Minnesota Pollution Control Agency

Review of Xcel Energy's Metropolitan Emission Reduction Proposal

December 30, 2002

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MPCA Review of Xcel Energy's

Metropolitan Emission Reduction Proposal

1.0 Introduction

On July 26, 2002, Northern States Power Company d/b/a Xcel Energy (Xcel) submitted an emission reduction proposal, the Metropolitan Emission Reduction Proposal (MERP) and accompanying rate rider, pursuant to Minn. Stat. § 216B.1692.[1] The proposal identified emission reduction options at three plants located in the Twin Cities metropolitan area:

- *Allen S. King, Bayport*: Installation of new pollution control equipment, boiler rehabilitation and life extension, with a modest increase in generation capacity of 12 percent.
- *High Bridge, St. Paul*: Replace existing coal-fired units with two natural gas combined-cycle units, eliminating air emissions from burning coal and with a substantial increase in generation capacity of 111 percent.
- *Riverside, Minneapolis*: Repower with two natural gas combined-cycle units, eliminating air emissions from burning coal and with a modest increase in generation capacity of 14 percent.

Table 1 shows that if implemented as proposed, these projects would result in huge reductions in key pollutant emissions. Emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) would be reduced by more than 90 percent. Emissions of particulate matter and mercury would be reduced by 70 percent and 76 percent, respectively.

Table 1. Comparison of annual overall emissions for the three plants before and after proposed changes

	SO_2	NO_X	PM_{10}	CO_2	CO	Lead	Mercury
Current annual emissions from these three plants (in tons per year)	34,178	24,206	954	6,545,727	860	266[2]	232[2]
Emissions change (in tons per year)	-31,880	-22,017	-667.1	-319,865	+80	-60[2]	-178[2]
Percent change	-93.3	-91.0	-69.9	-21.4	+9.3	-22.5	-76

[1] The complete text of the statute is shown in Attachment 1.

[2] Lead and mercury emissions are reported in pounds per year.

In this report, the Minnesota Pollution Control Agency (MPCA) provides the analysis of Xcel's proposal that is required under the emission reduction rider statute, based on its expertise in evaluating pollution control projects as part of its long-standing air quality regulatory programs. Specifically, Minn. Stat. § 216B.1692, Subd. 4 asks the MPCA to advise the Minnesota Public Utilities Commission (PUC) as to:

- Verification that the emission reductions project qualifies under Minn. Stat. § 216B.1692, Subd. 1;
- A description of the projected environmental benefits of the proposed project; and
- The MPCA's assessment of the appropriateness of the proposed MERP project.

In addition to answering the above questions in this report, the MPCA is also to provide the PUC with answers to two questions posed under Minn. Stat. § 216B.1692 Subd.5(c):

- Whether the project is needed to comply with new state or federal air quality standards; and
- Whether the emission reduction project is required as a corrective action as part of any state or federal enforcement action.

2.0 Summary

The MPCA has reviewed Xcel's proposal to determine whether the proposal qualifies under Minn. Stat. §216B.1692. The MPCA has also projected the environmental benefits from the implementation of this project, and has generally assessed the costs versus benefits of the emissions reduction proposal.

2.1 Qualifying Projects

The rates of air pollutants released by these plants at the end of their reconstruction/rehabilitation under MERP represent "best available control technology" at each plant, thus meeting conditions required under federal new source review regulations in place at the time Xcel made its filing. In making this determination, the MPCA has met its statutory requirement to determine whether the emissions reductions proposed meet applicable new source review standards, emit air contaminants at levels substantially lower than allowed by new source performance standards or reduce air pollutants to their lowest-cost effective level [Minn. Stat. §216B.1692, Subd. 4 (1)].

The MPCA has determined that the projects at the A.S. King and Riverside electric generating stations meet all conditions of Minn. Stat. § 216B.1692, and thus fully qualify for consideration under the statute. The High Bridge proposal meets the conditions of Minn. Stat. §216B.1692, except that the capacity of the plant increases by more than allowed for under the statute. The MPCA concludes that the first 100 MW of the 270 MW expanded generating capacity at High Bridge qualifies. The treatment of the cost of the remaining 170 MW of new generating capacity should be considered for "recovery above cost" if the PUC determines that it is appropriate as described by Minn. Stat. §216B.1692, subd. 5(b)(4).

Further, the MPCA has reviewed the proposal for each plant, and has determined that the project is not needed to comply with new state or federal air quality standards, nor is the project required as a corrective action as part of a state or federal enforcement action.

2.2 Project Costs

Because project costs are compared to the benefits of this proposal, project costs were reviewed to determine if they were within a reasonable range. This project involves essentially three different types of construction/rehabilitation: A.S. King involves some rehabilitation of the coal-fired boiler to extend its life along with the addition of highly efficient pollution control equipment. Riverside involves repowering the plant to combust gas instead of coal, and requires replacing portions, but not all, of the power producing equipment onsite. High Bridge is the construction of a new gas-fired generating station to retire a coal-fired station.

Construction costs for the A.S. King rehabilitation and the Riverside project fall within a reasonable range as defined by similar projects either nationally or within Minnesota.

The cost of reconstructing High Bridge appears to be about 20 percent higher than national figures for new greenfield plants, probably due to some unique site characteristics that need to be addressed for reconstruction on the existing power plant site. Xcel has explained several reasons for the higher costs associated with its work on the High Bridge project. The MPCA suggests that the PUC further explore the appropriateness of the portion of the High Bridge project costs that exceed the national average to assure that these costs are appropriate for the site's conditions.

2.3 Projected Environmental Benefits

The MPCA must describe the environmental benefits that result from the implementation of this project [Minn. Stat. §216B. 1692, Subd. 4 (2)].

The A.S. King, High Bridge and Riverside plants contribute significantly to total overall emissions of sulfur dioxide (SO_2) to Minnesota's air — the three plants alone represent almost half of SO_2 released by electric utilities in the state, and nearly a quarter of SO_2 emissions overall. The plants also are emitting sizable amounts of NO_x and mercury in Minnesota. The proposed project reduces SO_2 emissions from these plants by 93 percent, NO_x by 91 percent, and mercury by 76 percent.

Reductions in SO_2 and mercury will aid in continued improvements to Minnesota and the nation's water bodies. Evidence is showing that further SO_2 reductions are still needed to reverse ecological damage of acid rain. SO_2 converts to sulfates which when deposited as acid rain, appear to encourage bacteria in lakes to methylate mercury, that is, convert mercury into the form that is readily accumulated by fish. This proposal would reduce contributions of both SO_2 and mercury, thereby reducing factors that contribute to mercury contamination in the environment.

Fine particulates strongly correlate with increased health problems, including early death from cardiopulmonary disease and lung cancer. Researchers have not yet identified a threshold concentration where these health impacts disappear. Fine particulate effects extend even down to background levels.

Knowing this, EPA established an ambient standard for fine particles, $PM_{2.5}$, and requires state regulatory agencies to issue air alerts when monitoring shows actual ambient values approach levels that are still below the federal ambient standard. In 2001 and 2002, Minnesota experienced several air alerts for high levels of fine particles in Minnesota, and Minnesotans are suffering impaired health effects from fine particulates.

Because SO_2 and NO_x are contributing to widespread health concerns, the pollutants are subject to considerable regulation. Most notable is the Bush Administration's Clear Skies proposal to reduce power plant emissions. This proposal, as well as several others, measured health benefits when power plants' SO_2 and NO_x emissions are reduced. One such study evaluating emissions of coal-fired power plants in Minnesota finds that with reductions of the magnitude offered by this proposal, the net present value of health benefits in Minnesota could be at least $1.2 billion.

This is compared to a calculation of benefits also prepared by the MPCA using PUC externality values. The MPCA calculation extends benefits out to 2040, and uses a discount rate in keeping with public health benefits. This calculation shows PUC externality-based benefits of the MERP project to be $200 to $500 million (in 2001 dollars). Even this conservative treatment of the benefits of this emission reduction proposal shows benefits greater than that calculated by Xcel in its July filing ($58 – $127 million).

This benefit estimate does not attempt to fully address health issues associated with fine particulates. It also does not consider the reduction in mercury, regional haze, acid rain, ground level ozone and impacts felt by the communities around the three plants such as truck and rail traffic.

Xcel has presented the argument that the avoided costs related to the construction of an additional 385 MW over the original generating capacity at the three plants has a net present value of about $700 million. The MPCA concurs that there is real value to this generating capacity that is not reflected in the construction costs, nor in the assessment of benefits.

In addition to adding generating capacity, this project refurbishes about 1,100 MW of existing capacity without the need to develop new sites or construct new transmission lines. There is substantial benefit (perhaps in the several hundred million dollar range) for not having to replace this power in some other manner.

2.4 Appropriateness of the Project

There are many benefits to the project that are not directly quantifiable, many of which are described in this report. The proposal addresses multiple issues related to power plant emissions — reduction of $PM_{2.5}$ forming pollutants, reduction in mercury emissions, improved efficiency in generating electricity that is necessary to address global warming, and reduction in haze-forming pollutants. The MPCA notes that there could be substantial local improvements in the areas around the High Bridge and Riverside plants by eliminating coal burning at the plants.

The MPCA believes that this emission proposal is an important project to achieve improvements in many of these environmental problems, and that benefits of the project approximate and most likely exceed the capital cost of this project.

3.0 Qualifying Projects

Under Minn. Stat. § 216B.1692, Xcel has proposed emission reduction projects at three power plants located in the Minneapolis-St. Paul metropolitan area.

A. S. King
- A rehabilitation of the A.S. King plant in Bayport would add controls to significantly reduce emissions of SO_2, NO_X and PM_{10} while increasing the plant's capacity from 504 MW to 564 MW (a 60 MW increase in capacity). The King plant would continue to burn coal. The repowered plant would be functional in 2007.

High Bridge
- At the High Bridge plant in St. Paul, located near the Mississippi River in downtown, Xcel proposes to replace the existing coal-fired plant (with 243 MW of capacity) with a new natural gas-fired combined cycle plant with 515 MW of capacity (a 272 MW increase in capacity). Even with the proposed increase in capacity, the switch to a cleaner fuel and a more efficient combustion technology decreases emissions of SO_2, NO_X, PM_{10} and CO_2, while eliminating the emissions of mercury. The new plant would come online in 2008.

Riverside
- In northeast Minneapolis, Xcel proposes to convert its 387 MW Riverside plant from a coal-burning unit to a 439 MW combined cycle plant that uses natural gas (a 52 MW increase in capacity). The conversion from coal to natural gas drastically decreases emissions of SO_2, NO_X, PM_{10} and CO_2, while eliminating emissions of mercury. Electricity from the modified plant would come online in 2009.

The MPCA is charged with determining whether these proposals "qualify" for the cost recovery that is allowed under Minn. Stat. § 216B.1692. This section first describes how the MPCA considered the statutory requirements, then evaluates each plant proposal to determine if it is a qualifying project.

3.1 Minn. Stat. § 216B.1692 Subd. 1. Qualifying Projects.

Projects that may be approved for the emissions reduction rate rider under this section must:

1) be installed on existing large electric generating power plants as defined under Minn. Stat. § 216B.2421 subd. 2(1), that are located in the state and not subject to emission limitations for new power plants under the federal Clean Air Act;

   The definition of a large power plant under Minn. Stat. § 216B. 2421 includes the following:

   "Large energy facility" means any electric power generating plant or combination of plants at a single site with a combined capacity of 50,000 kilowatts (50 MW) or more and transmission lines directly associated with the plant that are necessary to interconnect the plant to the transmission system;

2) not increase capacity by more than 10 percent or 100 megawatts, whichever is greater;

This is a straightforward calculation of increased generating capacity over current facility generating capacity.

3) result in the existing power plant either:

i) complying with applicable new source review standards under the federal Clean Air Act;
ii) emitting air contaminants at levels substantially lower than allowed for new facilities by the applicable new source performance standards under the federal Clean Air Act; or,
iii) reducing emissions from current levels at a unit to the lowest cost-effective level when, due to the age or condition of the generating unit, the public utility demonstrates that it would not be cost effective to reduce emissions to the levels in item (i) or (ii).

3.1.1 New Source Review

New Source Review (NSR) is a federally mandated air quality program that was established in the 1977 Clean Air Act Amendments. It is designed to improve the quality of the air in areas that have poor quality air. These are called "nonattainment" areas because they do not meet the National Ambient Air Quality Standards (NAAQS). In attainment areas that do meet the NAAQS, NSR protects the quality of the air from significant deterioration.

NSR requirements may be triggered by the construction of new equipment with air emissions or by the modification of existing equipment with air emissions. In nonattainment areas, NSR requires the application of technology with the Lowest Achievable Emission Rate (LAER). The determination of LAER is fairly straightforward. For a specific emission unit, all potentially applicable technologies are assessed; the best performing technology is selected as LAER, since the review includes no assessment of the cost.

In attainment areas, NSR requires the application of the Best Available Control Technology (BACT).[3] A BACT review assesses technologies that can be potentially used to minimize the emissions from a new or modified unit. The BACT review includes an assessment of the economic, energy, and environmental factors associated with the various options.

[3] The official definition of BACT is found in 40 CFR 52.21(b)(12), which states that "[b]est available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

For the economic assessment, EPA guidance insists on a "top-down" review of the available emission-reducing technologies. The first (or "top") technology to be considered in a top-down BACT analysis would be the one selected as LAER if the review was performed for a nonattainment area. This results in the selection of BACT as the best-performing technology that is determined to be cost-effective. Technologies can be eliminated from selection if they are not technically feasible or if associated energy or environmental effects outweigh the emission reduction benefits.

The Twin Cities metropolitan area is currently classified as an attainment area, so the level of control proposed by Xcel for each of these plants will be compared to the MPCA's evaluation of what might be expected from a BACT analysis.

The question of whether the proposed projects comply with NSR is somewhat difficult to answer directly. NSR requires a case-by-case analysis that the MPCA does not perform until a highly detailed permit application is received. However, the MPCA has reviewed recent BACT determinations from the RACT/BACT/LAER Clearinghouse (RBLC) and from other sources.[4] The EPA operates the RBLC, a database that records emission rates achieved by technologies used to limit emissions that have been approved as BACT.

A review of the most recent submittals to the RBLC and to other associated databases provides an indication of the types of controls that have been placed on similar emission units and the emission limits that permitting authorities placed on these units under the NSR rules. Xcel's proposals can then be compared to a range of limits for the three pollutants of concern (SO_2, NO_X, and PM_{10}) at similar emission units.[5]

3.1.2 New Source Performance Standards

The New Source Performance Standards (NSPS) program was established in the 1970 Clean Air Act. Under NSPS, generation facilities constructed after 1972 are required to meet certain minimum performance standards with regard to emissions of several pollutants. Generation facilities that were constructed before 1972 are exempt from NSPS.

NSPS have been revised several times, and different standards apply to plants depending on the year they were constructed. NSPS have become progressively more stringent, so control requirements at plants subject to newer NSPS tend to be much more stringent than older NSPS requirements.

Under Minn. Stat. § 216B.1692, subd. 1(3), a project qualifies if it meets NSR requirements or if it would make emissions "substantially lower" than the NSPS would require. As will be

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[4] RACT means Reasonably Available Control Technology

[5] It is important to note that the NSR regulations do not apply to CO_2, mercury or $PM_{2.5}$.

explained in the next section, the proposed project meets one or both of these requirements for all three plants.[6]

3.2 Do the Projects Qualify Under 216B.1692 Subd 1?

3.2.1 A.S. King

Is it an existing large electric generating power plant as defined under Minn. Stat. § 216B.2421 subd. 2 that is located in the state and not subject to emission limitations for new power plants under the federal Clean Air Act?

The A.S. King plant is located in Bayport, Minnesota on the St. Croix River and has a net generating capacity of 504 MW. It meets the definition of a large electric generating power plant because it is larger than 50 MW. The boiler is a cyclone boiler that burns subbitumious coal. The boiler was constructed in 1968, before the Clean Air Act was passed, and thus before EPA promulgated NSPS for boilers. It is therefore not subject to the NSPS standards for power boilers. The project meets this requirement.

Does it increase capacity by more than 10 percent or more than 100 MW?

Xcel's proposal to modify this plant results in an increased electricity generating capacity of about 60 MW, less than the statute's specified 10 percent of existing capacity or 100 MW, whichever is greater. The project meets this requirement.

Does the project propose "best available control technology"?

Table 2 on the following page shows the current emission rates at the King plant and the emission rates that would result from Xcel's proposed emission reduction project with NSPS and BACT determinations for similar plants.

[6] Because the MPCA found this to be the case, there was no need to analyze the projects under the third ground for qualification in section 216B.1692, subd. 1(3)(iii).

Table 2. Comparison of Emission Data, including New Source Performance Standards, recent New Source Review Limits, existing and proposed emission rates for Xcel A.S. King.[7]

	Capacity		NO_x	SO_2	PM_{10}
	MW	*mmbtu/hr*	*Lb/mmBtu*	*Lb/mmBtu*	*Lb/mmBtu*
Current King emissions	504	5,205	0.71	1.39	0.019
New Source Performance Standards[8]			0.60 [9]	1.2[10]	0.03[11]
Recent Best Available Control Technology determinations for coal-fired facilities[12]					
Range of recent BACT determinations			0.07-0.15	0.12-0.25	0.015-0.018
Median of BACT determinations			0.095	0.155	0.017
Emissions, King Rehabilitated (MERP)[13]	564	5,205	0.10	0.12	0.018

The proposed emission rates for the rehabilitation of the A.S. King plant reflect BACT-like control levels. BACT is more stringent than the applicable NSPS. Because the proposal

[7] Emissions data from RACT/BACT/LAER Clearinghouse and National Coal-Fired Utility Projects Spreadsheet. A compilation of information supplied by all 10 EPA Regions about new utility projects occurring in their geographic area, provided the data on new coal-fired generation. This spreadsheet was found on the RBLC Web site (www.epa.gov/ttn/catca/projects.html#rblcdocs).

[8] New Source Performance Standards in 40 CFR 60 Subpart Da (40 CFR 60.40b-60.49b).

[9] These limits apply to units that are modified or reconstructed units burning subbituminous coal. A modified coal-fired unit would need to reduce NO_x by 65 percent.

A new unit would be required to meet a 1.6 lb/MWh limit. (It is difficult to convert directly from this limit to lb/mmBtu because the unit's conversion efficiency – energy output/ energy input – must be known.)

[10] This NSPS also requires a reduction of 90% of potential SO_2, or a minimum reduction of 70 percent if controlled emissions are below 0.6 lb/mmBtu.

[11] The NSPS restricts emissions of PM (not PM_{10}) from natural gas boilers. The NSPS requires a 99 percent reduction of uncontrolled PM from coal-fired boilers.

[12] These BACT determinations were made for units burning coal. Modifications recorded in the RACT/BACT/LAER Clearinghouse from 1999 to 2002 were included in the analysis. Values for NO_x were based on coal-fired cyclone boilers, while the values for SO_2 and PM_{10} were based on boilers using subbituminous coal.

[13] Emissions rates identified in Xcel Response to MPCA Request No.1, dated August 23, 2002, and the Xcel Response to MPCA Request No. 2, dated September 5, 2002.

achieves BACT-like control levels for coal-fired cyclone boilers, the project qualifies under this requirement.

Summary

The A.S. King proposal meets all three conditions of Minn. Stat. § 216B.1692, subd. 1, and thus is a qualifying project under the statute.

3.2.2 High Bridge

Is it an existing large electric generating power plant as defined under Minn. Stat. § 216B.2421 subd. 2 that is located in the state and not subject to emission limitations for new power plants under the federal Clean Air Act?

The High Bridge plant is located between Shepard Road and the Mississippi River in downtown St. Paul. It has four boiler units, two dedicated to producing steam for a manufacturer and two for generating electricity.

The electricity generating units, units 5 and 6, were brought online in 1956 and 1959 respectively. Unit 5 has the electricity generating capacity of 85 MW and Unit 6 has a capacity of 158 MW, for a total generating capacity of 243 MW. Because the facility is greater than 50 MW, it is a large generating station. The facility was brought online before the Clean Air Act was passed and thus before EPA promulgated NSPS for boilers. It is therefore not subject to the NSPS standards for power boilers. The project meets this requirement.

Does it increase capacity by more than 10 percent or more than 100 MW?

The proposed project for this location is to retire and demolish the current coal-fired plant, stack and related coal-handling equipment, and replace the generating station with a "2-on-1" combined cycle natural gas facility capable of generating 515 MW. The project increases generating capacity by about 270 MW, which is greater than the 100 MW increased generating capacity expressly allowed by the statute. The first 100 MW of this increase meets the requirement of the statute. The remaining 170 MW is discussed in the summary for this section.

Does the project propose "best available control technology"?

Table 3 shows the current emission rates at the High Bridge plant and the emission rates that would result from Xcel's proposed emission reduction project with NSPS and BACT determinations for similar plants.

Table 3. Comparison of emission data, including New Source Performance Standards, recent New Source Review limits, existing and proposed emission rates for Xcel High Bridge.

	Capacity		NO_x	SO_2	PM_{10}
	MW	*mmbtu/hr*	*Lb/mmBtu*	*Lb/mmBtu*	*Lb/mmBtu*
High Bridge 5, coal	85.2	869	0.58	0.37	0.013
High Bridge 6, coal	158	1,611	0.58	0.37	0.013
New Source Performance Standards[14]			0.20 [15]	0.20	0.03[16]
Recent Best Available Control Technology determinations for natural gas-fired facilities[17]					
Range of Recent BACT determinations			0.009-0.055	0.0008-0.216	0.0076-0.048
Median of BACT determinations			0.013	0.006	0.013
Emissions, High Bridge Combined Cycle (MERP)[18,]	515	3,761	0.011	0	0

Emission rates for the proposed new natural gas combined cycle plant are comparable to BACT control levels established for similar units. BACT is more stringent than the applicable NSPS. Because the proposal achieves BACT-like control levels, the project meets this requirement.

In addition, the emissions for this proposed plant are substantially lower than the emissions required by current state and federal standards for new power plants (NSPS).

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[14] New Source Performance Standards in 40 CFR 60 Subpart Da (40 CFR 60.40b-60.49b).

[15] These limits apply to units that are modified or reconstructed units burning natural gas. A modified natural gas-fired unit would need to reduce NOx by 25 percent.

A new unit would be required to meet a 1.6 lb/MWh limit. (It is difficult to convert directly from this limit to lb/mmBtu because the unit's conversion efficiency — energy output/ energy input — must be known.)

[16] The NSPS restricts emissions of PM (not PM_{10}) from natural gas boilers.

[17] These BACT determinations were made for combined cycle units burning natural gas. Modifications recorded in the RACT/BACT/LAER Clearinghouse in 2001 to 2002 were included in the analysis.

[18] Emissions rates identified in Xcel Response to MPCA Request No.1, dated August 23, 2002, and the Xcel Response to MPCA Request No. 2, dated September 5, 2002.

Xcel has represented emissions of SO_2 and PM_{10} from gas-fired facilities as zero. It must be recognized that while not precisely zero, direct emissions of these pollutants will be extremely small.

Summary

The High Bridge proposal meets all three conditions of Minn. Stat. § 216B.1692, subd. 1, except that the capacity of the plant would increase by approximately 270 MW, more than the 100 MW maximum allowed for projects to qualify under the statute. The MPCA concludes that the proposed emission reduction project up to the first 100 MW of the capacity increase fully qualifies.

The treatment of the cost of the remaining 170 MW of new capacity could be handled as an allowed "recovery above cost" if the PUC determines that it is appropriate to allow this recovery as "necessary to improve the overall economics of the qualifying project to ensure implementation under Minn. Stat. § 216B.1692, subd. 5(b)(4)." To the extent that the additional 170 MW of capacity is needed to improve the overall economics of the project, thus encouraging its voluntary implementation by Xcel, then costs of that additional capacity may also qualify for rate recovery.

3.2.3 Riverside

Is it an existing large electric generating power plant as defined under Minn. Stat. § 216B.2421 subd. 2 that is located in the state and not subject to emission limitations for new power plants under the federal Clean Air Act?

The Riverside Plant is located on the east bank of the Mississippi River north of downtown Minneapolis. It has three power boilers.

Boilers 6 and 7 were initially constructed in 1946 and 1948 respectively. Together, these two boilers generate steam for one steam turbine. Boiler 8, first installed in 1961, has a separate steam turbine.

Due to the dates of construction, these units were not initially subject to either NSPS or NSR regulations because they were built before the Clean Air Act was passed. A physical change was made to the facility in the 1980s, but EPA determined that the change did not trigger NSPS.

The plant's capacity exceeds 50 MW so it is an existing large electricity generating plant.

Does it increase capacity by more than 10 percent or more than 100 MW?

The proposed project involves the repowering of the Riverside plant. While the existing Unit 7 steam turbine and condenser will continue to be used, Xcel plans to install a natural gas-fired "2-on-1" combined cycle turbine arrangement. This will replace existing coal-fired boilers 6 and 7. Portions of the existing plant will be demolished.

The repowering of the plant will expand the generating capacity of the Riverside plant to 439 MW from its existing capacity of 386 MW. While the increase of 53 MW exceeds 10 percent of the facility's existing capacity, it remains below the limit of 100 MW (the maximum increase allowed under the statute), and thus meets this requirement.

Does the project propose "best available control technology"?

Table 4 shows the current emission rates at the Riverside plant and the emission rates that would result from Xcel's proposed emission reduction project with NSPS and BACT determinations for similar plants.

Table 4. Comparison of Emission Data, including New Source Performance Standards, recent New Source Review Limits, existing and proposed emission rates for Xcel Riverside.

	Capacity		NO_x	SO_2	PM_{10}
	MW	*mmbtu/hr*	*Lb/mmBtu*	*Lb/mmBtu*	*Lb/mmBtu*
Riverside 6/7	134	1,371	0.83	0.38	0.013
Riverside 8	226	2,233	0.99	1.26	0.078
New Source Performance Standards[19]			0.20 [20]	0.20	0.03[21]
Recent Best Available Control Technology determinations for natural gas-fired facilities[22]					
Range of Recent BACT determinations			0.009-0.055	0.0008-0.216	0.0076-0.048
Median of BACT determinations			0.013	0.006	0.013
Emissions, Riverside Combined Cycle (MERP)[23]	439	3,538	0.015	0	0

[19] New Source Performance Standards in 40 CFR 60 Subpart Da (40 CFR 60.40b-60.49b).

[20] These limits apply to units that are modified or reconstructed units burning natural gas. A modified natural gas-fired unit would need to reduce NO_x by 25 percent.

A new unit would be required to meet a 1.6 lb/MWh limit. (It is difficult to convert directly from this limit to lb/mmBtu because the unit's conversion efficiency — energy output/ energy input — must be known.)

[21] The NSPS restricts emissions of PM (not PM_{10}) from natural gas boilers.

[22] These BACT determinations were made for combined cycle units burning natural gas. Modifications recorded in the RACT/BACT/LAER Clearinghouse in 2001 to 2002 were included in the analysis.

[23] Emissions rates identified in Xcel Response to MPCA Request No.1, dated August 23, 2002, and the Xcel Response to MPCA Request No. 2, dated September 5, 2002.

As mentioned previously, Xcel has represented emissions of SO_2 and PM_{10} from gas-fired facilities as zero. It must be recognized that while not precisely zero, direct emissions of these pollutants will be extremely small.

It is reasonable to expect a slightly higher emission rate at the Riverside plant than at High Bridge because the project involves integrating new combustion and air pollution control equipment into an existing site with existing generation equipment. In particular, had this proposal been an entirely new plant (like the High Bridge plant), then the NO_x emissions rate might have been expected to be slightly lower.

However, the proposed NO_x emissions rate appears to be well within the range at which new combined cycle facilities that install BACT are expected to perform. Thus the proposal achieves a level of control reflecting the application of BACT and exceeds the applicable NSPS. Because the proposal achieves BACT, the project meets this requirement.

Summary

The Riverside proposal meets all the conditions of Minn. Stat. § 216B.1692, subd. 1, thus is a qualifying project under the statute.

4.0 Other Questions the PUC Must Consider

Minn. Stat. § 216B.1692, Subd. 5 requires the PUC to evaluate whether:

1. the emission reduction project is needed to comply with new state or federal air quality standards; or

2. the emission reduction project is required as a corrective action as part of any state or federal enforcement action.

The MPCA has evaluated both of these questions and has concluded the following:

1. None of the proposed projects are currently needed to meet any new state or federal air quality standards.

   These three plants do not have to meet any performance standards for new sources because they were built before the Clean Air Act passed and EPA had developed specific performance standards. (Also see the discussion regarding this in Section 6.) In addition, through ambient monitoring and/or dispersion modeling, the MPCA has determined that these projects are not required to meet any ambient air quality standards. Although there are several potential regulatory developments that may impose more limits on these plants, none are yet in effect.[24]

2. None of the proposed projects are currently required as a corrective action as part of any state or federal enforcement action.

   A potential enforcement action involves changes to the King plant's coal handling equipment that the MPCA believes may have been made without first obtaining a required permit. EPA, at Xcel's request, is deciding whether it agrees with the MPCA's interpretation of the federal requirement at issue.

   If EPA agrees that Xcel is subject to the federal standard, and thus should have obtained a permit before making changes, possible corrective actions would not involve the proposed projects. Xcel has already installed a dust collector as the pollution control equipment to reduce PM/PM_{10} from coal handling, and has conducted a monitoring analysis of the ambient air. Any further corrective action requirements would not include the proposed projects because they would affect coal handling, not the operation of, or emissions from, the boiler.

   On December 21, 2000 and May 6, 2002, EPA issued formal requests for information to Xcel regarding changes to several of its plants, including High Bridge, King and Riverside. Xcel completed their responses to these requests on May 4, 2001 and

[24] For a description of these potential developments, see Appendix A of the 2001 Energy Planning Report, pp. 103-105 (Attachment 2). Also see p. 2 of the 2002 update to that report. (Attachment 3)

October 28, 2002, respectively. EPA is in the process of deciding what, if any, enforcement action may occur based on the information provided by Xcel.

There has not been a state or federal enforcement action concluded against Xcel that requires as its corrective action any of the proposed projects.

5.0 Estimated Capital Cost of the Proposal

The MPCA analyzed the cost of the proposed project to determine whether the estimated costs are reasonable because they will end up being compared with the estimated benefits of the project. The MPCA has reviewed the construction costs of the proposals to determine whether they are within an expected reasonable range of costs.

The MPCA's experience in assessing the cost of projects has developed from its reviews of cost estimates of emission units and air pollution control equipment when assessing economic impacts of air pollution control policies and rules, and specifically from its experience reviewing and approving "best available control technology" (BACT) determinations used for air permitting.

5.1 Method of analysis

The MPCA compared Xcel's estimates of construction cost to estimates provided for similar-size plants using similar electrical generating technologies. In general, comparisons between generating choices are expressed as the capital cost for each kilowatt of capacity.

In order to determine whether the budgetary costs presented in the filing were within an expected reasonable range of cost, the MPCA sought out estimating tools or costs of actual projects of similar size and scope. Thus, a variety of cost estimates are used, and their accuracy is discussed when they are presented.

The MPCA recognizes that Xcel has provided a budgetary estimate, which will likely be refined by Xcel as specific site-assessment, design and procurement activities occur. The MPCA's understanding of budgetary estimates is that they are prepared to be within 30 percent of the final cost of the project, that is, final project costs may be 30 percent higher or lower than the budgetary estimate.

Xcel proposes a cost-recovery process that allows the PUC to review actual costs during construction, which is appropriate. The MPCA is at this point considering the budgetary estimates to compare them against expected environmental benefits of the project.

5.2 Assessment of A.S. King Cost Estimates

This project is a rehabilitation of an existing facility. The rehabilitation will improve combustion and generating efficiencies. No additional coal will be burned yet an additional 60 MW of generating capacity will be regained. The air pollution control aspect of this project includes the removal of existing electrostatic precipitators to install selective catalytic reduction (SCR) for NO_x control, and spray drying and fabric filters for acid gas and particulate control (SD/FF). Emission reductions were quantified earlier.

Xcel's cost estimates are based on their description of project costs in their response to Sierra Club's information request number 10. In that response, Xcel reports that the air quality portion is 55 percent of the total project cost.

The first set of cost information available to compare to Xcel's estimates comes from actual retrofits of flue gas desulfurization controls and NO_x controls at power plants. Retrofitting this equipment has been a common activity for power plants because of the acid rain control provisions required by the 1990 CAA amendments, as well as EPA's NO_x State Implementation Plan call for NO_x emissions reductions in the eastern United States in 1998.[25] The MPCA identified separate sources for estimating the cost of retrofitting with SCR and SD/FF. Costs reflecting average national capital costs were developed by EPA and are included in several reports that the U.S. Department of Energy's Energy Information Administration (EIA) prepared to assess the impacts of multi-pollutant control strategies (EPA 1998, EPA 1999a, EIA 2000).

EIA reports that the national average cost of adding flue gas desulfurization is about \$195/kW in 1997 dollars, or about \$215/kW in 2001 dollars. NO_x controls, specifically SCR for high NO_x emitters has a capital cost of about \$71/kW in 1997 dollars, or \$78/kW in 2001 dollars. (EIA 2000) To estimate the cost of retrofitting a fabric filter, the MPCA used cost estimating guidelines prepared by EPA, as this retrofit has not been commonly undertaken by power plants (EPA 1999a). The cost of retrofitting an FF for a 570 MW plant is currently estimated to be about \$69/kW.

Another source of cost estimating information is EPA's CUECost. CUECost is an electronic cost-calculating workbook that provides a means for air quality permitting authorities to estimate expected construction and operating costs of air pollution control equipment at power plants. The workbook has been used by permitting authorities and consultants in the preparation of BACT analyses, and allows the user to input site-specific design requirements of the proposed equipment.

The CUECost workbook was designed to produce "rough" cost estimates (+/-30 percent). In testing the model, the developers found that the model predicted estimated SD/FF construction costs within +/- 15 percent of the published capital costs of various power plant projects (Keeth). In order to ensure a conservative cost estimate, the MPCA selected input options that included burning Wyoming and Montana coals, difficult reconstruction (retrofit factors), with expected inflation of three percent per year.

CUECost estimates a total capital cost for an air pollution control retrofit on a 570 MW boiler to cost about \$210 million dollars, or about \$368/kW.

These estimated capital costs are compared in Table 5.

[25] The EPA has issued a requirement for dozens of states east of the Mississippi to substantially reduce NO_x emissions. These emissions, when transported to cities long distances away, contribute to the formation of ozone at levels that would exceed health-based air quality standards. Many power plants subject to this requirement have needed to retrofit NO_x controls to make the reductions expected of them.

Table 5. Comparison of capital cost estimates for A.S. King

	Size (MW)	2001 total project construction costs (in millions)	Installed Cost per kW generating capacity ($/kW)
Xcel's estimate — A.S. King, total capital cost	564	363	637
Rehabilitate boiler, turbine/generator		163	287
Total Air Pollution control cost		200	350
NO_x control (SCR)[26]		92	161
Acid gas control (SD/PJFF)[26]		108	189
Energy Information Agency 2001/EPA 1999a/EPA 1998 Total Cost of Air Pollution Control Retrofit (sum of individual estimates below)			362
NO_x control (SCR)			78
Acid gas control (LSD)			215
Particulate control (FF)			69
EPA CUECost Workbook Adding SCR/PJFF/LSD Total Cost of Air Pollution Control Retrofit	570	210	368
NO_x control (SCR)			85
Acid gas control (LSD)			185
Particulate Control (PJFF)			101

Table 5 reports the estimated costs to retrofit the A.S. King plant with pollution control equipment as compared to retrofit cost estimates from EIA and EPA. The table reports both the total air pollution control costs and separately reports costs to control NO_x and SO_2 (acid gas control/flue gas desulfurization).

Table 5 shows that the total air pollution control retrofit cost estimates for A.S. King is slightly lower than the total project costs estimated by CUECost and than national averages. The individual component costs are, however, significantly different. Xcel reports that SCR vendors' quotes have been much higher than is suggested by the national databases used to prepare the cost estimates in Table 5, due in part to the higher demand for SCR controls at utilities in the eastern United States. Unlike spray drying, SCR is not a "fully-matured" technology; it has not been installed and used over long periods of time where there are no real incremental

[26] SCR = selective catalytic reduction; PJFF = pulse jet fabric filter; LSD = lime spray drying; SD = spray drying

improvements in design and operation being made. Each recent installation still offers some instruction to equipment designers and utility operators for future improvements, and now-higher vendor quotes may reflect this. Xcel indicates that installing SCR will require sophisticated foundation and structural work at the King plant, which also may translate to a higher-than-average cost for this control device.

Spray drying and fabric filter estimates for A.S. King are lower than national estimates, due to it being a fully mature technology. Xcel reports receiving vendors' estimates that would manufacture and install both the spray drying and fabric filter components together, which leads to lower than average costs. Using a single equipment supplier to provide multiple units lowers the cost by eliminating the need for coordination and tie-in between two different manufacturers.

Xcel's capital cost estimates for the air pollution control equipment retrofit at A.S. King are within an expected reasonable range of cost. The project's expected cost is consistent with the capital costs experienced by the industry for this type of project.

5.3 Assessment of High Bridge Estimated Costs

The scope of this project requires the construction of combined cycle/steam generators and transmission capacity, and demolition of the existing four boilers.

Air pollution control benefits result from changing the fuel choice and combustion technology. Because changing combustion technology inherently results in pollution reductions, it is difficult to separate project costs between electricity generation and air pollution control, as was done at A.S. King.

To evaluate estimated construction costs, the MPCA sought out estimates for new advanced cycle combustion turbines, as this proposal is more in keeping with new plant construction.

Table 6. Comparison of capital cost estimates for High Bridge

	Size (MW)	2001 total project construction costs (in millions)	Installed cost per kW generating capacity ($/kW)
High Bridge, Xcel, advanced combustion combined cycle	515	$371	720
Energy Information Agency Outlook 2002, advanced combustion combined cycle[27]			607

No advanced combined-cycle project has been installed in Minnesota that allows direct comparison. The MPCA identified two natural gas-fired simple cycle turbine projects constructed in Minnesota of similar size to the High Bridge proposal. The PUC gave approval in 1999 and 2000 to construct two generating stations: Lakefield Junction and Pleasant Valley.

The Lakefield Junction project involved construction of a turbine/generation facility producing 515 MW. The project also included upgrading existing power lines, but no construction of new lines. The total cost of the project was $216 million.

The Pleasant Valley project included construction of a facility with a generating capacity of 434 MW. The project also involved constructing six miles of 161 kV transmission lines, and rebuilding approximately 17 miles of existing 69kV lines to 161/69 kV. The total cost of the project was $195 million.

These two plants are simple cycle peaking plants with a planned utilization rate of about five percent. They are technologically more simple and operate much less often than the intermediate-load plant proposed for High Bridge, and as such, are significantly less expensive to construct. As a result, they are not comparable to the High Bridge proposal.

The MPCA reviewed EIA's projected construction cost for the simple-cycle generating station to determine how accurate an approximation the EIA values are to costs experienced in Minnesota. Adjusting for inflation, the Lakefield Junction project was within 12 percent of the installed cost estimated by EIA (EIA 2002). Because the Pleasant Valley construction cost includes transmission lines, it is not a direct comparison to EIA costs. However, its construction cost is about 30 percent higher than EIA's estimates.

[27] EIA cost estimates include contingencies as suggested by EIA. The cost estimate has also been inflated by 2.5 percent per year.

EIA predicts new "greenfield" advanced combustion combined cycle generating stations to have an installed cost of about $607/kW.[28] This is down slightly from the EIA 1999 Energy Outlook where the installed cost of combined cycle stations averaged $641/kW. This decrease may suggest that as this type of electric generation is more widely deployed, its development costs may be falling[29].

The High Bridge project budgetary estimate appears to be about 20 percent higher than the average national cost for installing advance combustion combined cycle generating stations as reported by EIA ($720/kW for High Bridge compared to $607/kW from EIA). Xcel suggests that the difference in its construction estimates and the EIA cost estimates is due to the difference between greenfield construction and reconstruction at an existing power plant site. Xcel has included a certain number of cost factors that relate to expecting "unforeseen" site conditions.

Redevelopment of previously developed sites — "brownfield" construction — often requires some unique work to conform the site to its new use or to fit the new use on to the site. Some of the site-specific costs that may cause Xcel's cost estimate to be higher than average national costs include: the need for an extra cooling tower to eliminate steam and icing problems; site remediation; connection to gas infrastructure; and costs to tear down the existing plant.

5.4 Assessment of Riverside Estimated Costs

This project converts the coal-fired plant to natural gas — the existing steam generating equipment in use on Unit 7 will be retained. Air pollution control benefits occur from the change in fuel type. It is difficult to compare this project cost to retrofitting air pollution control equipment, or the construction of a new greenfield plant. Cost estimating tools like CUECost are not able to estimate the cost of converting combustion systems from coal to gas. Therefore, the MPCA compares the cost of this project to that of a similar completed project here in Minnesota, the repowering of the NSP Black Dog Plant in Burnsville.

Table 7. Comparison of Estimated Capital Costs for Riverside

	Size (MW)	2001 total project construction costs (in millions)	Installed Cost per kW generating capacity ($/kW)
Xcel Riverside	439	212	483
Xcel Black Dog Repower	290	164	565

The Riverside station has a current generating capacity of 387 MW; the proposed project results in the addition of about 52 MW of additional generating power, an increase of about 14 percent. The Black Dog repowering project added 114 MW, or a 63 percent increase in the generating capacity of the replaced units. The Black Dog repowering added considerably more generating

[28] "Greenfield" means construction at an undeveloped site (literally, building a plant in the middle of a "green field").

[29] We also note that while not a definitive cost study, a recent trade journal also reports installed costs of simple cycle turbine/generators in the "neighborhood" of $375/kW, and combined cycle stations to be around $600/kW. Power, August 2002. "Top Plants Survey" available at www.platts.com/engineering/issues/Power/0208/index0208.shtml

capacity than the Riverside repowering (114 MW v. 53 MW). The PUC approved the Black Dog project's Certificate of Need on July 21, 2000. The Riverside project cost appears to fall within the range of a similar project already approved by the PUC.

5.5 Summary
Construction costs for the A.S. King rehabilitation and the Riverside project fall within a reasonable range as defined by similar projects either nationally or within Minnesota.

The cost of reconstructing High Bridge appears to be about 20 percent higher than national figures for new greenfield plants, probably due to some unique site characteristics that need to be addressed for reconstruction on the existing power plant site. Xcel has explained several reasons for the higher costs associated with its work on the High Bridge project. The MPCA suggests that the PUC further explore the appropriateness of the portion of the High Bridge project costs that exceed the national average to assure that these costs are appropriate for the site's conditions.

6.0 Impacts of Power Plant Emissions

6.1 Contribution of Power Plants to Air Pollution in Minnesota

Electrical utility power plants are a major source of air pollution. In Minnesota, power plants contribute about 50 percent of total sulfur dioxide (SO_2) emissions, 16 percent of total nitrogen oxides (NO_X) emissions, 35 percent of carbon dioxide (CO_2, a greenhouse gas), 43 percent of mercury emissions and between 10 and 60 percent of other metals emissions.

Power plants are also a large contributor to fine particulate levels ($PM_{2.5}$) in Minnesota's air. The emissions of SO_2 and NO_x are converted through atmospheric reactions to create fine particulate. Power plants also directly emit particles, regulated as "PM_{10}," that is, particles with a diameter of 10 microns and less.

A detailed analysis of the emissions from Minnesota's power plants can be found on pages 93 – 98 of Attachment 2 (the environmental analysis from the 2001 Energy Planning Report).

Table 8 and Figures 1 – 5 show the contribution of the three Xcel power plants that were selected for emission reduction projects to total statewide emissions of these pollutants.

Table 8. Quantity of emissions of selected pollutants from Minnesota sources, 2000[30]

	SO_2 tpy	NO_X tpy	PM_{10} tpy	Mercury lb/yr	CO_2 tpy
A.S. King	27,251	14,354	307	69	3,763,594
High Bridge	3,459	5,397	430	66	1,839,005
Riverside	12,794	13,102	535	98	2,750,201
Total MERP Plants	43,504	32,853	1,272	233	8,352,800
Other point sources	91,209	133,741	50,901	2817	36,596,606
Area and mobile sources	54,922	366,259	841,920	593	64,160,115
Minnesota total	189,636	532,853	894,093	3,643	109,109,521

From the table above and from Figure 1 on the next page, it can be seen that the SO_2 emissions from the three Xcel plants (A.S. King, High Bridge and Riverside) contribute almost half of

30 Emissions of sulfur dioxide, nitrogen oxides, and particulate matter taken from the MPCA's Emission Inventory and the National Emission Inventory. Mercury emission data taken from Mercury Emissions in Minnesota – Draft: 2002 Update (MPCA). Carbon dioxide emission data were provided in a personal communication with Peter Ciborowski, MPCA.

Minnesota's estimated point source emissions or about one-fourth of the state's estimated total SO_2 emissions.[31]

Figure 1. Minnesota sulfur dioxide emissions, 2000 (total =189,636 tons)

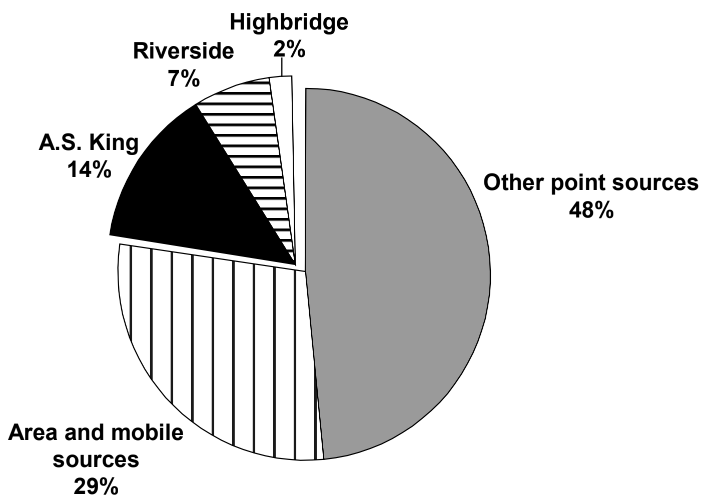
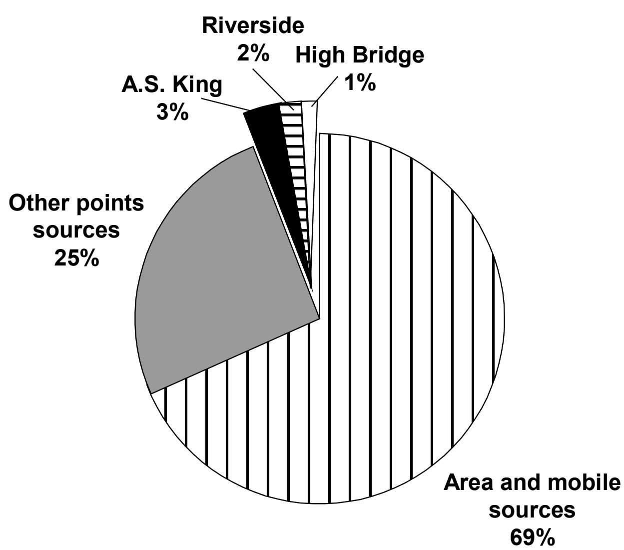


Figure 2 illustrates the relationship between the NO_X emissions from the three plants and those from other state sources. These power plants total about 20 percent of the point source emissions in the state or roughly six percent of NO_X generated in the state.

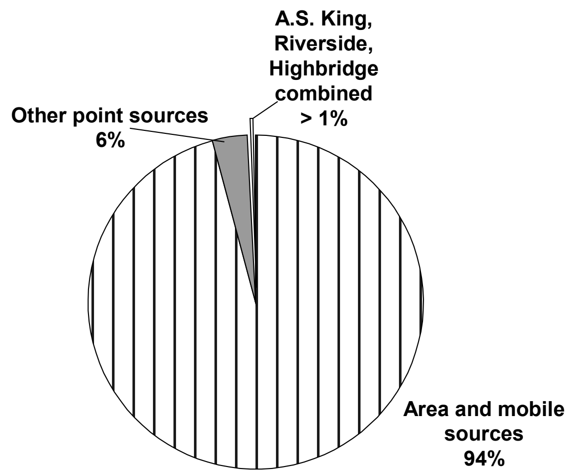
Figure 2. Minnesota nitrogen oxide emissions, 2000 (total = 532,853 tons)



[31] "Point sources" are facilities, such as power plants and large factories, that emit air pollution from a smokestack from a fixed location.

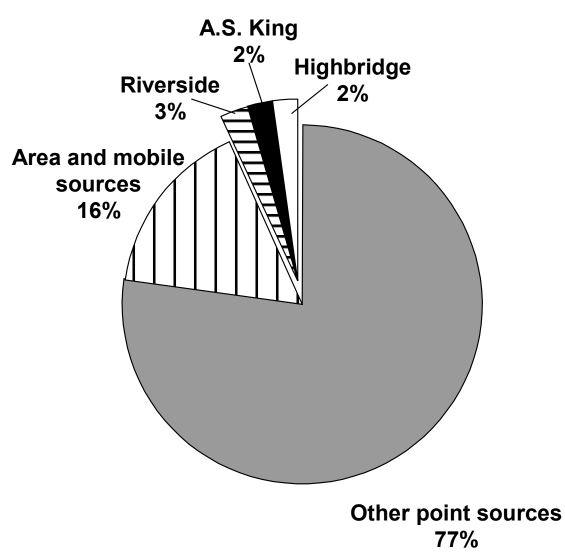
Figure 3 shows that these three metro area plants emit a very small portion of statewide PM_{10} emissions. While these plants are not large direct contributors to PM_{10}, Figures 1 and 2 show that they are significant contributors to SO2 and NOx emissions which once emitted, are the precursors of $PM_{2.5}$ formation.

Figure 3. Minnesota particulate matter emissions, 2000 (total = 894,093 tons)



Figures 4 and 5 demonstrate that these three metro area power plants emit small but significant portions of the statewide emissions of mercury and CO_2. Point sources emit a very large portion of the state's mercury emissions. As shown in Figure 4, more than four of every five pounds of mercury are emitted from point sources. Energy production overall contributes about one-half of the mercury released in Minnesota. About one in 16 pounds of mercury released in the state comes from one of these three power plants.[32]

Figure 4. Minnesota mercury emissions, 2000 (total = 3,643 pounds)

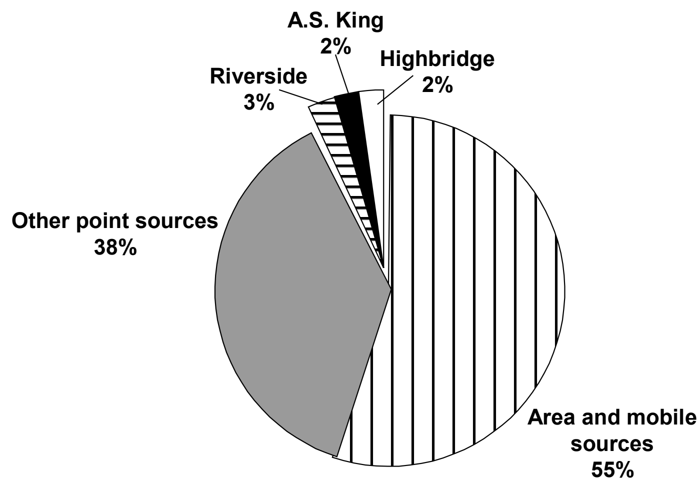


[32] For more information about mercury emissions in Minnesota and related impacts, see the MPCA's 2002 Mercury Reduction Program legislative report at www.pca.state.mn.us/hot/legislature/reports/2002/mercury-02.pdf.

Table 8 and Figure 5 provide the picture for CO_2, the primary greenhouse gas. Here, as with NO_X and SO_2, power plants in general and, specifically, these three power plants produce a significant share of the total emissions.

Together, the three plants share about seven percent of the state's total CO_2 emissions. Since point sources make up just under half of the state's emissions, these plants contribute about 15 percent of the point source emissions.

Figure 5. Minnesota carbon dioxide emissions, 2000 (total = 109,109,521 tons)



6.2 Environmental and Health Effects of Emissions from Power Plants

As described above, power plants contribute substantial amounts of pollutants to Minnesota's atmosphere. A variety of health and environmental effects have been linked to these pollutants. This section briefly summarizes these impacts.[33]

The Department of Commerce's 2001 Minnesota Energy Planning Report[34] contained a section on the health and environmental effects of electricity generation, which is Attachment 2 (pp. 98-103) of this report. Attachment 3 to this report, pp. 1-2, contains the 2002 update on effects of these emissions. This following section will briefly describe the most significant effects of power plant emissions and not duplicate the material in Attachments 2 and 3.

[33] Additional information about air pollution emissions can be found in the MPCA's 2001 Legislative Report *Air Quality in Minnesota: Problems and Approaches,* available on the MPCA Web site at www.pca.state.mn.us/hot/legislature/reports/2001/airquality.html.

[34] The full report is available at www.commerce.state.mn.us/pages/EnergyPolicy/2002PlanningRpt.pdf.

6.2.1 Particulate matter

Of particular concern today is the contribution of power plants to the amount of very small particles (or fine particulate matter, $PM_{2.5}$) found in the air. This concern has developed as a result of the increasing number of studies describing the adverse effects of very small particles on the respiratory and cardiovascular systems. Ambient air monitoring has shown that much of the fine particulate matter comes from nitrates and sulfates. This section describes what particulate matter is, how it is formed and its effects on human health.

With the passage of the 1970 Clean Air Act, Congress directed EPA to review the evidence for health and environmental effects of the well-known air pollutants, including particulate matter (PM). Congress instructed EPA to develop National Ambient Air Quality Standards (NAAQS) for their control. Through the establishment of NAAQS and efforts to achieve them, air pollutant levels decreased. Many people at that time believed the particulate matter air pollution problem was solved.

In the past 10 or 15 years, however, the availability of sophisticated statistical software, medical records databases and more extensive air pollution trend data has allowed new and better health science (epidemiology) studies. A remarkable number of studies consistently find a range of serious and other health impacts associated with levels of particulate in the ambient air lower than previously thought to have these effects.

While total ambient PM concentration levels have dropped, recent evidence shows that the size of the particle has health consequences. To help characterize the health effects, particles are described as falling into two sizes. The larger group of particles is identified as “coarse,” which has a diameter ranging from 2.5 to 10 microns (PM_{10}). “Fine” particles are those smaller than 2.5 microns ($PM_{2.5}$). The characteristics, sources and health effects of these two sizes of particulate matter are different.

Coarse particles from unpaved roads may become airborne when “kicked up” by vehicle traffic. Rock crushing operations generate coarse particles, as does the wind when it blows across the desert or agricultural fields. The particulate emissions from such sources can often be tracked by their plumes. These particles settle rapidly to the ground from the atmosphere, and so their impacts to health and environment occur fairly close to the source. Coarse particles tend to be caught by some of the body’s defense mechanisms, including the nasal passages and mucus membranes, and are often removed by regular body processes before embedding in the lungs.

In contrast, fine particles are invisible to the eye, deeply inhaled and not easily cleared by the lungs. Major sources are cars, trucks, construction equipment, coal-fired power plants, wood burning, vegetation and livestock. These particles can be directly released when coal, gasoline, diesel fuels and wood are burned.

Many fine particles are also formed in the atmosphere from chemical reactions of nitrogen oxides, sulfur oxides, organic compounds and ammonia. The reaction process occurs over great distances as the gases released from power plant stacks and other sources disperse in the air. Once airborne, fine particles tend to remain in the atmosphere for long periods of time (days to weeks) and travel hundreds to thousands of kilometers. This results in air impacts on local and regional scales.

Exposure to coarse particles is associated primarily with aggravating respiratory conditions, such as asthma. Fine particles are associated with a range of adverse health effects such as coughing; shortness of breath; aggravation of existing respiratory conditions like asthma and chronic bronchitis; increased susceptibility to respiratory infections; and heightened risk of premature death from heart attacks and respiratory conditions. As an example, two landmark epidemiology studies provided strong evidence that long-term exposures to fine particles caused increased early deaths from cardiopulmonary causes in the United States (Dockery et al. 1993; Pope et al. 1995; Krewski, 2000; Pope et al. 2002).

Hundreds of epidemiology studies have assessed the health effects evident within a few days after spikes of particulate concentrations, that is, "acute" or short-term exposures. Commonly these studies link daily fine particulate levels not only to increases in death rates, but to increased hospital admissions for cardiovascular disease, pneumonia, and chronic obstructive pulmonary disease.

Further, with improved research methods, health scientists have studied areas with lower levels of air pollution and have been unable to identify a threshold (a level below which no effect occurs) for some of the more serious health effects of particulate matter. So far, no threshold has been found at ambient levels (Schwartz et. al 2002).

6.2.2 EPA Response

The Clean Air Act requires EPA to review the scientific evidence and revise ambient air standards "from time to time" to accurately reflect the latest scientific knowledge about identifiable health effects. EPA undertook rulemaking in July 1997 to revise the ambient air quality standards in part to address the findings of the serious health impacts of long-term exposure to $PM_{2.5}$. Subsequently, EPA established an ambient air quality standard for these fine particles.

EPA retained the existing PM_{10} standard to continue to address the health effects from PM larger than 2.5 microns. EPA also issued new rules related to monitoring for $PM_{2.5}$ in the outdoor air.

Section 109 of the Clean Air Act directed EPA to set the ambient air quality standard such that the

> …level of air quality, in the judgment of the [EPA] Administrator, based on the criteria and allowing for an adequate margin of safety are requisite to protect public health. Clean Air Act, Sec. 109 (b)(1).

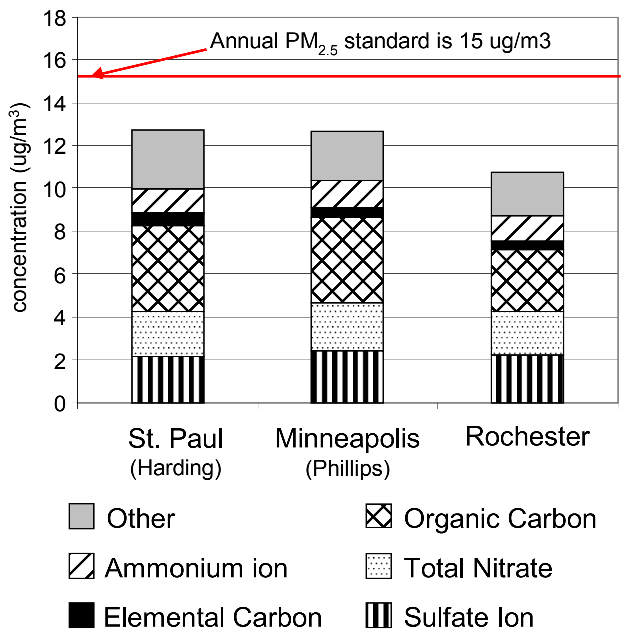
This language has been commonly assumed to imply that for these pollutants there are thresholds, levels below which there would not be adverse biological effects. Because of the inability to set a standard below which there would be no health effects, EPA chose to set a $PM_{2.5}$ NAAQS, and then required regulatory agencies to announce health advisories to the public when monitored $PM_{2.5}$ concentrations reach levels somewhat lower than the standard. EPA set an annual $PM_{2.5}$ ambient standard of 15 μg/m^3 and a 24-hour standard of 65 μg/m^3.[35] EPA requires the MPCA to announce an unhealthy air pollution alert when the 24-hour $PM_{2.5}$ concentration exceeds 40.5 μg/m^3.

6.2.3 $PM_{2.5}$ in Minnesota

$PM_{2.5}$ has been measured in Minnesota for about three years to determine whether Minnesota attains the NAAQS. The Twin Cities' $PM_{2.5}$ concentration in 2001 was 13 μg/m^3. Rural areas are lower. The Twin Cities' concentration is at the midrange of the U.S. metropolitan areas being monitored for compliance with the federal ambient air standard.

$PM_{2.5}$ is composed of many chemicals. When analyzing composition, the mass is classified as sulfates, nitrates, organic carbon, elemental carbon, ammonium ions, and other material, including metals and crustal material. Minnesota has three urban monitors measuring the composition of $PM_{2.5}$ which have been operating for about a year. Results of this monitoring are shown in Figure 6.

Figure 6. $PM_{2.5}$ composition in Minnesota (Sept. 2001 – Oct. 2002)



Power plants contribute significantly to several of the different fractions of $PM_{2.5}$. Coal-fired power plants are significant contributors to the sulfate component of $PM_{2.5}$ due to the total amount of SO_2 released from power plant stacks. To a lesser extent, they contribute a smaller fraction to the nitrate component due to their NO_x emissions.

[35] On Feb. 27, 2001, the U.S. Supreme Court unanimously upheld the constitutionality of the Clean Air Act as EPA had interpreted it in setting these health-protective air quality standards. On March 26, 2002, the U.S. Circuit Court rejected the remaining claims that EPA's decision was arbitrary and capricious and not supported by the evidence.

6.2.4 Air Alerts for Particulate Matter in the Twin Cities

EPA's Clean Air Science Advisory Committee recognized there may not be a risk-free threshold of $PM_{2.5}$ and concluded there may be a continuum of effects potentially extending down to background levels (64 Federal Register 42530-42549, Aug. 4, 1999). As ambient concentrations increase, more individuals are likely to experience effects, and the seriousness of health effects increases. Minnesotans are likely suffering effects from current levels of $PM_{2.5}$.

While this region meets the 24-hour $PM_{2.5}$ ambient standard of 65 $\mu g/m^3$ and the annual standard of 15 $\mu g/m^3$, the MPCA has had to issue air alerts when $PM_{2.5}$ levels reach 40.5 $\mu g/m^3$. EPA has specified 40.5 $\mu g/m^3$ for these warnings because research has shown that serious health effects can occur at levels below the federal NAAQS. The $PM_{2.5}$ air alert level was required to be reported for the first time in 2002.

One alert for fine particles was issued in 2002 when smoke from the Canadian fires reached Minnesota. More recently, in December 2002, an air alert for $PM_{2.5}$ was issued due to a temperature inversion that trapped fine particles near ground level.

In addition, a review of available $PM_{2.5}$ data indicates that concentrations in the Twin Cities reached levels considered "Unhealthy for Sensitive Groups" (children and the elderly) on seven days during calendar year 2000 and on four days during calendar year 2001, had $PM_{2.5}$ air alerts been required in those years. One $PM_{2.5}$ event considered "unhealthy" for all groups was monitored in October 2000 in Minneapolis. Monitoring data shows that unhealthy levels of $PM_{2.5}$ can occur throughout the year in Minnesota.

6.2.5 Ozone

Ground level ozone, also called "smog" forms in the atmosphere through chemical reactions involving NO_X, volatile organic chemicals and sunlight. In Minnesota, ozone pollution is primarily a summer problem because of the need for sunlight in the formation process.

Ozone can adversely affect healthy adults, however children — because of their continuing physical development — and people with existing respiratory problems are far more susceptible to its presence. Higher ozone levels can cause eyes to itch, burn and water, trigger asthma attacks, and prompt coughing, chest pains and difficult breathing. Because they generate large emissions of NO_X, power plants are a significant contributor to ozone.

6.2.6 Air Alerts for Ozone in the Twin Cities

EPA promulgated a new, more restrictive ozone standard in 1997. Currently, that standard is being met in Minnesota. However in the last two years, the MPCA has had to issue air alerts for ozone four times in 2001 and twice in 2002. These represent the first air pollution alerts that have been issued for ozone since the 1970s.

A recent study has determined that ozone levels appear to be increasing the Twin Cities. (Chinkin et al. 2002) If this trend continues and the Twin Cities becomes a nonattainment area for ozone, new federal regulations costing between $189 and $266 million per year would be required (Aulich and Neuson 1999). Requirements would include significant new restrictions on allowable emissions from point sources and significant air quality requirements for transportation planning in the metropolitan area.

6.2.7 Haze

High concentrations of fine particles reduces visibility. While haze may affect people at home and at work, impaired visibility is of greatest importance in places like national parks and wilderness areas, which people visit to enjoy recreational opportunities. However, they sometimes find scenic vistas obscured due to fine particles in the air. The difference in visibility between higher and lower pollution levels is shown in Figure A.14 in Attachment 2.

To address this, EPA promulgated a rule in 1999 that requires states to develop plans to return visibility in parks and wilderness areas to "natural conditions" by mid-century. Controlling power plant emissions will be necessary to reduce the fine particles causing impaired visibility. In Minnesota, plans to reduce haze in Voyageurs National Park and the Boundary Waters Canoe Area must be developed by 2008. The MPCA is working with nine other states to prepare a regional plan to reduce haze.

6.2.8 Global Climate Change

Global warming results from the accumulation of greenhouse gases in the atmosphere. These very long-lived gases act to absorb infrared radiation, trapping it in the lower atmosphere, leading to increasing temperatures of the earth's surface and lower atmosphere. The result of global warming affects every aspect of what we know as weather.

Power plants are the second largest source of greenhouse gas emissions in Minnesota, just slightly behind transportation fuel use. While there is some debate about what to do about the problem of global warming in the short-term, there is general agreement that in the long-term, greenhouse gas emissions must be substantially reduced.[36]

6.2.9 Mercury

Minnesota's fish are contaminated with mercury. Because contaminated fish are found in nearly every area of the state (as well as in commercial fish available to Minnesotans), the Minnesota Department of Health has issued safe-eating guidelines. MDH continues to provide lake- or stream-specific advice based on the results of fish sampling, but its current advice is expanded to include all fish caught while fishing in Minnesota. The MPCA has listed 784 lakes as "impaired waters" as a result of mercury contamination in fish. This means that humans must limit their fish consumption to avoid ingesting unsafe levels of mercury.

Most mercury entering lakes and streams in Minnesota comes from mercury deposited from the air. In northern Minnesota, rain and snow deposit about one gram of mercury to a 20 acre lake

[36] The MPCA described in some detail the mechanisms, causes and effects of global warming in Department of Commerce's 2001 Energy Planning Report, Appendix A, pp. 101 to 103. (Attachment 2)

each year. One gram of mercury is the amount in a fever thermometer or 50 fluorescent lamps. Minnesota has been one of several states that have led the nation in reducing releases of mercury to the air, particularly through eliminating the use of mercury in commercial products and their disposal.

However, energy production contributes about half of the mercury emitted in Minnesota. Energy production contributes to local deposition of mercury, as well as to the global pool of mercury.

6.2.10 Acid Rain

"Acid rain" refers to the deposition of acid that has formed in the atmosphere onto lakes, streams and forests. The acidification of a lake or stream can change its nature, sometimes substantially. The primary causes of acid rain are sulfur dioxide and nitrogen oxides released to the air. Coal-fired power plants are significant contributors to acid rain because of the SO_2 and NO_x they emit. Because of actions taken in the 1980's by the Minnesota legislature and the MPCA, the acidity of rainfall in Minnesota has improved.

In Title IV of the 1990 Clean Air Act Amendments, Congress created the Acid Rain program. Simply stated, Title IV required a fifty percent reduction in utility SO_2 emissions from 1985 levels by 2000. In addition, utilities needed to make some cuts in NO_X emissions.

To make the needed cuts in national SO_2 emissions, Congress approved a market-based approach. Existing utilities were given allowances based on their historical emissions. These allowances were less than the amount the power plants had previously emitted. This gave utilities the option of reducing their own SO_2 emissions or of buying SO_2 "reduction credits" from utilities that reduce their emissions below their allowances.

Congress used a different approach to reduce NO_X emissions. Utilities were required to meet a system-wide average NO_X emission rate. This allowed many utility companies to control emissions at one power plant without making changes at other facilities.

Minnesota's utilities, including Xcel, found that the SO_2 emission targets could be met by switching from Eastern coals to Western coals, and implemented that strategy. To meet the NO_X requirements, Minnesota's utilities cut emissions significantly at one plant and spread the emission reduction out over their entire system.

Unfortunately, rainfall acidity in the northeastern United States is still damaging the environment there, and it is generally acknowledged in the scientific and regulatory communities that further substantial reductions in these pollutants are needed.

7.0 Assessment of Benefits of the Proposed Project

7.1 Emission Estimates of the Proposal

The MPCA has independently calculated likely annual reductions in air emissions under Xcel's proposal, presented in tables 9 through 11 below. Current emissions are shown in Table 9.

Table 9. MPCA's estimated annual emissions for Xcel generating stations at current emission factors and typical operation.

	Capacity factor[37]	SO_2 (tpy)	NO_X (tpy)	PM_{10} (tpy)	CO_2 (tpy)	CO (tpy)	Lead (pounds)	Mercury (pounds)
A.S. King	0.70	22,182	11,331	303	3,271,501	432	207.5	68
High Bridge Unit 5	0.47	662	1,038	23	371,023	47	9.3	
High Bridge Unit 6	0.53	1,384	2,169	49	775,255	93	19.4	
High Bridge, Total		2,046	3,207	72	1,146,278	141	28.7	66
Riverside Unit 6/7	0.58	1,323	2,891	45	724,441	99	9.1	
Riverside Unit 8	0.70	8,626	6,778	534	1,403,507	188	20.5	
Riverside, Total		9,950	9,669	579	2,127,948	287	29.6	98
Three plants, Total		34,178	24,206	954	6,545,727	860	265.8	232

Emissions estimates after retrofits or reconstruction are shown in Table 10.

Table 10. MPCA estimated emissions after proposed changes.

	Capacity factor	SO_2 (tpy)	NO_X (tpy)	PM_{10} (tpy)	CO_2 (tpy)	CO (tpy)	Pb (pounds)	Mercury (pounds)
A.S. King	0.70	2,298	1,915	345	3,810,897	519	207.5	54
High Bridge	0.47	0[38]	107	0	1,087,230	198	0	0
Riverside	0.53	0	167	0	1,327,735	223	0	0
Three plants, Total		2,298	2,189	345	6,225,862	940	207.5	54

[37] "Capacity factor" reflects how much the plant will be used to generate electricity during the year. A capacity factor of 1.0 would indicate operation 100 percent of the time. Most plants are operated at a capacity factor of 0.80 or lower. The factors used on Table 9 are from Xcel's MERP proposal.

[38] As noted before, Xcel has represented emissions of SO_2 and PM_{10} from gas-fired facilities as zero. It must be recognized that while not precisely zero, direct emissions of these two pollutants will be extremely small.

Table 11. Comparison of annual overall emissions before and after the proposed changes.

	SO_2	NO_X	PM_{10}	CO_2	CO	Lead	Mercury
Emissions change (tpy)	-31,880	-22,017	-667.1	-319,865	+80	-60[39]	-178
Percentage change	-93.3	-91.0	-69.9	-21.4	+9.3	-22.5	-76

The MPCA calculations strongly agree with Xcel's estimates of emission reductions. Xcel reported emissions over a period of 10 years in its filing, and not annual emissions.[40] Xcel reports increased releases of CO_2 and CO at A.S. King due to increased generating capacity and facility utilization.

Mercury emissions should be virtually eliminated at High Bridge and Riverside upon conversion to natural gas, removing the release of 164 pounds of mercury per year[41]. With the implementation of MERP, mercury emissions are expected to be lowered by 20 percent at King, or about 14 pounds. Total mercury reductions from MERP from current operation is about 178 pounds, or approximately 12 percent of mercury emissions from coal-fired electricity generation in Minnesota.

7.2 Xcel Energy's Estimates of the Environmental Benefits from MERP

Xcel Energy uses the PUC's high environmental externality values and estimates that the net present value of MERP's environmental benefits will be $127 million over 10 years. Table 12 shows what assumptions were used to produce this estimate.

A.S. King's benefits were calculated using the PUC's metro fringe environmental externality values, while the urban values were applied to reductions at High Bridge and Riverside.

Mercury is not figured into Xcel's environmental benefits calculation because the PUC has not established an environmental externality value.[42] Similarly, $PM_{2.5}$ was not a regulated pollutant at the time the externality values were developed, so no externality value was established for this pollutant.

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[39] Changes in lead and mercury emissions are reported in pounds per year.

[40] See Attachment 4.A of Xcel's petition.

[41] www.xcelenergy.com/Environment/TRI2001MNWIbody.asp. Accessed October 3, 2002

[42] The PUC established externality values for lead emissions, however the amount of lead released (and further reduced by MERP) is so small that it does not change the benefit calculations.

Table 12. Xcel's Calculation of Environmental Benefits of Proposed Plan[43] (Net Present Value in 2001 dollars)

	King			High Bridge			Riverside			Total Proposal
	High Externality Value	Average Emissions, tpy reduced	Present value, benefits	High Externality Value	Average Emissions, tpy reduced	Present value, benefits	High Externality Value	Average Emissions, tpy reduced	Present value, benefits	Net present value, benefits
SO_2	0	23,700	0	0	3,100	0	0	12,000	0	0
NO_x	298	16,700	$18,799,000	1,094	4,400	$19,367,000	1,094	13,100	$58,174,000	$96,340,000
CO_2	3.47	-482,000	($17,998,000)	3.47	415,000	$2,636,000	3.47	1,570,000	$20,177,000	$4,815,000
CO	1.5	-100	($1,000)	2,054	20	($3,000)	2,054	140	$1,000	($3,000)
PM	3,229	90	($431,000)	7,187	100	$3,304,000	7,187	540	$22,669,000	$25,542,000
TOTAL			**$369,000**			**$25,304,000**			**$101,021,000**	**$126,694,000**

[43] Xcel filing, Attachment 4.B. Calculated for the period beginning the first full year a plant is back in service through 2020. While an externality value is provided for lead emissions, its contribution to this calculation is so small that the MPCA has chosen not to include it in these discussions.

7.3 Avoided Costs

Xcel's proposal results in an increase in generation capacity of 385 MW. This is equivalent to a good-sized power plant. Xcel refers to some MERP benefits as "avoided costs." Xcel assumes that by including this additional generation capacity in their MERP proposal, they would avoid significant costs associated with this additional capacity. The net present value costs minus the avoided costs result in a cost of about $900 million.

By making changes at existing power plant sites, the proposal eliminates the need for new transmission lines needed to bring power to Minnesota's load centers, and it eliminates the costs associated with developing a new plant. Xcel has estimated that avoided costs for the 2006 to 2034 period are $712 million.[44]

It is important to note that this does not take into account the "avoided emissions" that would be associated with this generation capacity. Adding new generation capacity of 385 MW to the current Xcel system, or purchasing an equivalent amount of power generated elsewhere, will result in greater overall emissions than proposed by this project.

In addition to the new generating capacity that will be added as a result of this project, Xcel also will be rebuilding or refurbishing more than 1,100 MW of power at existing plants. This will result in adding tens of years of additional useful life from these plants. This is important generating capacity located on existing transmission lines near load centers.

Xcel has not factored in the value of this benefit in their proposal. Considering their estimates of $712 million as the value of avoided costs for 385 MW of new power, the value of extending the useful life of the current 1,100 MW at these three existing plants must be in the several hundred million dollar range.

7.4 MPCA Estimate of Projected Environmental Benefits

The MPCA believes that Xcel's calculation of the environmental benefits with current PUC externality factors does not take into consideration a number of important factors. The MPCA has calculated the benefits of this project using several alternative assumptions. In addition, it is important to note that the PUC externality factors were developed for resource planning purposes, and evaluating resource planning decisions among different types of generation technology options, not for evaluating the health and environmental benefits of a particular project.

7.4.1 Time Period

Xcel's benefit estimates end in 2020. Since the MERP proposes physical changes that will last beyond 2020, environmental benefits will extend beyond 2020 as well.

A more appropriate statement of benefits and costs should have estimates that cover the likely duration of physical capital. Xcel estimates that MERP will extend the King plant's useful life

[44] Xcel Response to MPCA request for data Number 17. November 18, 2002.

by 20 years.[45] Since MERP will reconstruct the High Bridge and Riverside plants it seems appropriate to treat them as new plants, once MERP is complete. They should last at least as long as the refurbished King Plant. More conventional assumptions set the useful life of a utility plant at 30 years or more (EIA 2000).

In reply to an MPCA request, Xcel estimated costs for a period that extends to 2034. Estimates end in 2034 because Xcel assumes the PUC will not approve "life extensions" that go beyond 2034. The new and refurbished plants will be fully depreciated by 2034, so there is no more cost to estimate.

At the same time, Xcel expects that the refurbished plants' useful lives will extend beyond their book lives. Experience confirms this assumption.[46] This real world experience informs the assumptions many analysts make about the operating lives of electricity generating plants (EIA 1994, EIA 2002, DOE 1999, FERC 1980).

In the MERP case, it seems reasonable for planning purposes to think in terms of the project having a useful life that extends from completion of the project to at least 2040.

If benefit estimates are extended to 2040, total environmental benefits would double.[47]

7.4.2 Discount Rates

Xcel discounts its estimates — both benefits and costs — at a "corporate discount rate." The specific rate chosen is 7.9448 percent. It is a private rate of return that applies specifically to Xcel's financial operations. The firm, its shareholders and the PUC should take alternative investment choices into account when evaluating capital decisions. Xcel's allowed discount rate is appropriate for future costs.

However, although a private discount rate is appropriate for costs that Xcel will incur, different factors influence the discount rate for the value of environmental benefits. MERP's environmental benefits will accrue to a large community — one that extends well beyond Minnesota's borders. Unlike private benefits that belong to individuals, public benefits belong to everyone in an affected community. General price inflation will decrease the value of future

[45] Xcel Energy reply to MPCA information request number 2, September 5, 2002, p. 3-6)

[46] See data on the operating lives of retired and current plants in the Energy Information Administration's Form EIA-860A Database, www.eia.doe.gov/cneaf/electricity/page/eia860a.html.

[47] A rough estimate of the effect caused by extending the forecast period to 2040 shows a doubling of the net present value of benefits. However, the net present value of revenue requirements (costs) does not increase as fast, increasing by about 50 percent.

Extending the time period for benefit and cost estimates requires some care. Rates of change for the two factors are different. We can expect benefit values to increase because the PUC has declared that they will increase at the same rate as the money value of gross domestic product. (Benefit values seem likely to increase for other reasons as well. For example, rising incomes will increase benefit estimates. But these sorts of changes are less predictable.) On the other hand, Xcel predicts that costs and revenue requirements will decline (see Attachments B.2. and DOC-12-A. of Xcel's petition).

public benefits, so the same inflation-compensating rate should be used for both costs and benefits.

Financial risk is a different matter. Xcel's shareholders incur a risk that other investments may yield better rates of return. A significant portion of the corporate discount rate compensates Xcel's investors for the risk they accept with investment decisions. Risk does not affect public benefit values. Public benefits are spread so broadly that risk does not affect individuals. Everyone in a community affected by the MERP has the same chance, all other factors being equal, to enjoy the benefits of cleaner air. In this case, risk is moot because no one can choose, say, slightly dirtier air in exchange for some other public good they value more. Since public benefits accrue without risk, the discount rate for public benefits should be lower than the private discount rate.

EPA's Science Advisory Board has accepted, with qualifications, a three percent discount rate for public benefits:

> "Discounting future benefits and costs is conceptually appropriate and practically important… Unfortunately, there is substantial uncertainty about the appropriate discount rate to use. The rate of three percent proposed by the EPA seems reasonable, and other values should be employed in a sensitivity analysis. The Council supports EPA's proposed choice of discount rates, but recommends that EPA take pains to acknowledge conceptual and practical uncertainties inherent in the choice of discounting strategies." (EPA 2001)

Therefore, for the purposes of evaluating the project's public benefit, the MPCA thinks a more appropriate discount rate to use is three percent.[48] By way of sensitivity analysis, benefits discounted by three percent are compared with benefits discounted at Xcel's corporate discount rate. The lower discount rate nearly doubles the estimated value of environmental benefits.

7.4.3 Reconsideration of Benefits and Costs

MERP's capital costs are spread out over four years:

2006	$500.2 million
2007	$332.1 million
2008	$177.4 million
2009	$34.0 million
Total	$1,043.7 million

[48] MPCA adjustments take into account consideration of the Administrative Law Judge's 1996 recommendation that the PUC adopt values for CO_2 that are discounted at three and five percent.

The present value of $1.04 billion (2002 valuation, at a 7.9448 percent discount rate) is about $785 million. Xcel has also estimated a present value that combines both capital costs and returns on investment as allowed under PUC orders. This "revenue requirement" is $1.2 billion. It extends from 2006 to 2020. Because the MPCA believes the benefits will accrue well beyond 2020, it is appropriate to look at extending the cost estimate.

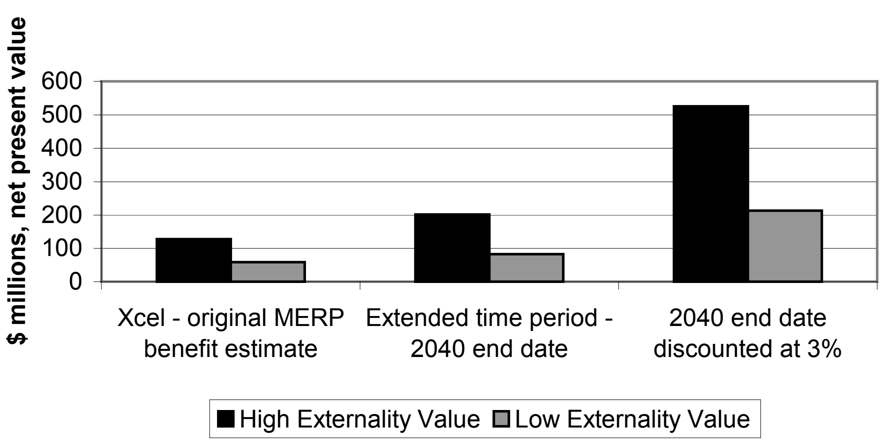
In reply to an MPCA request, Xcel estimated the net present value of revenue requirements for a period that extends from 2006 to 2034. Estimates end in 2034 because Xcel assumes the PUC will not approve "life extensions" that go beyond 2034. The new and refurbished plants will be fully depreciated by 2034, so there is no more cost to estimate.

The revised cost estimate is $1.6 billion.[49] Since this is the amount that Xcel's customers are expected to pay for MERP over a longer period of time, it is a more appropriate value that should be compared to MERP's benefits.

The net present value of the total project is approximately $1.6 billion, assuming the plant life beyond 2020 as described above. Taking avoided costs into account puts the net present value of the proposal closer to $900 million. Using a realistic time frame and a more appropriate discount rate, the benefits are estimated at between $200 million and $500 million when using the PUC's environmental externality factors. Figure 7 shows how the adjustments described earlier affect the estimate of benefits. This comparison does not take into account the substantial benefit of extending the useful life of the existing plants.

In addition, as described in the next section, the MPCA believes that this assessment of the MERP, even with the adjustments made so far, under-predicts the projects' benefits, and that benefits are at least equal to the net present value of this project.

Figure 7. Estimate of MERP Benefits to year 2040



[49] Xcel Response to MPCA request for data Number 16. October 25, 2002.

7.5 Alternative Means of Assessing the Benefits of Controlling Power Plant Emissions

Other studies have estimated the benefits of reducing coal-fired power plant emissions, many prepared to inform policy decision makers when imposing new emission reduction requirements. These studies provide estimates of the health effects avoided by reducing emissions of sulfur dioxide and nitrogen oxides.

The MPCA has identified four assessments that have been conducted in the United States estimating the benefits of reducing power plant emissions which are similar to Xcel's emissions reduction proposal. Although there are similarities between these studies and the approach used to develop the externality values used in Xcel's emissions reduction proposal, these four studies were conducted using more current methods than were available when externality values were developed.

For example, these studies incorporate health effects information from studies showing serious health effects from long-term exposures to particulate air pollution that has been recognized since the externality proceeding was completed. The parameters of the assessments and the benefits they estimate are briefly described below. Each of these follows the same general approach outlined in the following discussion. They differ somewhat in the assumptions used in calculating the health impacts and costs.

7.5.1 The Benefits Assessment Methodology

The following approach has typically been used to estimate the benefits of reduced air emissions;[50]

1. Define the reduction in emissions to be assessed.
2. Estimate the change in pollutant air concentrations over a defined geographic region. Computer models predict the concentrations of air pollutants by modeling the dispersion of pollution and estimate the formation of particles from SO_2 and NO_x and other chemicals in the atmosphere.
3. Characterize the location of exposed human populations and their current death and disease rates.
4. Identify the potency of particulate matter to increased adverse health effects from the epidemiology literature. (These measures, known as concentration-response functions, estimate the percent increase in a health effect in a population for a specified increase in the particulate matter concentration.)
5. Estimate the number of deaths or cases of disease avoided by reducing emissions. These estimates assume that particles are causally associated with health effects, and that all particle components have similar toxicity.
6. Some studies follow the estimate of the changes in disease or death incidence with an economic valuation, that is, calculating the economic benefits associated with avoiding these health effects.

[50] Besides the four studies described in this document, EPA has used this approach to assess the benefits of implementing the Clean Air Act in its report to Congress, and to assess the benefits of two specific regulations: the Tier 2 Gasoline regulations and the Heavy Duty Engine/Diesel Fuel rule.

Table 13 summarizes the expected emission reductions, the estimated health benefits and cost savings included in the four assessments described below. There are inherent uncertainties in this type of assessment. Complete studies recognize and describe the uncertainties associated with the estimated benefits. The table lists the estimated annual benefits from these studies with the estimated annual benefits from MERP, based on Xcel's calculation using the PUC's externality values.

A recent National Academy of Sciences report (NAS 2002) and EPA's Science Advisory Board (SAB 2001) each reviewed EPA's methods for estimating health benefits from reducing air pollution, with an emphasis on the method of assessing benefits from reducing $PM_{2.5}$. Both generally supported these types of benefits analyses to estimate the benefits of air pollution reductions, and recommended that future studies more fully describe the uncertainties associated with the estimated benefits.

Some of the important uncertainties of the four studies below include the uncertainty when modeling emission estimates for facilities in the future, the chemical formation and dispersion of particulates, and the concentration-response function of particles from specific sources. Other uncertainties inherent in other similar scientific inquiries, and having differing importance, include variability of population demographics and heterogeneity, intersubject variability, health and exposure baselines.

7.5.2 EPA's Clear Skies Initiative

In 2001, the Bush Administration proposed the "Clear Skies Initiative" to reduce emissions from electric power generating utilities. Nationwide, the Clear Skies Initiative is estimated to reduce emissions of sulfur dioxide by 73 percent, nitrogen dioxides by 67 percent, and mercury by 69 percent.

The largest estimated benefits come from reducing the level of ambient particles. The estimated national annual monetary benefits in 2020 are $89 billion for 12,000 avoided premature deaths and $3.2 billion for 7,400 fewer cases of chronic bronchitis, totaling $93 billion for all estimated health effects. The estimate of avoided early deaths is based on studies of the potential cumulative effect of long-term exposure to particles.

EPA separately estimated the impacts of pollutant reductions that occur over much shorter time periods. This short-term estimate concludes that on a national scale, 7,400 early deaths would be avoided by reducing power plant emissions.

In Minnesota, EPA projected that a Clear Skies program would reduce particulate matter levels across the state, and result in 100 fewer early deaths due to their health effects. Because $PM_{2.5}$ is a regional pollutant, benefits estimated in Minnesota are a result of emission reductions in Minnesota and other states, and reductions in Minnesota result in benefits in other states. All health improvements combined result in $1 billion in benefits in Minnesota from Clear Skies.[51]

[51] Details of the assessment of the human health benefits expected from the Clear Skies Initiative can be found at www.epa.gov/clearskies/tech_adden.PDF.

7.5.3 Eight Utilities Study

Eight utility systems in the eastern half of the United States were the subject of a study to estimate the health impacts of emissions from their coal-fired power plants (Abt Assoc. 2002). This assessment estimated that roughly 5,900 premature deaths might be avoided if emissions ceased from these plants. The study did not attempt to translate these deaths and other respiratory effects into economic terms. The study estimates emissions from power plants in Illinois and Indiana contributing significantly to deaths in Missouri, Illinois, Indiana, Wisconsin and Minnesota.

7.5.4 Two Massachusetts Power Plants

Harvard researchers Levy and Spengler estimated the health benefits of reducing SO_2 and NO_x emissions from the Brayton Point and Salem Harbor coal-fired power plants in Massachusetts (Levy and Spengler 2002). Their analysis compared current emissions with emission rates estimated under best available control technology (BACT), which results in emission reductions of 57,348 tons of SO_2 and 11,074 tons of NO_x per year from the two plants.

The predicted reductions of ambient annual $PM_{2.5}$ concentrations ranged from 0.006 ug/m3 to 0.2 ug/m^3 $PM_{2.5}$ covering a 600 km by 600 km area in the Northeast U.S. This study estimates that this reduction in SO_2 and NO_x would reduce about 70 premature deaths each year over a total population of 33 million. Additional health effects were not considered. While suggesting caution when calculating the value of the avoided early deaths, the authors used standard EPA valuation for a statistical life and determined these avoided deaths represent a $400 million benefit per year.

7.5.5 Minnesota Power Plants

Nelson estimated the public health impacts of particulate emissions from current coal-fired power plants in Minnesota, and the impacts if these plants switched from burning coal to burning natural gas (Nelson 2000). The study concluded that by switching from coal to natural gas, about 25 early deaths would be avoided. Other health benefits include fewer new cases of bronchitis, emergency room visits, days of respiratory symptoms, and days of restricted activity. This study calculated that the economic benefit from switching to natural gas is $165 million per year (1996 dollars).

This study recognizes that using high stacks at power plants to disperse pollutants means that much of the damage from the emissions occur outside Minnesota. However, Xcel's Riverside plant was estimated to have the highest incidence of early deaths (nine) due to its location within a heavily populated area.

Table 13. Comparison of benefits when power plant emissions are reduced.

Benefit Assessment	Annual Benefits ($/yr)[52]	Avoided Deaths	NO_x reductions (tons per year)	SO_2 reductions (tons per year)
Clear Skies (nationally)	$93 billion	12,000	5,000,000	2,500,000
Clear Skies in Minnesota	$1 billion	100	91,000	17,000
Eight Utilities	Not calculated	5,900	Not presented	Not presented
Two MA Power Plants	$400 million	70	11,000	57,000
Minnesota Power Plants	$165 million	25	53,700	57,000
Xcel Emissions Reduction Proposal			22,000	31,900

Table 13 shows the estimated annual benefits calculated by each of the studies described above. Applying the Minnesota high environmental externality factors to the average annual emissions avoided by implementing this project would result in an annual benefits estimate of about $24 million (2001 dollars). This low value compared to the results of the recent studies above strongly suggests that the PUC's externality factors are not in concert with other researchers and institutions' assessment of the impacts of power plant emissions.

Since the PUC adopted its externality values, the weight of evidence for significant public health impacts from breathing fine particles is significantly stronger and more widely recognized. Peer reviewed methods for estimating health benefits from reducing SO_2 and NO_x emissions and the associated long-term exposures to fine particle air pollution were used in the assessments above, and are being used to support developing federal regulatory programs like the Clear Skies Initiative, as well as national ambient air standards.

A comparison between Xcel's estimated benefits from the MERP proposal and the results of the four studies above strongly suggest that externality values underestimate the health benefits of lowering emissions. There is compelling evidence that greater benefits accrue if the health impacts resulting from fine particulates were re-evaluated using methods similar to the Bush Administration's Clear Skies Initiative or these other assessments. Xcel's proposal results in emission reductions about half that evaluated by Nelson, suggesting that benefits could be at least $80 million per year (in 1996 dollars) — half of the benefits estimated in Nelson after the project is fully implemented. This translates to a net present value of more than $1.2 billion (in 2001 dollars) for the pollution reductions that are achieved with the MERP project.

[52] Note that the annual benefits shown in this table represent calculations in different years and thus reflect different dollar values. They are presented here to show the magnitude and range of benefits associated with reducing emissions from coal-fired power plants.

The four studies summarized above rely on models to simulate benefits associated with emission reduction scenarios. The models are mathematical estimates of real world relationships. They rest on statistical foundations that are subject to bias and uncertainty. However, these models, and others like them, are tools that environmental regulators use to evaluate potential regulations and decide on what emission reductions should be made.

The body of scientific evidence persuades the MPCA that Xcel Energy's estimates significantly undervalue MERP's environmental benefits, and that alternative assessment techniques would place benefits on par with the costs of the project.

7.6 Conclusions on the Estimation of Quantifiable Benefits

- The net present value of the project for the period 2006 to 2034 minus the avoided costs for the 385 MW of new capacity ($712 million) is about $900 million.
- Xcel's costs and benefits are calculated through 2020. Since these plants will last many years longer than that, using a larger timeframe to calculate costs and benefits is appropriate.
- Xcel used a corporate rate to discount costs and benefits. A lower discount rate is more appropriate to assess public benefits.
- Adjusting for longer plant life and lowering the discount rate, the benefits calculated from PUC externality values become $200 – $500 million.
- The calculation does not account for the value of extending the useful life of approximately 1,100 MW of existing power by decades.
- The calculation does not adequately account for the cost of impacts of fine particles on human health, as demonstrated in Section 7.5.

In addition to the growing weight of evidence related to the damages from fine particles, there have been refinements in various assumptions. For example, the estimated value of a statistical life has increased since the PUC first conducted public hearings on the establishment of the externality values. A "statistical life" is the amount people are willing to pay to reduce the *risk* of dying. When the PUC set environmental externality values in 1995, the value of a statistical life was estimated to be approximately $3.5 million. Since then, new analyses have increased the estimated value of a statistical life.

EPA, in its regulatory impact analyses, now assumes a statistical life value in the $6 million range. EPA's analyses have so far passed review and criticism by its Science Advisory Board. EPA continues to refine its estimates for review and comment by the Science Advisory Board. Increasing the value of a statistical life estimate to conform to EPA's current practice doubles the portion of Xcel's current present value benefits estimate related to death caused by air pollution.

Benefits are also under-predicted in the assignment of zero as an externality value for SO_2. This value was developed under the assumption that the costs of all damages were internalized in the cost of allowances under the 1990 Clean Air Act regulations allowing SO_2 emissions trading. The damages focused primarily on the impacts of acid rain on the ecosystems.

Recent research suggests that the SO_2 reductions required in the 1990 amendments have been insufficient to reverse the ecological damages of acid rain, and further reductions of 50 to 80 percent in SO_2 releases from the electric power industry are still necessary (Gbonda-Tugbawa, 2002). Additionally, epidemiological studies have strengthened the links between fine and sulfate particles with early death from cardiopulmonary disease and lung cancer (Pope et al. 2002, Krewski et al. 2000).

Evidence also suggests that sulfates encourage bacteria to methylate mercury, that is, convert mercury to a form that readily enters the food chain and bioaccumulates in fish. Researchers believe that reducing SO_2 emissions and the resulting sulfate deposition would likely reduce the amount of mercury that bioaccumulates (Branfireun et al. 1999, Gilmour et al. 1992).

Despite this range of human health and environmental advantages to reducing SO_2 emissions, Xcel's assessment of the benefits of the MERP proposal assigns no benefits to SO_2 reductions. The PUC's environmental externality values were designed and adopted for use in resource planning. The externality values are generalized estimates given for model power plants in rural, suburban and urban settings. These plants don't really exist — they are idealized. While some of the underlying assumptions may be appropriate for this purpose, the externality values have limited applicability to specific projects such as those proposed for the MERP.

The MPCA is certain that the PUC's externality values, when applied to a project such as the MERP, greatly underestimate the health and environmental benefits of the proposal. The MPCA has demonstrated the degree to which the benefits are underestimated in this section by showing the benefit measured in similar analyses elsewhere.

There is compelling evidence that greater health benefits accrue if the health impacts resulting from fine particulates were to be evaluated using methods similar to the Bush Administration's Clear Skies Initiative or other assessments. For this analysis, the MPCA has attempted a very simple calculation which places benefits closer to the cost of this project

While it is simply not possible to quantify health and environmental benefits with accuracy, the MPCA finds that the benefits of the project roughly balances, if not exceeds, the costs of the project.

8.0 Other Benefits

The previous analysis of benefits in reducing power plant emissions does not include any consideration of benefits related to the following important environmental and health issues:

- Reduced emissions of mercury and other bioaccumulative metals.

  The accumulation of mercury in fish tissue is a pervasive issue in Minnesota as well as many other states and countries. Power plants in Minnesota account for about half of the state's mercury emissions. An extensive discussion about the mercury problem in Minnesota and what is being done about it can be found in the MPCA's 2002 report to the Legislature, available at www.pca.state.mn.us/hot/legislature/reports/2002/mercury-02.pdf. Metal emissions from power plants are discussed in Attachment 2.

  Evidence suggests that sulfates encourage bacteria to methylate mercury, that is, convert mercury present in the environment to the form (methylmercury) that readily bioaccumulates in fish. A decrease in SO_2 emissions, and the resulting decrease in atmospheric sulfate deposition, would likely reduce the amount of methylmercury that accumulates in fish. (Branfireun, et al.1999, Gilmour et al. 1992) The MERP project thus offers improvements to the environment by first reducing mercury emissions and by reducing SO_2 emissions that may be participating in causing fish contamination in lakes.

- Reduced contribution to ground level ozone (smog), regional haze and acid deposition.

  These three problems are all serious, but rising levels of ozone in the Twin Cities area is of particular, immediate concern. More discussion on these issues is available in Attachment 2.

- Reduced impacts from truck and rail traffic, and ash disposal.

  More information about these impacts can be found in section 8.2.

- Reduced need for development of new energy generation sites and new transmission lines.

  If the existing generation capacity at these sites is not maintained, and if new generation needs are to be met elsewhere, then new generation sites and transmission lines will be needed. Development of energy generation sites and transmission lines requires a substantial amount of land, may require significant infrastructure upgrades, and is extremely controversial.

All of the items listed above are — or have a potential to — causing harm to human health and/or the environment. All of these impacts will be reduced as a result of implementing these projects. However, estimating a specific, or even a ballpark, associated benefit is not possible.

8.1 Environmental Justice

In recent years there has been growing concern that minority populations and/or low-income populations bear a disproportionate share of adverse health and environmental effects. Many of our older and more polluting industries are located near minority and low income residential areas. [53] Higher traffic densities and hence mobile source emissions also exist in the core areas of Minneapolis and St. Paul, and lead to higher levels of various toxic air contaminants (MPCA 2001).

EPA defines Environmental Justice as the "fair treatment for people of all races, cultures, and incomes, regarding the development of environmental laws, regulations, and policies." In September 1999, the MPCA adopted an environmental justice policy that, among other goals, is intended to ensure "that minority and economically disadvantaged communities in Minnesota do not bear a disproportionate share of the involuntary risks and consequences of environmental pollution."

The Riverside and High Bridge plants are located in areas of high minority population and high poverty rates relative to metropolitan averages. (See Figure 8) The project helps to minimize the local impact of these facilities on the health and well being of the surrounding neighborhoods. This is largely the result of the proposed fuel switch from coal to gas. The project will also significantly reduce mercury emissions.

Health effects from mercury deposition and uptake in fish are of most concern to pregnant women who eat fish caught from contaminated lakes. Fish eating habits of Native American and Southeast Asian communities in Minnesota likely place them at higher risk than the population as a whole. Because the project reduces local impacts at Riverside and High Bridge, and because it reduces mercury emissions it is consistent with MPCA's environmental justice goals.

8.2 Local Impacts

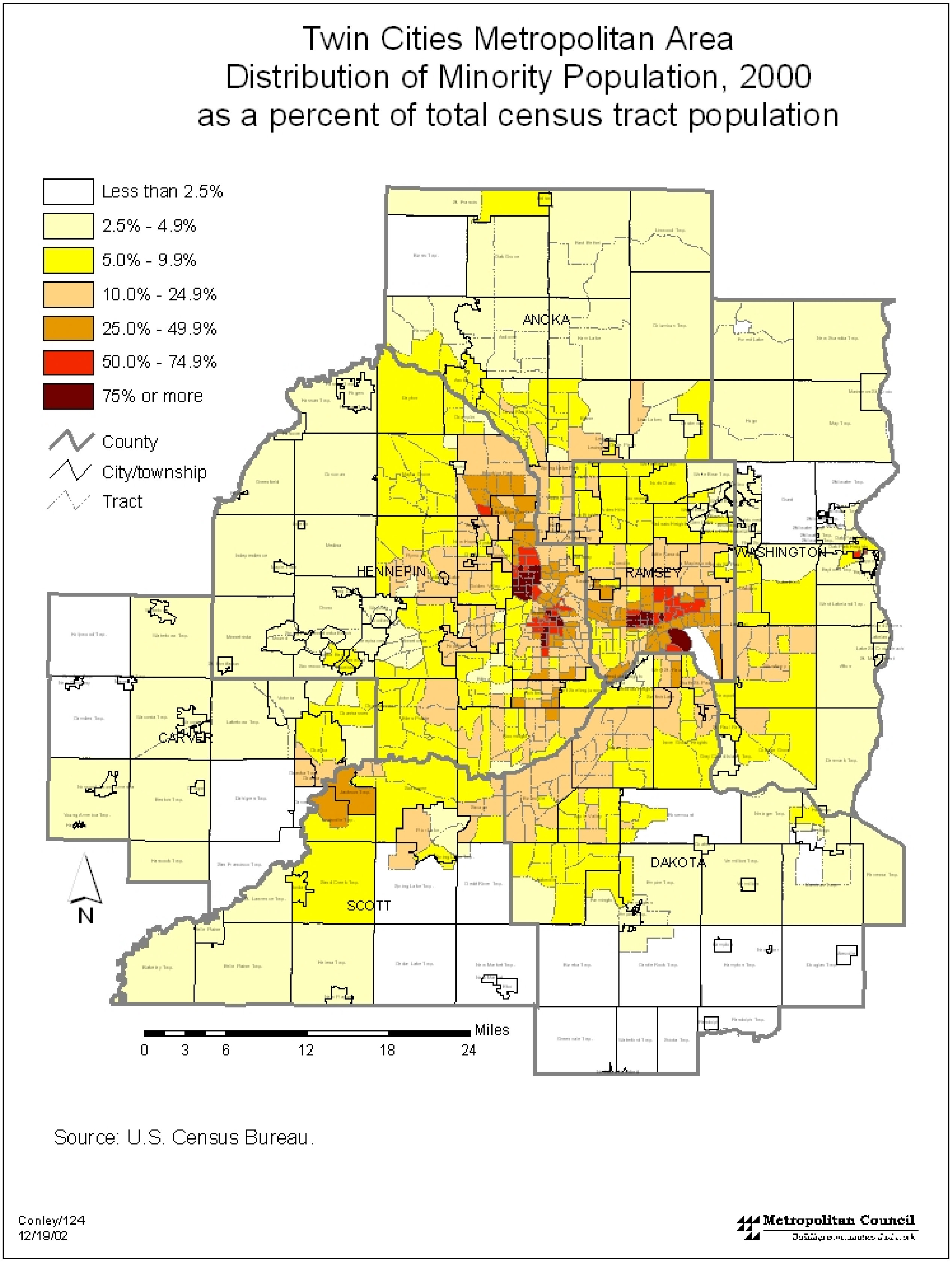
Local benefits will accrue in the neighborhoods surrounding the High Bridge and Riverside plants when they are converted to natural gas. After conversion, all coal and ash hauling would cease and changes would occur in the appearance of the facilities. Traffic and appearance would remain roughly the same at the King plant.

8.2.1 Truck and rail traffic

Coal is delivered to all three plants via rail. Three to four unit trains (115 cars) per week are currently delivered to both the High Bridge and Riverside plants. Ash from all three plants is trucked to a landfill. Approximately 1,700 trailer loads per year leave the High Bridge site. Approximately 2,800 trailer loads per year leave the Riverside site. In addition, in the summer, there is significant on-site use of a watering truck to minimize dust and fire danger. All of this traffic should be eliminated if the plants convert to natural gas.

[53] See, for example, Sheppard et al., "Examining Environmental Equity in Hennepin County and Minneapolis," CURA Reporter, Sept 1999.

Figure 8



Twin Cities Metropolitan Area
Distribution of Minority Population, 2000
as a percent of total census tract population
Less than 2.5%
2.5% - 4.9%
5.0% - 9.9%
10.0% - 24.9%
25.0% - 49.9%
50.0% - 74.9%
75% or more
County
City/township
Tract
ANOKA
HENNEPIN
RAMSEY
WASHINGTON
CARVER
SCOTT
DAKOTA
N
Miles
0
3
6
12
18
24
Source: U.S. Census Bureau.
Conley/124
12/19/02
Metropolitan Council

8.2.2 Dust

The handling and processing of coal inevitably results in the release of coal dust. Xcel minimizes the release of dust through many mitigation measures including watering. If the project proceeds, no coal will be used at Riverside and High Bridge. This will remove the source of any uncontrolled dust emissions from coal handling.

8.2.3 Appearance

The reconstruction of the Riverside and High Bridge plants will result in changes to the appearance of these sites. The coal storage areas (125,000 tons at High Bridge and 135,000 tons at Riverside) will be eliminated. The current exhaust gas stacks will be removed and replaced with lower stacks. These changes will make the sites on the Mississippi River look less "industrial."

8.2.4 Water Usage and Discharge

Conversion from coal to gas at the Riverside and High Bridge plants will result in cleaner wastewater at both plants. River water usage at the High Bridge plant should remain at about current levels, whereas usage at the Riverside plant will be reduced.

8.2.5 Noise

Noise is generated by activities related to transport of fuel and ash, and from activities related to plant operation. If the project is implemented, noise related to transport will be reduced at the Riverside and High Bridge plants. It is difficult to determine specific impacts from new operations such as the new gas turbines before site specific designs are developed.

8.2.6 Land Use

During the past three decades, the Twin Cities area has recognized the beauty and recreational benefits of the river corridors that are an integral part of the area. Numerous regional and local parks have been designated on the Mississippi, Minnesota, and St. Croix rivers. (See Figure 9)

The National Park Service, in cooperation with Metropolitan Council, the Minnesota Department of Natural Resources, and local authorities has designated two major river corridors for protection and improvement. The St. Croix National Scenic Riverway was established in 1968 and the lower St. Croix was added in 1972. The Allen S. King plant borders the St. Croix River. The Mississippi National River and Recreation Area was established in 1988. It extends along both sides of the river from Dayton to Hastings. The High Bridge and Riverside plants are both located on the Mississippi River within this area.

Under the MERP, the High Bridge and Riverside plants would be converted to natural gas. As outlined above, gas fired facilities should have less local visual and environmental impact than coal facilities. The improvements at the High Bridge and Riverside sites should be more in line with city, state, regional and Park Service plans for the Mississippi River corridor than continued operation as coal fired facilities.

Community concern for these plants is quite high. For example, this year, the MPCA was planning to re-issue the air permit for the Riverside Plant with no significant changes. (Air permits expire every five years.) During the formal public comment period the MPCA received adverse comments from more people than have ever commented on a permit.

Figure 9

9.0 Appropriateness of the Proposed Projects

When the Clean Air Act was passed in 1970, existing power plants were grandfathered and thus exempt from having to upgrade pollution control equipment. Expectations were that as these grandfathered plants aged, they would be either replaced with a new plant, or refurbished in such a way that pollution control upgrades would be required.

Thirty-two years later, these expectations have not been met. In Minnesota and across the country, older plants have been nursed along, with regular repairs, and have lasted long beyond their original expected useful life. They continue to emit at much higher levels than would be allowed any newer power plant.

Through the years, environmental and health experts have identified a number of serious problems linked to power plant emissions that have required corrective actions. Two of the most significant are the acid rain controls required by the Clean Air Act Amendments of 1990, and the NO_x reductions needed to reduce regionally transported ozone pollution in the eastern United States. Even these actions have not been enough.

It is now recognized that further reductions are needed in SO_2 and NO_x to protect the environment from acid rain. The new federal ozone standard will require even greater power plant reductions to help cities reach compliance. And, there are new problems that have been linked to power plant emissions as well.

Regional haze regulations will likely require emission reductions in SO_2 and NO_x from power plants. Global climate change concerns may ultimately require CO_2 reductions from this industry. Coal burning power plants are one of the most significant sources of mercury emissions in Minnesota and the nation. Finally, and perhaps the most serious, fine particulates, which have been scientifically linked to major health problems, including death, are in part the result of power plant emissions.

Nationally, the need to reduce emissions from power plants has been recognized in all circles. The debate has moved from why, to what, how much and by when? Damage/cost studies are now emerging that demonstrate the huge environmental and health benefits that may be gained from reducing power plant emissions. Perhaps the most interesting is the assessment associated with President Bush's Clear Skies legislation that projects benefits of $93 billion nationally and $1 billion in Minnesota.

9.1 Costs and Benefits

Before summarizing the costs and benefits of this MERP proposal, it is helpful to know that Xcel has already implemented Phase 1 of a significant emission reduction project in Colorado. Xcel has now proposed a Phase 2 emission reduction project in the Denver, Colorado area.

The magnitude of the costs and benefits estimates for projects like this can appear large. It has been many years since the PUC has been presented with a project of this size. The last major coal plant to be built in Minnesota was Xcel's Sherburne County Unit 3, built in the 1980's. That 871 MW plant was built at a cost of about $1 billion.

The pollution control equipment for Sherco III represented about one-third of the plant's total cost. The MERP proposal involves rebuilding or rehabilitating about 1,100 MW of generating capacity to like-new condition and adding 385 MW of new capacity, for a total of about 1,485 MW of capacity.

While it has not been possible to provide a detailed quantitative cost-benefit analysis of Xcel's MERP, the MPCA has reviewed both the projected capital costs of the MERP proposal, and its estimated benefits. The MPCA has concluded that the project cost is approximately $1.6 billion net present value, when assuming a plant life beyond 2020.

After considering the avoided costs associated with the benefits of the additional generation capacity from the project, the costs are more in the range of $900 million. Remember that the avoided costs to not take into account the fact that this project also extends the useful life of 1,100MW of existing capacity at these three plants for decades. There is a substantial benefit (perhaps in the several hundred million dollar range) for not having to replace this power in some other manner. Rebuilding or rehabilitating generating capacity at these sites takes advantage of existing transmission lines that are near load centers.

Using a more realistic timeframe for benefit accrual and using a more appropriate discount rate, the benefits are estimated at between $200 million and $500 million when using the PUC's externality values.

It is unfortunate that current science and economics makes it impossible to fully and quantitatively assess all the benefits associated with a project like this. Keep in mind what this benefit estimate *does not* quantitatively measure or consider.

- It does not quantify all health information associated with fine particulates. Recent damage estimates link virtually all of the potential costs of power plant emissions to fine particulate. Xcel's assessments do not include effects of long-term exposure to fine particulate matter.
- It does not account for the fact that SO_2 emissions play an important role in fine particulate formation and account for perhaps 20 percent or more of the mass of fine particulates in Minnesota's atmosphere (Figure 6) and one-third nationally.
- It does not account for benefits that occur more than 200 miles away. Recent benefit assessment estimates indicate that the majority of benefits will occur at significant distances from where the emissions occur.
- It does not account for mercury reductions. The reductions proposed in MERP are significant, reducing mercury emissions from power plants in the state by more than 10 percent. Mercury remains one of the most important environmental problems for Minnesota lakes and streams.
- It does not consider many specific local benefits, particularly those associated with the elimination of coal handling at two of the plants.

- It does not consider the fact that, with the additional generation capacity, one or more sites would not have to be developed for a power plant and the need for additional transmission lines would be reduced.

In weighing the projected costs for this three-plant proposal against the estimated benefits as well as the benefits that cannot be quantitatively estimated, the MPCA believes that the benefits, at the very least, approximate and most likely exceed the projected costs.

Finally, the MPCA will address the appropriateness of each individual plant project.

9.2 Allen S. King

This plant is mostly operated as a base load plant. Given the cost of coal vs. natural gas, it is reasonable to continue to burn coal at this plant for base load generation capacity. The emission controls proposed by Xcel approximate state-of-the-art controls for a coal-fired facility.

It is possible that in the next few years, Xcel will need to begin major modifications at this plant in order to be able to continue operations into the future. Such modifications would likely trigger the need to install pollution control equipment similar to what is proposed in the MERP. However, the environmental benefits will occur many years sooner under this voluntary emission reduction proposal.

The MPCA believes that it is appropriate to allow cost recovery for this project as specified by the statute.

9.3 High Bridge

This plant is an intermediate load plant. It is reasonable to consider converting an intermediate load plant over to natural gas. Also, this plant is located near downtown St. Paul and is surrounded by a densely populated urban area where new housing is being developed. The emission controls proposed are appropriate for this type of generation technology.

The MPCA believes that it is appropriate to allow cost recovery for this project as specified by the statute. The generating capacity expansion above the 100 MW limit in the statute should be considered for "recovery above costs," if the PUC finds that the additional capacity is needed for the economic viability of the project and would ensure that Xcel implements the project as a whole

9.4 Riverside

This plant is an intermediate load plant. It is reasonable to consider converting an intermediate load plant over to natural gas. Also, this plant is located near downtown Minneapolis and is surrounded by a densely populated urban area. The emission controls proposed are appropriate for this type of generation technology. This plant, although quite old, still has significant useful life. Clearly the conversion to natural gas is being proposed primarily for emission reduction benefits.

The MPCA believes it is appropriate to allow cost recovery for this project as specified by the statute.

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216B.1692. Emissions reduction rider

Subdivision 1. Qualifying projects. Projects that may be approved for the emissions reduction-rate rider allowed in this section must:

(1) be installed on existing large electric generating power plants, as defined in section 216B.2421, subdivision 2, clause (1), that are located in the state and that are currently not subject to emissions limitations for new power plants under the federal Clean Air Act;

(2) not increase the capacity of the existing electric generating power plant more than ten percent or more than 100 megawatts, whichever is greater; and

(3) result in the existing plant either:

(i) complying with applicable new source review standards under the federal Clean Air Act; or

(ii) emitting air contaminants at levels substantially lower than allowed for new facilities by the applicable new source performance standards under the federal Clean Air Act; or

(iii) reducing emissions from current levels at a unit to the lowest cost-effective level when, due to the age or condition of the generating unit, the public utility demonstrates that it would not be cost effective to reduce emissions to the levels in item (i) or (ii).

Subd. 2. Proposal submission. A public utility that intends to submit a proposal for an emissions reduction rider under this section must submit to the commission, the department, the pollution control agency, and interested parties its plans for emissions reduction projects at its generating facilities. This submission must be made at least 60 days in advance of a petition for a rider and shall include:

(1) the priority order of emissions reduction projects the utility plans to pursue at its generating facilities;

(2) the planned schedule for implementation;

(3) the analysis and considerations relied on by the public utility to develop that priority ranking;

(4) the alternative emissions reduction projects considered, including but not limited to applications of the best available control technology and repowering with natural gas, and reasons for not pursuing them;

(5) the emissions reductions expected to be achieved by the projects and their relation to applicable standards for new facilities under the federal Clean Air Act; and

(6) the general rationale and conclusions of the public utility in determining the priority ranking.

Subd. 3. Filing petition to recover project costs. (a) A public utility may petition the commission for approval of an emissions reduction rider to recover the costs of a qualifying emissions reduction project outside of a general rate case proceeding under section 216B.16. In its filing, the public utility shall provide:

(1) a description of the planned emissions reduction

project;

(2) the activities involved in the project;

(3) a schedule for implementation;

(4) any analysis provided to the pollution control agency regarding the project;

(5) an assessment of alternatives to the project, including costs, environmental impact, and operational issues;

(6) the proposed method of cost recovery;

(7) any proposed recovery above cost; and

(8) the projected emissions reductions from the project.

(b) Nothing in this section precludes a public utility or interested party from seeking commission guidelines for emissions reduction rider filings; however, commission guidelines are not required as a prerequisite to a public utility-initiated filing.

Subd. 4. Environmental assessment. The pollution control agency shall evaluate the public utility's emissions reduction project filing and provide the commission with:

(1) verification that the emissions reduction project qualifies under subdivision 1;

(2) a description of the projected environmental benefits of the proposed project; and

(3) its assessment of the appropriateness of the proposed project.

Subd. 5. Proposal approval. (a) After receiving the pollution control agency's environmental assessment, the commission shall allow opportunity for written and oral comment on the proposed emissions reduction rate rider proposal. The commission must assess the costs of an emissions reduction project on a stand-alone basis and may approve, modify, or reject the proposed emissions reduction rider. In making its determination, the commission shall consider whether the project, proposed cost recovery, and any proposed recovery above cost appropriately achieves environmental benefits without unreasonable consumer costs.

(b) The commission may approve a rider that:

(1) allows the utility to recover costs of qualifying emissions reduction projects net of revenues attributable to the project;

(2) allows an appropriate return on investment associated with qualifying emissions reduction projects at the level established in the public utility's last general rate case;

(3) allocates project costs appropriately between wholesale and retail customers;

(4) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the qualifying projects to ensure implementation;

(5) recovers costs from retail customer classes in proportion to class energy consumption; and

(6) terminates recovery once the costs of qualifying projects have been fully recovered.

(c) The commission must not approve an emissions reduction project and its associated rate rider if:

(1) the emissions reduction project is needed to comply with new state or federal air quality standards; or

(2) the emissions reduction project is required as a corrective action as part of any state or federal enforcement action.

(d) The commission may not include any costs of a proposed project in the emissions reduction rider that are not directly allocable to reduction of emissions.

Subd. 6. Implementation. Within 60 days of a final commission order, the public utility shall notify the commission and the pollution control agency whether it will proceed with the project. Nothing in this section commits a public utility to implementing a proposed emissions reduction project if the proposed project or terms of the emissions reduction rider have been either modified or rejected by the commission. A public utility implementing a project under this section will not be required for a period of eight years after installation to undertake additional investments to comply with a new state requirement regarding pollutants addressed by the project at the project generating facility. This section does not affect requirements of federal law. The term of the rider shall extend for the period approved by the commission regardless of any subsequent state or federal requirement affecting any pollutant addressed by the approved emissions reduction project and regardless of the sunset date in subdivision 8.

Subd. 7. Evaluation and report. By January 15, 2005, the commission, in consultation with the commissioner of commerce and commissioner of the pollution control agency, shall report to the legislature:

(1) the number of participating public utilities and qualifying projects proposed and approved under this section;

(2) the total cost of each project and any associated incentives;

(3) the reduction in air emissions achieved;

(4) rate impacts of the cost recovery mechanisms; and

(5) an assessment of the effectiveness of the cost recovery mechanism in accomplishing power plant emissions reductions in excess of those required by law.

Subd. 8. Sunset. This section is effective until June 30, 2006.

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APPENDIX A: DEALING WITH ENVIRONMENTAL IMPACTS OF EXISTING ELECTRIC GENERATION

The environmental impact of electricity is a significant factor in energy policy and planning to meet Minnesota's generating capacity deficit. Because different generating technologies range from significant air emissions (coal) to low air emissions (natural gas and biomass) to no air emissions (wind, solar and nuclear), energy policy and generation mix choices that will be made in the next few years may require other up-front policy choices to manage environmental impacts. The state should evaluate the benefits and cost-effectiveness of adding more pollution control to existing generating plants based on the environmental effects described in this section, and require installation of controls as appropriate. If generation technology choices in the future include significant new air emissions, this policy decision is even more necessary.

The first part of this section analyzes the environmental impacts of the current electric generating system in Minnesota, and explores alternatives to reduce or mitigate those impacts. This section focuses on air emissions, which are the single largest source of environmental impact from electricity generation. This section will explain the air emissions that result from electricity generation in Minnesota, describe the health and environmental impacts of those emissions, describe the regulatory programs that have been in place to mitigate environmental impacts, and describe upcoming pollution control programs that will require further emission reductions from electricity generation, or require that current levels of emissions not grow any larger. Finally, this section will discuss options for further emissions control in Minnesota's existing coal plants, most of which were not required to meet the most stringent Clean Air Act requirements because they were constructed before those requirements took effect.

Figure A.1: Electric Utility Contribution to Current Minnesota Air Emissions

	1999 Emission to the Air (thousand tons)	% of Estimated Statewide Emissions
Greenhouse Gases	35,982	26%
Nitrogen Oxides	87	18%
Sulfur Dioxide	95	58%
Carbon Monoxide	8	<1%
Fine Particulate Matter (2.5 microns)	?	large
Lead	0.03	62%
Mercury	0.0008	40%
Other Metals (Chromium, Arsenic, Nickel)	NA	10-60%

Source: PCA

Current and Forecasted Emissions from Electric Generation in Minnesota

Air emissions from electricity generation in Minnesota are shown in Figure A-1 for 1999 in tons of emissions and as a percent of total statewide air emissions from all emitting sectors from Minnesota. Included are air emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), carbon monoxide (CO), fine particulate matter ($PM_{2.5}$), lead, mercury, other metals, and greenhouse gases. With the exception of CO emissions, electricity generation currently contributes a substantial fraction of total statewide air emissions. One-fifth of NOx emissions and one-quarter of greenhouse gas emissions from Minnesota sources derive from electricity generation, while electricity generation accounts for about 40 percent of all statewide mercury emissions and 58 percent of statewide SO_2 emissions. Sources of $PM_{2.5}$ in the state are less certain, and are currently being studied in preparation for implementing the new federal air quality standards for $PM_{2.5}$. However, it is thought that coal combustion during electricity generation could be a large source.

There are about 350 generating units located in Minnesota supplying power to the grid, some 9395 MW of installed capacity. Using 1999 plant utilization rates as a measure, about 6,900 MW of this would be classified as baseload capacity, with 2,050 MW classi-

Figure A.2: Nonnuclear Baseload or Intermediate Load Electricity Generating Units at Large Plants

	Capacity (summer) (MW)	Principal Fuel	Load Type	Start-up Date	NSPS Status Vintage (Year)
Xcel Energy					
Sherburne County					
unit 1	712.0	coal	Baseload	1976	n/a
unit 2	721.0	coal	Baseload	1977	1976
unit 3	871.0	coal	Baseload	1987	1986
Allen King	571.0	coal	Baseload	1958	n/a
Riverside					
unit 7	150.0	coal	Baseload	1987	1986
unit 8	221.5	coal	Baseload	1964	n/a
High Bridge					
unit 5	97.0	coal	Intermediate	1956	n/a
unit 6	170.0	coal	Intermediate	1959	n/a
Black Dog					
unit 3	113.2	coal	Intermediate	1955	n/a
unit 4	171.8	coal	Intermediate	1960	n/a
XCEL total	3,959.6				
LS Power	252.1	gas	Intermediate	1998	1997
Rochester Publ. Util.					
Silver Lake					
unit 4	60.3	coal	Intermediate	1969	n/a
Minnesota Power					
Clay Boswell					
unit 1	69.0	coal	Intermediate	1958	n/a
unit 2	69.0	coal	Baseload	1960	n/a
unit 3	346.3	coal	Baseload	1973	n/a
unit 4	535.0	coal	Baseload	1980	1979
Syl Laskin					
unit 1	55.0	coal	Baseload	1953	n/a
unit 2	55.0	coal	Baseload	1953	n/a
subtotal	110.0				
Minnesota Power total	1,129.3				
OtterTail Power					
Hoot Lake					
unit 2	64.9	coal	Intermediate	1959	n/a
unit 3	84.0	coal	Intermediate	1964	n/a
Otter Tail Power total	156.9				
Minnesota Total	**5,355.7**				

**Does not include nuclear power reactors Monticello and Prairie Island 1 & 2.*

Figure A.3: Net Generation and Emissions During 1999 from Electric Generation Plants Located in Minnesota

	1999 Net Generation (MWH)	Emissions NOx (tons)	SO2 (tons)	CO2 (tons)	Hg (lb.)
Xcel Energy					
Sherburne County	13,289,695	22,285	20,667	15,864,259	809.57
Allen King	3,295,770	18,479	27,251	3,465,485	58.8
Riverside	2,164,668	12,176	13,441	2,279,736	88.92
High Bridge	1,185,039	3,946	2,942	1,457,755	60.73
Black Dog	1,382,947	7,080	3,005	1,795,939	44.81
Minnesota Power					
Clay Boswell	6,172,773	12,382	17,305	7,230,445	315.93
Syl Laskin	570,635	1,570	1,008	646,863	38.50
Otter Tail Power					
Hoot Lake	629,190	1,365	2,479	870,831	30.88
Rochester Publ. Util.					
Silver Lake	206,166	683	2,184	183,044	8.33
LSP Cottage Grove	650,667	51	2	306,597	NA
TOTALS	**29,547,550**	**80,017**	**90,284**	**34,100,954**	**1456.47**

Source: PCA

fied as peaking, and the remainder as intermediate load capacity. Baseload plants are plants that, over the course of a year, operate more than 50 percent of the time. Intermediate-cycling plants operate between 15 and 49 percent of the time, while peaking plants operate 0 to 14 percent of the time.

Most air emissions in Minnesota derive from large baseload and intermediate cycling facilities. Baseload and intermediate cycling facilities located in Minnesota of more than 100 MW of capacity are listed in Figure A-2, along with summer capacity rating, facility start-up date, fuel type, and the status of each plant under the New Source Performance Standards (NSPS) of the federal Clean Air Act. Under NSPS, generation facilities constructed after 1972 are required to meet certain minimum performance standards with regard to air emissions of SO_2, NOx, CO, lead, and particulate matter. Generation facilities that were constructed before 1972 are exempt from NSPS.

NSPS have been revised a number of times, leading to the application of different standards to different plants depending on the year of their construction. NSPS have become progressively more stringent, so control requirements at plants subject to newer NSPS tend to be much more stringent than older NSPS requirements.[134] Where NSPS applies, Figure A-2 indicates the vintage (year) of NSPS standard to which the facility is subject. While NSPS applies to five generating units, four are subject only to older, less stringent NSPS. Fifteen large baseload and intermediate load generating units are exempt from NSPS entirely, comprising 3,030 MW of the 5,559 MW (55 percent) of installed baseload and intermediate-load capacity in the state.

Emissions at Minnesota's large baseload and intermediate plants for 1999 are shown in Figure A-3 for SO_2, NOx, CO_2 and mercury. In 1999, 80,017 tons of NOx and 90,284 tons of SO_2 were emitted to the atmosphere from large baseload and intermediate load plants larger than 100 MW located in Minnesota. In 1999, mercury emissions from these facilities were an estimated 1,456 lbs., while some 34.1 million tons of CO_2 was emitted from these plants. In 1999, net generation at these plants was some 29.5 million megawatt-hours. As might be expected, the greatest emissions occurred at the two largest generation facilities, Xcel Energy's Sherburne County facility and Minnesota Power's Clay Boswell generating facility.

Emissions of SO_2, NOx, CO_2 and mercury per kWh of net electricity generation is shown in Figure A-4 for 1999 for baseload and intermediate load plants of 100 MW or more located in Minnesota. Emissions of NOx vary from 0.0002 to 0.01 lb. per kWh, or by about 50-fold from the lowest emitting to the highest emitting facility. Emissions of SO_2 vary from 0.0001 lb. per kWh to 0.021 lb. per kWh, or by more than 100-fold from the lowest to the highest emitting facilities. Emissions of CO_2 range from 0.94 lb. per kWh to 2.77 lb. per kWh, and those for mercury from 0.00002 to 0.00007 lb. per MWH. The current performance standards for NOx for new or modified coal-fired facilities is equivalent to about 0.001 lb. per kWh, and that for SO_2 to about 0.001 to 0.002 lb. per kWh.[135]

The lowest emitting baseload or intermediate load facility per kWh-generated is the natural gas-fired LSP-Cottage Grove cogeneration facility. Xcel's King and Riverside plants are the highest emitting plants presently in service for NOx, and the King plant and the Silver Lake facility owned by Rochester Public Utility are the highest emitting plants for SO_2. Regarding CO_2, the Hoot Lake and Black Dog facilities are the top-emitting plants, while for mercury, Sherburne County and Syl Laskin are the top-emitting facilities.

The wide range of emissions per kWh of net electricity generated results from, among other factors, differences in the type of fuels used, the use and vintage of any pollution control equipment, and the efficiency of conversion of thermal energy to electricity at the plant. While there exists no commercially available control technology for CO_2 and mercury, depending on type, pollution control equipment can lower emissions of NOx and SO_2 by 30 to 85 percent. The efficiency of power generation in converting the energy content of fuel to electricity typically varies from about 32 percent for older existing coal-fired facilities to 55 percent for new combined cycle natural gas units. Pollution control equipment installed at baseload and intermediate load generating facilities located in Minnesota is listed in Figure A-4.

On a per kilowatt hour basis, emissions of SO_2 and NOx have declined on a statewide basis. Total emissions, however, continue to rise.

Emissions trends for all Minnesota electricity generating plants are shown in Figures A-5 to A-8 for

Figure A.4: Emission Rates Per Unit of Electricity Generated at Minnesota Electric Generating Plants

	Emission Rate (lb./kWh generated)				Primary Emission Controls[a,b]	
	NOx	SO2	CO2	Hg	SO2	NOx
Xcel Energy						
Sherburne County	0.003	0.003	2.39	0.00000006	scrubbers	LNC, LNB
Allen King	0.011	0.017	2.10	0.00000002		
Riverside	0.011	0.012	2.11	0.00000003		
High Bridge	0.007	0.005	2.46	0.00000005		
Black Dog	0.010	0.004	2.60	0.00000003		
Minnesota Power						
Clay Boswell	0.004	0.006	2.34	0.00000005	scrubbers	LNC
Syl Laskin	0.006	0.004	2.27	0.00000007		
Otter Tail Power						
Hoot Lake	0.004	0.008	2.77	0.00000005		LNB
Rochester Publ. Util.						
Silver Lake	0.007	0.021	1.78	0.00000004	1	
LSP Cottage Grove	0.0002	0.000	0.94	NA		SCR

[a] LNC1 = low NO_X coal and air nozzles with close coupled overfire air; LNC2 = low NO_X coal and air nozzles with separated overfire air.
[b] low NOx controls 1 at Sherburne County unit 1 and low NO_X controls 2 at Sherburne County unit 2. Wet scrubbers at Sherburne County units 1 and 2 and Clay Boswell unit 4, dry lime scrubbers at Sherburne County unit 3.

Figure A.5: Sulfur Dioxide Emissions from Electricity Generation in Minnesota

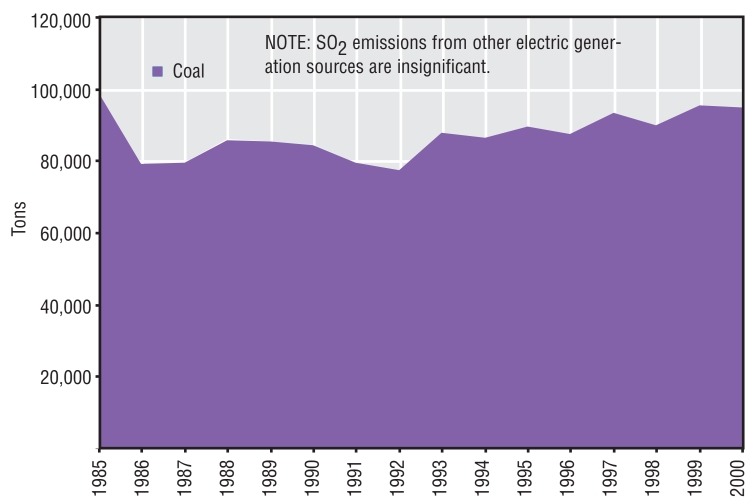


Figure A.6: Nitrogen Oxides Emissions from Electricity Generation in Minnesota

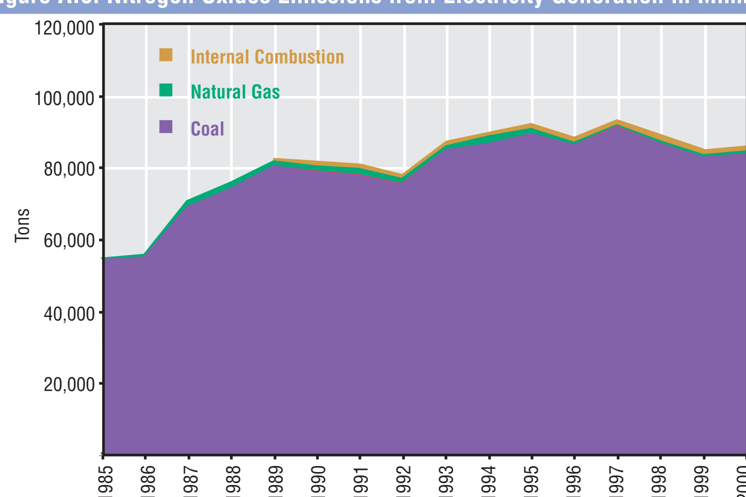


Figure A.7: Greenhouse Gas Emissions from Electric Generation in Minnesota

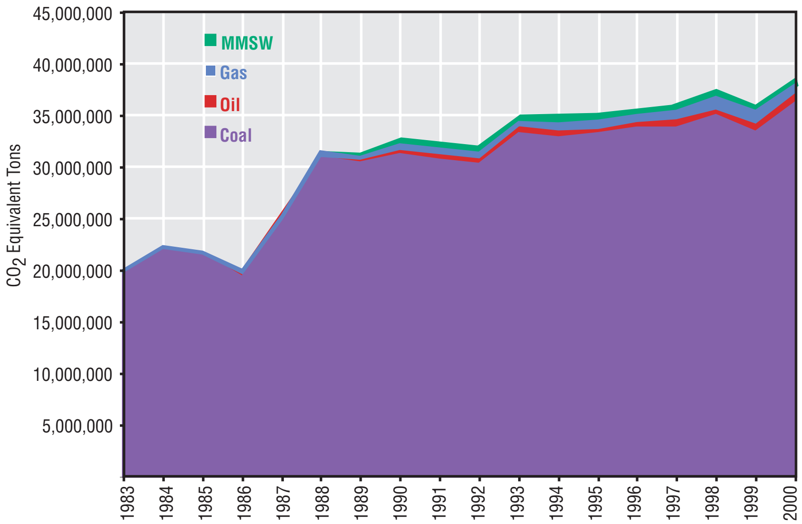


Figure A.8: Mercury Emissions from Electric Generation in Minnesota

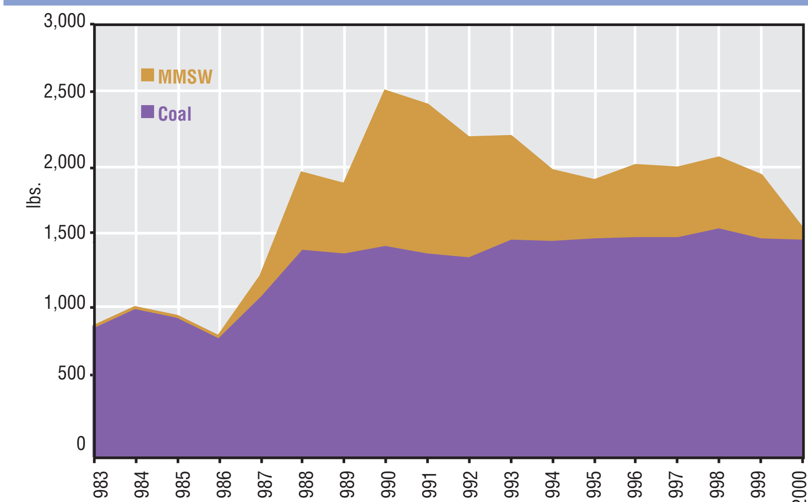
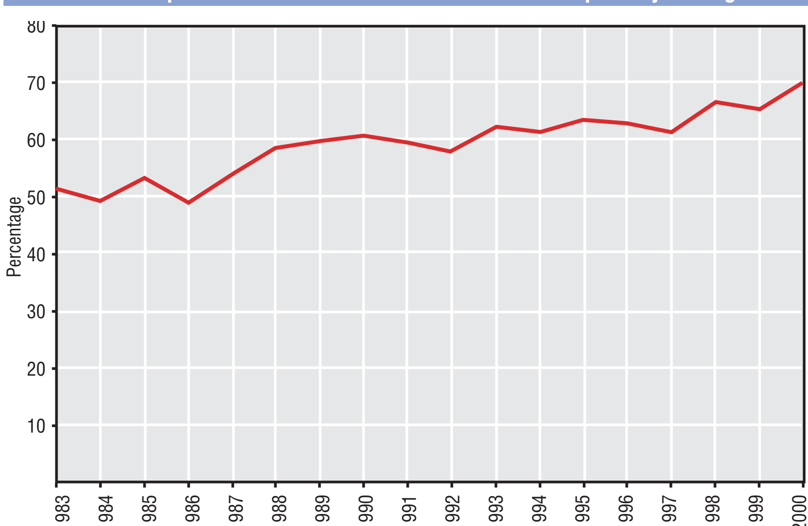


Figure A.9: Net Electric Generation in Minnesota Baseload Plants as a Percentage of Potential Generation at 8760 Hours of Operations and Reported Plant Net Summer Generation Capability Rating



sulfur dioxide, nitrogen oxides, carbon dioxide, and mercury. Figures A-5 and A-6 show SO_2 and NOx emissions, respectively, from electricity generation from 1985 to 2000. These figures show that most emissions of SO_2 and NOx result from coal-fired facilities. Emissions of SO_2 have increased from about 78,000 tons in 1986 to about 95,000 tons in 2000, or at an overall average rate of about 1.3 percent per year.

SO_2 emissions prior to 1986 were higher, falling from the early 1980s to 1986 due to increased use of low sulfur western coal as a fuel. Since 1985, NOx emissions have increased from 58,000 tons per year to about 87,000 tons per year, or about 2.7 percent per year.

The estimated long-term trend in emissions of greenhouse gases is shown in Figure A-7. About 99 percent of all greenhouse gases produced during electricity generation in Minnesota are in the form of carbon dioxide. Emissions of nitrous oxide (N_2O) comprise most of the remainder. In terms of fuels, most emissions of greenhouse gases derive from coal combustion, with the combustion of solid waste, petroleum coke and natural gas contributing only a small part to total emissions. Since 1983, emissions of greenhouse gases from electricity generation in Minnesota have approximately doubled, increasing from about 20 million CO_2-equivalent tons to the current 38.6 million CO_2-equivalent tons. Emissions are increasing at a rate of 3.9 percent per year.

Finally, Figure A-8 shows the estimated 17-year trend in mercury emissions from electricity generation in Minnesota. Most mercury that is emitted during power production in Minnesota currently is derived from coal combustion. Due to enhanced mercury controls at solid waste incinerators, emissions of mercury from electricity generation have declined about 40 percent since 1990, falling from about 2,500 lb. of mercury in 1990 to the current 1,500 lb. in 2000. With most emissions from solid waste incineration now eliminated, at present levels of emission control any increase in coal combustion at Minnesota's electricity generation facilities will result in increased mercury emissions to the atmosphere.

With the exception of unit 3 at Xcel Energy's Sherburne County facility, relatively little new generation capacity has been built in Minnesota since

1983. Most of the increases in air emissions have derived from higher utilization rates of existing plants. Historical utilization rates for baseload and intermediate load plants larger than 100 MW in Minnesota are shown graphically in Figure A-9. This figure shows that utilization rates have steadily increased since 1983, rising statewide from 50 percent to the current estimated 70 percent. Much of this has occurred at coal-fired facilities, resulting in the upward movement of air emissions depicted in the Figures A-5 through A-8.

With regard to increased utilization of existing generating plants, the long-term trend favors at least some increased utilization. A further increase in capacity factors at existing facilities of 5 percent or more might be achievable. In their respective integrated resource plans filed with the PUC, Xcel Energy, Minnesota Power and Otter Tail Power in aggregate forecast an increase in coal throughput through existing facilities of about 2.5 million tons of coal between 1999 to 2010.

In addition to increased utilization of existing facilities, new plants will be added. Figure 3-3 in Chapter 3 of the main report lists the generating plants under construction or planned in Minnesota. This list does not include conversion of the LTV Taconite Harbor power plant for use in supplying the grid with electricity. LTV is currently in a bankruptcy proceeding. The Hoyt Lakes and Taconite Harbor facilities are for sale in the bankruptcy proceeding. The conversion of the Taconite Harbor plant to a grid power plant will shift approximately 3,000 tons of SO_2, 2,850 tons of NOx and 1.2 million tons of CO_2 from the industrial sector to the electricity generating sector.

Based on the emission and operating characteristics of similar types of newly constructed or operating plants, Figure A-10 estimates the contribution of this expansion in statewide generation capacity to annual statewide emissions of SO_2, NOx and greenhouse gases.[136] These additions can be expected to generate about 3.5 million MWh of additional electricity each year. Annually associated with this generation, however, would be an extra 1.6 million tons of carbon dioxide, 980 tons of SO_2 and 1,290 tons of NOx. This translates to an increase in statewide emissions of about 4 percent for CO_2, and 1 and 1.5 percent for SO_2 and NOx, respectively.

Using the projected increase in coal throughput at existing facilities, current emission levels (see Figure A-3) and emissions associated with new con-

Figure A.10: Estimated Extra Annual SO_2, NOx and CO_2 Emissions Associated with Permitted or Planned Expansions to Service or Capacity Added Since 2000

Plant Name	Generation: Capacity (Summer) (MW)	Capacity Factor (%)	Net Generation (MWH/yr)	Efficiency in Converting Fuel to Electricity	Emissions: SO_2 (tons)	NO_X (tons)	CO_2 (Tons)
Pleasant Valley units #1-3	434	5	190,092	0.34	1	18	110,934
Lakefield Junction units #1-6	480	5	210,240	0.34	1	20	122,692
New Ulm unit #7	22	5	9,636	0.34	0	1	7,717
Cascade Creek units #3-4	50	5	21,900	0.34	0	2	12,780
Potlatch Cloquet unit #8	24	65	136,656	0.32	0	66	84,734
Navitas gas turbine	250	5	109,500	0.34	1	10	63,902
Otter Tail Power Solway unit #1	44	5	19,272	0.34	0	2	11,247
Prairie-Gen unit #1	49	5	21,462	0.34	0	2	12,525
St. James Diesel Plant units #1-7	12	5	5,256	0.25	9	117	5,725
Worthington Diesel Plant units #1-6	14	5	6,132	0.25	10	136	6,679
Black Dog units #2,5	143[a]	45[c]	1,144,757	0.5	-28[d]	-41[d]	435,075[d]
District Energy unit #7	25	65	142,350	0.2	39	182	61,668
Heartland Energy and Recycling	4	65	22,776	0.2	7	14	36,824
Fibrominn Biomass Power Plant	50	65	284,700	0.22	155	353	-
Northome Biomass Plant	15	65	85,410	0.26	14	56	-
Perham Resource Recovery	2.5	65	14,235	0.2	2	36	11,746
Grand Rapids power plant	195[b]	65	1,110,330	0.42	767	316	625,590
Total	**1,813.5**		**3,534,704**		**978**	**1,288**	**1,609,838**

[a] net increase in generation capacity after conversion of existing unit 2 to combined cycle gas turbine, retirement of existing unit 1, and addition of unit 5. [b] net increase in generation capacity after subtraction of internal Blandin demand. [c] 45% capacity factor at 290.4 MW of capacity at repowered unit #2 and new unit #5. [d] estimated emissions at repowered unit #2 and new unit #5 less 1999 emissions from old units #1 and 2.

NOTE: In addition, approximately 3,020 tons of existing SO_2 emissions, 2,849 tons of existing NO_X emmissions and 1,215,921 tons of CO_2 would be shifted from the industrial sector to the electricity generation sector with the conversion of the 187.7MW LTV-Taconite Harbor plant to a generating facility serving the grid.

Figure A.11: Historic and Forecasted Emissions of CO_2, SO_2 and NOx from Electricity Generation in Minnesota

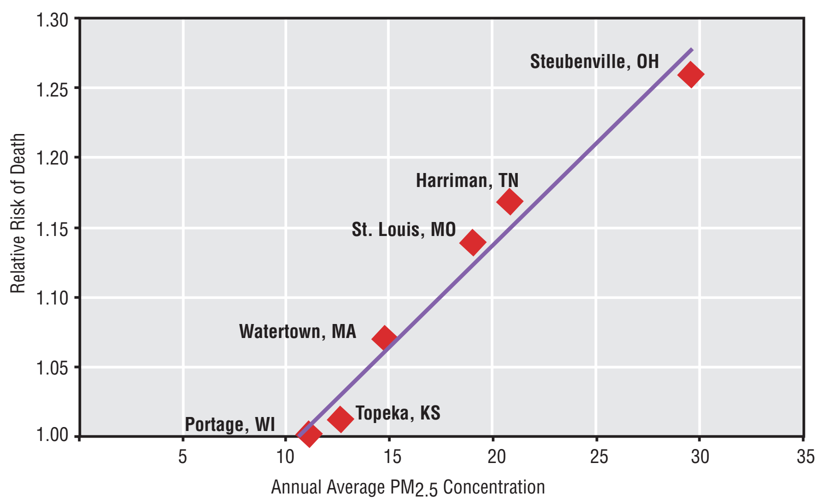
	2000	Year 2005	2010
CO_2			
Baseline 2000 Emissions	38,638,000	38,638,000	38,638,000
Emissions from Increased Use, Existing Plants[a]	-	454,000	3,208,000
Emissions from New Generation Capacity	-	1,610,000	1,610,000
total	38,638,000	40,702,000	43,456,000
SO_2			
Baseline 2000 Emissions	94,915	94,915	94,915
Emissions from Increased Use, Existing Plants[a]	-	1,065	7,494
Emissions from New Generation Capacity	-	978	978
total	94,915	96,958	103,387
NO_X			
Baseline 2000 Emissions	88,291	88,291	88,291
Emissions from Increased Use, Existing Plants[a]	-	1,125	7,435
Emissions from New Generation Capacity	-	1,288	1,288
total	88,291	90,704	97,014

Sources:Figures 3.3 and 3.13 above

[a] Calculated from projected increased coal use from 1999 levels at large baseload and intermediate load plants, as given in the integrated resource plan filings of Xcel Energy, Minnesota Power and Ottertail Power

NOTE: emissions from the Taconite Harbor plant are not included, since these would not represent new emissions but simply a shifting of emissions from the industrial sector to the electricity generation sector.

Figure A.12: Relative Risk of Death vs. Fine Particle ($PM_{2.5}$) Concentration



struction (see Figure A-10), aggregate statewide emission levels from electricity generation facilities located in Minnesota are forecasted in Figure A-11 through 2010. This forecast does not include any new generation needed to meet the capacity deficit forecast in Chapter Two, beyond the current projects listed in Figure A-10. Figure A-11 shows that CO_2 emissions will increase 4.8 million tons by 2010, leading to a roughly 12 percent increase in emissions from current levels by 2010. In the case of NOx, emissions will increase 8,723 tons by 2010, or 10 percent. SO_2 emissions will increase 8,472 tons by 2010, or 9 percent.

Finally, it might be noted that the projections given in Figure A-11 assume that no new pollution control requirements are instituted in the state and that emissions will continue at current rates per MMBtu of energy input. The imposition of more stringent controls on existing plants could dramatically change this rate, thereby reducing levels of future emissions.

Health and Environmental Impacts of Electric Generation

Sulfur dioxide and nitrogen oxides emitted from power plants interact with other compounds in the air to form fine particles and to cause acid rain. Nitrogen oxides react with volatile organic compounds to form ozone in hot, sunny weather. Mercury is a toxic pollutant that contaminates some fish, making them unsafe for human or wildlife consumption. Carbon dioxide is a greenhouse gas that contributes to global climate change. This section briefly describes the health and environmental impacts of these pollutants.[137]

Particulate matter

Airborne particulate matter, especially very small particles from combustion sources such as power plants, diesel and gasoline powered engines and vehicles, and wood burning, are creating health concerns at current outdoor concentrations. Particles are emitted directly, or can be formed when ammonia and combustion gases such as nitrogen oxides and sulfur dioxide chemically transform into particles. Very small particles are inhaled deeply into the lungs where the body cannot easily remove them.

A substantial body of published scientific literature, such as the Harvard Six Cities Study findings displayed in Figure A-12, have shown an association between increased particles in the air and premature death from heart and respiratory disease.[138] Numerous studies also show the number of asthma attacks per day goes up as particles in the air increase.[139]

In 1997, EPA added two new standards for fine particles ($PM_{2.5}$), set at 15 micrograms per cubic meter and 65 micrograms per cubic meter, respectively, for the annual and 24-hour standards. Beginning in 2002, based on three years of monitoring data, EPA will designate areas as nonattainment that do not meet the standards. Monitored yearly, average concentrations of fine particles in the Twin Cities typically range from 11 to 14 micrograms per cubic meter. Scientists studying health effects have found health effects at levels below the standards. In cities with lower particle concentrations, including some likely to meet current federal ambient air standards, both hospital admissions and deaths from heart and lung disease rise when particles in the air increase.[140] EPA reviews air quality standards about every five years. EPA is currently revising the Criteria Document for Particulate Matter to reflect the recent evidence regarding ambient particulate matter air concentrations and health effects. EPA may use this information to propose a more restrictive particulate matter standard.

While the evidence for health effects from air pollution has strengthened over time, especially fine particles derived from fossil fuel combustion, scientists are actively researching *how* particles contribute to these health effects: What are the biological mechanisms? Which physical and chemical properties of the particles are most relevant to their toxicity? Answering these questions will help determine which sources are most culpable.

Methods are unavailable to specifically apportion health effects based on differences in emission sources. Given this uncertainty, human health risk estimates are simply based on particle mass. Using the assumption that fine particles from all sources have an equal ability to cause adverse effects, several researchers have developed ballpark estimates of the benefits from reducing power plant emissions.

One article referenced an estimate that reducing emissions from older coal-fired power plants in the U.S. could provide substantial benefits to public health, including the avoidance of 18,700 premature deaths, 3 million lost work days, and 16 million restricted activity days each year—primarily due to reductions in particulate emissions.[141] Other studies, such as that by the Environmental Law Institute shown in Figure A-13, have tried to quantify the public health-based financial benefits of reducing particle emissions from power plants.

Figure A.13: Billions of Dollars Saved in Public Health Costs as Result of Reduced Use of Coal in ElectricGeneration in Comparison to Business-as-usual Scenario for 2010

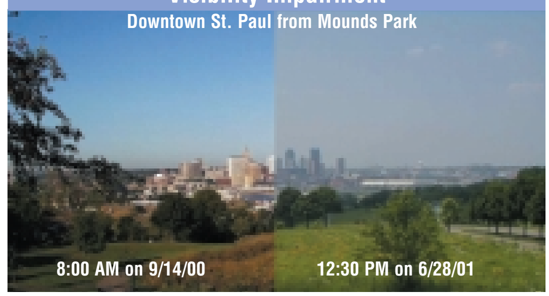
	Morbidity	Mortality	Total
SO2	1.2	23.2	24.5
NOx	0.4	1.6	2.0
Total	1.6	24.8	26.4

*Data from Environmental Law Institute Report, May 2001. Health benefits calculated only as result of particulate reductions due to lowered SO_2 and NO_X emissions under the scenario of 50 percent reduction in coal with replacement primarily by natural gas. The report notes that because of the uncertainties in the estimation of health benefits, the assumptions made for these calculations were conservative and therefore these estimates may provide lower benefit estimates compared to other studies. In addition, the health benefits modeled did not include co-benefits of lowered urban ozone levels, reduced acid deposition and eutrophication, and increased visibility. Nor does the estimate include the benefits of lowered mercury or carbon dioxide emissions. Values are calculated for the U.S.

In addition to health impacts, small particles reflect light more efficiently than large particles and reduce visibility. Particles are not the only cause for visibility impairment but they are a major contributor. Figure A-14 shows how the Twin Cities skyline can look depending on the degree of visibility. The concentration of particles in the air was 15 micrograms per cubic meter on the left and 35 on the right.[142]

Figure A.14: Particulate Pollution Contributes to Visibility Impairment

Downtown St. Paul from Mounds Park

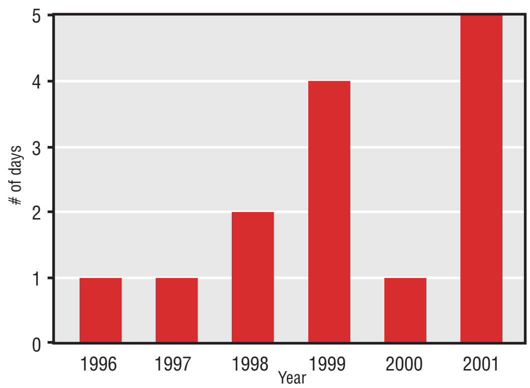


Ozone

Ozone can be good or bad depending on where it is found. In the earth's upper atmosphere, ozone occurs naturally and forms a protective layer that blocks out harmful ultraviolet radiation. In the earth's lower atmosphere, ozone is formed when pollutants (nitrogen oxides and volatile organic compounds) emitted from power plants, transportation, industrial plants and other sources react chemically in sunlight.

Ozone pollution is a concern in the summer when weather conditions needed to form it—hot, sunny days—typically occur. Minnesota currently meets federal and state ozone standards. However, this past summer, for the first time since the mid-1970's, air advisories were issued on six days for the Twin Cities due to ozone. Ozone effects can include respiratory irritation, coughing, throat irritation, chest

Figure A.15: Number of Days with Ozone Levels Greater than the 8-Hour Standard (ppb)



tightness, lung injury, asthma aggravation, and increased susceptibility to respiratory infections. Those most susceptible to the effects of ozone include children and adults who are active outdoors and people with respiratory disease.

Figure A-15 shows the number of days that the daily 8-hour average ozone concentration exceeded the standard for the past five years. Two more summers like 2001 could cause parts of Minnesota to be designated as nonattainment. (The method for determining attainment states requires several years of data). Nonattainment results in a federally mandated plan typically including controls on large stationary sources and mobile sources.

Mercury

Of Minnesota's 85,000 square miles, 5,100 square miles are covered by lakes, rivers and streams, but a particularly toxic form of mercury, methyl mercury, contaminates the fish in much of Minnesota's waters. Surprisingly, the fish in some of Minnesota's most remote, pristine lakes are among our most contaminated. Tourism is a major industry in these areas, due in part to the good sport fishing. In most waters in Minnesota, over 95 percent of the mercury falls from the atmosphere in rain or as dry fallout. It gets into the lakes when it is washed out of the atmosphere in rain or falls as fine particles, is converted to methyl mercury in sediments and wetlands, and then accumulates up the aquatic food chain to reach high concentrations in fish.

Methyl mercury is a nerve poison, so eating too much contaminated fish can harm health. If a person does not eat a large amount of game fish, they are probably not at risk. However, children and developing fetuses are susceptible to subtle, long-term nerve damage, even with small amounts of methyl mercury. Therefore, the Minnesota Department of Health—in its annual fish consumption advisory—provides guidance on how many fish are safe to eat. In addition, mercury contamination could also be affecting the health of fish-eating wildlife, like loons. The long-term solution to this problem is not to limit how much fish people eat (which offers no protection to Minnesota's wildlife), but to reduce the input of mercury to lakes.

Up to 90 percent of the airborne mercury landing on northern Minnesota lakes blows in from outside the state. Ten percent of the mercury comes from in-state sources. Coal-fired power plants within Minnesota contribute incrementally to the contamination of any particular lake or river within Minnesota. Other sources can have larger local impacts depending on the amount of mercury released, the species of mercury, and stack height.

Mercury in the environment undergoes many transformations before it is finally taken up into fish. Because the total pool of mercury is too large, the amount of mercury being emitted and the amount of mercury already in the environment needs to be reduced, regardless of emission source or chemical form.

Metals

Power plants also emit metals such as cadmium, arsenic, vanadium, chromium, nickel and lead. Lead has historically been a concern in Minnesota's urban areas.

Atmospheric lead is emitted from a variety of stationary sources. Nationwide, primary and secondary metals processing, waste incineration other than municipal waste, and aircraft are the most significant air emissions contributors of lead today. Coal burning in utility boilers contributes about 2 percent to the total releases of lead to the air today. According to EPA's National Air Pollutant Emission Trends Report (1999), total lead emissions from all sources dropped from 220,860 short tons in 1970 to 4,199 short tons in 1999. Nationally, coal burning in utility boilers released 327 tons of lead in 1970, and 72 tons in 1999.[143]

In Minnesota, lead in the air has dropped significantly. Between 1984 and 1994, average lead concentrations decreased 87 percent, from 0.53 µg/m3 to 0.06 µ/m3 (compare to the national ambient air quality standard of 1.5 µ/m3). Minnesota's emissions profile is similar to the national profile, suggesting that today, the most significant contributors to atmospheric lead emissions are metals processing (lead and other metals smelters) and aircraft use of leaded fuel.[144]

Global Climate Change

Global warming results from the accumulation in the atmosphere of very long-lived gases that act to absorb infrared radiation, trapping it in the lower atmosphere and leading to globally rising surface and atmospheric temperatures. As a result of global warming, virtually every component of what we know as weather will change. Temperature will change. Rainfall will change, both in terms of its intensity, its distribution across seasons, and in its aggregate annual amount. Surface evaporation will change, as will seasonal soil moisture, run-off and stream flow. Some seasons will lengthen in duration, some dramatically shorten. The length of periods of peak heat and humidity will change, as will cloudiness, wind speed, patterns of storminess, and virtually every other component of weather.

These changes, should they occur, could dramatically effect the ecology of Minnesota. Ecological systems are tightly coupled to prevailing climate. As climate changes, ecological communities change. In Minnesota, ecological systems vary widely from a cold climate boreal forest in the extreme north to a warm temperate oak parkland in the south, woodland in the east and prairie in the west. As climate changes, particularly as it warms, Minnesotans will see a progressive forced northward march of conditions favorable to warm temperature forests now dominant to our south, and the progressive shrinkage of cool and cold climate vegetation types. Few ecological systems now found in Minnesota are likely to survive this without significant disruption.

Figure A.16: Carbon Emissions, CO_2 Concentrations and Temperature Change, 1000-2000

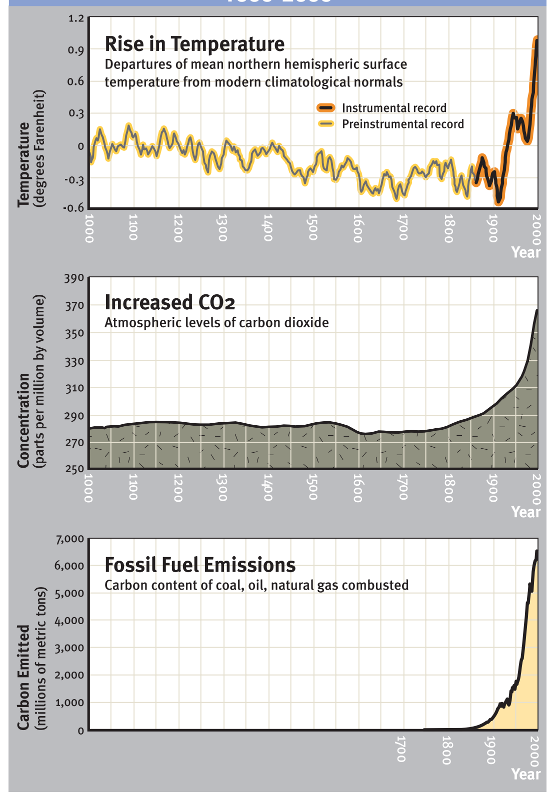


Chart by Matt Kania

Gases that contribute to global warming are called greenhouse gases. The principal greenhouse gas is carbon dioxide or CO_2. Most human-produced CO_2 is emitted during the combustion of coal, oil and natural gas. Since the beginning of industrialization about 150 years ago, atmospheric concentrations of CO_2 have risen about 30 percent, as shown in Figure A-16. Continued dependence on these fuels as the principal global source for energy will result in at least a doubling of preindustrial atmospheric concentrations of CO_2, and perhaps as much as a tripling. It has been widely accepted in the scientific community for three decades that a doubling of the preindustrial level of CO_2 will cause mean global surface temperature to rise between 1.5 and 4.5 degrees Celsius—a view reaffirmed by the U.S. National Academy of Sciences earlier in 2001 in its latest scientific review of the question.[145]

Since the beginning of industrialization, the mean surface temperature of the earth has risen about 0.7 degrees Celsius. For many hundreds of years prior

Figure A.17: Principal Heath and Environmental Impacts of Air Pollutants Emitted From Coal-Fired Power Plants

Pollutant	Effects	Geographical Scope of Effect*
Sulfur Dioxide	Respiratory disease, acidification, crop losses, visibility impairment	Local, regional
Nitrogen Oxides	Respiratory disease, acidification, crop losses, visibility impairment, eutrophication	Local, regional
Particulate Matter	Respiratory and cardiac disease, premature death, visibility impairment	Local, regional
Mercury	Central nervous system disease	Local, regional, global
Metals	Various - depends on the metal	Local, regional
Secondarily formed pollutants		Local, regional
•SO_4 from SO_2	Acidification	
•NO_3 from NO_X	Acidification, eutrophication	
•$PM_{2.5}$ from SO_2 and NO_X	Respiratory disease, prematuredeath, visibility impairment	
•Ozone from NO_X	Respiratory disease, visibility impairment	
Carbon Dioxide	Climate change	Global

*Local: Within 100 miles; Regional: Within 1,000 miles

to industrialization, global surface temperature was very stable at levels much cooler than now. Beginning in 1900, global temperatures abruptly turned up in a warming without any parallel in the record of the prior 1,000 years. (see Figure A-16)

Most climatologists expect the warming trend to continue and even accelerate as emissions of greenhouse gases continue to accumulate in the atmosphere. It has been common for several decades to find in the scientific literature estimates of future warming of 2 to 3 degrees Celsius over the next 50 to 100 years. Recently, the UN Intergovernmental Panel on Climate Change concluded that, accounting for uncertainties, mean global surface temperature will rise 1.4 to 5.8 degrees Celsius over the next 100 years.[146]

In general, the degree of forecasted warming is roughly comparable to the amount of warming that the earth experienced at the end of the last ice age, when rising global temperatures changed a perennial winter-like climate throughout much of the northern half of the northern hemisphere into the present warm climate. This provides a measure of the intensity and geographic scale of the changes in ecological and other natural systems that are contemplated. As a rule of thumb, each 1 degree Celsius rise in temperature in the Northern Hemisphere is associated with a northward displacement of climatic and ecological regions of about 100 miles.

Once present in the atmosphere in elevated concentrations, CO_2 persists in the atmosphere at elevated concentrations for hundreds of years. This renders a CO_2-induced warming, once initiated, essentially irreversible by natural means over a time scale of several lifetimes.

In 2000, the U.S. Department of Commerce prepared a national assessment of impacts from global warming. Specific effects that are thought likely to result in Minnesota include:

- retreat of the spruce-fir ‘boreal’ forest of the Boundary Waters Canoe Area and replacement by northern hardwood forest;
- progressive replacement of much of the aspen-birch forest for northern Minnesota by temperate deciduous forest and deciduous savanna, and associated decline in habitat for some wildlife currently inhabiting the state;
- loss of 50 to 100 percent of stream habitat for cold water fishes like brook trout and decline of habitat for cold water fishes in shallow Minnesota lakes;
- heightened influx of invasive species into Minnesota waterways and lakes;
- expansion of insect populations in Minnesota, requiring more intensive public health measures associated with the control of insect-borne diseases;
- reduced Great Lakes lake levels, requiring new investments in harbor facilities in Duluth-Superior, and affecting the competitiveness of the Great Lakes shipping business and industries that depend on it; and
- reduced opportunities for winter recreation.

Agricultural production is thought likely to increase. However, due to higher summer surface temperatures, the number of days conducive to the formation of high levels of ozone may increase, leading to declining air quality. Large new public expenditures may become necessary to account for climatic uncertainty in the design of sewage and wastewater treatment facilities, the in-land barge system and the flood control infrastructure.

It is now generally recognized that some limit on atmospheric CO_2 levels will be necessary in the future to minimize the risks of global climate change to society. Current global policy is summarized in the provisions of the 1992 United Nations Framework Convention on Climate Change, of which the U.S. is a signatory. Under the terms of the Convention, the parties are required to implement policies to stabilize their emissions of greenhouse gases to the atmosphere at 1990 levels. The stated goal of the Convention is the avoidance of 'dangerous' human interference in global climate. The level at which to cap CO_2 concentrations has yet to be determined.

Acid Rain

Acid rain—or acid deposition- causes acidification of lakes and streams and contributes to damage of trees and many sensitive forest soils. The primary causes of acid deposition are sulfur dioxide and nitrogen oxides. Thus, coal-fired power plants are significant contributors to acid rain. Acid deposition is a complex problem whose sources are often distant from its impacts and is highly variable across time and geography. Prevailing winds blow the compounds that cause both wet and dry acid deposition across state and national borders, and sometimes over hundreds of miles.

Acid rain causes a cascade of effects that harm or kill individual fish, reduce fish population numbers, completely eliminate fish species from a water body, and decrease biodiversity. Some types of plants and animals are able to tolerate acidic waters. Others, however, are acid-sensitive and will be lost as waters become more acidic. The impact of nitrogen on surface waters is also critical. Nitrogen plays a significant role in episodic acidification and new research recognizes the importance of nitrogen in long-term chronic acidification as well. Nitrogen is also an important factor in causing eutrophication (oxygen depletion) of water bodies.

In Minnesota, our lakes and soils are fairly well-buffered and the effects of acid rain are not considered a problem here. However, in the northeastern United States soils and lakes are much more sensitive to the effects of acid rain. Despite declining national emissions of sulfur dioxide, recent scientific study is showing that the capacity of lakes and soils to recover from acid deposition is less than previously thought.[147] Many lakes in the northeast U.S. are acidic and have few or no fish. *Science* reports the researchers are calling for an additional 80 percent cut in emissions beyond the current mandate and that may only bring partial recovery to fish and trees by 2050.[148]

Conclusion

Power plants—especially coal-fired power plants—contribute significantly to the environmental and health impacts from air pollution. Figure A-17 summarizes the key air pollutants emitted from electric generation and their effects on health and the environment.

Current and Developing National Regulations Governing Utility Emissions

This section's review of current and developing national programs will show that, due to these health and environmental effects, utilities must continue to reduce emissions under programs already being implemented and further cuts are expected to be required under new programs. As a result, total emissions from utilities in the future will have to be significantly lower than today, including emissions from whatever new generation capacity is needed.

In the past thirty years, numerous federal regulations and programs have affected air emissions from the electric power industry as shown in Figure A-18. Arguably the most successful and cost-effective program has been the Acid Rain Program—an emissions "cap and trade" approach that has resulted in sulfur dioxide emissions dropping 4.5 million tons and nitrogen oxides emissions dropping 1.5 million tons from 1990 levels nationally. However, based upon the failure of lakes and streams to recover despite the drop in emissions, some scientists are calling for further reductions beyond the 1990 Clean Air Act Amendments.

New Source Review is an older, more traditional regulatory program that is undergoing change. One intent of New Source Review is to require existing plants to improve their emissions control when they undergo a major modification. The New Source

Figure A.18: Major National Air Quality Programs Affecting U.S. Electric Utilities

1970
National Air Standards/ State Implementation Plans

New Source Review/Visibility Programs
PM_{10} National Air Standard

1980

1990
UN Framework on Climate Change International Treaty (USA signatory)

Acid Rain SO_2 Phase 1
Acid Rain NOx Phase 1
NOx NSPS Revision

2000
Acid Rain NOx Phase 2 and SO_2 Phase 2

Assess Attainment of Revised $PM_{2.5}$ and Ozone Air Standards
Interstate NOx Air Pollution Petitions/NOx State Plans
US/Canada NOx Treaty
Periodic Review of Ozone & $PM_{2.5}$ Air Standard
Mercury Standards Implemented/Implement Regional Haze Rules
Kyoto Protocol or alternative US Response

2010

Review process identifies the most appropriate (i.e., lowest) level of emissions for a process on a case-by-case basis and applies the current best available control technology to the source.[149]

In the near future, electric power plants will be the focus of a number of major initiatives to reduce air emissions, described in the next few paragraphs.

Mercury National Emission Standard for Hazardous Air Pollutants

EPA is developing a rule to limit mercury emissions from utilities. As required by the 1990 Clean Air Act Amendments, EPA studied emissions of hazardous air pollutants (or air toxics) from fossil-fuel-fired power plants and found in December 2000 that air toxics control (e.g. mercury control) is appropriate for coal-fired and oil-fired utility boilers. EPA is scheduled to propose a Maximum Achievable Control Technology standard by 2003 for these sources that is expected to focus on mercury control.

Regional Haze Rules

EPA recently finalized a regional haze rule designed to return visibility to natural conditions in national parks and wilderness areas. The rule will require power generators to reduce SO_2 and NOx emissions either through implementation of best available retrofit technology or a trading program yet to be developed.

Implementation of New $PM_{2.5}$ and Ozone Standards

Since the $PM_{2.5}$ national ambient air quality standard for fine particles was set in 1997, dozens of new published studies, taken together, collectively strengthen the association between $PM_{2.5}$ and severe human health effects. In 1997, EPA also established a new standard for ozone. If a state has areas that do not meet an air quality standard, then the Clean Air Act requires the state to adopt emissions control requirements in the form of State Implementation Plans to bring nonattainment areas into compliance.

The MPCA will be able to determine its compliance status with the $PM_{2.5}$ standard in 2002 (3 years of data is needed to determine compliance). The MPCA expects Minnesota will be below the standards, but by a narrow margin. Recent exceedances of the ozone standard in Minnesota and states to the east suggest the possibility of future control requirements in Minnesota to address the ozone problem. Power plants are significant contributors to $PM_{2.5}$ and ozone precursor emissions.

NOx Reduction Requirements

In 1998, EPA finalized the NOx State Implementation Plan (SIP) call which requires the District of Columbia and 19 states (whose emissions contribute significantly to downwind ozone nonattainment problems) to revise their SIPs to control summertime NOx emissions. In response, all of these states are choosing control strategies that focus on reducing power plant emissions. In a separate action, in January 2000, EPA finalized a rule which was issued in response to petitions from some northeastern states under section 126 of the Clean Air Act. The rule requires large electric generating units and large boilers and turbines in 12 states and D.C. to control summertime NOx emissions under the Federal NOx Budget trading program beginning May 1, 2003. Minnesota is currently not one of these states.

Potential Multi-Pollutant Regulation Proposal by the Administration

EPA and the White House are working to finalize the details of a legislative proposal that will set limits on the utility emissions of three major air pollutants—nitrogen oxides, sulfur dioxide and mercury—through the use of a “cap and trade” program. The strategy consists of establishing an emissions cap for existing sources. In return for the cap, New Source Review would be relaxed and plants undergoing a modification would not necessarily need to install the best available control technology.

Multi-Pollutant Regulation Proposals by Congress

Legislation has been introduced in both the House and Senate that would require power plants to further reduce emissions. Representative Waxman’s bill (H.R. 1256) and Senator Jefford’s bill (S. 556) are very similar. Both bills would require:

- Plants 30 years old or more to comply with requirements for new sources within five years after enactment.
- Aggregate emissions reductions—not facility specific reductions.
- 75 percent reduction in NOx emissions from 1997 levels by 2007.

- 75 percent reduction in SO_2 emissions from Phase II acid rain levels by 2007.
- 90 percent reduction in mercury emissions from 1999 levels by 2007.
- Carbon dioxide emissions to 1990 levels by 2007.
- Regulations within 2 years. (S. 556 would require each plant to achieve reductions if EPA fails to meet timeline.)

Both bills may allow market-oriented mechanisms, except for mercury, to achieve these reductions. They also would allocate required emissions reductions equitably, taking into account reductions before enactment of the legislation. Jefford's bill also includes policies to reduce the rate of growth in natural gas consumption.

Reducing Emissions from Existing Power Plants

By applying proven pollution control technologies at Minnesota's existing coal-fired power plants, utility companies can reduce the emission rates of several pollutants. In particular, proven technologies can be installed that would significantly reduce the emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) at Minnesota's power plants.

Within the last ten years, Minnesota's electric utilities reduced SO_2 and NOx emission rates at some of their power plants, primarily to comply with the Acid Rain provision of the 1990 Clean Air Act Amendments. The Acid Rain program allows system-wide averaging; companies can reduce emissions significantly at one plant while other plants continue to emit at higher levels. To comply with the SO_2 provisions of the Acid Rain program, many of Minnesota's power plants switched from the higher sulfur coals they were using to lower-sulfur coals. Few, if any, plants were significantly modified to meet the new standard. To meet the NOx requirements of the Acid Rain program, companies that needed to reduce their system-wide emissions may have modified one or two facilities, while the others are operated as before. With a significant reduction at a small number of units, the company's average could meet the standard.

By using these methods to comply, the utilities have preserved opportunities for further improvement. For example, none of Minnesota's large power plants meet both of the emission standards for SO_2 and NOx for new plants set in the federal New Source Performance Standard (NSPS) for electric utility generating units.[150] (The NSPS basically requires a 90 percent reduction in the amount of SO_2 that the plant could emit without added controls. The NSPS sets a limit of 1.6 pounds of NOx per megawatt-hour of electricity generated.) Figure A-19 shows the characteristics of Minnesota's baseload

Figure A.19: Characteristics of Selected Baseload and Intermediate Load Coal-Fired Utility Boilers in Minnesota

Name	Approximate Capacity	Boiler type	Estimated SO_2 Emission rate	Estimated NOx Emission rate
MP – Clay Boswell 1	70 MW	Wall-fired	0.85 lb/mmBtu	0.4 lb/mmBtu
MP – Clay Boswell 2	70 MW	Wall-fired	0.85 lb/mmBtu	0.8 lb/mmBtu
MP – Clay Boswell 3	350 MW	Tangential	0.85 lb/mmBtu	0.3 lb/mmBtu
MP – Clay Boswell 4	535 MW	Tangential	0.15 lb/mmBtu	0.3 lb/mmBtu
MP – Syl Laskin 1	55 MW	Tangential	0.3 lb/mmBtu	0.5 lb/mmBtu
MP – Syl Laskin 2	55 MW	Tangential	0.3 lb/mmBtu	0.5 lb/mmBtu
OPC – Hoot Lake 2	65 MW	Tangential	0.6 lb/mmBtu	0.6 lb/mmBtu
OPC – Hoot Lake 3	85 MW	Wall-fired	0.6 lb/mmBtu	0.3 lb/mmBtu
RPU – Silver Lake	60 MW	Wall-fired	1.7 lb/mmBtu	0.4 lb/mmBtu
Xcel – A. S. King	570 MW	Cyclone	1.6 lb/mmBtu	1.1 lb/mmBtu
Xcel – Black Dog 3	115 MW	Wall-fired	0.35 lb/mmBtu	0.3 lb/mmBtu
Xcel – Black Dog 4	170 MW	Wall-fired	0.35 lb/mmBtu	0.8 lb/mmBtu
Xcel – High Bridge 5	100 MW	Wall-fired	0.4 lb/mmBtu	0.4 lb/mmBtu
Xcel – High Bridge 6	170 MW	Wall-fired	0.4 lb/mmBtu	0.6 lb/mmBtu
Xcel – Riverside 6	80 MW	Wall-fired	0.4 lb/mmBtu	0.9 lb/mmBtu
Xcel – Riverside 7	150 MW	Wall-fired	0.35 lb/mmBtu	0.9 lb/mmBtu
Xcel – Riverside 8	220 MW	Cyclone	1.4 lb/mmBtu	1.1 lb/mmBtu
Xcel – Sherco 1	710 MW	Tangential	0.2 lb/mmBtu	0.3 lb/mmBtu
Xcel – Sherco 2	720 MW	Tangential	0.2 lb/mmBtu	0.3 lb/mmBtu
Xcel – Sherco 3	870 MW	Wall-fired	0.35 lb/mmBtu	0.3 lb/mmBtu

NOTES: Data as reported by US Department of Energy for 1999.
Clay Boswell unit 4 and Sherco units 1, 2, and 3 are controlled for SO2.
NOX controls are installed at Clay Boswell unit 4, A..S. King, and Sherco units 1, 2, and 3.

Figure A.20: Characteristics of Modeled Boilers

Model Number	Capacity	Boiler Type	Uncontrolled SO_2 Emission Rate	Uncontrolled NOx Emission Rate	Facility with Similar Characteristics
1	100 MW	Wall-fired	0.9 lb/mmBtu	0.6 lb/mmBtu	MP: Clay Boswell 2
2	100 MW	Tangential	0.4 lb/mmBtu	0.45 lb.mmBtu	OTP: Hoot Lake 2
3	150 MW	Wall-fired	0.35 lb/mmBtu	0.7 lb/mmBtu	Xcel: High Bridge 6/ Riverside
4	400 MW	Cyclone	1.5 lb/mmBtu	0.9 lb/mmBtu	Xcel: A.S. King
5	400 MW	Tangential	0.85 lb/mmBtu	0.35 lb/mmBtu	MP: Clay Boswell 3

and intermediate coal-fired utility boilers, and their estimated emission rate.

The MPCA analyzed several control technologies that can be applied to the types of electricity generating units found in Minnesota. The SO_2 control efficiency and the cost of three types of scrubbers[151] were evaluated using five models. Characteristics of these models and Minnesota facilities with similar characteristics are shown in Figure A-20.[152] Because the boiler design does not usually affect whether a scrubber can be installed, the three SO_2 control methods were applied to each of the five models.

The MPCA also assessed a larger number of NOx control technologies for the same five models. While some of the control technologies can be added on to almost any boiler (e.g., selective catalytic reduction, or SCR; and selective non-catalytic reduction, or SNCR; and natural gas reburn), some control methods must be matched with specific boilers.[153]

Three boiler configurations were investigated. Wall-fired units are the most common boiler types found in Minnesota. The NOx emissions from wall-fired units may be reduced by the installation of low-NOx burners (LNB) with or without overfire air (OFA). Minnesota also has a few tangentially-fired boilers and cyclone boilers. Coal-and-air nozzles may be installed to reduce NOx in tangentially fired boilers with either close-coupled overfire air or separated overfire air, or both.[154] To reduce emissions at cyclone boilers, coal reburning technology may be added.

Figure A.21: Estimated Costs for Installing SO_2 Controls on Plants (low-cost technology to meet NSPS)

Model Number	Baseload Annual Capital Cost (millions, 1997$)	Intermediate Load Operating Cost (millions, 1997$)	Annual Operating Costs (millions, 1997$)
1	38.4	2.8	2.3
2	38.4	2.8	2.3
3	56.4	4.1	3.4
4	134.1	10.0	8.2
5	134.1	10.0	8.2

*Values to be added

The MPCA looked at three SO_2 control technologies on five boiler models in Figure A-21. Minnesota has a number of coal-fired utility boilers that are used to generate electricity in Minnesota. These units vary by their size, the type of boiler, and by their SO_2 emission rate. To assess the range of costs for controlling SO_2 emissions, the MPCA looked at three SO_2 control technologies on the five boiler models introduced earlier. The three flue-gas desulfurization options each achieved at least a 90 percent reduction in emissions (LFSO, which achieves an SO_2 reduction of 95 percent; LSD, 90 percent; and MEL, 95 percent). Calculations were performed at two capacity factors (a baseload case of 65 percent and a intermediate load case of 40 percent).

Using an EPA analysis of SO_2 scrubbers[155]as the basis of the computation, the MPCA estimated that the cost of installing SO_2 controls on these boilers would range from about $40 million to nearly $190 million, with the cost increasing with the size of the boiler.[156, 157] Estimates of annual operating costs (fixed plus variable) ranged from roughly $2 million to about $10 million. (Note that capital costs are the same for both baseload and intermediate load facilities.) Operating costs increase with the size of the boiler and with increased use. Similarly, the estimated annualized costs range from roughly $5.5 million to over $25 million, rising as the size of the boiler rises and also with increased use.[158]

The cost-effectiveness of control is figured by dividing the annualized cost by the number of tons of SO_2 removed from the flue gas (and therefore not emitted to the atmosphere). For the five modeled boilers, the estimated cost of the lowest-cost control at baseload conditions ranged from $1159 to $4861 per ton of SO_2 removed. For intermediate loads, the estimated cost-effectiveness decreased; the cost per ton ranged from $1729 to $7316.

The cost-effectiveness of a control option usually increases with the amount of SO_2 removed. (In other words, the cost to remove a ton of a pollutant decreases.) This amount of SO_2 removed is related to the level of the uncontrolled emissions and the removal efficiency of the control technology. For a given capacity factor and control technology, the order of cost-effectiveness for the boilers (from highest to lowest) is likely to reflect the order of maximum annual emissions (from highest to lowest). Because emissions are tied to boiler use, controls installed at units with higher capacity factors (such as baseload plants) are likely to be more cost-effective than those added at boilers with lower capacity factors (intermediate load plants and peaking plants).

These trends are generally supported in the analysis. Figure A-22 shows that controlling Model 4 would be the most cost-effective choice. Controlling the other models, particularly Models 2 and 3, would be less cost-effective.[159]

To evaluate the effectiveness and cost of control technologies that reduce emissions of NOx, the MPCA again used the five boiler models presented in the discussion of SO_2 control technologies. The number of control configurations analyzed varied with the different boiler models, as the applicable control technologies varied by boiler type. In addition, some control technologies could be used together. An EPA model was used to determine the effectiveness of the control technologies and to calculate their costs.[160, 161]

The most effective single control technology was SCR (selective catalytic reduction). The analysis assumed that SCR reduced high concentrations of NOx by 80 percent and low concentrations of NOx by 70 percent.[162] Four of the five models were able to meet the NSPS standard for NOx (1.6 pounds of NOx per megawatt-hour) with only SCR. Alone, however, SCR was not usually the most cost-effective control technology. Frequently, a combination of technologies achieved the desired reductions for the lowest cost.

As shown in Figure A-23, the cost of installing effective controls (i.e., those that would allow the controlled unit to meet the standard of 1.6 lb NOx/MW-hr) ranged from about \$9 million to roughly \$27 million. Costs for a specific type of control rose as the size of the controlled unit increased. In addition, though, the type of unit played a role, with wall-fired units being the least expensive to control to this level, and cyclone units the most expensive units to control. Figure A-24 shows the most cost-effective control technology that achieved the desired emission level, and the associated cost per ton of NOx controlled. Again, the highest-polluting units (in this case, models 3 and 4) were the most cost-effective to control.

The analyses above indicate that, to meet the requirements that New Source Performance Standards place on new electricity generating units, utility companies must spend an estimated \$1000 to \$7000 per ton of SO_2 removed and an estimated \$650 to \$2300 per ton of NOx removed. This compares with values in the literature for similar changes of an estimated \$322 per ton of SO_2 removed[163] and an estimated \$975 to \$2140 per ton of NOx removed.[164]

The MPCA did not investigate the efficiency or cost of technologies to control mercury and carbon dioxide. Few control efficiencies or cost estimates have been firmly established for retrofits to reduce mer-

Figure A.22: Estimated Cost to Meet NSPS Standard for SO_2 Emissions

Model Number	Lowest Cost Option to Meet NSPS for SO_2 (selected technology)	Cost-effectiveness for a Baseload Plant	Cost-effectiveness for an Intermediate Load Plant
1	Magnesium-enhanced lime	$2,088/tpy	$3,146/tpy
2	Magnesium-enhanced lime	$4,697/tpy	$7,079/tpy
3	Magnesium-enhanced lime	$4,861/tpy	$7,316/tpy
4	Magnesium-enhanced lime	$1,159/tpy	$1,729/tpy
5	Magnesium-enhanced lime	$2,044/tpy	$3,051/tpy

Figure A.23: Estimated cost for installing NOx controls on plants(low-cost technology to meet NSPS)

Model number	Capital cost (millions, 1995$)	Baseload annual operating cost (millions, 1995$)	Intermediate Load annual operating cost (millions, 1995$)
1	8.8	.8	0.7
2	11.6	1.1	0.9
3	14.5	1.1	1.1
4	26.8	4.2	3.6
5	15.5	1.5	1.1

Figure A.24: Estimated Costs to Meet NSPS Standard for NOx Emissions[a]

Model Number	Lowest cost option to meet NSPS for NOx (selected technology)	Cost-effectiveness for a baseload plant	Cost-effectiveness for an imtermediate load plant
1	SCR	$973/tpy	$1499/tpy
2	Gas Reburn with SCR	$1353/tpy	2290/tpy
3	LNB with SCR	$694/tpy	$1086/tpy
4	LNC3 with Gas Reburn	$653/tpy	$957/tpy
5	LNC2 with Gas Reburn	$1034/tpy	$1422/tpy

[a] cost in 1995 dollars

Figure A.25: Estimated Rate Impact of Installing SO_2 Controls on Plants (Low-Cost Technology to Meet NSPS)

Model Number	Facility with Similar Characteristics to:	Annual 2000 Residential MWH Usage[1] (a)	Baseload Cost Per MWH Per MWH 2000 $[2] (b)	Annual Baseload $ Cost per Residential Customer[3] (c)	Intermediate Load Cost Per MWH 2000 $ (d)	Annual Intermediate Load Residential Customer[4] (e)
1	Clay Boswell 2	8.32	1.2381	10.30	1.1924	9.92
2	Hoot Lake 2	10.23	2.3816	24.35	2.2743	23.25
3	High Bridge 6/Riverside	7.78	0.4802	3.74	0.4612	3.59
4	A.S. King	7.78	1.3804	10.74	1.3316	10.36
5	Clay Boswell 3	8.32	3.4615	28.79	3.2970	27.42

Assumes that these additions do not lengthen the life of the facility. Longer life would reduce the annual costs.
[1] MN Jurisdictional Annual Report [2] Sheet 1 [3] column (a) times column (b) [4] column (a) times column (d)

Figure A.26: Estimated Rate Impact of Installing NOx Controls on Plants (Low-Cost Technology to Meet NSPS)

Model Number	Facility with Similar Characteristics to:	Annual 2000 Residential MWH Usage[1] (a)	Baseload Cost Per MWH 2000 $[2] (b)	Annual Baseload $ Cost per Residential Customer[3] (c)	Intermediate Load Cost Per MWH 2000 $ (d)	Annual Intermediate Load Residential Customer[4] (e)
1	Clay Boswell 2	8.32	0.3140	2.61	0.3044	2.53
2	Hoot Lake 2	10.23	0.8151	8.33	0.7699	7.87
3	High Bridge 6/Riverside	7.78	0.1313	1.02	0.1313	1.02
4	A.S. King	7.78	0.3543	2.75	0.3363	2.62
5	Clay Boswell 3	8.32	0.4545	3.78	0.4160	3.46

Assumes that these additions do not lengthen the life of the facility. Longer life would reduce the annual costs.
[1] MN Jurisdictional Annual Report [2] Sheet 1 [3] column (a) times column (b) [4] column (a) times column (d)

cury emissions. However, the U.S. Environmental Protection Agency (EPA) and U.S. Department of Energy (DOE) continue to examine the injection of activated carbon and other control technologies that reduce mercury emissions. Increasing the efficiency of existing plants or switching fuels from coal to natural gas also reduce mercury emissions.

At present, no economically feasible technologies exist for the capture and disposal of CO_2 from power plant flue gases.[165] Three opportunities exist for CO_2 emissions control by the electric utilities. To reduce CO_2 emissions during electricity generation, electricity generators could switch from coal to natural gas. On a per kilowatt-hour basis, the combustion of natural gas to produce electricity results in the production of about one-third of the CO_2 produced when using coal as a fuel source. Second, electricity generators could offset emissions through carbon sequestration in standing biomass and soils. During plant growth, carbon dioxide is removed from the atmosphere and stored in plant biomass or soils. The average acre of timberland in Minnesota stores about 30 tons of carbon.

The Department of Commerce estimated the residential rate impact of installing central technology on the existing Minnesota plants that most resemble the modeled units. Rate impacts range from $3.59/year to $27.42/year for SO_2 controls, as shown in Figure A-25. For NOx controls, rate impacts range from $1.02/year to $7.87/year, as shown in Figure A-26. If controls are installed at more than one plant in one utility system and/or for both pollutants, total rate impacts can be estimated by summing the individual rate impacts.

These estimates assumed that the addition of pollution controls would not increase the useful life of the facility. While all of the representative facilities are older plants, even among the five facilities, the remaining life for depreciation purposes is more than twice as long as the oldest facility.[166] Rate impacts would decrease if the control equipment were depreciated over a longer period of expected plant operation.

Policy Recommendations

This section provided detailed information on the current level of emissions from electricity generation in the state, the different environmental impacts associated with those emissions, and a survey of relevant national environmental program initiatives. While electric generation is not the only source contributing to the environmental problems described in this section, it is a major source of these types of problematic emissions. Electric generation must not increase and should, over time, decrease its contribution to harmful air emissions. As we add new power plants, we must take care not to compound existing problems. If new plants are constructed that result in significant new sources of emissions, emissions from existing plants should be subject to stricter controls or some of the existing plants should close to ensure no net increase in overall emissions from the electric generation sector.

In 2001, the legislature responded to growing public concern over air emissions from existing electric generating plants by enacting an emissions reduction rider that allows utilities to propose cost-effective pollution controls on existing plants, and receive rate recovery. Minnesota's largest utility, Xcel Energy, has agreed to analyze possible emission control options at three of its plants by the summer of 2002. The study by Pollution Control Agency staff of possible control options presented in this section of the report will give policymakers a sense of the kinds of costs that would be incurred in installing pollution control equipment at selected existing facilities.

Policy considerations for the legislature include whether to require other utilities to prepare studies on cost effective pollution controls at some of their major existing uncontrolled generating plants. Another issue that may need to be addressed, depending on the response of utilities to the opportunity provided by the emission rider, would be to require certain projects to be implemented that the Public Utilities Commission determines to be cost-effective for ratepayers and to have significant positive impact on environmental emissions. The present emissions rider language makes implementation of a project entirely voluntary with the utility. Lastly, since it is likely that new electric generation plants constructed in Minnesota to meet growing demand for electricity will increase overall emissions of air pollutants, emissions at existing plants should be reduced by at least as much as new emissions.

ENDNOTES

134. This is because NSPS are based on the best available technology at the time they are adopted, and control technologies of the 1990s are superior to those of the 1970s.

135. NSPS do not regulate mercury and CO_2 emissions.

136. Figure A-10 includes the two new gas peaking plants, Pleasant Valley and Lakefield Junction, because they were added in 2001 and their emissions thus occur after 1999. Figure A-10 also includes a handful of small capacity additions that were not listed in Figure 3-3 in Chapter 3 of the main report because their construction is below the thresholds for PUC approval.

137. Other sources of these pollutants also contribute to these pollution problems, but as shown in Figure A-1, electric generation is a significant or predominant source category for these pollutants.

138. Dockery, D.W., C.A. Pope III, X. Xu, J.O. Spergler, J.H. Ware, M.E. Fay, B.G. Ferris, Jr., and F.E. Speizer, 1993. An Association Between Air Pollution and Mortality in Six U.S. Cities, New England Journal of Medicine, *pp. 281-287.*

139. EPA. Air Quality Criteria for Particulate Matter, Office of Research and Development, EPA/600/p. 95/001, April 1996.

140. Daniels, J.J., Dominici, F., Sanet, J.M., Zeger, S.L., 2000. Estimating Particulate Matter-Mortality Dose-Response Curves and Threshold Levels: An Analysis of Daily Time-Series for the 20 Largest US Cities, American Journal of Epidemiology, *Vol. 152, No. 5, pp. 397-406.*

Schwartz, J. 1999. Air Pollution and Hospital Admissions for Heart Disease in Eight U.S. Counties. Epidemiology, Vol. 10, No. 1, pp. 17-22.

Schwartz, J. and A. Zanobetti, 2000. Using Meta-Smoothing to Estimate Dose-Response Trends Across Multiple Studies, with Application to Air Pollution and Daily Death. Epidemiology, *Vol. 11, No. 6, pp. 666-672.*

141. Science, vol 293 17 August 2001, at 1257.

142. The left photo was taken on Sept. 14, 2000 at about 8:00 a.m. from Mounds Park in St. Paul. The right photo was taken on June 28, 2001 at 12:30 p.m.

143. U.S. EPA, 2001. National Air Emissions Trends. Website http://www.epa.gov/ttn/chief/trends/trends99/tier3_yrsemis.pdf accessed December 10, 2001.

144. MPCA. Minnesota Air: Air Quality and Emissions Trends. September 1997, p. 153.

145. The US National Academy of Sciences reviewed the underlying science of global climate change in 1979, 1981, 1983, 1987 and 1991, concluding in each instance that, with a doubling of atmospheric CO_2, mean global surface temperature would rise 1.5 to 4.5 degrees Celsius.

146. While there is virtually no debate about the reality of the observed surface warming, scientists debate the degree to which mean global surface temperature will rise. However, even climate skeptics have concluded that at least some continuation of the observed 20th century warming is likely. To the degree that they have furnished estimates of future warming, these scientists have tended to support forecasts near the lower end of this range, 1 to 2 degrees Celsius, with one low value near 0.5 degrees Celsius.

147. BioScience, March 2001/ Vol 51 No. 3 pp. 180 –198.

148. Science Vol. 292, April 13, 2001 pp. 195-196.

149. New source review, because it is case-by-case, does not suffer from the control requirement failing to be equal to stringent new technology. New source review was enacted to address this deficiency in the design of the NSPS program.

150. The New Source Performance Standards for utilities (40 CFR 60 Subparts D, Da, and Db) address emissions of SO_2, NOx, and particulate matter. Emissions of other pollutants, including mercury and carbon dioxide, are not restricted by these regulations. A federal emission limit for mercury will probably be a part of a new National Emission Standard for Hazardous Air Pollutants (NESHAP) for utilities. The U.S. Environmental Protection Agency does not regulate carbon dioxide.

151. The three SO_2 control technologies are limestone forced oxidation (LFSO), limestone spray drying (LSD), and magnesium-enhanced lime (MEL). Each of these flue-gas desulfurization technologies use scrubbing to reduce SO_2 emissions.

152. The "representative" facilities exhibit characteristics that most closely resemble the modeled units. However, the characteristics of the modeled units and the identified facilities are not identical.

153. While most SO_2 emissions are formed from the direct combustion of sulfur contained in the coal, NOX emissions are formed in two ways. First, nitrogen in the coal can be oxidized (combusted). This creates a relatively small amount of NOx. The second way in which NOx is formed involves the heating of the air provided for combustion. When heated, the nitrogen in the air may react with nearby oxygen to form NOx. This reaction is more likely at higher temperatures. It generates most of the NOx created at a utility boiler.

By redesigning the combustion chamber, the amount of NOx generated by the second method can be limited. However, this requires boiler-specific modifications. This is the reason that some of the control methods must be matched with specific boilers.

154. Coal-and-air nozzles with close-coupled overfire air is referred to as LNC1. When coal-and-air nozzles are used with separated air, it is called LNC2. LNC3 refers to the case in which both types of air supply are used with the nozzles.

155. Srivastava, Ravi K., and Jozewicz, Wojciech. Controlling SO_2 Emissions: An Analysis of Technologies. EPA/600/SR-00/093, November 2000.

Also: Srivastava, Ravi K. Controlling SO_2 Emissions: A Review of Technologies. EPA/600/R-00/093, November 2000.

156. Costs for SO_2 controls are provided in 1997 dollars.

157. The actual costs of installing SO_2 controls at a particular plant must be determined on a case-by-case basis. This analysis relies on average costs from previous installations.

158. Annualized costs are calculated by distributing the cost of the initial installation over the lifetime of the equipment, plus interest, and adding that cost to the annual operating costs. In this case, an interest rate of 6 percent and a twenty year life were used.

159. Model number 2 had a cost-effectiveness of $4697/ton, while model number 3 had a cost-effectiveness of $4861/ton. Model number 4's cost-effectiveness was $1159/ton.

160. EPA. Analyzing Electric Power Generation Under the CAAA. Office of Air and Radiation, July 1996.

161. The actual costs of installing NOx controls at a particular plant must be determined on a case-by-case basis. This analysis relies on costs from previous installations.

162. High NOx concentrations are those exceeding 0.5 lb/mmBtu.

163. Energy Information Administration. "The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update." (Costs in 1995 dollars.)

164. Butraw, Dallas; Palmer, Karen; Bharvirkar, Ranjit; and Paul, Anthony. "Cost-effective Reduction of NOx Emissions from Electricity Generation." Discussion Paper 00-55, Resources for the Future, December 2000. (Costs in 1997 dollars.)

165. It is expected that systems for CO_2 capture could be commercially available within several decades at reasonable costs.

166. The remaining lives are: 6 years for Boswell 2, 11.3 years for Hoot Lake, 7.9 years for High Bridge 6, 5 years for King, and 12 years for Boswell 3.

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Environmental Section for the Energy Planning Report Update:

Recent Concerns about Air Pollution from Power Plants

A comprehensive discussion of the impacts of power plants on public health and the environment can be found in the 2001 Energy Planning Report. Since publication of that report, there has been increasing concern about two pollutants that are linked, in part, to power plant emissions – fine particulates and ozone.

Fine particulate matter is a complex mixture of very small liquid droplets or solid particles in the air. Major sources are cars, trucks, construction equipment, coal-fired power plants, wood burning, vegetation and livestock. These particles can be directly released when coal, gasoline, diesel fuels and wood are burned. Many fine particles are also formed in the atmosphere from chemical reactions of nitrogen oxides, sulfur oxides, organic compounds and ammonia. Fine particulates are associated with increased hospitalizations and deaths due to respiratory and heart disease and can worsen the symptoms of asthma. People with respiratory or heart disease, the elderly and children are the groups most at risk. Fine particles are also major contributors to reduced visibility (haze). Power plants are significant sources of fine particulates because of their emissions of SO_2 and NOx.

PM-2.5

In the past year since publication of the 2001 Energy Planning Report, the evidence that fine particles in the atmosphere are linked to health effects has strengthened. Scientists are finding serious health impacts at levels below the federal air quality standard. This evidence indicates that Minnesotans are likely impacted by breathing fine particulates. While this region meets the annual PM-2.5 ambient standard of 15 μg/m3 and the 24 hour standard of 65 μg/m3, the Minnesota Pollution Control Agency (MPCA) has had to issue air alerts when PM-2.5 levels reach 40.5 μ/m3. EPA has specified 40.5 μ/m3 for these warnings because research has shown that serious health effects can occur at levels below the standard. Air reached alert levels for fine particles twice in 2002. One event occurred when smoke from Canadian forest fires reached Minnesota. In addition, a review of available PM-2.5 data indicates that concentrations in the Twin Cities reached levels considered “Unhealthy for Sensitive Groups” on seven days during calendar year 2000 and on four days during calendar year 2001. One PM-2.5 event considered “Unhealthy” was monitored in October 2000 in Minneapolis. PM-2.5 events can happen throughout the year, although the causes of high PM levels may differ seasonally.

Ozone

Another pollutant that is receiving increased attention is ozone. Ground level ozone, also called “smog,” is formed in the atmosphere by chemical reactions involving NOx, volatile organic chemicals, and sunlight. Ozone pollution is primarily a summer problem because of the need for sunlight in the formation process. Ozone affects healthy adults, but children and people with existing respiratory problems are most susceptible to its presence. Ozone causes eyes to itch, burn and water, triggers asthma attacks, and can cause coughing, chest pain and difficult breathing. Power plants are a significant contributor to ozone because of their emissions of NOx.

EPA promulgated a new, more restrictive ozone standard in 1997. Currently, Minnesota is considered to be in compliance with that standard. However in the last 2 years, the MPCA has had to issue air alerts for ozone—4 times in 2001 and twice in 2002. These represent the first air pollution alerts issued for ozone since the 1970's. A recent study commissioned by the MPCA has determined that ozone levels appear to be increasing the Twin Cities[1]. If this trend continues and the Twin Cities drops out of compliance for ozone, new federal regulations costing up to $250 plus million per years would be required[2].

Regulatory Activities on the Horizon

Several major regulatory initiatives will affect power plant emissions. These regulations would have significant impacts on the operations and emissions of power plants in Minnesota. They could also play a role in decisions about new generating capacity.

First, EPA recently finalized a rule to improve visibility in National Parks and Wilderness Areas (called the Regional Haze Rule.) This rule requires the development of plans to improve visibility by 2007-2008. Power plants play an important role in the formation of haze, but it is not yet known to what extent emissions will be reduced through this regulation. There is a multi-state regional planning effort underway to identify what emission reductions will be needed to reduce regional haze.

Second, EPA's new ambient air standards for PM2.5 and ozone are in effect. Plans to address these standards will likely also be due in the 2007-2008 timeframe. Even if these standards are being met in Minnesota, it is possible that emission reductions will be required from power plants in Minnesota to help meet the standards in other states, such as Wisconsin, Illinois and Michigan.

Third, EPA is currently developing a rule to limit mercury emissions from fossil-fuel-fired power plants. This rule is required by the 1990 Amendments to the Clean Air Act. The rule is expected to be proposed by 2003, finalized by 2004 and implemented by 2008. At this time it is not known to what degree emissions of mercury in Minnesota would be impacted.

Fourth, because these different regulations are proceeding on separate tracks and timeframes, there are congressional proposals to address all of these issues, including greenhouse gas emissions in some proposals, through multi-pollutant legislation. The two main proposals include a Senate bill and the White House proposal (Clear Skies.) Both require different but substantial reductions in emissions over widely different timeframes. Both would likely require substantial emission reductions, at older power plants.

Next Steps Towards Reductions: Xcel Metropolitan Emissions Reduction Proposal

In 2001, the legislature responded to growing public concern over air pollution from existing electric generating plants by enacting Minn. Stat. §2168.1692, an emissions reduction rider that allows utilities to propose cost-effective pollution controls on existing plants, and receive recovery of the costs in their rates. On July 26, 2002, Xcel Energy submitted a proposal that would substantially reduce emissions from the King, Riverside and High Bridge plants, and recover costs in a proposed rate rider.

The MPCA has reviewed the Xcel proposal and is required by the statute to provide its analysis to the Public Utilities Commission (PUC) on:

1. Whether the project qualifies for the rider;

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[1] L.R. Chikin et. al. Preliminary Assessment of Ozone Air Quality in the Minneapolis/St. Paul Region. Sonoma Technology, Inc. October 2002.

[2] T. R. Aulich and K. N. Neusen. Estimated Economic Impact of Twin Cities Ozone Nonattainment. Minnesota Chamber of Commerce, February 1999.

2. The projected environmental benefits from the project; and
3. Its assessment of the appropriateness of the project.

The MPCA's filing will initiate the decision-making process before the PUC. The PUC will ultimately decide on the reasonableness of the proposed emissions reduction rider. After the PUC makes its decision, Xcel Energy will decide whether to proceed with the projects, which are voluntary.

Benefits of Reducing Power Plant Emissions

Several studies have been conducted to estimate the economic and health benefits of reducing the emissions from power plants. Four of those studies are summarized below and in Table X.

EPA's Clear Skies Initiative

The Bush Administration proposed the "Clear Skies Initiative" to reduce emissions from electric power generating utilities. Nationwide, the Clear Skies Initiative is estimated to reduce emissions of sulfur dioxide, nitrogen dioxides and mercury by 73%, 67%, and 69%, respectively from 2000 baseline levels.

The largest estimated benefits were related to the reduction of fine particle pollution primarily through the reduction in emissions of SO2 and NOx. As of 2020, the estimated national annual monetary benefit was $93 billion for 12,000 avoided premature deaths, followed next by $3.2 billion for 7,400 fewer cases of chronic bronchitis. This estimate includes the assessment of the potential cumulative effect of long-term exposure to particles. EPA separately estimated the impacts of these pollutant reductions presuming that PM effects are limited to those that accumulate over much shorter time periods. This separate estimate concludes that nationally 7,400 early deaths would be avoided by reducing power plant emissions.

In Minnesota, EPA projected that a Clear Skies program would reduce particulate matter levels across the state, and result in 100 fewer early deaths due to particulate matter effects. EPA further estimated that all health improvements combined result in $1 billion in benefits in Minnesota from Clear Skies. Because PM2.5 is a regional pollutant, benefits estimated in MN would be a result of emission reductions in MN and other states.[3]

Eight Utilities Study

Eight utility systems in the eastern half of the United States were the subject of a study to estimate the health impacts of the projected 2007 emissions from their coal-fired power plants[4] [5]. This assessment estimated that roughly 5,900 premature deaths might be avoided if emissions ceased from these plants. The study did not attempt to translate these deaths and other respiratory effects into economic terms. The study shows emissions from power plants in Illinois and Indiana contributing significantly to deaths in Missouri, Illinois, Indiana, Wisconsin and Minnesota.

Two Massachusetts Power Plants

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[3] Details of this cost study for the Clear Skies initiative are on EPA's webpage at www.epa.gov/clearskies

[4] Rockefeller Family Fund. Particulate-related Health Impacts of Eight Electric Utility Systems. April 2002. http://www.rffund.org/abt%20report%20FINAL.pdf

[5] The year 2007 was chosen to allow for full implementation of two federal air pollution control requirements expected to affect power producers: the Acid Rain program and the EPA 1999 NOx SIP for the eastern half of the United States.

Harvard researchers Levy and Spengler estimated a portion of the health benefits of reducing SO2 and NOx emissions from the Brayton Point and Salem Harbor coal-fired power plants in Massachusetts[6]. Their analysis compared current emissions with emission rates estimated under best available control technology (BACT), which results in decreases of 57,348 tons of SO2 and 11,074 tons of NOx per year from the two plants. This study estimates that this reduction in SO2 and NOx would reduce 70 premature deaths each year over a total population of 33 million. Levy cautioned that while it should be considered illustrative, using standard EPA valuation for premature death, these avoided deaths represents a $400 million benefit per year. This study only looked at death and did not address other health problems that these emissions cause or contribute to.

Minnesota Power Plants

Nelson estimated the public health impacts of particulate emissions from current coal-fired power plants in Minnesota, and the impacts if these plants switched from burning coal to burning natural gas.[7] The study concluded that by switching from coal to natural gas at Minnesota's electric utility boilers, 25 early deaths would be avoided. Other health improvements were also estimated, and include fewer new cases of bronchitis, emergency room visits, days of respiratory symptoms, and days of restricted activity. This study calculated that the economic benefit from switching to natural gas to reduce emissions from these power plants is $187 million per year (1996 dollars).

This study recognizes that using high stacks at power plants to disperse pollutants means that much of the damages from the emissions occur outside Minnesota. However, Xcel's Riverside plant was estimated to have the highest incident of early deaths (7) due to it being located within a heavily populated area.

Table X. Comparison of Benefits when power plant emissions are reduced.

Benefit Assessment	Annual Benefits	Avoided Deaths	NOx reductions	SO2 Reductions
	$/yr		Tons/yr	Tons/yr
Clear Skies (nationally)	$93 billion	12,000	5,000,000	2,500,000
Clear Skies in Minnesota	$1 billion	100	91,000	17,000
Eight Utilities	Not calculated	5,900	Not provided	Not provided
Minnesota Utilities	$187 million	25	53,700	57,000
Two MA Power Plants	$400 million	70	11,000	57,000

Reducing Emissions from Small Electrical Generators

Background

Small stationary generators are used for emergency power and to an increasing extent, in distributed generation applications. Emergency generators are used to replace grid power when weather or some other action interrupts the distribution of power, and are typically used on situations where human life and public

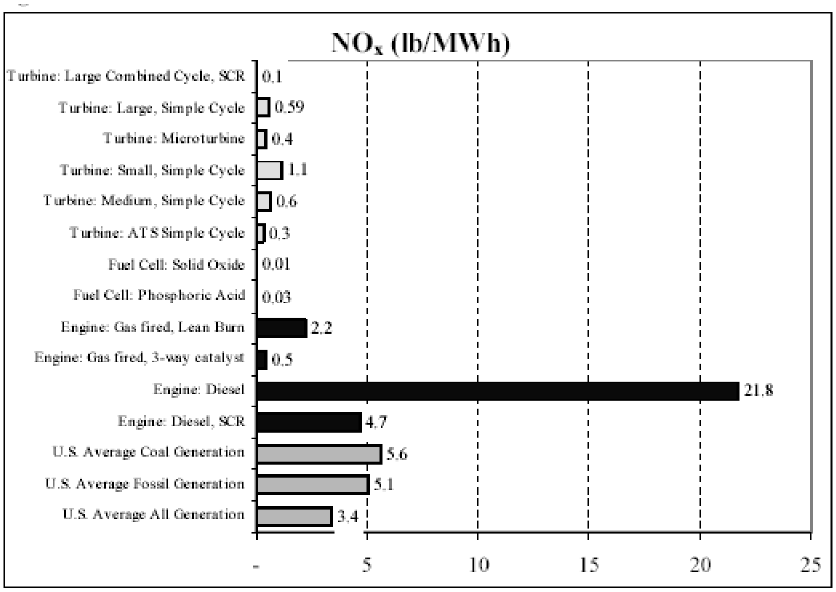
[6] Levy and Spengler. Modeling the Benefits of Power Plant Emission Controls in Massachusetts". Journal of Air and Waste Management Association 52:5-18.

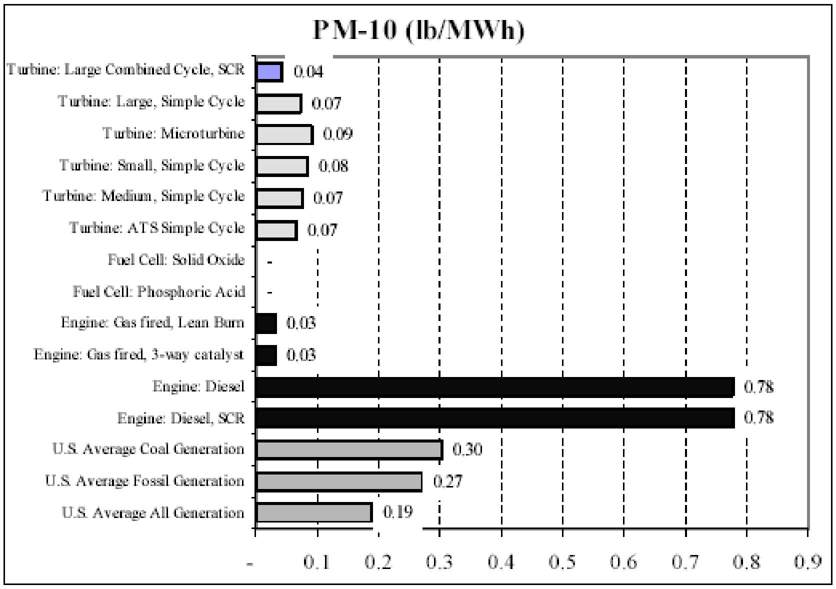
[7] Nelson, C.D. 2000. The Public Health Impacts of Particulate Emissions from Coal-fired Power Plants in Minnesota. Thesis. Master of Science. University of Minnesota.

safety are a concern. Distributed generation is generally grid connected and displaces energy that would otherwise be generated by large centralized power plants. Distributed generation can benefit a generation system through increased reliability, lower transmission line losses and lower peak demand from centralized generators. The increased use of emergency and distributed generators (EDG) raises concerns for local health effects and exacerbation of the metropolitan ozone problem, particularly since EDGs are most likely to be used in the summer on days when ozone levels may be high. In Minnesota there are easily more than a thousand small electric generators in place, ranging from emergency generators at hospitals, manufacturing facilities and commercial real estate, to peak shaving generators in a variety of locations with interruptible service contracts.

Small fossil-fueled generators typically have low exhaust stacks and can be located near sensitive populations. As can be seen from the following figures, diesel engines have much higher emission rates for nitrogen oxides (NOx) and particulate matter than other forms of electrical generation. Most concerns for the direct health impacts of EDG therefore center on diesel powered equipment. California has identified diesel particulate as a carcinogen, and has begun a program to clean up mobile and stationary diesel engines. EPA has established a health based standard for fine particles, and is in the process of reviewing the fine particle standard in light of new evidence of mortality effects at lower ambient levels than previously thought to have effects. NOx can cause respiratory effects in high concentrations.

High levels of ozone occur in the Twin Cities area on hot sunny summer days. The demand for peak shaving generation also tends to be highest on hot summer days. The pollutants generated by diesel and other generators will contribute to ozone formation at downwind locations.





Source: reference ____

SCR stands for selective catalytic reduction, a technology for reducing NOx emissions

The last three bars in each chart refer to the emissions from the generation of electricity in the U.S. from burning coal, all fossil fuel combustion and from all forms of generation.

EPA has not established emission standards for NOx and particulate emissions from small stationary EDG. EPA is in the process of developing standards for air toxics emissions from reciprocating internal combustion engines. However, it is not anticipated that particulate and NOx emissions will be substantially reduced through the air toxics standard because particulate and NOx are regulated by a different section of the Clean Air Act.

Principles for Regulation

In anticipation of the growth of EDG, measures should be taken to insure that public health is protected. Emission standards should be developed to insure that new or even existing generators are cleaner. Several principles could guide development of these measures:

- New generation should be at least as clean as current centralized power stations
- Standards for similar engines in other uses (on and off- road mobile sources) should be a starting point
- Minnesota should remove incentives for grid connection of high pollution technology (Commerce should have input here __________)

Regulatory Developments in Other States

At least three models are available for regulation of EDG emissions. The Regulatory Assistance Project (RAP), a Vermont/Maine non-profit, coordinated the development of model rules for small generators. The workgroup that developed the rules consisted of utility and environmental regulators and industry representatives.

The Vermont/Maine model RAP rules:

- Affect all types of small generators
- Are more stringent for higher use generators
- Tighten emission limits over time
- Are based on EPA non-road emission standards

The model rules were released in August of 2002. RAP staff anticipate that Connecticut and Massachusetts will be the first states to adopt the model rules.

California is developing toxic control measure rules for new stationary diesel engines and existing diesel engines over 50 horsepower. These rules include limits for NOx emissions.

California's proposed rules:
- Are more stringent for higher use engines
- Are based on best available technology
- Assume availability of very low sulfur fuel as will be required by EPA regulations
- Apply to owners or operators
- Exempt agricultural uses
- Establish compliance dates for existing engines in 2005-2007

California Air Resources Board (CARB) staff anticipate that the rulemaking will be completed in the first half of 2003. Once completed, the rules could form the basis for nationwide regulation of emissions from stationary diesel engines. Manufacturers will build equipment and retrofits for the large California market. Due to economies of scale, other states could adopt similar restrictions at relatively low cost.

Finally, in 2001, Texas adopted permitting requirements regulating NOx from new small generating units. The standards vary by location and are phased in over four years.

Voluntary Approaches

The amount of particulate matter emitted by a diesel engine without a particulate trap is directly proportionate to the sulfur content of the fuel. According to EPA regulations, low sulfur (<15ppm) diesel fuel must be used in on-road diesel engines by 2006. It is also likely that low sulfur diesel fuel will be required for non-road mobile sources once concerns about adequate fuel supply have been resolved. A limited amount of low sulfur diesel fuel is available now in the Twin Cities. A voluntary effort could be mounted to expand this supply and channel some to stationary engines.

Retrofit devices are available for some diesel engines to remove particulate emissions. They work best when paired with low sulfur fuel. Retrofit campaigns for school buses and other mobile sources have been successfully completed in various locations across the country. The feasibility of a program to retrofit the larger diesel generators could be investigated. Retrofit costs should fall within the $2,000 to $8,000 range.

Finally, the use of biodiesel fuel can reduce emissions of particulates and organic compounds from generators. The higher the percentage of bio-to-diesel concentration, the greater the emissions benefit. Biodiesel fuel is becoming more available in Minnesota and could be a part of a voluntary effort to reduce emissions. A new state law requires 2 percent biodiesel in diesel fuel beginning in June 30, 2005.