for western coals, as increasingly restrictive provisions of the Clean Air Act Amendments of 1990 are triggered into the next century. The published composite AEO forecasts for western coal would differ from the specific forecasts for specific regions and sulfur grades.

Cannot Update Cost of One Fuel and Not Others

Minnegasco's suggested long-term price for natural gas is lower than that used in the DEIS. The present value costs of the selected larger-volume gas alternatives would be lowered by from $30 $ million (Alt. No 2 & 3) to $40 million (Alt. No. 4 & 7) compared to the EIS projections.

According to Minnegasco, the Minnegasco natural gas guarantees for the natural gas, fuel oil alternatives 4 and 7 (when combined with the St. Paul campus alternatives), offered for these two high natural gas volume alternatives, would result in the 25-year net present value comparisons shown in the following two tables.

However, the financial projections are intended to provide a consistent basis with which to compare alternatives, Therefore, it is not logical to update or lower the costs of one fuel without updating the costs of other fuels as well.

PRESENT VALUE OF COMBINED ALTERNATIVES
Base Case
Minnegasco Revised Financial Projections with Gas Guarantees
PV 1/1/94 ($ in Millions)

	Minneapolis	St. Paul	Total
Alt. Nos. 1 & 11	245.3	80.6	325.9
Alt. Nos. 1 & 13	245.3	102.2	347.5
Alt. Nos. 3 & 11	256.6	80.6	337.1
Alt. Nos. 3 & 13	256.6	102.2	358.8
Alt. Nos. 4 & 11	245.7	80.6	326.3
Alt. Nos. 4 & 13	245.7	95.6	341.3
Alt. Nos. 6 & 11	264.2	80.6	344.7
Alt. Nos. 6 & 13	264.2	102.2	366.4
Alt. Nos. 7 & 11	258.3	80.6	338.9
Alt. Nos. 7 & 13	258.3	95.6	353.9
Case A			411.2
Case B			426.2

PRESENT VALUE OF COMBINED ALTERNATIVES
3.37% Electricity Escalation Rate
Minnegasco Revised Financial Projections with Gas Guarantees
PV 1/1/94 ($ in Millions)

	Minneapolis	St. Paul	Total
Alt. Nos. 1 & 11	242.0	80.6	322.6
Alt. Nos. 1 & 13	242.0	102.2	344.2
Alt. Nos. 3 & 11	272.8	80.6	353.4
Alt. Nos. 3 & 13	272.8	102.2	375.1
Alt. Nos. 4 & 11	262.0	80.6	342.6
Alt. Nos. 4 & 13	262.0	95.6	357.6
Alt. Nos. 6 & 11	267.1	80.6	347.7
Alt. Nos. 6 & 13	267.1	102.2	369.3
Alt. Nos. 7 & 11	314.8	80.6	355.2
Alt. Nos. 7 & 13	314.8	95.6	370.2
Case A			417.5
Case B			448.8

EIS Uses Consistent Fuel Pricing for Project and Alternatives

Only Alternatives 4 and 7 lack the capability of firing solid fuels, yet even those alternatives have fuel flexibility. The University does not suggest how solid fuel burning capability would affect fuel prices for Case A, Case B, Alternative 1, Alternative 3, or Alternative 6. Therefore, the EIS uses consistent fuel pricing for both the University's project and alternatives.

COMMENT 11h

EIS Overstates Value of Cogenerated Electricity

The DEIS substantially overestimates NSP's expected fuel cost escalation and should be revised. Based on historical data, fuel costs will not increase faster than general inflation. Market forces, deregulation, and technological advances will force electricity prices to remain at the general inflation rate, below that estimated in the DEIS. The 5.0% electricity escalation rate in the DEIS is higher than the 3.6% inflation rate projected by NSP. An escalation rate of 3.37% should be used instead. (NSP, UofM/FW)

The value of cogenerated electricity is inflated because all of the costs of a large University cogeneration project were not included in the analysis. (NSP)

RESPONSE 11h

Assumptions on Value of Electricity Consistent with Other DEIS Assumptions

To ensure consistency among assumptions and across alternatives in the DEIS, the same fuel price escalation rates were applied in each of the assumptions and in each of the alternatives.

Both the value and cost of electricity were escalated at 5% per year, which assumed that 70% of NSP's rates were non-fuel costs, and that 30% were fuel and purchased power costs. Because fuel price escalation rates used in the Screening Analysis were updated for the Financial Projections, the assumed escalation rate for the value and cost of electricity was changed from 4.7% to 5.0%.

UofM/FW's Proposed Escalation Rate is Inconsistent with its Fuel Price Escalation Comments

In their comments, the UofM/FW proposed escalating the value of electricity at the general inflation rate, based on their interpretation of NSP's June 1993 fuel price forecast. The UofM/FW did not, however, propose changing the DEIS fuel price escalation rates, which are higher than the general inflation rate. Because fuel is a significant part of NSP's rates, it would be inconsistent to assume that NSP's rates would escalate at the general inflation rate while the University's fuel costs would escalate at a rate above inflation.

NSP's Proposed Escalation Rate Ignores Coal Quality and Increases in Coal Transportation Costs

NSP proposed escalating the value of electricity by less than the general inflation rate, based on a short-term internal projection and on a DRI forecast of coal prices. NSP's proposed escalation rate, however, ignores the escalation in coal transportation costs which were included in the DEIS fuel price escalation rates.

NSP's proposal is inconsistent with the DRI forecast for electric rates referenced in its comments, and with the fuel price and electric cost assumptions in the DEIS.

Also, the DEIS fuel escalation rates are based on AEO price forecasts for regional sources of very-low sulfur subbituminous coal, the demand for which is projected to increase faster than the average rate for western coals, as increasingly restrictive provisions of the Clean Air Act Amendments of 1990 are triggered into the next century.

Recent Historical Data Only Useful if Patterns are Expected to Continue

NSP commented that escalation in its rates and fuel costs in the recent past was lower than projected in the DEIS. NSP did not, however, conclude that this historical pattern of rates and fuel costs would continue into the future. Recent historical patterns in NSP's rates and fuel costs are not necessarily the best indicator of future costs.

An additional scenario has been added to the FEIS, assuming the electricity escalation rate of 3.37% suggested by NSP. This scenario implicitly assumes that the NSP rates will remain below inflation, although fuel costs to the University would increase at the rates assumed in the EIS.

DEIS Provided Independent Assessment of NSP's Rates

The DEIS provided an independent assessment of NSP's rates based on electric cost and fuel price escalation assumptions consistent with assumptions used elsewhere in the DEIS.

Since NSP would lose electric load if the University began cogenerating electricity, NSP advocates relatively low electric rate projections, which decrease the economic value of cogeneration. Therefore, an independent assessment of NSP rates are used in the base case FEIS projections rather than the projections discussed in NSP's comments or the projections submitted by NSP in 1993.

COMMENT 11i

Interconnect Costs Not Included for Cogeneration Alternatives

The cost of interconnecting the cogeneration system with the UofM's distribution system is not included in the discussion of alternatives. No requests were made to NSP regarding various technical specifications necessary to ensure reliability, such as power flow calculations, fault current, etc. The additional studies necessary to determine the interconnect costs and difficulties would cost an additional $32,000 to $180,000. (NSP)

RESPONSE 11i

Interconnection Costs Included in DEIS

The equipment necessary to interconnect each alternative's electrical generation with the existing University electrical system was included in the conceptual design. Therefore, the interconnection costs were included in the EIS.

COMMENT 11j

Labor Costs Underestimated

The staffing estimates for the alternatives described in the EIS are inaccurate. The staffing estimates prepared by Burns and Roe for Foster Wheeler, Inc. are accurate. (Local Union 160, IBEW)

The DEIS underestimates the number of employees necessary for the alternatives, and underestimates the labor costs per employee. (UofM/FW)

RESPONSE 11j

DEIS Used Number of Employees Consistent With Local DHC Utilities

The DEIS estimated the number of plant employees consistent with the experience of local commercial district heating and cooling utilities. District Energy St. Paul, Inc., for example, employs 20 plant personnel to operate a coal fired steam plant that produces hot water, chilled water, and electricity.

The DEIS did not consider the University's prior power plant operating experience, because the University's numbers were outdated and no longer useful. (Since those numbers were submitted, Foster Wheeler has reduced staffing and has indicated that further staff reductions were planned.)

The DEIS employee estimates are consistent with the International District Energy Association Member Profile Study statistics for output per employee for large (1,500,000 MMBtu or greater) systems.

Labor Costs Per Employee Should Be Adjusted

The DEIS used an average cost per employee in fiscal year 1995 of $50,000. This cost per employee was based on information provided by the University of Minnesota. However, the UofM/FW comments provide new information about labor costs. EIS labor costs per employee should be increased to $55,000 per year. The basis for this adjustment is contained in the discussion of labor costs by George J. Delarche, General Manager, Foster Wheeler Twin Cities, Inc.

COMMENT 11k

Present Value Cost Calculations Should Be Revised

In the present value cost calculations, the start date for the Alternatives should be the same as for Case A and Case B. Residual values should also be added. (UofM/FW)

RESPONSE 11k

Start Date for Alternatives Consistent With University's Recommendation

The start dates used in the initial screening analysis were identical for Case A, Case B and the alternatives. The University's consultant commented that identical start dates were not reasonable because substantial design and development work was already underway for Case A and Case B but not for the alternatives. The DEIS reflected agreement with this comment.

No Basis For Calculating Residual Value

There is no basis for calculating the residual value of cogeneration and heating plants, and the UofM/FW does not provide any. The value of any cogeneration or heating plant would be dependent on factors such as fuel use, fuel costs, and environmental regulations. Further, simply delaying investment would increase residual value 25 years from the present.

COMMENT 11l

EIS Should Consider Carbon Taxes

Carbon taxes are a virtual certainty and should be evaluated in the EIS. (Abrahamson)

RESPONSE 11l

Hypothetical Carbon Taxes Could Be Calculated from Emission Rates

Recent federal attempts to impose a carbon tax have not been revived. Predicted annual CO_2 emission rates are provided in Chapter 6, and hypothetical carbon taxes could be calculated from those.

COMMENT 11m

Use of Externality Costs Questioned

The FEIS should expand its discussion of environmental costs based on interim externality values throughout the EIS, and use them to evaluate the costs and benefits of all the alternatives and mitigation options. (SORC)

The FEIS should show the externality costs based on net emissions after adjusting for cogeneration. (City of Mpls, PCA)

The FEIS should not rely on the interim environmental cost values adopted by the PUC for the following reasons.

- The legislation authorizing the PUC to determine externality values applies to utility resource planning only. Consequently, using interim values in the EIS is improper and illegal.
- Using interim values is premature.
- Externality estimates for utility planning may be abandoned, restricted, or eliminated judicially as they have been in many states. Massachusetts externality values, which the Minnesota PUC has largely relied on, were recently overturned in state court.
- The CO_2 value in particular should not be used, in part because the cause and effect relationship between CO_2 emissions and harmful effect cannot and is not likely to be accurately quantified. (Center for Energy and Economic Development)

RESPONSE 11m

The valuation of environmental costs is a complex issue on which the Minnesota PUC has recently competed lengthy hearings. The policy issues involved are largely outside the scope of the EIS on a specific proposal.

In addition, the PUC interim values and other proposed values are mostly intended as tools in utility resource planning. Their use is more questionable in the context of determining externalities for a specific project.

For illustration, however, the 25-year NPV costs were calculated using PUC interim values and the MPCA's submitted high value for mercury ($9781/lb). The table below shows the results using the highest value in the range of each pollutant. Carbon dioxide accounted for by far the highest percentage of any pollutant, from 75% to 90% of all calculated costs.

Base Case Present Value of PUC Interim Externality Values
($ Millions)

Alternative	Without Cogeneration	With Cogeneration Credit
Case A	74	51
Case B	83	16
Alternative No. 1 and No.11	118	118
Alternative No. 3 and No. 13	88	33
Alternative No. 4 or 7 and No. 13	63	9
Alternative No. 6 and No. 13	69	49
Alternative No. 2 and No. 13	46	46

	A.S. King (Tons/Yr)	Riverside (Tons/Yr)	Sherco (Tons/Yr)	Highbridge (Tons/Yr)	Black Dog (Tons/Yr)	MN Valley (Tons/Yr)	Total (Tons/Yr)	Avr. Emission Factor Lb/mWh
SO2	25994	5678	19635	2635	4001	655	58550	6.194
CO	576	259	2531	189	322	8	3886	.411
PM10	458	131	2089	470	199	8	3357	.355
NOx	24061	7818	29492	3713	5007	157	70250	7.4313
VOC	76.8	30	295	21	27	1	452	.0478
Generation, mWh	3,430,540	1,446,297	12,042,741	740,927	1,207,396	38,351	18,906,252	

References:

(1) Emissions information extracted from 1992 Emission Inventories prepared by NSP and submitted to the Minnesota Pollution Control Agency.

(2) Generation information extracted from NSP's 1982 FERC Form 1.

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