TEN-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES

TO THE

SOUTH DAKOTA
PUBLIC UTILITIES COMMISSION

SUBMITTED BY
XCEL ENERGY
JULY 2002

Xcel Energy

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20:10:21:04 EXISTING ENERGY CONVERSION FACILITIES

Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company"[1]) has two existing energy conversion facilities in South Dakota. The tables below provide the required information on these facilities.

Pathfinder

1.	Location	Sioux Falls, South Dakota
2.	Type Nameplate Capacity	Steam Boiler 75 MW
3.	Net Capacity Annual Production	Summer: 61 MW Winter: 0 MW 2000: -1263 MWh 2001: -1726 MWh
4.	Water Source and Annual Consumption	NA
5.	Fuel Type Source Annual Consumption	Natural Gas Northern Natural Gas Co.[2] 2000: 6351 Mcf 2001: 0 Mcf

Angus Anson

1.	Location	Sioux Falls, South Dakota	
2.	Type Nameplate Capacity	Combustion Turbine 105 MW each unit (2 units)	
3.	Net Capacity Annual Production	Summer: 110.5 MW (each unit) Winter: 128.0 MW (each unit) 2000: 112,005 MWh (total) 2001: 126,940 MWh (total)	
4.	Water Source and Annual Consumption	NA	
5.	Fuel Type Source Annual Consumption	Natural Gas Northern Natural Gas Co. 2000: 1,117,512 Mcf 2001: 1,694,416 Mcf	Fuel Oil 2000: 807,456 gal 2001: 242,347 gal

6. No retirement date has been set for either facility. The condition of Xcel Energy's generating equipment is monitored, and as the age increases, an evaluation of continued operation is periodically performed. Based on a nominal average service life of 35 years, the Pathfinder Power Plant retirement date is estimated at the end of the year 2003.

[1] The Company is the successor to Northern States Power Company ("NSP"), which merged with New Century Energies, Inc. to form Xcel Energy Inc. Prior Ten-Year Plans were submitted by NSP.
[2] The Company also owns an intrastate fuel delivery facility approximately 13 miles long which transports the natural gas from the interconnection with Northern Natural Gas Co. to the Pathfinder and Angus Anson generating plants.

20:10:21:05 PROPOSED ENERGY CONVERSION FACILITIES

Xcel Energy does not have energy conversion facilities under construction in the State of South Dakota. Xcel Energy proposes to fulfill future electric generating resource needs primarily through a competitive bidding process. The specific generation technology and location of future generation facilities will be determined through the competitive bidding process. A copy of the Executive Summary of Xcel Energy's 2000 Resource Plan filing to the Minnesota Public Utilities Commission ("MPUC") and a copy of the MPUC order approving the 2000 Resource Plan (with modifications) is included as Appendix A.[3]

On May 3, 2002, Xcel Energy submitted a report to the MPUC and the Minnesota Polution Control Agency ("MPCA") proposing a package of projects to be completed over the next seven years at three of its generating plants in the Minneapolis-St. Paul metropolitan area. These voluntary projects are designed to reduce air emissions through rehabilitation and/or repowering of metro area coal plants. As a result of these proposed improvements, generating capacity of these three plants could increase. The proposal requires review and approval by the MPUC and the MPCA.

20:10:21:06 EXISTING TRANSMISSION FACILITIES

Listed below are Xcel Energy's existing transmission facilities operating at 115 kV or above in the southeastern South Dakota area. A map showing the location of Xcel Energy's transmission lines is included as Appendix B.

Type 115 kV - AC

1. Lawrence Substation in Sioux Falls to the Lincoln County Substation south of Sioux Falls - 11 miles.

2. Lincoln County Substation south of Sioux Falls to the Cherry Creek Substation (west side of Sioux Falls) - 10 Miles.

3. Cherry Creek Substation to the Grant Substation west of Sioux Falls - 24 miles.

4. Grant Substation west of Sioux Falls to Northwest Public Service (NWPS) at Mitchell - 24 miles to Wolf Creek Interconnection owned by Xcel Energy, remainder owned by NWPS.

[3] The Company will file its next Resource Plan with the MPUC in December 2002.

5. Lawrence Substation in Sioux Falls to the Western Area Power Administration (WAPA) Substation in Sioux Falls - 1 mile.

6. Lawrence Substation in Sioux Falls to the Split Rock Substation approximately 5 miles northeast of Sioux Falls (circuit # 1) - 2 miles.

7. Split Rock Substation to the Pathfinder Substation approximately 4 miles northeast of Sioux Falls - .8 miles.

8. Pathfinder Substation to the Pipestone Substation in Pipestone, Minnesota. Approximately 34 miles of this line are in the state of South Dakota - 42 miles total.

9. Lawrence Substation in Sioux Falls to the Split Rock Substation approximately 5 miles northeast of Sioux Falls (circuit# 2). Approximately 1 mile of this line is double-circuited with the Split Rock-Magnolia 161 kV line - 2.6 miles total.

10. Split Rock Substation to the West Sioux Falls Substation - 17.3 miles.

11. West Sioux Falls Substation to the Cherry Creek Substation - 3.5 miles.

12. Split Rock Substation to Cherry Creek - 20 miles.[4]

13. Split Rock to Angus Anson generating plant - 1/4 mile.[4]

Type 161 kV - AC

1. Split Rock Substation approximately 5 miles northeast of Sioux Falls to Alliant Energy interconnection near Luverne, Minnesota.

   Approximately 1 mile of this line is double-circuited with the second Lawrence-Split Rock 115 kV line. Approximately 11 miles of this line are in the state of South Dakota - 20 miles total.

Type 230 kV - AC

1. Split Rock Substation to the WAPA Sioux Falls Substation - 1 mile.[4]

[4] This line was in-service at the time of our July 2000 filing but was inadvertently omitted from that Report.

Type 345 kV - AC

1. Split Rock Substation northeast of Sioux Falls to the WAPA's 345 kV line between Watertown and Sioux City. This is a double-circuit line - 5.1 miles.

20:10:21:07 PROPOSED TRANSMISSION FACILITIES

Xcel Energy has requested a Certificate of Need ("CON") from the MPUC for transmission development to provide generation outlet capability for anticipated wind and other renewable generation development along the Buffalo Ridge, which runs from Northeastern South Dakota through Southwestern Minnesota into Northwestern Iowa. Among the options under consideration are two electric transmission line proposals which would include new transmission in South Dakota. These are:

- A 345 kV transmission line from Sioux Falls, SD (the Xcel Energy Split Rock Substation) east to Lakefield, MN. Approximately 10 miles of this line would be in South Dakota.

- A 115 kV line from near Brookings, SD (the Western Area Power Administration White Substation) east to Lake Benton, MN. Approximately 6 miles of this line would be in South Dakota.

The CON record includes several alternative construction options to meet varying levels of generation outlet need. The CON docket is now pending before an Administrative Law Judge, who will make recommendations to the MPUC on the recommended alternative. A final MPUC decision is expected in 2002.

20:10:21:08 COORDINATION OF PLANS

All major transmission and generation planning performed by Xcel Energy is now coordinated through the Midwest Independent System Operator, Inc. ("Midwest ISO") on a regional basis, consistent with the Federal Energy Regulatory Commission ("FERC") orders (a) dated May 2000 authorizing the transfer of functional control of the Company's high voltage transmission system to the Midwest ISO, and (b) dated December 2001 finding the Midwest ISO to be the first FERC-approved regional transmission organization ("RTO"). The Midwest ISO is continuing the use of the existing subregional planning groups of the Mid-Continent Area Power Pool ("MAPP") which coordinate the planning of the utilities within the MAPP region. This coordination applies to all Xcel Energy facilities in Minnesota, North Dakota, South Dakota, and Northern States Power Company – Wisconsin (jointly "Xcel Energy-North") facilities in Wisconsin and Michigan. This joint planning is intended to maximize use of existing facilities and minimize the amount of new facilities. Additional regional planning coordination is provided by the Dakotas-Montana Power Suppliers Group.

20:10:21:09 SINGLE REGIONAL PLANS

Xcel Energy is continuing to work with the Midwest ISO and other area utilities to evaluate potential transmission needs in the future and to develop coordinated regional plans as required to meet those needs.

20:10:21:10 SUBMISSION OF REGIONAL PLANS

Further regional additions will include continued development and use of the 115, 230, and 345 kV systems. Specific plans for additional facilities will be developed through the Midwest ISO regional planning process , and submitted with a subsequent ten-year plan when the need is clearly identified.

20:10:21:11 UTILITY RELATIONSHIPS

Xcel Energy is a utility operating company subsidiary of Xcel Energy Inc., a registered public utility holding company, and is affiliated with four regulated public utilities: Cheyenne Light, Fuel & Power Company, Northern States Power Company-Wisconsin ("NSPW"), Public Service Company of Colorado, and Southwestern Public Service Company. Xcel Energy and NSPW are members of the Midwest ISO, the first FERC-approved regional transmission organization, or RTO. At this time, the Midwest ISO is providing regional security coordination and tariff administration for its member transmission owners, but the Company has not yet transferred functional control of its transmission facilities to the Midwest ISO. Xcel Energy and NSPW remain members of MAPP, which continues to provide certain Regional Reliability Coordinator ("RRC") functions required by the North American Electric Reliability Council ("NERC"). The Company contracts with the Western Area Power Administration for certain transmission services needed to serve the Company's retail loads in South Dakota.

The five Xcel Energy Operating Companies are all proposed members in the TRANSLink Transmission Company LLC independent transmission company ("ITC"). FERC recently approved the TRANSLink ITC by order dated April 25, 2002. The TRANSLink ITC is expected to commence operations in 2003 subject to the oversight of the Midwest ISO for the Company's facilities in South Dakota, subject to receipt of various required regulatory approvals.

20:10:21:12 EFFORTS TO MINIMIZE ADVERSE EFFECTS

Xcel Energy uses a multi-step effort to minimize adverse effects resulting from siting, constructing, operating and maintaining large electric generating plants and high voltage transmission lines. These efforts relate to long-range planning and coordination, environmental site and route analysis, and mitigative construction and operation practices.

Xcel Energy now coordinates its plans for large electric generating plants and high voltage transmission facilities with the Midwest ISO other area power suppliers and load serving entities in order to develop, whenever possible, joint use facilities. Coordination with others can reduce the number of facilities by providing for joint ownership and operation of individual facilities.

Once the need for generation or transmission is identified, an initial site or route search is begun by defining a broad study area in which the facility should be located. A broad range of information about the physical, biological, and cultural environment within the study area is collected. As information on such factors as land use, air and water quality, plants and animals, transportation and social services, and local and regional employment becomes available, various siting criteria are used to define preferred and alternate routes and sites. Xcel Energy prefers to develop a project with the cooperative assistance of state and local agency officials and possibly affected landowners in order to assure the widest possible considerations of information, concerns, and options. It is Xcel Energy's policy to insure compliance with all local, state and federal regulatory requirements in the development and location of proposed projects.

Because of the detail involved in a major generation or transmission project, Xcel Energy prefers to complete detailed site and route engineering once permits have been granted. This permits last minute adjustments to be completed, which can take into account concerns that may arise during construction. Such flexibility allows concerns regarding factors such as structures, locations, land use, construction techniques, to be mitigated without undue delay and expense.

Xcel Energy is committed to working with affected landowners to mitigate environmental and land use problems which may arise in relation to necessary and proper construction and maintenance activities.

20:10:21:13 LOAD MANAGEMENT EFFORTS

Xcel Energy's load management impacts and expenditures for 2000 and 2001 are provided in the following table.

	2000		2001	
	Connected kW	$	Connected kW	$
C&I Voluntary TOD Rate	5,317	$ 85,657	2,738	$19,453
Small Business Voluntary TOD Rate	453	$ 19,452	770	$30,098
Residential Saver's Switch	4,448	$ 267,323	2,342	$132,599
Small Business Saver's Switch	653	$ 20,535	2,664	$69,496
Total	10,871	$ 392,967	8,514	$ 251,646

20:10:21:14 LIST OF REPORTS RELATED TO PROPOSED FACILITIES

Southwest Minnesota/Southeast South Dakota Electric Transmission Study Phase 1: Transmission Outlet for Southwest Minnesota (Buffalo Ridge Area) Generation Additions (0-400 MW beyond initial 425 MW of renewable generation mandated by statute), November 13, 2001.[5]

20:10:21:15 CHANGES IN STATUS OF FACILITIES

There have been no changes in the status of Xcel Energy's facilities in South Dakota in the past two years.

20:10:21:16 PROJECTED ELECTRIC DEMAND

The forecast of native energy requirements and peak demand for the state of South Dakota is shown in Table Xcel-SD-1. Xcel Energy produces its long-range "median" system[6] forecasts of native energy requirements, summer peak, and winter peak demand. For planning purposes, Xcel Energy-North also develops a bandwidth (called semi-high and semi-low scenarios) to supplement its "median" forecasts. These two scenarios are intended to describe uncertainty in a business-as-usual context: a relatively narrow range of US economic growth with no basic change in the relationship between the regional and national economies. Table Xcel-1 through

[5] This report identifies the potential transmission additions now pending review in the CON docket noted above.
[6] "System" refers to Xcel Energy-North, which is the five-state electric service territory of Northern States Power Company (Minnesota, North Dakota, and South Dakota) and Northern States Power Company – Wisconsin (Wisconsin and Michigan).

Table Xcel-3 show the long-range system forecast of native energy requirements, summer peak, and winter peak demand for the Xcel Energy-North system. Table Xcel-SD-1 shows the South Dakota portion of the system forecast.

The forecast for the Xcel Energy-North system is based on forecasts of jurisdictional sales by major customer class: residential with and without space heating, small commercial and industrial (SC&I), and large commercial and industrial (LC&I). Each customer class is modeled independently for the five states in the Xcel Energy-North service territory. The native energy requirements are determined by applying a loss factor on total sales.

The Xcel Energy-North system peak is apportioned to jurisdictions based on the native energy requirements by state and the load factor by state. Consequently, the summer and winter "peak loads" provided in Table Xcel-SD-1 represent the South Dakota jurisdiction customer demand at time of Xcel Energy-North's total system seasonal peak demand. This "coincident" demand is appropriate for generating capacity requirement forecasting.

It is important to note, however, that a "non-coincident" peak demand must be used in evaluating transmission capacity requirements. This is because the transmission system must be able to supply the full local customer demand at all times. Due to load diversity caused by weather variations within the Xcel Energy-North multi-state power system, peak customer demands in Xcel Energy's South Dakota service areas can be as much as 10 percent higher than the demands registered during the hour in which the total system peak demand occurs. It is these local "non-coincident" peak demands that determine the need for transmission improvements required for load serving functions.

20:10:21:17 CHANGES IN ELECTRIC ENERGY

Table Xcel-SD-1 shows the projected volume and percentage increase in energy demand for Xcel Energy's South Dakota service territory for each year relative to 2002.

Table XCEL-SD-1
Xcel Energy
State of South Dakota
Forecast of Electric Energy Requirements and Peak Demand

	Winter Peak (MW)	Summer Peak (MW)	Energy (GWh)	Change In Energy (GWh)	% Change In Energy
2002	252	346	1,722		
2003	254	350	1,766	44	2.6%
2004	259	358	1,810	44	2.5%
2005	266	363	1,851	41	2.3%
2006	270	370	1,896	45	2.4%
2007	276	378	1,936	40	2.1%
2008	284	389	1,993	56	2.9%
2009	291	398	2,037	45	2.2%
2010	298	407	2,087	49	2.4%
2011	304	416	2,131	44	2.1%
2012	311	425	2,178	47	2.2%
2013	318	435	2,229	50	2.3%
2014	326	446	2,287	58	2.6%
2015	334	458	2,344	57	2.5%
2016	343	470	2,408	64	2.7%
2017	352	482	2,470	63	2.6%
2018	361	495	2,534	64	2.6%
2019	370	507	2,598	63	2.5%
2020	380	520	2,664	67	2.6%
Average Annual Growth Rate, 2000-2018:					
% growth:	**2.8%**	**2.8%**	**3.0%**		

Notes: 1). Peak Load is co-incident to the NSP system peak.
2). Winter Peak = MAPP Winter Peak season, 2002 is 2002-2003

Table Xcel-1
Xcel Energy
System Net Energy Requirements (MWh)

Year	Semi-Low (MWh)	Median (MWh)	Semi-High (MWh)
2002	42,880,289	43,812,188	44,911,692
2003	43,401,626	44,710,084	46,123,890
2004	44,110,210	45,693,635	47,468,531
2005	44,749,468	46,607,164	48,690,230
2006	45,544,059	47,662,529	50,062,854
2007	46,161,773	48,563,377	51,263,294
2008	46,877,493	49,570,270	52,588,464
2009	47,427,743	50,410,313	53,750,069
2010	48,024,636	51,305,058	54,989,226
2011	48,527,565	52,110,692	56,153,682
2012	49,014,574	52,907,790	57,318,734
2013	49,502,611	53,714,719	58,503,398
2014	50,047,343	54,592,597	59,771,393
2015	50,501,195	55,382,047	60,948,465
2016	50,989,609	56,227,860	62,194,637
2017	51,410,846	57,008,843	63,376,071
2018	51,828,299	57,797,994	64,569,964
2019	52,242,156	58,592,406	65,787,397
2020	52,731,019	59,480,258	67,131,008

Average Annual Growth Rate, 2002-2020:			
% growth:	**1.1%**	**1.7%**	**2.2%**

Table XCEL-2
Xcel Energy
System Net Summer Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2002	7,718	7,881	8,081
2003	7,726	7,960	8,226
2004	7,821	8,103	8,437
2005	7,916	8,246	8,636
2006	8,020	8,394	8,843
2007	8,130	8,555	9,062
2008	8,257	8,735	9,303
2009	8,354	8,886	9,517
2010	8,465	9,050	9,749
2011	8,555	9,195	9,964
2012	8,641	9,339	10,179
2013	8,728	9,484	10,396
2014	8,829	9,647	10,634
2015	8,913	9,792	10,854
2016	9,004	9,948	11,088
2017	9,081	10,092	11,310
2018	9,158	10,238	11,534
2019	9,234	10,384	11,760
2020	9,325	10,549	12,014

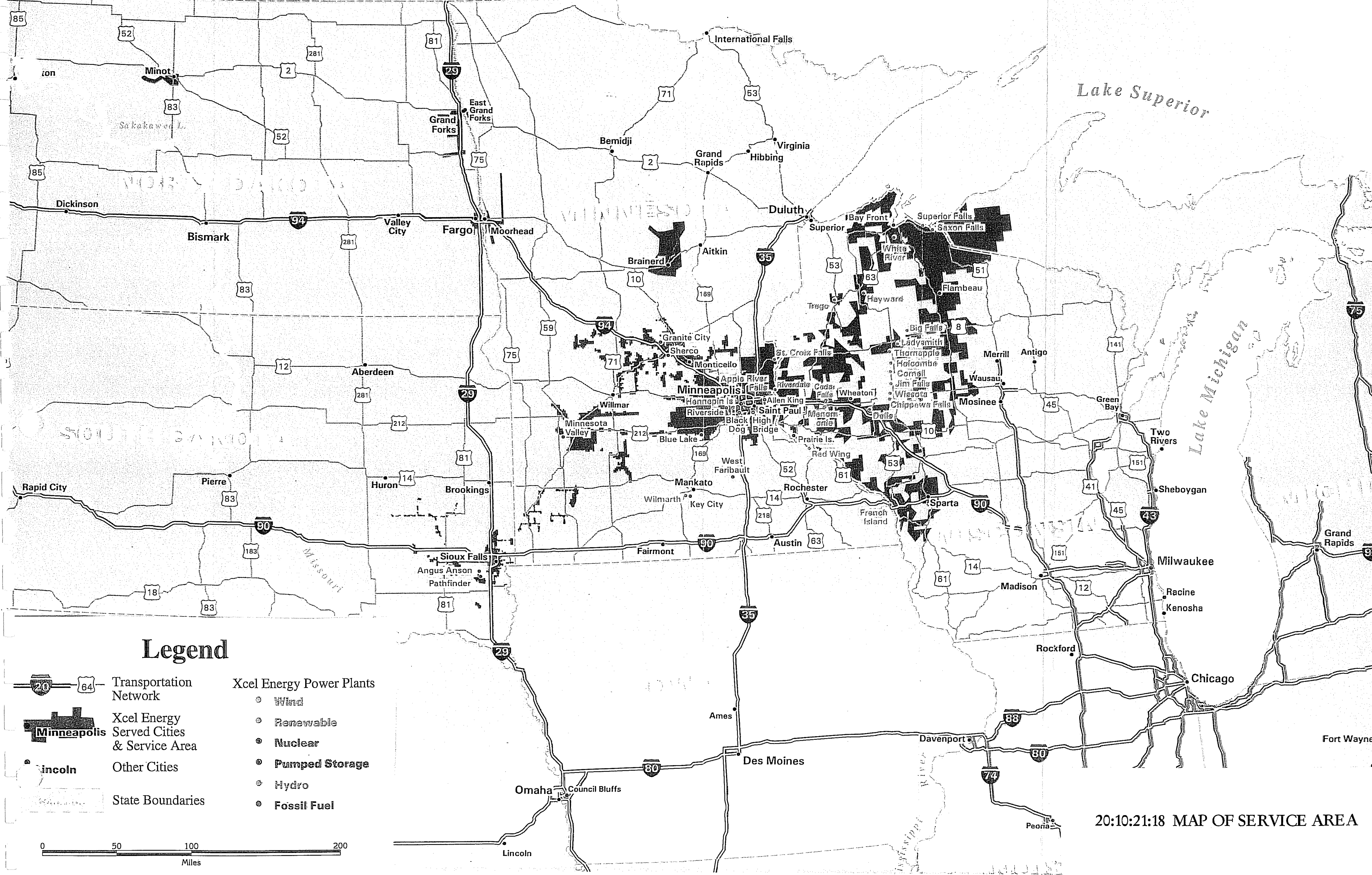
Average Annual Growth Rate, 2002-2020:

% growth:	**1.1%**	**1.6%**	**2.2%**

Table XCEL-3
Xcel Energy
System Net Winter Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2002	6,369	6,531	6,716
2003	6,367	6,566	6,794
2004	6,468	6,702	6,972
2005	6,590	6,858	7,169
2006	6,693	6,996	7,348
2007	6,791	7,129	7,521
2008	6,882	7,258	7,692
2009	6,970	7,384	7,862
2010	7,051	7,502	8,026
2011	7,120	7,610	8,183
2012	7,208	7,740	8,362
2013	7,295	7,869	8,543
2014	7,370	7,987	8,712
2015	7,437	8,098	8,875
2016	7,520	8,229	9,060
2017	7,589	8,346	9,231
2018	7,658	8,464	9,404
2019	7,725	8,581	9,579
2020	7,793	8,700	9,757
Average Annual Growth Rate, 2002-2020			
% growth:	**1.1%**	**1.6%**	**2.1%**

Note: Winter Peak = MAPP Winter Peak season, 2001 is 2001-2002 winter peak.



20:10:21:18 MAP OF SERVICE AREA

APPENDIX A

Xcel Energy 2000 Resource Plan Executive Summary

MPUC Order Approving Xcel Energy's 2000 Resource Plan

1. Executive Summary

Northern States Power Company ("NSP") is pleased to submit to the Minnesota Public Utilities Commission ("MPUC" or the "Commission") our 2000 Resource Plan.

This plan:

- projects customer demand and energy use through 2015;
- analyzes scenarios for meeting that need; and
- recommends a course of action to follow that should create the best overall value for customers.

We look forward to the productive discussion with all stakeholders with regards to this plan.

Resource planning is a complex, interactive process. Identification of needs and assessment of potential resources cannot occur in a vacuum. Planners must consider a variety of other factors and exercise judgement when developing a plan. A key factor complicating many of the uncertainties affecting this plan is the on-going restructuring of the electric utility industry.

While NSP has filed this Resource Plan in accordance with the PUC's requirements, the Company asserts that many of the reasons for implementing the process have changed since its adoption. Nationally, integrated resource planning gained recognition as a part of the Energy Policy Act of 1992 when it was adopted as a part of our federal energy policy. At state level, the practice was recognized in laws adopted in 1993. The IRP was implemented with the intention of evaluating alternatives for all aspects of the vertically integrated electric business. The goals of the process included the ability to better manage electric costs, improve reliability, and reduce dependence on particular resources.

With the disaggregation of the electric industry, however, the traditional integrated planning process has not provided an effective opportunity to address many of these issues. The effect of unbundling the transmission system, together with the deregulation of generation at the federal level, and in most states, has introduced a new set of influences that shape the resource selection process. Today the electric utility industry relies much more on a market-based system of resource allocation that reflect regional needs than a centralized state process.

Looking forward, market forces are expected to play an even greater role in generation resource selection than they have in the past. Similarly, the transmission segment of the electric delivery system, which will remain regulated, must be planned and operated on a regional basis to achieve the desired level of competitiveness in the wholesale market place. Consequently, regional planning of the wholesale market's transmission infrastructure and business systems requirements represent the greatest opportunities to increase the competitiveness and reliability of this industry.

In response to the changing structure of this industry, many states have amended their Resource Planning process consistent with a competitive market to incorporate regional considerations beyond the energy needs of individual utility's load and generation capability. In some instances, the planning process may consider the needs of the entire state as well as national considerations. This planning process will more likely reflect the effects of competition and industry change on consumers.

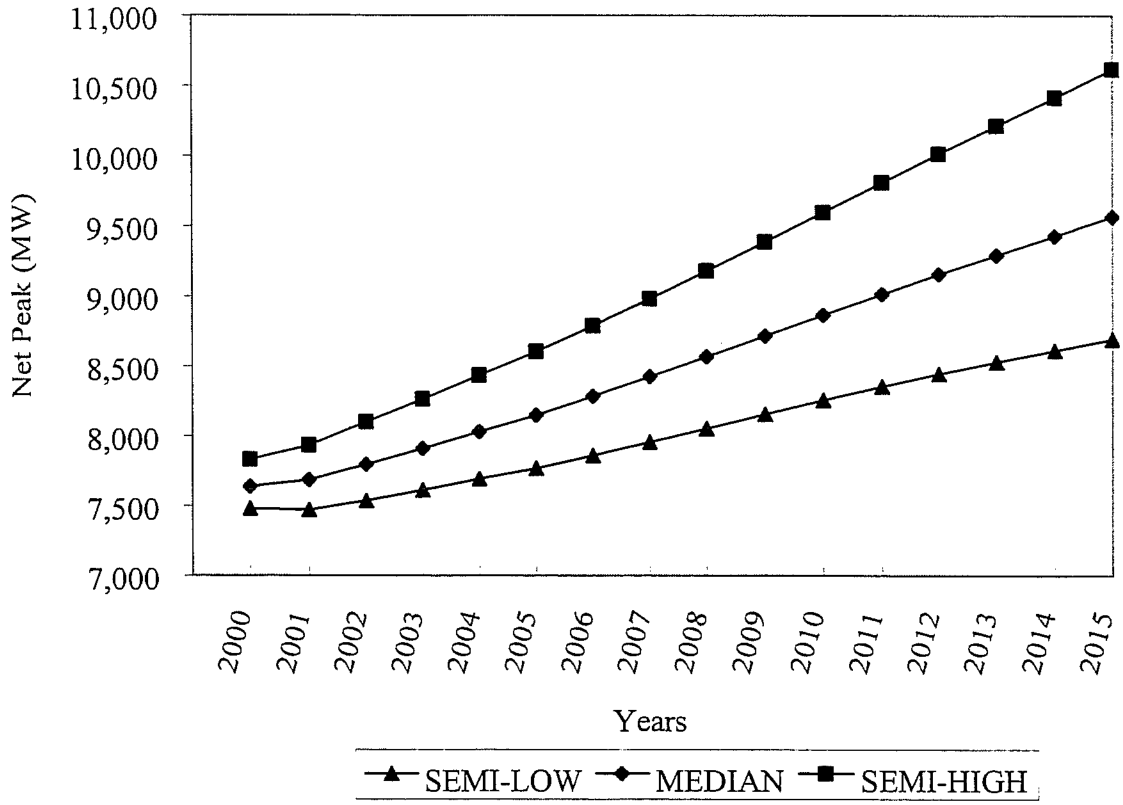
The Company proposes that with this Resource Planning process, the Commission also consider the need for the integrated resource plan to evolve to a statewide strategic planning process that can provide for the long-term needs of the state and consumers in a competitive wholesale marketplace with regional transmission organizations and open access transmissions. The Company understands that legislative changes may also be necessary to accomplish this goal.

This process may also help address the generation supply in the region, which is projected to be inadequate over the 2000-2008 horizon. The Mid-Continent Area Power Pool projects only a small increase of power over this period, while the system may require additional capacity of nearly 5,400 MW by Summer 2008. Generating capacity that in the past may in part have been directed at the Midwest is instead being directed to other parts of the country – notably, the coasts – where restructuring has already occurred. The resource needs NSP has identified in this plan are consistent with MAPP's regional findings. Substantial new investments will be necessary to meet customer's demand for electricity in this area. Concern exists that the uncertainty regarding the regulatory and restructuring process in the Midwest has increased the perceived risk of investments relative to other parts of the country and dampened participation by investors. While NSP believes that movement to more generation deregulation is the best means of addressing this concern, clearly this is the type of statewide/regional issue that the resource planning process should begin to address.

Demand Forecast

NSP prepared a long-range forecast of electric energy requirements and peak electrical demand for the period 2000 – 2015. The forecast shows an average annual growth rate of 1.65 percent in energy consumption and 1.63 percent in peak demand requirements. These growth rates translate into an increase in peak demand for electricity of 100 to 150 MW per year. By 2015, peak demand will increase to somewhere between 9,900 and 11,800 MW and annual electrical energy consumption by those that are currently within NSP service territory will be between 48,750,000 and 60,000,000 MWh. Our median demand forecast is presented below.

Figure 1-1 Net Summer Peak (MW)



Resource Needs

There is considerable uncertainty about NSP's resource needs by the end of the planning period primarily because of the uncertainty surrounding the future of nuclear power in Minnesota. There is less uncertainty about generating capacity additions necessary to ensure reliable and economical electric service in the shorter term.

When the uncertainties of forecasting, power supply, and reserve margins are combined, NSP's cumulative Resource Needs could range anywhere from 4,650 to 7,500 MW by the end of the planning period. After reducing projected resource needs by NSP's proposed conservation and load management goals, NSP's cumulative long-term resource needs estimates vary from 2350 to 5200 MW.

In the near term, the range in forecasts is narrower and the uncertainty in available generating capacity is less. By 2005, NSP expects cumulative resource needs ranging up to 555 and half way through the planning period, 2007, needs in the range of up to 715 MW. These resource needs estimates are after conservation and load management goals are included.

Analysis

After Resource Needs have been identified, an important step in the planning process is to test a broad spectrum of resource combinations that might be used to meet future electrical demand. In this analysis process, the impacts of various energy policy objectives can be tested. From the analysis, one can judge whether any adjustments to the anticipated requirements are necessary and it can include actions in its 5-year plan to better manage future critical issues.
In this resource plan we examine the effects associated with variability in the future demand for electricity and different levels of conservation and load management. We examine the potential effects of increased commitments to electricity generated with renewable resources and the implications of several

different nuclear power futures. This resource plan also examines the potential impacts the global warming issue could have on the Minnesota's economy and power supply decisions.

Demand Side Management

We are pleased to report that with the help of a work group of interested parties our energy and capacity impact goals associated with conservation and load management in this resource plan are on the order of 5 percent higher than the 1998 Plan goals. These proposed increases in DSM goals have been incorporated into our planning.

The Work Group's analysis has also identified areas of possible improvement that if successful, could raise our DSM program's impacts by 20 percent or more as the Commission challenged in the 1998 Resource Plan order. However, there is a great deal of uncertainty surrounding our ability to achieve the additional impacts and their cost. The work group chose not to include the additional impact levels in this plan's DSM goals. Instead, NSP has expanded some of the programs in its current Conservation Improvement Program ("CIP") and will propose pilot programs in its next CIP filing to further explore the performance of the more uncertain strategies identified by the Work Group. In that way, long-term DSM goals can be explored without jeopardizing the reliability of our power supply.

Fossil Fleet

Approximately 45 % of the electricity used by NSP's customers come from fossil fueled generating plants. For the most part this Resource Plan assumes the existing fossil fleet will continue to operate as it does now through the fifteen-year planning period.

NSP has begun a program of making small incremental improvements at existing plants that will result in approximately 40 MW of additional generating capacity. For example, air inlet cooling technology has been installed at the Inver Hills Peaking Plant and will be installed at the Anson Peaking plant this summer.

In the 1998 Resource Plan, interest was expressed in examining the feasibility of converting coal-fired power plants to natural gas combustion. NSP agreed to investigate the feasibility of converting Black Dog units 1 and 2 from coal to natural gas. The feasibility studies found that Black Dog could be converted to natural gas combustion and that the most efficient and economical approach was to repower Black Dog Units 1 and 2 using natural gas, combined cycle technology. A new combustion turbine and a heat recovery steam generator will be installed at Black Dog. The new facility will utilize many of the existing Unit 1 and 2 components including the Unit 2 steam turbine and generator. The repowered facility will result in 114 MW of additional plant output, greater fuel efficiency, and better environmental performance through reduced air emissions. The Public Utilities Commission issued a Certificate of Need authorizing the construction of the facility on June 28, 2000.

NSP has agreed to continue investigations of the feasibility of converting some of its coal fired plants to natural gas combustion. Within the next year feasibility studies will be completed at High Bridge and Riverside.

Nuclear Power

The Prairie Island Nuclear Generating Plant and the Monticello Nuclear Generating Plant continue to be cornerstones in NSP's diversified mix of resources for the production of reliable electricity. Electricity supply issues in the second half of the planning period depend heavily on whether nuclear power will continue to be part of the state's resource mix. The reliability concerns previously referenced will be impacted significantly by the choices made regarding continued operations of these plants.

On June 25,1999, Prairie Island's Unit 1 became the first reactor in the world rated at 560 megawatts gross capacity to produce 100 million megawatt-hours of electricity. Unit 2 at the Prairie Island plant generated its 100 millionth megawatt hour of electricity during last October (10/28/99).

Unit 2 set a production record in 1999, generating 4,597,443-megawatt hours. This surpassed the previous Unit 2 record set in 1994 of 4,552,960 megawatt hours. Additionally, unit 2 set a record run for the site, operating non-stop for 446 days before being taken off line for a scheduled refueling outage in May 2000.

Monticello's and Prairie Island's future continues to depend on resolution of the spent fuel storage issue. Prairie Island can operate until 2007 with currently authorized spent fuel storage. Monticello can operate through its licensed life, 2010, with on site storage, but no longer.

Spent Fuel Storage: The Department of Energy's program to establish a permanent spent fuel depository at Yucca Mountain, Nevada is, at best, a decade away from completion. Efforts to amend the National Nuclear Waste Policy Act to facilitate interim storage developed by the federal government failed for lack of only a few votes to over ride the president's veto.

The most promising solution is a proposal to privately develop national interim storage. Private Fuel Storage ("PFS") is a consortium of eight nuclear utilities, including NSP, that is working to build an interim spent fuel storage facility on the West Central Utah reservation of the Skull Valley Band of Goshute Indians. PFS and the Skull Valley Band of Goshute Indians entered into an agreement in December 1996 that allows for storage of spent fuel away from the Prairie Island Plant. The proposed facility is subject to licensing approval by the Nuclear Regulatory Commission ("NRC"). NSP is optimistic about the project's chances for timely success based on steady progress in the NRC licensing process; resolution of a majority of intervenors' contentions; continuing support from the Skull Valley Band of Goshute Indians; and growing support among members of the public.

PFS proposes to license, build, and operate an above ground, interim facility to store spent nuclear fuel from its member plants, as well as from other nuclear plants. The facility is designed to accommodate up to 4,000 dry storage containers, or 40,000 metric tons of spent fuel. The facility would be constructed in stages as necessary to accommodate storage requirements.

PFS anticipates that the NRC will issue permits for the facility in 2001 and the storage facility could be operating by the end of 2003.

Relicensing: In part because of the uncertainty surrounding the spent fuel storage issue, NSP has not made decisions about whether to apply for permission to continue to operate its nuclear power plants for an additional 20 years. Applications must be made to the NRC six or more years before the current licenses expire and the work to prepare applications takes approximately two years. Therefore, NSP must decide within the next two years whether to begin the process of application preparation for the Monticello plant. A decision for the Prairie Island Plant is probably a few years away. To date four nuclear power plant licensees have made application for 20-year extensions to their operating licenses and 26 others have announced their intention to also apply.

Licenses have been renewed for Calvert Cliffs Units 1 and 2 on March 23, 2000 and for Duke Power's Oconee Units 1, 2, and 3 on May 23, 2000.

Nuclear Plant Life in Modeling: For planning purposes NSP has assumed that Prairie Island will continue to operate till the end of its licensed life as part of the comparison case. This assumption is the result of the progress that has been made in establishing a national interim storage facility by PFS. This resource plan also examines alternative scenarios to that assumption. A scenario has been developed to examine the effects of premature shut down of the plant in 2007. Another scenario was developed to examine the effects on resource selection if the plant licenses were extended 20 years. The analysis demonstrates that the longer Nuclear Power remains part of the State's mix of generating resources the more economical the State's power supply will be.

Steam Generators at Prairie Island: Additional sensitivity analysis was done to examine the effects of increasing maintenance costs associated with existing steam generator components in Unit 1 at the plant.

Past assessments of the steam generator tube inspection and maintenance program have indicated that the steam generators could continue to be operated under the inspection and maintenance program as long as corrosion effects continued along then existing trends. During the last two refueling outages however, some steam generator tubes at Prairie Island Unit 1 have shown indications of corrosion in new areas of the steam generators not previously experienced.

In this Resource Plan we have compared two power supply scenarios related to steam generators at Prairie Island. The first simulates power supply costs associated with continuing to inspect and repair steam generators as long as possible. Unit 1 at Prairie Island is assumed to close by 2009 because of high costs and declining performance. The second option investigates the impacts of replacing Unit 1 steam generators by 2004. The analysis indicates that Prairie Island can produce power more economically if steam generators are replaced, provided current spent fuel storage limitations can be overcome. NSP continues to evaluate whether to replace steam generators on Unit 1 at Prairie Island. We are taking incremental steps to preserve the option to replace steam generators in Unit 1 at Prairie Island as early as 2004.

Renewables

The renewables development program that came out of the 1994 Prairie Island legislation has resulted in the largest ongoing commitment to wind and biomass resources in the country. NSP is in the midst of an aggressive acquisition program that will meet the renewables targets of the law on time.

To date NSP has contracted for nearly 300 MW and selected in bidding another 50 MW of wind powered electrical generation. On June 23, 2000 NSP issued an Request for Power ("RFP") for an additional 80 MW of wind powered generation that will ensure that at least 425 MW of wind generation is in service or contracted for by the end of 2002 as required.

NSP has contracted for 25 MW of wood waste fueled generation to be developed by St. Paul District Energy as part of their downtown St. Paul system and for 50 MW with EPS Beck to develop whole tree burning electric generation. Negotiations with a company proposing to develop a poultry litter fueled power plant are underway to fulfill the remaining 50 MW increment of the 125 MW mandate.

A preliminary analysis examining the possibility of meeting at least half of the new demand for electricity with renewables based generation indicates that such a future may be economical. However the analysis is very sensitive to cost and performance assumptions, especially those associated with wind powered generation. The intermittent and highly variable production characteristics of wind power are not well represented in modeling exercises. Our findings are further support for an all source competitive acquisition program that will allow us to obtain more accurate actual information about power supply options rather than rely on modeling assumptions.

Environment

NSP's fossil-fueled plants are in compliance with the Clean Air Act provisions limiting the emission of oxides of Nitrogen. Over fire air systems have been installed at Sherco 2 and at King and investigation of combustion improvements at Riverside 8 will begin soon. NSP has submitted a voluntary mercury reduction plan and continues to work with PCA and EPA as they consider further actions to reduce anthropogenic sources of mercury.

In this filing, the Commission's environmental cost estimates were used in the examination of resource plan alternatives. The application of externalities did not materially affect the relative merit of resource plan scenarios.

This Resource Plan also examines the impact that future CO_2 regulation might have on power supply decision making. Recently developed economic models that simulate the impact of the cost of carbon regulation were used to estimate impacts on Minnesota's economy and the associated reductions in the demand for electricity. The cost of compliance was substantially higher and the impact on the State's economy was substantially more adverse in simulations in which Minnesota or the United States tried to unilaterally reduce green house gas emissions compared to simulations of international reduction agreements and global trading in emission reductions. Simulations of international carbon reduction agreements with emission allowance trading programs did not materially effect resource planning decisions. The exercise further emphasizes the importance of nuclear power in any efforts to manage carbon emissions in the future. The scenario in which Prairie Island and Monticello continue to operate 20 years beyond their current licensed life result in 45 million fewer tons of CO_2 emissions compared to the base case in which they are replaced at the end of their licensed life.

Transmission

As with other utilities in the country, NSP's transmission system is operating with very little excess capacity. Major improvements will be necessary as generation is added and customer demands continue to grow. The new market created by Open-Access transmission tariffs, have increased the volume of transactions often to the point of raising the transmission network loading to its limits—in fact, to the point where line loading relief and curtailment procedures are implemented more frequently than ever before.

In October 1999, NSP was approved for membership in the Midwest Independent System Operator (MISO) organization. The MISO is a non-stock, not-for-profit organization which will be authorized to maintain system reliability, provide open access transmission service and coordinate planning and maintenance activities. The target date for MISO to begin operations is November 1, 2001. NSP retains ownership of the facilities involved, and has received federal approval to transfer operational control of our 100 kV and above transmission facilities to the MISO. NSP is working with the state Commissions to keep them informed of the MISO transition process.

Transmission planning is a dynamic on going process. Studies completed since the last Resource Plan include long-range looks at the Twins Cities metropolitan area, west-central Minnesota and Hastings area of Minnesota. Additionally, an assessment was made of the southwest Minnesota area.

For the metro area, significant expenditures will be required over the next 15 years with two-thirds of it needed for projects with in the next 5 years. Most of the development will involve the 115 kV network and conversions from 69 kV to 115 kV to accommodate expanding local growth in the outskirts of the metro area.

In out-state Minnesota, separate system problems need to be resolved in the west central area and Hastings areas.

Work is underway to assess the transmission capability in southwestern Minnesota and southeastern South Dakota. The relatively small amount of electric load, the increasing number of requests for interconnection and existing high level of wind generation in this area of the state, create a 115 kV system which is highly sensitive to fluctuations in transmission loading. Major transmission work will be needed to allow continued generation development in the southwest part of Minnesota.

NSP performed an analysis of the generation potential on the transmission system. Without consideration for site suitability, the assessment identifies the western Twin Cities metropolitan area as having the greatest potential to accept generation, primarily because of the high electric load density, the well-developed transmission system and lack of existing generation in the southwest Metro area. Other areas of the transmission system, which could potentially accept smaller amounts of generation, are scattered through western Minnesota, the Sioux Falls area and northern Wisconsin.

Five-Year Plan

NSP plans on taking the following steps during the next five years to ensure continued reliable electricity supply to our customers.

Resource Acquisition: NSP plans the following schedule of competitive procurement to meet the growing demand for electricity.

Table 1-1 NSP Proposed Bid Schedule

RFP Issued	Resource Type	Amount	In-Service
2000	Mandated Wind	80 MW	2002
2001	All-Source	100-600 MW	2003 - 2005
2002	All-Source	up to 400 MW	2006 - 2008
2003	All-Source	up to 500 MW	2007 - 2009
2004	All-Source	up to 600 MW	2008-2010

Additional solicitations may be necessary depending on the future of nuclear power in Minnesota.

DSM: NSP Plans to develop a series of conservation and load management programs designed to reduce the demand for electricity by the amounts shown in the following schedule and implement them through the CIP process.

Table 1-2 Incremental DSM Impacts and Costs
State of Minnesota 2000-2004

	2000	2001	2002	2003	2004
Demand (MW)	82.8	88.7	79.1	64.7	61.2
Energy (GWh/yr.)	191.8	196.2	167.7	164.4	165.0
Program Costs	33.1	33.2	32.1	30.4	30.4

(Nominal $ Million; impacts are full-year basis, consistent with CIP filings. Data for 2000 and 2001 are per the DOC 5/8/00 Decision for NSP's CIP)

***Fossil Fleet Improvements*:** NSP will continue to make incremental improvements in the performance of its peaking plants and will examine the feasibility of natural gas conversions in its metro coal fired power plants. Studies will be completed at High Bridge and Riverside by July 2001.

Nuclear Power: The Private Fuel Storage consortium, including NSP, will continue to aggressively pursue an interim spent fuel storage facility in Skull Valley Utah with the goal of operation by the end of 2003. NSP intends to re-evaluate by the end of 2001, the need to solicit replacement power proposals to cover the risk of premature shut down of the Prairie Island Plant. Additional replacement power solicitations may be necessary depending on nuclear power relicensing decisions. NSP will continue to evaluate the replacement of steam generators at Prairie Island Unit 1 and take steps necessary to preserve the option of replacing steam generators as early as 2004. NSP will decide whether to begin the preparation of license renewal applications for the Monticello Plant in the next year or two and for Prairie Island toward the end of the five-year action plan period.

Renewables: NSP will finish the implementation of 425 MW of wind powered electric generation and 125 MW of biomass powered generation as required in Minnesota legislation. We will continue to encourage renewables developers to participate in all source competitive procurement efforts.

Transmission: NSP will continue to participate in regional planning activities in MAPP and then MISO. NSP will work with the City of Wilmar to seek the permits necessary to convert the Wilmar to Paynesville 115 kV line to 230 kV. NSP will pursue other projects as necessary to provide adequate outlet capacity to new generation and to ensure system reliability.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Gregory Scott	Chair
Edward A. Garvey	Commissioner
Marshall Johnson	Commissioner
LeRoy Koppendrayer	Commissioner
Phyllis A. Reha	Commissioner

In the Matter of Northern States Power Company's Application for Approval of its 2000-2014 Resource Plan

ISSUE DATE: August 29, 2001

DOCKET NO. E-002/RP-00-787

ORDER APPROVING XCEL ENERGY'S 2000-2014 RESOURCE PLAN, AS MODIFIED

PROCEDURAL HISTORY

On July 10, 2000, Northern States Power Company d/b/a Xcel Energy (Xcel or the Company) filed its 2000-2014 Resource Plan (Resource Plan) and filed a supplement on September 6, 2000. The Company's plan was assigned to this docket.

Between November 9 and March 5, 2001, the Commission received comments and reply comments on the Company's Resource Plan from the following: Michael O. Leavitt, Governor of Utah; the Minnesota Department of Commerce (the Department); Communities United for Responsible Energy (CURE); North American Water Office (NAWO); Center for Energy and the Environment (CEE); the Residential and Small Business Utilities Division of the Office of the Attorney General (RUD-OAG); Reliant Energy Minnegasco (Minnegasco); Mississippi Corridor Neighborhood Coalition (MCNC); the Prairie Island Indian Community (PI Community); Minnesotans for an Energy-Efficient Economy (ME3); the Izaak Walton League of America (IWLA); and Clean Water Action Alliance.

The Commission met on June 7, 2001 to consider the Company's Resource Plan.

FINDINGS AND CONCLUSIONS

I. RESOURCE PLANNING IN GENERAL

The resource planning statute and rules are detailed, but they basically require utilities to file biennial reports on (1) the projected energy needs of their service areas over the next 15 years; (2) their plans for meeting projected need; (3) the analytical process they used to develop their plans for meeting projected need; and (4) their reasons for adopting the specific resource mix proposed to meet projected need. Minn. Stat. § 216B.2422 and Minn. Rules Chapter 7843. These requirements are designed to strengthen utilities' long term planning processes by providing input from the public, other regulatory agencies, and the Commission.

Although the Commission must approve, reject, or modify the resource plans of investor-owned utilities, the resource planning process is largely collaborative and iterative.

It is collaborative because there are few hard facts dictating resource choices or deployment timetables. The facts on which resource decisions depend -- how quickly an area and its need for electricity will grow, how much electricity will cost over the lifetime of a generating facility or a purchased power contract, how much conservation potential the service area holds and at what cost -- all require the kind of careful judgment which sharpens with exposure to the views of engaged and knowledgeable stakeholders.

It is iterative because analyzing future energy needs and preparing to meet them is not a static process; strategies for meeting future needs are always evolving in response to changes in actual conditions in the service area. When demographics, economics, or technologies change, so do resource needs and strategies for meeting them. While a concrete document is necessary to focus discussion, parties' positions evolve over the course of each resource plan proceeding, and from one proceeding to the next. Commission decisions, too, may well be refined by decisions in subsequent proceedings.

II. THE LEGAL STANDARD

The statute directs the Commission to "approve, reject, or modify the plan of a public utility, as defined in section 216B.02, subdivision 4, consistent with the public interest." Minn. Stat. § 216B.2422, subd. 2.

The rules require the Commission to consider at least the following factors in evaluating resource plans:

> Resource options and resource plans must be evaluated on their ability to:
>
> > A. maintain or improve the adequacy and reliability of utility service;
> >
> > B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
> >
> > C. minimize adverse socioeconomic effects and adverse effects upon the environment;
> >
> > D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
> >
> > E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.
> >
> > Minn. Rules, part 7843.0500, subp. 3.

III. THE COMPANY AND ITS RESOURCE PLAN

A. The Company

Xcel is an electricity and natural gas provider based in Minneapolis. Xcel was formed by the merger of Denver-based New Century Energies and Minneapolis-based Northern States Power Company. The Company has a combined total (regulated) generation capacity of more than 15,000 megawatts (MW) and serves about 3 million electricity customers and 1.5 million natural gas customers through its regulated operating companies in 12 states. In addition to Northern States Power Company's traditional service areas in the states of Minnesota, Wisconsin, North Dakota, South Dakota, and Michigan, Xcel has customers in Colorado, Arizona, Kansas, New Mexico, Oklahoma, Texas, and Wyoming.

Xcel provides electric service to approximately 1.1 million customers in Minnesota. The largest clusters of customers in Minnesota are in the Twin Cities and St. Cloud areas.

B. The Resource Plan

The Company's resource plan covers the period from 2000 through 2014. Xcel's process of producing the current integrated resource plan was similar to the one used for its 1998 plan. The Company started its analysis by forecasting its customers' future demand. Xcel's forecast was produced in June 1999 and then re-calibrated to the Company's most recent short-term budget forecast, developed in February 2000. In its last resource plan docket, the Company's forecast methodology was approved with minor modifications; the forecast for the current filing was produced using that methodology, as modified.

The Company created a comparison (or base) scenario to use as a benchmark to compare with other planning alternatives. The Company assumed a level of demand-side management (DSM) recommended by a DSM work group created after the last resource plan docket. Other assumptions used in creating the comparison scenario are listed on pages 33-34 of the Company's July 10, 2000 filing. Using its assumptions, the Company applied the Electric Generation Expansion Analysis System (EGEAS) model to find the plan of generation additions that minimized economic impacts. The Company then tested the sensitivity of resource additions to a slower or more robust economy with associated changes in the demand for electricity. The results for the three cases were as follows: for the semi-low forecast, a present value of revenue requirements (PVRR) of $23.8 million (2000 $) for 3,235 MW of cumulative capacity additions; for the median forecast, a PVRR of $26.7 million for 4,175 MW; and for the semi-high forecast, a PVRR of $30.2 million for 5,200 MW.

Xcel created a significant number of DSM and supply-side scenarios to compare to the base scenario described above. For example, Xcel evaluated various incentive levels for DSM projects, and the Company looked at various ways of meeting the 50% and 75% conservation/renewables scenarios required by Minn. Stat. § 216B.2422, subd. 2. The Company also considered scenarios involving premature shutdown of the Prairie Island Nuclear Plant and 20-year life extensions for both nuclear plants.

NSP determined its projected resource additions by comparing its projected resource needs or obligations with the Company's committed resources. NSP's resource obligations included the forecast of summer peak demand, the MAPP minimum reserve requirement of 15%,[1] and contracted obligations to sell to others.

Xcel indicated that, when the uncertainties of forecasting, power supply, and reserve margins are taken into account, the Company's cumulative resource needs range from 4,650 to 7,500 MW by the end of the planning period. The Company added that its DSM goals reduce those long-term projections to between 2,350 and 5,200 MW. Xcel added that nearer term projections of needs are less uncertain.

Xcel estimated its supply-side resource needs by the given dates to be in the following ranges: by 2005, 176-1,009 MW; by 2010, 663-2,002 MW; and by 2014, 1,918-3,563 MW.[2] The Company proposed to meet its resource needs primarily through a series of competitive procurement processes. The planned schedule for the various acquisitions is given in Tables 1-1 on page 15 and 3-1 on page 31 of the resource plan. Xcel noted that additional requests would be necessary to replace capacity from its nuclear plants.

IV. SUMMARY OF COMMISSION ACTION

The Xcel resource plan is long and complex, explaining in detail the factual assumptions, analytical tools, and business and policy rationales behind the hundreds of decisions which make up the plan. Most of these decisions are routine, but some are contested, and a few raise important public policy issues.

In this Order, the Commission modifies certain sections of the resource plan as authorized by Minn. Stat. § 216B.2422, subd. 2 consistent with the public interest and approves the entire plan as so modified.[3] In the following sections, the Commission will explains the modifications it has made to the Company's 2000-2014 Resource Plan and any requirements it is making with respect to the Company's next plan.

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[1] Xcel suggested in its resource plan that price volatility in the wholesale market could necessitate raising utility reserve margins above this current minimum.

[2] For its median forecast, the Company's projections are 555 MW by 2005, 1,270 MW by 2010, and 2,735 MW by 2014.

[3] In addition, while considering Xcel's Resource Plan, the Commission concluded that it would be appropriate to examine the potential for the Company's rate and tariff design to achieve DSM savings and to send appropriate pricing signals to ratepayers. The Commission has opened a new docket and issued a separate Order opening this investigation: *In the Matter of an Investigation into Using Rate Design to Achieve the Demand-side Management Goals of Xcel Energy*, ORDER OPENING INVESTIGATION, Docket No. E-002/CI-01-1024 (July 20, 2001).

V. PLANNING PROCESS AND DEMAND FORECASTS

A. Party Comments

The Company's planning process and demand forecasts were generally uncontroversial. While the Prairie Island Community (PI Community) argued that independent power producer activity could significantly increase as Minnesota moves to a more open market, the impact of this development on Xcel's power needs remains speculative at this time.

The Department stated that Xcel's forecasting was reasonable for planning purposes and recommended that the Commission accept the Company's forecast of energy requirements and summer peak demand. The Department noted some discomfort, however, with two adjustments that the Company made in its forecasting process. For the years 2000-2004, Xcel substituted its short-term budget-oriented forecast for its long-term forecast. For the remaining years of the planning period, the Company adjusted its long-term forecast by subtracting from it the difference between the 2004 long-term and short-term forecasts. The Department recommended that Xcel meet with the Department and any other interested parties by September 1, 2001 to discuss ways to improve the integration of the short- and long-term forecasts.

B. Commission Action

Having considered the parties' comments, the Commission will accept the Company's forecasts of energy requirements and summer peak demand as reasonable and adequate for planning purposes. The Commission will also accept the Company's bidding plan as a reasonable and prudent approach to meeting customers' needs, recognizing that some change in specific dates and amounts are likely as the procurement process moves forward.

As to the Department's concern for integrating the short- and long-term forecasts, the Commission finds the Department's recommendation appropriate and will, therefore, direct the Company to meet with the Department and any other interested parties by September 1, 2001 to discuss integration of the short- and longer-term forecasts and possibly other modeling issues and require the Company to use cost information from its all-source winning bids to evaluate the cost of future resources in both its IRP and the all-source bidding process (see page 26 of the Department's initial comments).

Regarding the information requested by the Department, the Commission believes that this information could be helpful and will, therefore, require the Company to submit the information requested by the Department (in the format specified in Table 14 on page 22 of the public version of the Department's initial comments) as a compliance filing in this proceeding or before the issuance of its next all-source bid RFP, whichever comes first, and also require the Company to provide the same type of information in its next resource plan.

VI. RESOURCE NEEDS/ RESERVE MARGIN

Xcel included in its resource plan a concern about the adequacy of a 15% reserve margin under current conditions. Xcel suggested in its resource plan that price volatility in the wholesale market could necessitate raising utility reserve margins above this current minimum.

The Department commented on Xcel's suggestion that utilities might have to increase their reserve margins (e.g., to 20%). The Department reported the Company as stating that assumptions on the value of unserved energy is the prime reason for its tentative conclusion that increasing their reserve margins might be appropriate. However, the Department questioned the accuracy of the Company's choice of $3,000 per MWh and its decision to use the figure throughout the planning period. The Department added that sensitivity analysis revealed the Company's expansion plan changed as the assumed value was increased from $0 per MWh toward $3,000 per MWh. In view of these considerations, the Department recommended that the Commission withhold any conclusion on increasing the reserve margin until at least the next resource plan proceeding. The Department also recommended that the Company be directed to meet with the Department to discuss EGEAS modeling of unserved energy and other concerns.

The RUD-OAG also recommended that the Commission not approve any increase in the reserve margin at this time. RUD-OAG stated that the Company did not provide any documentation that 20 percent would be a cost-effective level.

At the hearing, the Department focused its objection on the Company's use of $3,000 per Mwh when modeling the cost of unserved energy and its use of this the figure throughout the planning period. The Department argued that using this high number tended to overestimate the cost of energy that the Company would be forced to buy if its resources were inadequate to meet demand and hence overvalue the benefit of (and hence inappropriately promote) increasing its reserve margin. The Department recommended that the Commission require the Company to use the customer buyback rate instead of the $3,000/MWh when modeling the cost of unserved energy and use that rate only in the peak months.

The Commission is not convinced that the record supports or even that it is necessary to choose at this time the exact proxy that Xcel should use when modeling the cost of unserved energy. The Commission clarifies that the Company is not proposing to change the reserve margin at this time so the issue of appropriate modeling proxy is not imminent. At the same time, however, the Commission recognizes that the Department has identified an issue of potential future relevance and the Company has been made aware of the Department's concern.

For now, then, the Commission will not specify a particular number but will simply direct the Company to use an appropriate number when modeling the cost of unserved energy and be prepared to justify that number to the Department. The Commission expects that the record will be fully developed on this issue if and when it returns to the Commission.

VII. DEMAND-SIDE MANAGEMENT ISSUES

A. Investigation to Increase DSM Financial Incentives

Both ME3 and CEE recommended that the Commission review and update Xcel's DSM financial incentive mechanism.

The Department, however, argued that to reopen the financial incentive issue as part of this resource plan docket would be inappropriate because the Commission can decide whether Xcel's financial incentive plan should be modified when it reviews the annual CIP tracker filings.

The Commission agrees with the Department on this point. Under the Company's current DSM financial incentive plan, incentive mechanisms are monitored and the incentive plans are reviewed as part of the utilities' financial incentive and CIP tracker filings made in May. This is adequate occasion for updating Xcel's DSM financial incentive mechanism as warranted.

B. Demand-Side Management (DSM) Goals

DSM goals (energy and capacity impact goals associated with conservation and load management expenditures) impact resource plans in that DSM reduces the amount of energy and/or power the company will have to provide to its customers. DSM achievements are considered resources in the resource planning process because they prolong a company's ability to meet the energy needs of its customers without producing or procuring additional energy.

1. Xcel's Proposal: DSM Base Scenario

The Company created a comparison (or base) scenario to use as a benchmark to compare with other planning alternatives. The Company assumed 1) an energy conservation goal which was 6 percent higher than the 1998 energy conservation goal; 2) a demand savings goal which was 1 percent higher than the 1998 demand savings goal; and 3) DSM expenditures or costs (incentives to ratepayers) projected to be 2 percent higher than the 1998 plan.

The Company based this base scenario on the recommendations of a DSM Work Group that it created after the last resource plan docket. The Company noted that the Work Group was composed of NSP staff, environmental organizations, regulatory agency staff, a customer organization, and supporting consultants.

2. The IWLA's Recommendation: 125 Percent Scenario

The IWLA recommended a higher level of DSM expenditures than proposed by Xcel. The IWLA stated that it participated in the Company's DSM Work Group but still believes that a higher level of DSM expenditures than proposed by Xcel is warranted. The IWLA explained that, since Xcel's DSM analysis was completed, a substantial change in the cost-effectiveness of DSM has occurred. This change is due to the increase in natural gas prices, making additional DSM expenditures cost-effective.

The IWLA recommended requiring DSM expenditures at a level equal to 125 percent of the Company's proposed scenario. Cumulative energy savings for the 15 year planning period associated with the 125 percent incentive level (2,935 GWh) are 12 percent higher than Xcel's proposed goal. Cumulative demand savings associated with the 125 percent incentive level (1,030 MW) are 13 percent higher than Xcel's proposed goal.

The IWLA stated that setting DSM goals too high could result in fewer energy savings because without the hope of earning a financial incentive, the Company might curtail spending above the mandated 2 percent CIP spending level. Thus, the IWLA suggested that the DSM goal be set at an ambitious yet achievable level: 125 percent.

3. Center for Energy and the Economy (CEE): 125 Percent Scenario

CEE also recommended that the Commission adopt the DSM goals at the 125 percent incentive level. CEE suggested that the increased goal should be recognized as aggressive and be revisited in the Company's next resource plan.

CEE participated in the Work Group that Xcel convened to find additional energy savings. CEE stated that the Work Group found that there is a large degree of uncertainty in estimating future energy savings because the market for some technologies is largely saturated and there is uncertainty about the costs, availability, and timing of new technologies.

Nevertheless, CEE stated that recent developments warrant a re-evaluation of the Work Group's findings. CEE noted that subsequent to the completion of the Work Group activities, Xcel finished its EGEAS analysis, which indicates that its PVRR is optimized at the 125 percent incentive level. In addition, one of Xcel's preliminary assumptions was that real natural gas prices would not increase. And recently, large price spikes in natural gas have raised concerns. CEE stated that as energy prices increase, DSM becomes more cost-effective and new opportunities arise for additional savings.

4. The RUD-OAG's Recommendation: 125 Percent Scenario

The RUD-OAG noted that in Xcel's proposed base case plan, the Company's energy and demand savings goals are only 6 percent and 1 percent higher respectively than the 1998 goals. The RUD-OAG stated that the goals associated with the 125 percent incentive level are cost-effective, realistically achievable, and consistent with the Commission's desire to encourage Xcel to set higher DSM goals in this resource plan. The RUD-OAG stated that analysis of the risks and benefits may lead the Commission to adopt DSM goals higher than the 125 percent level, but not higher than the 175 percent incentive level.

In support of its position, the RUD-OAG noted, among other things, that the Company's own analysis shows that it is more cost-effective to adopt the DSM goals associated with the 125 percent incentive level than with the Company's recommended base case, and higher levels of DSM may be more cost-effective depending on the actual transmission and distribution savings. The RUD-OAG also noted that preliminary results for 2000 show that Xcel's energy savings in 2000 were over 225 GWh and demand savings were over 166 MW at a cost of $34.8 million. According to the RUD-OAG, this shows that Xcel is able to achieve substantially more conservation at a significantly lower cost than that proposed on an annual basis by the 125 percent incentive scenario.

5. The Department's Recommendation

The Department noted that every proposal to increase DSM spending above the minimum statutorily mandated minimum CIP spending requirement involves a certain degree of risk. The Department stated, however, that the risks and associated costs of each proposed level must be weighed against the incremental benefits to be achieved. Based on its analysis of the benefits and risks of higher DSM goals, the Department recommended that the Commission adopt a goal 75 percent higher than the Company's proposal (base case scenario). Hereafter the Department's recommendation is referred to as the 175 percent scenario.

The Department argued that Xcel's modeling led to overly conservative DSM goals for two main reasons: 1) it did not use current (much higher) natural gas prices and 2) did not adequately consider transmission and distribution savings. Even so, the Department stated that the Company's modeling (conducted subsequent to the Work Group's recommendations) does not support such a low DSM goal, but instead indicates an optimal level of DSM for Xcel lying somewhere between the 125 percent incentive scenario and the 175 percent incentive scenarios, depending on the true impact of DSM on the Company's transmission and distribution (T&D) expenditures.[4]

In addition, the Department stated that even under Xcel's outdated gas price assumptions and considering that the most likely T&D benefits lie in between the extremes of no benefits and maximum benefits, the Company's modeling shows that the 150 percent scenario is optimal in terms of minimizing the present value of revenue requirements (PVRR).

In doing its own DSM modeling, the Department used higher natural gas pricing assumptions (based on current gas price information) and added the same avoided T&D costs as Xcel did. The result was that the 175 percent incentive scenario was optimal scenario in terms of minimizing the present value of revenue requirements (PVRR). According to the Department's model, achieving the results of the 175 percent scenario yields an incremental benefit of $56 million.

The Department acknowledged the declining efficiency of DSM spending (that at higher levels it costs more to achieve additional DSM savings), but argued that the sensitivity scenarios reflected those expected declines in efficiency and that, therefore, the Company can be expected to achieve the results of the 175 percent model.[5] The Department concluded that the incremental risks and costs of the 175 percent scenario are manageable and that the reward (the incremental PVRR reductions) of that scenario outweighs the risk.

The Department's position was supported by Clean Water Action Alliance, ME3, and the PI Community.

6. Commission Analysis and Action

The Commission begins its approach to DSM issues guided by the fact that increasing reliance on conservation is a dominant theme of the resource planning statute and that, all other things being equal, cost-effective DSM is preferable to generation options in terms of air and water pollution and preserving finite resources. The key question here is how much DSM is reasonable to expect/require of Xcel. Having considered this matter carefully, the Commission is convinced by the Department's arguments that the 175 percent scenario is reasonable and, on balance, preferable to the Company's proposal.

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[4] The Department noted, for example, that the Company's modeling results indicate that Xcel's PVRR is lowest in the 125 percent incentive scenario even when Xcel assumed that DSM has no impact on T&D costs.

[5] The Department noted that the Company has, in fact, achieved the annual energy savings of the 175 percent sensitivity scenarios every year from 1993 to 1998.

The Company urged caution based on limitations in the modeling process, but the Department's adjustments to the Company's modeling approach appear responsible. The Company also questioned whether it would be able to achieve the conservation savings associated with the 175 percent scenario. However, although the Company will doubtless encounter decreasing efficiency in its DSM expenditures as it pursues higher savings levels, the Department's modeling shows that it will be cost-effective to spend at least the amount of money associated with the 175 percent scenario.

Also, history supports the Department's optimism about the Company's ability to achieve DSM goals. Every year from 1993 to 1998 the Company has achieved savings at that level and preliminary figures for 2000 indicate that the Company was again able to attain the annual energy- and demand-savings goals of the 175 percent scenario, and at a cost more than $35 million less than the average cost used in the Department's modeling.

In addition, the Department reported that Xcel's consultant charged with creating the various DSM scenarios informed the Department that the Company could achieve all the DSM scenarios and at a lower cost than estimated.

Moreover, the Company's caution against a "sharp increase" in DSM goals or spending seems overstated. The Company's currently approved **demand-savings goal** for 2000 is 85 MW, while the annual average demand savings for 2002-2006 in the 175 percent scenario is only 3 MW larger: 88 MW. And while the increase in the **energy-savings goal** is much larger (42 GWh), ramp-up time to achieve that goal seems more than adequate since the Company will have reserve margins in excess of 20 percent through 2005 and will, hence, be able to operate existing plants longer to meet any energy-savings shortfalls in the first five years.

Finally, Xcel's Resource Plan (even incorporating the more aggressive DSM goals) does not contemplate any energy needs that will be unmet from available resources for several years. Before these needs necessitate procurement of additional resources, the Commission will be reviewing future resource plans and revisiting the question of whether the 175 percent scenario is appropriate. If, in fact, the 175 percent scenario proves unachievable, the Commission can adjust it.[6]

To conclude, having balanced the risks against the benefits and noting the safety net (ability to adjust the goal in a timely manner if it proves unachievable), it appears to the Commission that the 175 percent scenario is the appropriate approach at this time. The Commission will adopt the DSM goals associated with the 175 percent incentive scenario: 3,253 GWh cumulative energy savings in Minnesota over the planning period and 1,174 MW cumulative peak demand savings in Minnesota over the planning period.

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[6] The Commission will revisit the Company's DSM goals in the next resource plan. If the Commission, Xcel, or any other party finds it necessary to revisit the DSM goal decision prior to the next resource plan, a filing could be made or the Commission could initiate an action on its own motion. The Commission trusts that the Company will not interpret these statements as an invitation not to exert good faith efforts to achieve the 175 percent goals adopted in this Order.

C. Reporting Progress Toward DSM Goals

As the previous section (Section B) indicates, the Commission has great interest in the Company achieving significant DSM gains. To keep the Commission fully apprised of the Company's progress in meeting the 175 percent incentive scenario, the Commission will order Xcel to report on its progress to meet the goals as part of its next CIP status report to be filed April 1, 2002. Similarly, the Department issues an analysis of Xcel's status report in June. The Commission will ask the Department to address in that analysis Xcel's progress in meeting DSM goals.

D. Continued Development of Modeling Issues

In addition, to facilitate further development of DSM modeling issues that play such an important part in resource planning, the Commission will order the Company to meet with the Department and other interested parties, prior to the next resource plan, to discuss DSM modeling issues, including but not limited to the sharp increase in DSM costs between 2014 and 2015, and the low costs for non-Minnesota DSM, as proposed by the Department and the PI Community.

VIII. NUCLEAR POWER ISSUES

Xcel's Prairie Island Nuclear Generating Facility produces approximately 1,100 MW. Xcel's resource plan for the years 2000-2014 set forth three scenarios involving electricity generated by its nuclear facility at Prairie Island:

- Scenario 1: Prairie Island operates to the end of its licenses (2013 for Unit 1 and 2014 for Unit 2);
- Scenario 2: Shutdown in 2007 due to spent fuel restrictions[7]; and
- Scenario 3: Renewal of operating licenses. Prairie Island operates for another 20 years: to 2033 for Unit 1 and to 2034 for Unit 2.

[7] The Commission clarifies that the Prairie Island legislation (Minn. Stat. §§ 116C.771 and 116C.778) does not specify a shutdown date, but establishes a limit on the amount of dry storage casks that can be used at the facility. When enacted in 1991, the shutdown date projected based on full-scale operation and the 17 container limitation was 2001. Subsequently, the Commission has approved an additional 195 storage spaces using temporary storage racks in the section of the pool used for cask loading and unloading operations. In addition, the Company received permission from the NRC to use a higher burn-up rate for the fuel at Prairie Island. As a result of this change, the reactors are refueled less often, generating fewer spent fuel assemblies, thereby extending the life of the storage pool and the generating facility itself. Due to these developments, all parties agree that the full-scale operation of Prairie Island facility has been extended from 2001 to 2007.

A. Xcel's Plan and Comments

Xcel noted that the future of the Prairie Island facility depends on the resolution of the spent fuel storage issue. The Company acknowledged that while movement can be seen in the federal effort to develop a permanent repository, such as the development and release of a draft environmental impact statement, the availability of a repository is at least 10 years away, beyond the 2007 shutdown date.

Xcel suggested that the most likely solution to its current storage dilemma is the private initiative to establish an interim storage facility in West Central Utah on the reservation of the Skull Valley Band of Goshute Indians. Xcel indicated that, while there will be legal challenges to the private storage facility, the developers and Goshutes have so far overcome challenges to the approval of the lease agreement. Xcel stated that the legal issues will cost time and money but expressed the belief that they can be dealt with in a time frame that makes this a viable option for away-from-reactor storage.

The Company also listed two ways to increase on-site storage: re-racking the pool and adding more dry storage containers. Xcel indicated that technical improvements have been developed which would allow for a third re-racking of the pool at an estimated cost of $22,300,000 in 2002 dollars. Xcel pointed out that the dry storage facility at Prairie Island was constructed to accommodate up to 48 spent fuel containers.

Finally, Xcel proposed to maintain the option of replacing the steam generator in Prairie Island Unit 1 in 2004. Xcel explained that although it was initially believed that the generator vessels for both units at Prairie Island would last through the license period, critical tube materials within the generators have been showing signs of corrosion that have required unexpectedly high levels of inspection and maintenance and continue to deteriorate. As a result, the Company explained, it has continued to evaluate whether to replace the steam generators in Unit 1.

B. The Department's Comments

The Department identified four major issues related to nuclear power:

- availability of spent fuel storage for Prairie Island
- replacement of a steam generator at Prairie Island Unit 1
- mitigation of the risks of early shutdown of Prairie Island
- relicensing both Monticello and Prairie Island.

1. Availability of Spent Fuel Storage

The Department reviewed Xcel's options for securing adequate spent fuel storage (on-site and off-site) for continued operation under existing legal requirements and found a lack of definitive information.

2. Replacement of the Steam Generator for Unit 1

The Department examined both the ratepayer implications of the proposal to replace the steam generator at Prairie Island Unit 1 and the impact of the proposal on the present value of revenue requirements (PVRR).

- Regarding the ratepayer impact, the Department concluded it is unlikely that installing a new steam generator would cause an increase in the cost of fuel or energy purchases, as long as Prairie Island continues to operate.

- Regarding the impact of the proposal on the PVRR, the Department noted that only if Prairie Island operates to the end of its operating license or beyond will the replacement of the steam generator provide sufficient rewards to cover its expense and, therefore, there is significant risk associated with the replacement of steam generators at Prairie Island. The Department noted, however, that since most of the costs associated with the replacement of a steam generator are capital costs, costs which are incurred at the risk of shareholders until recovery is requested and considered in a rate case, Xcel's plan to keep open the option of replacing a steam generator in 2004 is, at this time, at the risk of its shareholders.

The Department concluded, however, that the Commission should take no position on the Company's proposal to maintain the option to replace the steam generator in Unit #1 in 2004. The Department argued that due to the uncertainty regarding the availability of spent fuel storage there was not sufficient information to determine whether replacement of the steam generator would be cost-effective.

3. Xcel's Planning for a Shutdown of the Prairie Island Facility

The Department then reviewed Xcel's bidding process plans for securing replacement power in the event that its Prairie Island facility was required to shutdown pursuant to the current legislation (currently projected as sometime in 2007). Referring to the Company's "short time" scenario (replacement available June 2007) and "long time" scenario (replacement available January 2009), the Department noted that these timelines could possibly be shortened by overlapping (conducting concurrently) certain parts of the bidding process. The Department noted, however, that if the longest duration is assumed and no overlap were to occur, replacement power would not be available until January 2009, fully one year after Prairie Island was shut down. Under this scenario, even with significant overlap, the replacement power would not be available in time and Xcel would need to purchase the replacement power off the market to make up for the delays.

4. Relicensing the Monticello and Prairie Island Facilities

The Department agreed with Xcel that this is the most economic approach to providing energy to consumers and noted that both relicensing and not relicensing present environmental trade-offs. The Department stated that if the facility is relicensed, more spent fuel will be generated and if the facility isn't relicensed, it will most likely be replaced by fossil fuel generation, resulting in a significant increase in greenhouse gas emissions, seven percent higher than for the license extension scenario.

The Department recommended that, due to the lack of definitive information on the availability of spent fuel storage, the Commission take no action at this time on Xcel's proposal to replace the steam generator. The Department recommended that the Commission direct Xcel to issue the Prairie Island contingent request for proposals (RFP) no later than the third quarter 2001.

C. Comments of the RUD-OAG

The RUD-OAG agreed with other parties that Xcel should, at the appropriate time, issue an RFP for the replacement of Prairie Island. As to the specific timing of the RFP, however, the RUD-OAG urged the Commission to balance the considerations of maintaining reliability, ensuring cost-effective options are not foreclosed, and timing the RFP such that vendors will offer serious bids.

D. Comments of the Izaak Walton League of America (IWLA)

IWLA stated that without a resolution to the storage problem, Prairie Island will shut down in 2007, requiring the replacement of 1,050 MW of power generation and that it is unrealistic for the Company to rely on the Private Fuel Storage initiative as a solution to its storage dilemma, particularly given the expressed opposition to the project by the Governor of Utah.

IWLA urged the Commission to require Xcel to issue a contingent bid RFP no later than July 1, 2001. IWLA indicated that a July 1, 2001 issue date would allow bids to be received and analyzed prior to the Company's next resource plan filing due July 1, 2002. IWLA warned that accepting the Company's proposal to reevaluate the timing of a contingent bid RFP at the end of 2001 would not allow action by the Commission in Xcel's 2002 resource plan.

E. Comments of Minnesotans for an Energy-Efficient Economy (ME3)

ME3 characterized Xcel's September 6, 2000 supplemental filing as a "wait and see" proposal. ME3 suggested that Xcel has been delaying the development of a contingent bid RFP since 1995. ME3 stated that the RFP was viewed as a way to assure reliability and still not obligate the Company to procure resources unless and until they are needed. ME3 asserted that a review of the history of planning for the replacement of Prairie Island demonstrates that regulators and the Legislature have had expectations of a detailed analysis. However, Xcel has chosen instead to substitute its own judgement on what amount of planning and analysis is necessary.

ME3 argued that given the enormous uncertainties regarding spent fuel storage, the looming reliability crisis, the time needed to solicit and evaluate contingent bids, and the logistics of bringing new resources on line, it is time to put our attention to finding the replacement capacity for Prairie Island.

F. Comments of the Prairie Island Indian Community

The PI Community recommended that the Commission order Xcel to immediately undertake consultations with interested parties to develop a contingency plan and RFPs to replace the power production of Prairie Island and issue a contingent bid RFP no later than the second quarter of 2001. The Community also urged the Commission to set a strict time line to keep Xcel on track and require the Company to report to the Commission on the progress being made.

Regarding Xcel's proposal to replace the steam generators at the Prairie Island facility in 2004, the Community recommended that the Commission take no action and put Xcel on notice that the it does not support expenditures related to the replacement of steam generators at this time.

G. Comments of the Clean Water Action Alliance (CWAA)

CWAA stated that the Company's plan to operate Prairie Island for as long as possible is in the short-term interest of Xcel's shareholders and is not in the long-term interest of society as a whole. CWAA asserted that Xcel is trying to force a repeat of the 1994 situation in which the state is forced to allow additional dry storage casks or face an immediate shutdown of Prairie Island and the resulting energy shortage. According to CWAA, the Company's failure to propose a phase-out plan and instead to propose replacing the steam generators in 2004 is part of that plan.

CWAA noted that nuclear waste storage and transportation issues remain controversial and unresolved and criticized each of the suggested storage options examined by Xcel, including Yucca Mountain and Skull Valley, Utah. CWAA recommended that Xcel be required to immediately produce a phase-out plan to replace the Prairie Island and Monticello nuclear generating facilities.

H. Comments of Communities United for Responsible Energy (CURE)

Among CURE's concerns are:

- the need for Xcel to develop a legitimate contingency plan for the replacement of Prairie Island
- the need for a review of the environmental and cost assumptions underlying the Limited Certificate of Need
- the development and use of externalities and socioeconomic costs in estimating the value of continued operations at Prairie Island and the associated replacement costs
- the development of the true costs to taxpayers of interim and long-term storage of waste at Prairie Island.

As a representative of local communities, CURE indicated concern that the planning and reporting requirements set out in the certificate of need and the 1994 Prairie Island legislation are carried out. CURE advocated the integration of energy planning with decommissioning and waste disposal issues and for greater public accountability in the funding, managing and monitoring of nuclear waste. CURE noted that while it is the Company's responsibility to comply with state and agency decisions, it is the responsibility of state agencies like the Public Utilities Commission to enforce those decisions and represent the public interest.

I. Commission Analysis and Action

In its February 17, 1999 Order, the Commission had directed NSP to develop a bidding process that was unbiased in its treatment of renewable forms of energy generation and submit it to the Commission at least 90 days before filing any RFPs for new generation. At the hearing, Xcel noted that the Commission's February 17, 1999 Order effectively prevented Xcel (NSP's successor) from filing any request for proposals for new generation until 90 days after the Company had filed a description of its new all-source competitive bidding process.

Subsequently, the parties (including Xcel) agreed that Xcel would provide a status report on its new all-source competitive bidding process (providing fairness to renewables) by July 15, 2001 and that if the Commission waived the 90 day requirement of the February 17, 1999 Order the Company would propose an RFP to the Commission by September 30, 2001.

The Commission finds that the purpose of the 90-day review requirement can be met while accommodating the need to make responsible progress on preparations to replace the Prairie Island generation, for Xcel to issue a timely RFP for replacement energy. The Commission notes that parties directly aligned with the request for the new (fair-to-renewables) bid process and the 90 day review (IWLA and ME3 in particular) favored waiving the 90-day requirement in these circumstances.

The Commission, therefore, will accept the parties' agreement that Xcel provide a status report on the fairness-to-renewables-in-the-bid-process issue by July 15, will waive the requirement that Xcel file a description of an unbiased all-source competitive bidding process (unbiased in its treatment of renewable forms of energy generation) at least 90 days before filing any request for proposals for new generation, and will direct Xcel to propose an RFP to the Commission by September 30.

IX. XCEL'S DISTRIBUTED GENERATION REPORT

In the stipulation filed in its merger proceeding (Docket No. E,G-002/PA-99-1031), Xcel agreed to perform a distributed generation (DG) study and submit a report by the end of 2000. The Commission accepted the stipulation, approved the merger, and directed Xcel to abide by the stipulation.

A. The Company's Report

On January 5, 2001, the Company submitted its DG report, discussing the potential for DG on the Company's system to meet customers' needs economically, reduce transmission and distribution investments, and improve air quality. The report also presented several case studies providing an analytical framework for considering the effectiveness of DG in specific applications. Xcel stated that its study and report provided a good starting point for continued discussions on DG's role in Minnesota's energy future.

B. Party Comments

1. The Department

The Department acknowledged that Xcel's report did not include distributed resources other than generation, but accepted and agreed with the Company's explanation that the general analytical approach of its study can be used to derive the avoided cost for an area, which then can be used as a screening for potential DSM projects. The Department added that, since cost numbers are not yet available for storage systems and DSM options, it is not possible to use the study to make any conclusions about the broader category of distributed resources.

The Department stated that Xcel's study was also limited in other respects, but despite the limitations of the study, the Department recommended that the Commission accept the report as complying with the requirement in the stipulation and Order from Xcel's merger docket. The Department also recommended that the Company use information in the report, as well other information (e.g., natural gas prices, emissions, development of interconnection standards, and consideration of combined heat and power applications of DG), when it prepares its DG tariff.

In its reply comments, the Department indicated that the Commission should focus on Xcel's upcoming DG tariff. The Department suggested a 90-day comment period on the Company's filing. The Department indicated that review of the DG tariff filing should help identify areas needing further study.

2. RUD-OAG

RUD-OAG stated that the report is an important preliminary step to identify when DG may be appropriate to serve the needs of Xcel's customers. RUD-OAG noted some shortcomings of the report but did not recommend rejecting the report. RUD-OAG recommended that Xcel include DG as a part of its resource mix in its next resource plan and that the Company develop a detailed analysis of different types of DG taking into account factors such as reliability and environmental impacts.

3. Minnegasco

Minnegasco stated that the focus is far too narrow and the approach too conservative; as a result, the report ignored the comprehensive benefits that DG applications can provide to customers, the environment, and overall system operation. According to Minnegasco, the review of DG technologies should consider benefits of DG for both suppliers and customers, examine potential barriers to DG, and develop incentives to promote these emerging technologies. Minnegasco recommended that Xcel revise its report to add case studies with combined heat and power applications, including updated tables and emissions estimates to properly reflect that technology.

Minnegasco supported many of the other parties' comments on Xcel's report: the likelihood of cost reductions for DG technology; the limited nature of the Company's cost-effectiveness analysis; the need for standardized, affordable interconnection standards; the revamping of tariff structures to ensure that DG applications are fairly treated; and the use of DG incentives. Minnegasco stated that additional follow-up work should be done now in this proceeding.

Accordingly, Minnegasco recommended that the Commission require Xcel to:

- rework its DG supplement by including a complete analysis of base-load cogeneration, microturbines, and other appropriate DG technologies, using up-to-date costs and forecasted cost reductions, applying system credits as is done in the Conservation Improvement Program, and analyzing projects from the customer and societal perspectives

- continue to work with the parties in developing standardized interconnection standards and in identifying and developing the components of the DG tariff, with the intent of reducing regulatory barriers and developing regulatory incentives.

4. ME3

ME3 objected that Xcel's report focused primarily on benefits to the utility rather than on benefits to the customers, raised concerns about the economic analysis included in the report, and stated that the report failed to deal with barriers to DG development. Finally, ME3 noted recent reliability concerns, such as those in California, and argued that distributed technology could help address the increased need for reliability occasioned by the use of sensitive electronic components.

ME3 recommended that the Commission:

- require Xcel to consult with the other parties for the purpose of implementing three distributed generation pilot projects (using three different technologies at three different locations) not later than September 1, 2002, with a report on the evaluation of these projects to be filed no later than May 1, 2004
- require Xcel to file a comprehensive DG tariff no later than July 1, 2001, including an evaluation of the Standby Service Rider and provisions for fair and equitable grid access through modern interconnection standards and contracts
- open a docket to ensure that adequate regulatory mechanisms are in place to encourage the development of cost-effective and clean DG and to evaluate various ways of acquiring DG (e.g., through competitive bidding, the existing Conservation Improvement Program, or alternative approaches).

5. CURE

Like ME3, CURE stated that the report looked at DG from the perspective of the utility and therefore did not accurately reflect the full potential of DG. CURE listed several ideas for further exploration--creative ways to deal with the need for backup and standby service for DG options, sizing of fuel cells to alleviate distribution complexities, and investment incentives for DG.

CURE agreed with Xcel that the current study should be considered foundation for further work on distributed resource development. CURE expressed hope that the framework provided by Xcel will lead to future policy recommendations about how to encourage DG and advance public policy goals.

CURE recommended that the Department commission a supplemental report to allow a broader economic development, exploring different sets of assumptions than used by Xcel. CURE also recommended that the Department and the Commission work toward developing a consensus among stakeholders on generation costs, and how they may change, before analysis is started. CURE added that the Department and Commission should make certain such information is brought forward for public review and comment.

CURE explained that its primary concern is integrating energy data and analysis into planning efforts at the state and local levels and recommended that the Department and Commission work to facilitate the integration of energy issues into comprehensive planning venues such as those overseen by Minnesota Planning.

Finally, CURE recommended that agencies and utilities work to develop inventories and mapping projects, such as the cogeneration mapping project currently underway at the Minnesota Environmental Quality Board (MEQB), to facilitate "meaningful choice" for industries, communities and other parties willing to work toward greater DG deployment.

6. North American Water Office (NAWO)

NAWO expressed disappointment in the report, both in the number of technologies considered and the manner in which DG technologies would be used. According to NAWO, the problem is the existence of dirty and dangerous central station plants and the study should have focused on how DG could contribute to solving that problem.

NAWO stated that suitable topics for study are the kinds and levels of incentives necessary to persuade customers to install small generators. NAWO stated that Xcel could investigate the types of incentives needed to encourage landowners to allow installation of wind machines on their farms and evaluate the role of landfill gas and whole-tree burning plants. NAWO objected that the report totally ignored cogeneration, even though it was specifically mentioned in the stipulation.

NAWO recommended that the Commission reject Xcel's report and order the Company to resubmit it with special emphasis on studying methods to replace significant amounts of fossil and nuclear fuel, using changes in utility practices, marketing strategies, and other innovations needed to attain this goal. NAWO also recommended that the Commission require the resubmitted report to set a timetable for changing from central station power to DG.

C. Commission Analysis and Action

Although the Xcel's Distributed Generation (DG) Report is not all that it could have been (as the commenting parties have noted in detail), the Commission finds that the report substantially complies with the requirement in the stipulation and Order in Xcel's merger docket (Docket No. E,G-002/PA-99-1031) and will, therefore, approve it.

At the same time, the Commission is impressed by the concerns raised by the parties and will direct the Company to consider both the report (a starting point as suggested by the Department) and the issues identified by the commenting parties in preparing the DG tariff filing. To assure that parties and other interested persons have an opportunity to develop the record with respect to these concerns in Xcel's DG tariff filing docket, the Commission will allow interested persons 90 days from the date of submission to file comments on the Company's DG tariff filing.[8]

The Commission notes that this treatment of the DG Report is the best for the public from a practical standpoint, too, since it allows the DG issues to be further developed in the practical setting of the DG tariff docket, rather than getting bogged down in compliance filing disputes in the context of this resource plan docket.

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[8] Xcel made its DG tariff filing on June 13, 2001. It was assigned to Docket No. E-002/M-01-937.

X. OTHER GENERATION ISSUES

A. Conversion of Units at High Bridge and Riverside to Natural Gas

The Mississippi Corridor Neighborhood Coalition (MCNC), a federation of twenty community groups dedicated to Mississippi River and neighborhood reclamation in Minneapolis, requested that Xcel's Riverside Plant in Minneapolis be converted to use natural gas as a fuel. MCNC indicated that the request is based on public health and environmental concerns, which it identified.

As part of Xcel's merger docket, the Company agreed to study the feasibility and economic impact of converting High Bridge Units 3 and 4 and then Riverside Units 7 and 8 to natural gas.

The Commission will not take definitive action on the conversion question at this time, since the Company's study has not been reviewed. This issue may be revisited.

B. Xcel's Obligation to Acquire an Additional 400 MW of Wind

IWLA indicated that, despite a flawed analysis of wind bids in Xcel's 1999 RFP process, a wind project was a winning bidder. IWLA stated that this validates the provision in the Commission's Order from NSP's last resource planning proceeding requiring the Company to add an additional 400 MW through its all-source bidding process.

IWLA expressed some concern, however, regarding Xcel's intention to fulfill the 400 MW of wind requirement, given the Company's decision to apply the 50 MW selection to the initial 425 MW statutorily required rather than the additional 400 MW ordered by the Commission. IWLA recommended that the Commission consider Xcel's selection of a wind bid in the 1999 all-source bidding process to be a *de facto* fulfillment of the stipulation that wind be "least cost" and that the Commission make a finding to that effect in its Order in this docket to remove any doubt about Xcel's obligation to acquire 400 MW of additional wind generation.

The Commission agrees that Xcel's selection of a wind bidder in its most recent all-source bidding process is promising and finds that there is insufficient reason at this time to go beyond the language of the Order in the Company's last resource plan proceeding, which is clear about what the Company is required to do.

C. Other Recommended Modifications to Xcel's Resource Plan

Based on its view that Xcel underestimated the amount of independent power producer activity likely to take place in Minnesota during the planning period, the PI Community recommended that the Commission order the Company to modify its resource plan by:

- adequately addressing the availability and cost of current and anticipated independent power producer (IPP) activity in Minnesota and neighboring states;
- fully describing its estimates of avoided costs for transmission and distribution (T&D), specifying areas on its system which are highly stressed, and analyzing the impact on appropriate levels of distributed generation; and

- creating a timetable to achieve the 2001 and 2002 statutory biomass dates or, alternatively, providing a plan for dealing with the consequences of violating the Prairie Island legislation.

Regarding the PI Community's last-listed recommendation, the Commission does not believe that this is necessary or appropriate. The statutory requirements are what they are, Xcel knows what they are, and any possible violations of those dates are too speculative at this point. As to the other recommendations to require additional information on IPP activity, T&D costs, and DG, the Commission does not find that it would be appropriate to prolong this proceeding by requiring Xcel to file this material in this docket.

ME3 recommended that the Commission require that resources acquired during the planning period include cogeneration and distributed generation when in the public interest. The Commission will decline to make that clarification. The existing resource planning rules describe when a resource option is in the public interest and the Commission finds no reason to elaborate beyond that. At this time, there is no specific set of facts before the Commission requiring application of those rules.

XI. TRANSMISSION AND DISTRIBUTION ISSUES

A. Xcel's Discussion

Xcel included an extensive discussion of transmission issues. The Company discussed its involvement with the Midwest Independent System Operator (MISO), tariff concerns, the Midwest Area Power Pool (MAPP) transmission planning process, expanded use of the transmission system, line-loading relief procedures, and plans for specific system improvements.

B. The Parties' Comments

Xcel's discussion of transmission elicited significant comments from the other parties:

The Department recommended that the Commission require the Company to provide in its next resource plan filing information on new transmission facilities down to 69 kV. The Department suggested that the information be provided in the same format as is provided to MAPP for the biennial transmission plan. The Department also recommended that the Commission require Xcel to provide two other types of transmission information: 1) a copy of the Southwest Minnesota Bulk Transmission System Study regarding the Company's analysis of transmission issues near Buffalo Ridge; and 2) in its next resource plan a region-by-region assessment of threats to the Company's transmission system security and adequacy.

ME3 recommended that, because the 50% renewables/DSM scenario includes 4,500 MW of cost-effective wind resources, the Commission should require that Xcel develop a plan to install transmission to move that level of wind power to appropriate load centers.

The PI Community recommended that Xcel be required to fully describe its estimates of avoided costs for transmission and distribution, specify the areas of its system which are more stressed, and analyze how changing those costs would impact the appropriate levels of distributed generation.

In its reply comments, RUD-OAG recommended accepting the Department's proposals and rejecting the ME3 proposal. RUD-OAG stated that the reports requested by the Department would provide important information on additional transmission needs and identify plans for new transmission to serve the Company's customers. However, RUD-OAG added that it would be premature (as requested by ME3) to require a plan to move 4,500 MW of wind generation; rather, the information requested by the Department should be received and evaluated first.

Xcel accepted the Department's recommendation, stating that the Department's request for information is reasonable given the importance of reliable delivery infrastructure.

C. Commission Analysis and Action

The Commission acknowledges the comments of all parties but notes that Xcel's major report to the Commission on these issues is due November 1, 2001, as required by a recently enacted statute: Minn. Stat. § 216B.2425. In the interests of efficient use of resources of all parties and not duplicating work, the Commission will impose no additional requirements at this time.

XII. OTHER ENVIRONMENTAL ISSUES

A. The Department's Comments

SO_2: The Department stated that Xcel has not performed any analysis to determine whether its current strategy for containing emissions of SO_2 is the least-cost method of compliance. The Department recommended that the Company be required to include such an analysis in its next resource plan.

NO_x: The Department stated that although Xcel currently is in compliance with NO_x requirements, the Company is continuing its analysis of needed reductions and how to obtain them. The Department recommended that the Company be required to include in its next resource plan an analysis explaining whether and how its NO_x strategy is the least-cost method of compliance.

Mercury: The Department stated that in response to discovery Xcel estimated air releases of mercury from its sources in Minnesota to be 1,079 pounds in 1990 and 831 pounds in 1999. The Department recommended that since the Minnesota Pollution Control Agency (MPCA) and Xcel cannot currently quantify reductions goals for the Company, the Commission require the Company to include in its next resource plan an update on its mercury reduction goals, strategies, and achievements.

CO_2 and global warming: The Department stated that global warming is a serious future threat to our environment and that the Company therefore must continue to monitor potential regulations and mitigation methods and to expand its contingency planning. The Department indicated that in its next resource plan the Company should provide 1) a report on industry-based initiatives for cutting greenhouse gas emissions and 2) an expansion of its CO_2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation.

B. ME3's Comments

Mercury: ME3 stated that despite the serious nature of mercury emissions and despite the goals of the voluntary reduction program, Xcel has identified no emissions reductions for year 2000. ME3 recommended that the Commission require Xcel to report regularly on the trend in its mercury releases and to set quantitative targets for reducing emissions by an amount commensurate with achieving the Company's share of the statewide mercury reduction goals.

Reduction of Greenhouse Gases: ME3 noted that Xcel has not yet released any evaluation of the impacts of non-regulatory approaches to emissions reductions. ME3 cited increases in the use of wind and DSM as a strategy that would reduce greenhouse gases while providing other benefits, including reductions in the releases of mercury, SO_2, NO_x, and particulates. ME3 therefore recommended that the Commission require Xcel to expand its climate change preparation activities to include voluntary emission reduction targets and to prepare a plan to reach those targets.

C. Xcel's Comments

Xcel stated that it is in compliance with all environmental regulations and argued that its environmental compliance should be considered before environmental agencies and not by the Commission in the context of resource planning.

D. The Commission's Analysis and Action

The Department and ME3 raise valid concerns that are a legitimate part of resource planning considerations. The Commission has a statutory duty to take environmental and socioeconomic effects into account in its decisions. In addition, methods and timing of environmental compliance could have a significant effect on ratemaking, a key component of the Commission's responsibilities. In short, the Commission clearly has the authority to require in resource plans the information requested by these parties.

Given the relevance of these issues and the Commission's responsibilities, the Commission will require Xcel, in its next resource plan, to include the following items:

a. an analysis of whether the Company's current SO_2 strategy is the least-cost method of compliance;

b. an analysis of whether the Company's current NO_x strategy is the least-cost method of compliance;

c. an update of the Company's mercury reduction goals, strategies, and achievements;

d. a copy of the report on mercury that Xcel is required by statute to file with the legislature;

e. a brief summary of industry-based initiatives for cutting greenhouse gas emissions; and

f. after discussions with the Department, an expansion of its CO_2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation.

XIII. MISCELLANEOUS ISSUES

Parties raised several other concerns:

- whether statewide planning should replace the current process for considering individual filings by the utilities;
- whether the uncertainty regarding electric utility restructuring in the Midwest has "increased the perceived risk of investments relative to other parts of the country" and "dampened" interest in investing in new generation in this part of the country;
- whether the Commission should be involved in the directing of forecasts to facilitate state energy planning, to foster the use of distributed generation and renewable technologies, and to help mitigate impacts of energy generation and transmission demands on the regional system; and
- whether "trade secret" practices which have limited the openness and inclusiveness of the Commission's dockets are overused or misused.

Although these issues may be significant and relevant to utility resource planning, the current resource planning docket is not generic and therefore is not the appropriate forum to deal with them.

XIV. NEXT RESOURCE PLAN

In addition to the several specific directives that the Commission has given in this Order for Xcel's next resource plan, the Commission clarifies that the plan cover primarily the traditional five-state service territory of Northern States Power.

Finally, the Commission will vary the two-year filing interval provision of Minn. Rules, Part 7843.0300, subp. 2 and extend the date for filing the next resource plan from July 1, 2002 to December 1, 2002. The Commission finds that the requirements for granting a variance pursuant to Minn. Rules, Part 7829.3200 are met in this case.

- In light of the time expended processing this resource plan and the number of items directed to be added to the next plan, it would impose an excessive burden upon Xcel to require it to file its next resource plan on July 1, 2002.
- Granting the extra time to incorporate the items identified in this Order into a solid resource plan is in the public interest.
- Finally, since the filing deadline is set solely by Commission rule and not by statute, extending that deadline does not violate a standard imposed by law.

Consequently, Xcel's next resource plan will be due on the extended date: December 1, 2002.

In the course of its consideration of Xcel's Resource Plan, the Commission concluded that it would be appropriate to examine the potential for the Company's rate and tariff design to achieve DSM savings and to send appropriate pricing signals to rate payers. The Commission has issued a separate Order opening this investigation: ORDER OPENING INVESTIGATION issued July 20, 2001 in Docket No. E-002/CI-01-1024.

ORDER

1. The Commission hereby approves Xcel's 2000- 2014 Resource Plan, as modified in this Order.

2. The Commission accepts the Company's forecasts of energy requirements and summer peak demand as reasonable and adequate for planning purposes and accepts the Company's bidding plan as a reasonable and prudent approach to meeting customers' needs, recognizing that some change in specific dates and amounts are likely as the procurement process moves forward.

3. Xcel shall meet with the Department and any other interested parties by September 1, 2001 to discuss integration of the short- and longer-term forecasts and possibly other modeling issues and require the Company to use cost information from its all-source winning bids to evaluate the cost of future resources in both its IRP and the all-source bidding process (see page 26 of the Department's initial comments).

4. Xcel shall submit the information requested by the Department (in the format specified in Table 14 on page 22 of the public version of the Department's initial comments) as a compliance filing in this proceeding or before the issuance of its next all-source bid RFP, whichever comes first. The Company shall also provide the same type of information in its next resource plan.

5. Xcel shall use an appropriate rate when the Company models the cost of unserved energy and justify that rate to the Department. Consideration of any possible change in the reserve margin is deferred until at least the next resource plan proceeding.

6. Xcel shall report on its progress and ability to meet the DSM savings goals (as adopted herein) in the Company's Conservation Improvement Program (CIP) status report to be filed on April 1, 2002. The Department is asked to file a copy of its analysis of Xcel's April 1 Status Report with the Commission.

7. Xcel shall meet with the Department and other interested parties, prior to the next resource plan, to discuss DSM modeling issues, including but not limited to the sharp increase in DSM costs between 2014 and 2015, and the low costs for non-Minnesota DSM, as proposed by the Department and the PI Community.

8. The Commission adopts the DSM goals associated with the 175 percent incentive scenario, as proposed by the Department, ME3, CWAA and the PI Community:

    - 3,253 GWh cumulative energy savings in Minnesota over the planning period and
    - 1,174 MW cumulative peak demand savings in Minnesota over the planning period.

9. The Commission accepts the parties' agreement that Xcel will provide a status report on the fairness-to-renewables-in-the-bid-process issue by July 15 and propose an RFP to the Commission by September 30, 2001, waives the requirement imposed by the Commission's February 17, 1999 Order in NSP's previous Resource Plan Docket (E-002/RP-98-32) that NSP file a description of an unbiased all-source competitive bidding process (unbiased in its treatment of renewable forms of energy generation) at least 90 days before filing any request for proposals for new generation, and directs Xcel to abide by its agreement to propose an RFP to the Commission by September 30, 2001.

10. The Commission accepts Xcel's Distributed Generation (DG) Report as substantially complying with the requirement in the stipulation and Order in Xcel's merger docket (Docket No. E,G-002/PA-99-1031).

11. Xcel shall, in its DG tariff filing , consider the report and the issues identified by the commenting parties.

12. Interested persons shall have 90 days from the date of Xcel's DG tariff filing to file comments on the DG tariff filing. The Commission invites the parties to raise in their comments any DG issues that they believe Xcel and the regulatory agencies need to address with respect to DG.

13. In its next Resource Plan, Xcel shall provide

    a. an analysis of whether the Company's current SO_2 strategy is the least-cost method of compliance;

    b. an analysis of whether the Company's current NO_x strategy is the least-cost method of compliance;

    c. an update of Company's mercury reduction goals, strategies, and achievements;

    d. a copy of the report on mercury that Xcel is required by statute to file with the legislature;

    e. a brief summary of industry-based initiatives for cutting greenhouse gas emissions; and

    f. after discussions with the Department, an expansion of its CO_2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation.

14. In its next Resource Plan, Xcel shall cover primarily the traditional five-state territory of Northern States Power Company.

15. The Commission grants a variance from the two-year requirement of Minn. Rules, Part 7843.0300, subp. 2 and designates December 1, 2002 as the filing date for Xcel's next Resource Plan.

16. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Mark E. Oberlander for

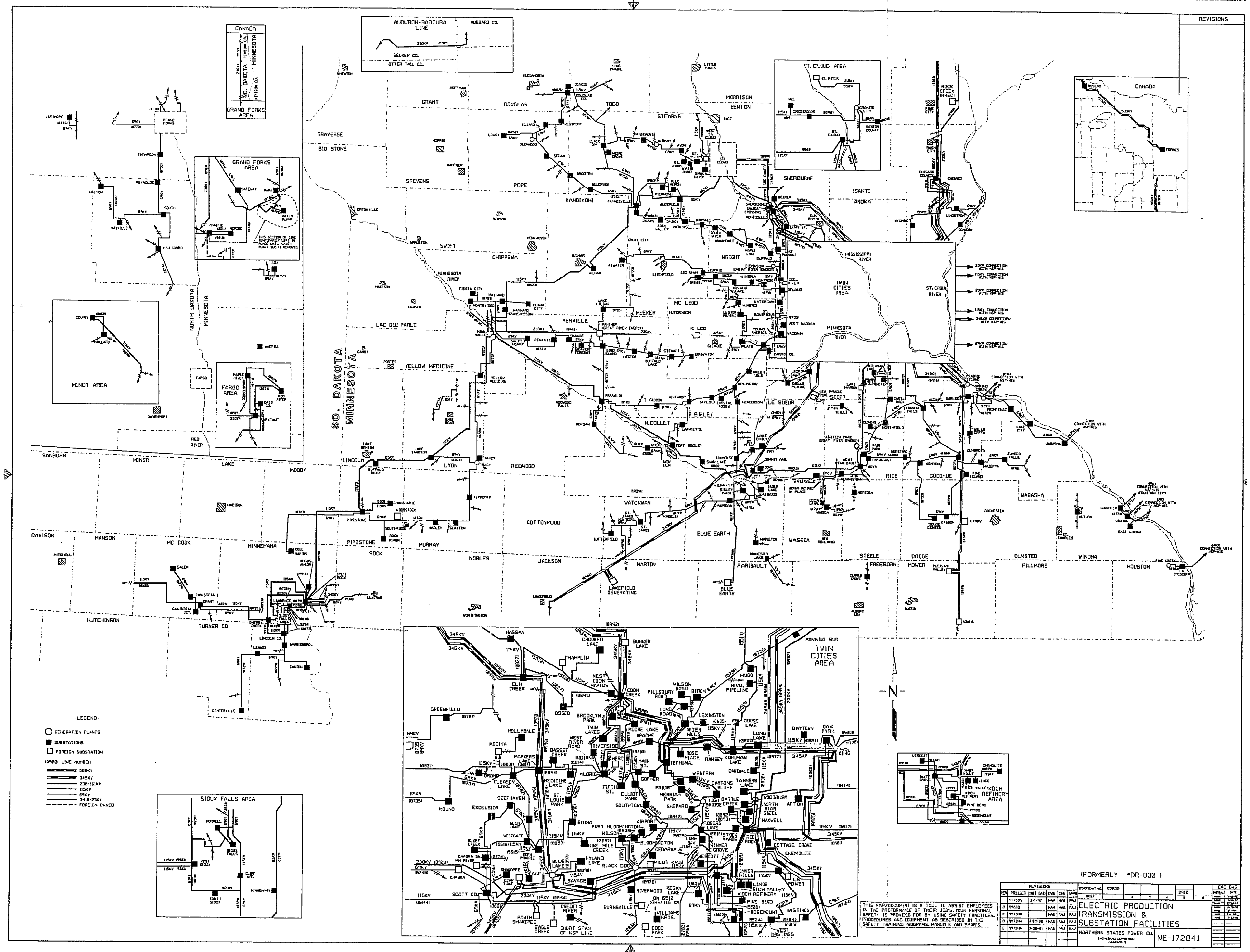
Burl W. Haar
Executive Secretary

(S E A L)

This document can be made available in alternative formats (i.e., large print or audio tape) by calling (651) 297-4596 (voice), (651) 297-1200 (TTY), or 1-800-627-3529 (TTY relay service).

APPENDIX B

Xcel Energy Transmission Lines


TWIN CITIES AREA
ST. CLOUD AREA
GRAND FORKS AREA
MINOT AREA
FARGO AREA
SIOUX FALLS AREA
KOCH REFINERY AREA
AUDUBON-BADOURA LINE
SO. DAKOTA
MINNESOTA
NORTH DAKOTA
CANADA
-LEGEND-
GENERATION PLANTS
SUBSTATIONS
FOREIGN SUBSTATION
(0980) LINE NUMBER
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345KV
230-161KV
115KV
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REVISIONS
(FORMERLY "DR-830)
THIS MAP/DOCUMENT IS A TOOL TO ASSIST EMPLOYEES IN THE PREFORMANCE OF THEIR JOB'S. YOUR PERSONAL SAFETY IS PROVIDED FOR BY USING SAFETY PRACTICES, PROCEDURES AND EQUIPMENT AS DESCRIBED IN THE SAFETY TRAINING PROGRAMS, MANUALS AND SPAR'S.
ELECTRIC PRODUCTION
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