

Direct Testimony and Schedules
James R. Alders

Before the Public Utilities Commission of
The State of South Dakota

In the Matter of the Application of
Northern States Power Company, a Minnesota corporation

For Authority to Increase Rates for
Electric Service in South Dakota

Docket No. EL09-_____
Exhibit____(JRA-1)

Energy Supply

June 30, 2009

1 **I. INTRODUCTION AND QUALIFICATIONS**

2
3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 A. My name is James R. Alders. My business address is 414 Nicollet Mall,
5 Minneapolis, Minnesota 55401.

6
7 Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

8 A. I am Director, Regulatory Administration, for Xcel Energy Services Inc.,
9 (“XES” or the “Service Company”) a Minnesota corporation operating in
10 South Dakota. XES is the service company for the Xcel Energy Inc holding
11 company system, and thus provides services to the Company.

12
13 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

14 A. I graduated from the University of Minnesota in 1973 with a Bachelor of
15 Science degree in Urban Studies and later a Masters degree in Business
16 Administration from St. Thomas in 1991. As the Director of Regulatory
17 Administration since April 2008, my current job responsibilities include
18 oversight of the development, preparation and support of all the Company’s
19 regulatory requests for approval needed for resource plans, resource
20 acquisitions, power plants and transmission lines in Minnesota, South Dakota,
21 and North Dakota. Throughout my 33 year tenure with the Company, I have
22 been employed in various positions responsible for the routing and siting of
23 new energy facilities such as transmission lines and power plants, as well as the
24 acquisition of regulatory approvals, including Certificates of Need for those
25 facilities. Since 1994, I have been extensively involved in development of the
26 Company’s resource plans and represented the Company before state and
27 federal regulators in various resource planning and Certificate of Need

1 proceedings. My resume is included with my testimony as Exhibit____(JRA-
2 1), Schedule 1.

3
4 Q. FOR WHOM ARE YOU TESTIFYING?

5 A. I am testifying on behalf of Northern States Power Company, a Minnesota
6 corporation operating in South Dakota (“Xcel Energy” or “the Company”).
7 The Company is a wholly owned utility operating company subsidiary of Xcel
8 Energy Inc.

9
10 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

11 A. I will provide testimony regarding the improvements made at our energy
12 supply facilities since our last South Dakota electric rate case and the reason
13 these investments are beneficial to the system. Since 2006, the last year in
14 which the Company earnings were adequate, Xcel Energy has added
15 approximately \$1.6 billion in new generation plant investment. The Company
16 has made every effort to ensure that our generating resources are able to
17 operate at their highest level of performance, providing reliable power to meet
18 the growing needs of our customers. I believe the generation investments
19 made to support this effort have been prudent and reasonable.

20
21 Q. HOW HAVE YOU ORGANIZED YOUR DIRECT TESTIMONY?

22 A. My testimony is organized into discussion of capital improvements made to
23 Existing Fossil Resources, Nuclear Supply and Renewable Resources, followed
24 by our plans for Future Generation Projects. Generally, I describe the
25 projects within each of the generation types in chronological order by facility.
26 Some of these projects have only recently been completed or, are scheduled

1 for completion yet this year. I will conclude with a brief mention of some of
2 our forthcoming projects.

3
4 Q. WHAT PROJECTS WERE COMPLETE BEFORE 2007 AND WHICH WERE
5 COMPLETED IN 2007 OR LATER?

6 A. Projects completed prior to 2007 include:

- 7 • Angus C. Anson;
- 8 • Black Dog Units 1 and 2 Repowering Project;
- 9 • Prairie Island Upgrades; and
- 10 • The Blue Lake Project.

11
12 Completed energy supply projects in 2007 and later include the Company's
13 efforts to refurbish, repower and extend the lives of our existing natural gas,
14 coal and nuclear generating facilities, as well as our first Company-owned wind
15 project that went into service at the end of 2008. Projects completed in 2007
16 or after include:

- 17 • Allen S. King Plant Rehabilitation;
- 18 • High Bridge Repowering;
- 19 • Riverside Repowering
- 20 • Sherburne County Plant Improvements;
- 21 • Monticello Relicensing and Site Improvements; and the
- 22 • Grand Meadow Wind Project.

23
24 Anticipated construction plans in the next couple of years include repowering
25 Sherco Unit 3, Bay Front Boiler #5, the Nobles and Merricourt Wind

1 Projects and capacity increases and fuel storage facility enhancements at our
2 nuclear facilities.

3
4 **II. EXISTING FOSSIL GENERATION RESOURCES**

5
6 **ANGUS C. ANSON**

7 Q. HAVE THERE BEEN NEW RESOURCES BUILT IN SOUTH DAKOTA SINCE OUR
8 LAST GENERAL ELECTRIC RATE CASE?

9 A. Yes. The Company has installed 3 new generating units at our existing Angus
10 C. Anson (“Anson”) site east of Sioux Falls, SD. In 1994 the Company
11 constructed two simple cycle combustion turbines (Units 2 and 3) at the
12 Anson site. Together they provide about 217 MW of new capacity at an
13 installed cost of \$73.1 million. A subsequent project in 2000, equipped the
14 Anson units with inlet cooling systems to increase generating capacity.
15 Cooling inlet air during hot and humid conditions increases air density and
16 flow rate, which correspondingly increases power output on days when it is
17 needed most. The improvement at Anson yielded an additional 20 MW of
18 capacity.

19
20 In 2005, at a cost of about \$64 million, the Company installed a third natural
21 gas-fired unit (Unit 4) adding 160 MW at Anson, bringing the total plant
22 capacity to 377 MW. Unit 4 is predominantly used to cover the summer
23 peaking load. In 2007, during the summer months of June, July and August,
24 the unit averaged a capacity factor of 19.3%. If this unit would not have been
25 available that summer, we could not have been able to supply the load needed
26 for the Sioux Falls area without incurring transmission penalties from the

1 Western Area Power Administration. Due to the cool summer in 2008, the
2 peaking units were not needed as much as during normal summer conditions.

3
4 In April of 2009 we also replaced vanes and blades on the Unit 3 generator for
5 just under \$2 million. The blades and vanes had gotten to the end of their
6 useful life and could no longer be refurbished. Improvements in our gas line
7 to the plant are planned for later this year in response to a federal regulation
8 put into effect to limit potential problems with high pressure gas lines that
9 have resulted in some explosions in the past. This project will cost almost \$1
10 million.

11
12 **BLACK DOG 1 & 2 REPOWERING PROJECT**

13 Q. PLEASE DESCRIBE THE BLACK DOG 1 & 2 REPOWERING PROJECT.

14 A. Xcel Energy repowered Black Dog Units 1 and 2 with a 290 MW natural gas
15 combined-cycle Unit 5 in 2002 at a cost of \$113 million. The Unit 1
16 boiler/turbine and the Unit 2 boiler were originally installed in the 1950s as
17 coal-burning units. These units were retired in place with the exception of the
18 turbine/generator from Unit 2. The new Unit 5 consists of a natural gas-fired
19 turbine-generator combined with a heat recovery steam generator. Exhaust
20 heat from Unit 5 powers the Unit 2 steam turbine. The repowering project
21 boosts output over that provided from the two original units by approximately
22 114 MW and results in greater operating efficiency and cleaner power
23 production. Based on 2006 through 2008 mercury emissions data, Unit 5
24 eliminates up to 35 pounds of mercury emitted annually from the Xcel Energy
25 system, approximately 4% of the total.

26

1 In addition to supplying needed capacity and providing environmental
2 benefits, this project also created additional reliability and made use of an
3 existing generating site close to a load center. Labor savings were realized as
4 the combined cycle technology requires less employees for operation and
5 maintenance.

6
7 **BLUE LAKE**

8 Q. PLEASE SUMMARIZE THE BLUE LAKE PROJECT.

9 A. Based on an identified peaking need in our resource plan, in 2005, the
10 Company invested about \$100 million to install two natural gas fired simple
11 cycle combustion turbines at our Blue Lake peaking plant near Shakopee,
12 Minnesota. The additional units added 160 MW of capacity to the existing 225
13 MW of oil-fired capacity. As part of the project we also needed to build a
14 double-circuit, 230 kV/115 kV line approximately 4,000 feet in length.
15 Adding the two new turbines brought the total number of combustion
16 turbines at Blue Lake up to six. This also required some additional employees
17 to be available for plant operations and maintenance.

18
19 The plant is used to cover peaking demand predominately in the summer. For
20 the months of June, July and August of 2007, the two newest units averaged a
21 capacity factor of 10.7% and 14.1% respectively. The 2008 capacity factors
22 were lower because of the cooler summer that lessened our need for peaking
23 capability.

24
25 **ALLEN S. KING**

26 Q. PLEASE DESCRIBE THE COMPANY'S REHABILITATION EFFORTS AT THE ALLEN
27 S. KING PLANT ("KING").

1 A. To ensure long-term benefits to our customers, we undertook major
2 rehabilitation/life extension work at this plant. The resulting project makes
3 this plant available to serve our customers for at least an additional 25 years.
4 Further, the project resulted in the recovery of 60 MW of capacity and energy
5 that had been lost due to degradation and fuel switching, restoring the King
6 plant to its full original output of 564 MW with plant investment of
7 approximately \$488 million. This additional capacity and energy is now
8 available to serve our customers at very little additional operating expense
9 using state-of-the-art pollution control equipment. The rehabilitated King
10 plant began operations in 2007.

11

12 Q. WHAT WAS THE KING PLANT'S CONDITION AT THE TIME THE REHABILITATION
13 PROPOSAL WAS MADE?

14 A. To remain a reliable part of Xcel Energy's generation fleet, the King plant was
15 in need of significant upgrades. King had reached the end of its economic life
16 and would have ceased operations in 2005. By 2001, King's forced outage rate
17 had risen to concerning levels and the plant was experiencing a number of
18 problems typical of its heavy use and vintage.

19

20 Q. CAN YOU PROVIDE SPECIFIC EXAMPLES OF THE DEGRADATION EXISTING AT
21 THE KING PLANT PRIOR TO ITS REHABILITATION?

22 A. Yes. In 2001, our Energy Supply division conducted condition assessments of
23 both the boiler and the steam turbine. The boiler pressure retaining
24 components were failing on a regular basis, reducing the availability, reliability,
25 and capacity factor of the plant. Data showed that the frequency of the
26 failures was rising at an increasing rate. Babcock and Wilcox ("B&W"), our
27 consulting engineers, conducted an assessment of the boiler and found that

1 the boiler floor was in poor condition: physically distorted and metallurgically
2 weak. B&W also reported that the floor and the cyclone burners of the boiler
3 were the longest surviving original components of all 1960's vintage cyclone-
4 fired, supercritical boilers. All similar boilers built by B&W had floors and
5 cyclones that had been replaced at least once, with some units having replaced
6 some or all of those components twice. Based on this information and actual
7 experience with plant performance, it was obvious that swift action was
8 needed for the King Plant.

9
10 Q. AT THE TIME THE PROJECT WAS PROPOSED, WHAT WAS THE COST ESTIMATE
11 FOR REPLACING KING PLANT GENERATION WITH NEW GENERATION
12 RESOURCES?

13 A. Our estimates of the cost of natural gas combined-cycle construction were
14 roughly in the \$711/kW to \$827/kW installed range, not including any related
15 transmission costs. Our King Plant rehabilitation project had completed costs
16 around \$851/kW installed, including all transmission necessary to deliver the
17 energy to the integrated system. Assuming new generation could have been
18 constructed at or near the King Plant site, we had estimated new base load
19 coal generation at roughly \$1,500/kW to \$1,800/kW (excluding potential
20 transmission costs due to plant configuration changes). We concluded that
21 the rehabilitation of the King Plant was the best option for our customers.

22
23 Q. HOW IS THE REHABILITATED KING PLANT OPERATING?

24 A. While the King plant itself operates well, we have found the new emissions
25 control equipment requires more labor to operate and maintain. Additionally
26 the costs of chemicals required for the emissions controls system continue to
27 show significant cost increases.

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Q. PLEASE DISCUSS USE OF THESE CHEMICALS IN MORE DETAIL.

A. As part of the plant’s rehabilitation, we installed emission control equipment that requires chemicals to effectively remove the pollutants. The equipment was installed to result in a net reduction of emissions from the project as was required under federal law, which required the emissions limits in the permit to be “comparable to Best Available Control Technology (“BACT”). Meeting this standard allowed the project to be a “Qualifying Project” under the Minnesota Emissions Reduction Rider Statute (Minn. Stat. 216B.1692), qualifying for cost recovery under a separate rate rider in Minnesota. We have also been granted authority by the Commission to recover King related environmental costs through the Environmental Cost Recovery Rider pursuant to SDCL 49-34A, Sections 97 through 100.

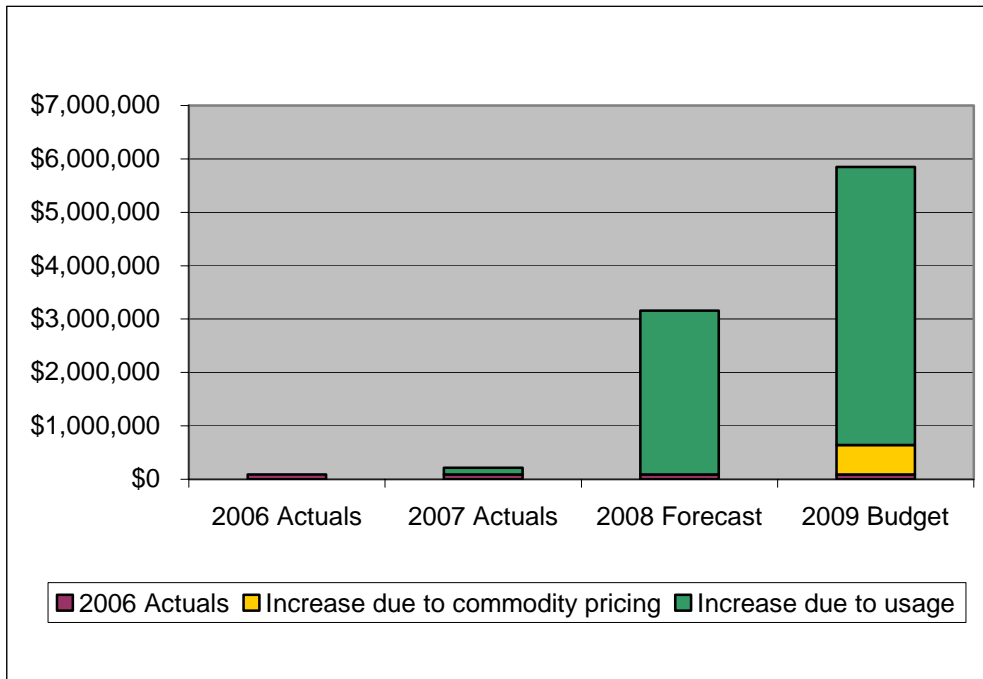
We started operating the equipment at the same time that the rehabilitated unit went in service. Lime and ammonia are used to control SO₂ and NO_x emissions. The lime is used in the Dry Flue Gas Scrubber to remove SO₂ and the ammonia is used in the Selective Catalytic Reduction unit to remove NO_x. At the King Plant, the pollution control equipment can achieve the permitted rates of 0.12 pounds SO₂ per million BTU (lb/mmBtu) and 0.10 lb NO_x/mmBtu. Without the chemical reagents, SO₂ emissions would be on the order of 0.57 lb SO₂/mmbtu and 0.80 lb NO_x/ mmBtu.

Q. PLEASE DISCUSS THE CHANGES WITH RESPECT TO CHEMICAL COSTS.

A. Our chemical cost budget has increased by over 500 percent compared to 2007 actuals. As indicated in Figures 1 and 2, this increase is driven by significant increases in the price of chemicals and quantities we purchase.

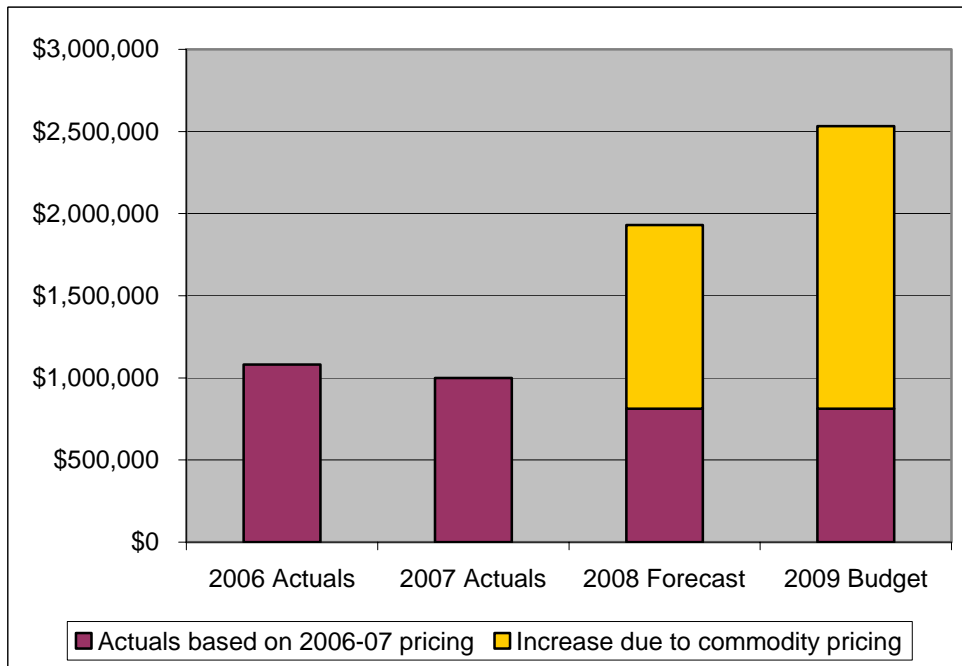
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Figure 1
NSPM Generation Ammonia Cost Trend



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Figure 2
NSPM Generation Sulfuric Acid/Caustic Cost Trend



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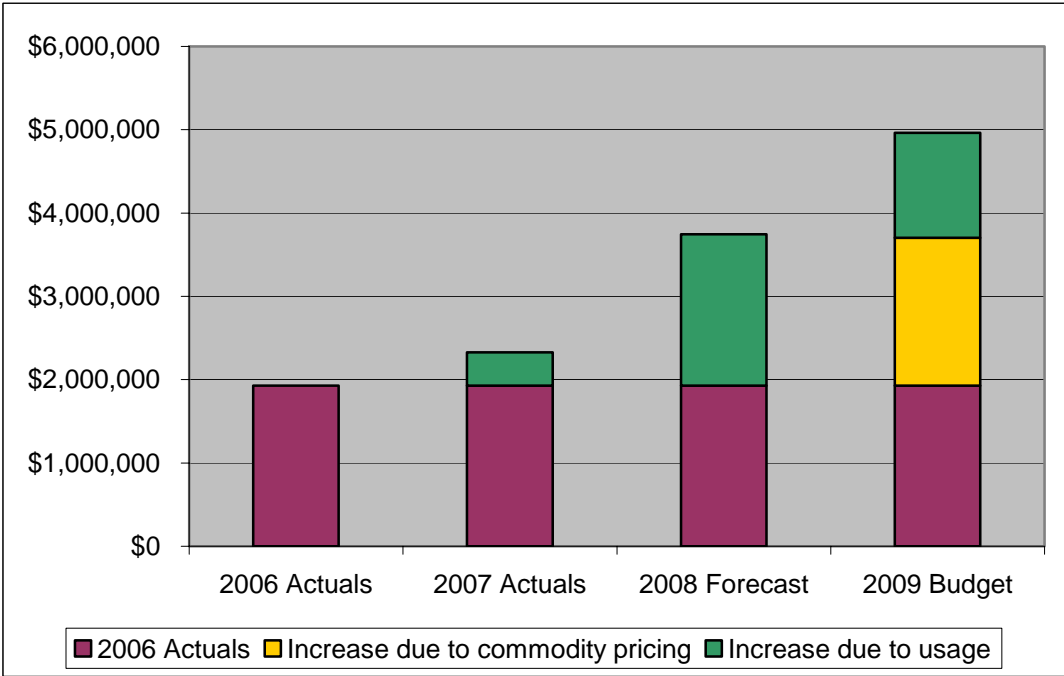
2 Q. HAVE YOU EXPERIENCED SIMILAR INCREASES IN THE USAGE AND COMMODITY
3 COST OF LIME?

4 A. Yes. Usage of lime increased both at the King Plant with the installation of
5 new pollution-control equipment and at Sherco, where we are increasing the
6 removal rate of SO₂. The following chart indicates the cost trend of lime used
7 in the operation of our generating plants.

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Figure 3
NSPM Generation Lime Cost Trend



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HIGH BRIDGE

Q. WHAT IMPROVEMENTS HAVE OCCURRED AT THE HIGH BRIDGE PLANT?

A. Similar to the King Plant, High Bridge was nearing the end of its useful life. We replaced the 243-MW, older coal plant with a 515-MW, natural gas combined-cycle facility located at the same site with plant investment of approximately \$354 million. This conversion used existing infrastructure while at the same time allowed us to increase capacity and preserve existing transmission and other infrastructure at a strategic location on the system. System reliability reasons precluded abandoning generation at this strategic location, however long-term use of coal at this St. Paul urban site was increasingly problematic. Switching to natural-gas-fired generation at this

1 location was the best long-term solution for our customers. The new facility
2 at High Bridge began operation in 2008.

3
4 Q. HOW DOES THE SIZE OF THE NEW HIGH BRIDGE PLANT COMPARE WITH THE
5 CAPACITY AND ENERGY OF THE PLANT BEFORE IT WAS REHABILITATED?

6 A. The original High Bridge coal plant was 243 MW; conversion to natural gas
7 resulted in 515 MW of capacity on our system, a net increase of 272 MW. In
8 contrast, the alternative project would have resulted in a net decrease of
9 capacity of about 4.4 MW (as a result of the operation of some of the air
10 quality control equipment).

11
12 Q. WHAT WOULD HAVE BEEN THE COST OF REPLACING THE HIGH BRIDGE PLANT
13 AT A LATER DATE?

14 A. The costs of installing new generating facilities have risen rapidly in the past
15 five years. At the time we proposed this project, we estimated the installed
16 cost of new combined cycle generation to be between \$711/kW and
17 \$827/kW. Our current estimate for a new, combined-cycle generating facility
18 is over \$1100/kW, more than 33 percent higher. The savings from converting
19 High Bridge when we did is even greater than this difference, because we were
20 able to acquire low-cost turbines on the secondary market.

21
22 Q. HAS THE ADDITION OF INCREASED CAPACITY AT THE HIGH BRIDGE PLANT
23 MITIGATED TRANSMISSION CONGESTION AND ULTIMATELY COSTS FOR ALL
24 CUSTOMERS?

25 A. Yes. High Bridge is located in the heart of a densely populated metropolitan
26 area. Most of our baseload plants, including our nuclear and large coal
27 facilities, are located significant distances from our load centers. To facilitate

1 the siting of these large baseload facilities outside of metropolitan areas, the
2 Company must continue to maintain some resources within load centers to
3 ensure transmission stability and minimize overall transmission congestion.
4 Further, in the Midwest Independent Transmission Operator (“MISO”) Day 2
5 environment, which began operation in April 2005, energy providers are
6 directly assessed costs for the transmission congestion they impose on the
7 system by delivering energy from generators to load. The High Bridge Plant
8 location helps mitigate these costs for all customers.

9
10 **RIVERSIDE**

11 Q. PLEASE DESCRIBE THE RIVERSIDE PLANT AND THE REPOWERING PROJECT.

12 A. Built in 1911 and located in Northeast Minneapolis, MN on the Mississippi
13 River, Riverside was the oldest coal-fired plant in the Xcel Energy system and
14 had a net dependable capacity of 360 MW. Low-sulfur, sub-bituminous
15 Western coal was burned at the plant.

16
17 Repowering of our Riverside Plant was recently completed with the facility
18 beginning commercial operations in 2009, with plant investment of
19 approximately \$262 million. We replaced the existing Unit 7 at this coal-fired
20 plant with two natural gas combustion turbines operating in a combined-cycle
21 and retired Unit 8. This project provides approximately 439 MW of accredited
22 capacity (a net increase in Uniform Rating of Generating Equipment
23 (“URGE”) capacity of about 53 MW) while eliminating coal emissions from
24 this site.

25
26 Q. HOW DOES THE RIVERSIDE PROJECT COMPARE TO THE SIMILAR WORK DONE
27 AT HIGH BRIDGE?

1 A. Riverside’s capacity rating is less than the capacity of the new High Bridge
2 facility because of the utilization of the smaller, existing equipment at the
3 Riverside Plant. However, it still represents the most cost-effective design for
4 this particular plant site. Like High Bridge, the refurbished Riverside Plant will
5 allow the Company to maintain and expand generating capacity in a strategic
6 urban area where vital transmission infrastructure already exists while doing so
7 in an environmentally responsible way. Similar to our other plant conversions,
8 we also expect to see labor savings in the long run, most likely in 2010 after we
9 complete the 12-month warranty inspection, as the combined cycle technology
10 requires less employees for operation and maintenance.

11

12 Q. WAS ANY PORTION OF THESE THREE PROJECTS MANDATED BY MINNESOTA
13 LAW?

14 A. No. Xcel Energy proceeded with development of the three above-described
15 projects on a voluntary basis because we believed they would provide
16 significant benefits to our customers throughout our service territories. We
17 chose an expansive approach that would achieve multiple goals, benefitting
18 our customers, our system, and other stakeholders. We selected projects that:

- 19 • created energy-supply benefits by adding approximately 400 MW of
20 additional capacity and associated energy to meet our customers’ needs;
- 21 • developed additional capacity and energy without significant new
22 transmission infrastructure;
- 23 • maximized use of existing plant sites and other infrastructure, keeping
24 generation located at critical interfaces on the system;
- 25 • maintained needed fuel diversity;
- 26 • met current and expected environmental requirements for generation
27 facilities;

- 1 • hedged future risks to the Company and the region; and
- 2 • responded to community concerns.

3
4 Q. DID XCEL ENERGY CONSIDER AN ALTERNATIVE APPROACH TO THE
5 REHABILITATION PROJECTS AT HIGH BRIDGE AND RIVERSIDE?

6 A. Yes. We proposed an alternative plan for consideration that was approximately
7 half the cost of our proposals for High Bridge and Riverside, but achieved *less*
8 *than* half the benefits. The alternative would have kept these plants on coal,
9 and would have required major emissions upgrades at each of the sites. The
10 alternative plan would not have resulted in any additional capacity at High
11 Bridge and Riverside. We concluded that that alternative plan faced too many
12 obstacles operationally, economically, from environmental regulators, and
13 from local concerns to be selected.

14
15 **SHERBURNE COUNTY**

16 Q. DESCRIBE THE PERFORMANCE OF YOUR LARGEST NON-NUCLEAR BASE-LOAD
17 FACILITY.

18 A. Operational performance at the Sherburne County (“Sherco”) plant, our
19 largest plant, has been excellent. For example, between 2005 and 2007, the
20 availability and reliability of all three generating units have been in the second
21 or first quartile in accordance with the North American Electric Reliability
22 Corporation (“NERC”) measures. The following table lists three key reliability
23 metrics for the three Sherco units for the period 2005 through September
24 2008.

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Table 1
Key Reliability Metrics – Sherburne County Plant

Year	2005	2006	2007	2008 (through Sept)
Annual Equivalent Unplanned Outage Rate	7.20%	5.12%	4.14%	5.33%
Annual Equivalent Availability	88.30%	89.70%	89.70%	91.20%
Total Generation in Net MWh	15,379	15,469	15,874	11,358

(Source: North American Reliability Corporation, Generation Availability Reporting System).

In 2007, the plant’s Equivalent Unplanned Outage Rate (“EUOR”) was in the 1st quartile of all plants reporting under the NERC standards as reported in the NERC Generating Availability Data System (“GADS”). In addition, 2005, 2006 and 2007 were record generation years for the Sherco facility.

Q. HAS THE COMPANY INVESTED IN ANY CAPITAL IMPROVEMENT PROJECTS AT SHERCO SINCE 2006?

A. Yes. Investments are needed to maintain the high level of plant performance Sherco has provided system-wide to all our customers. Some of the larger investments include:

- 1) ***Environmental Improvements:*** To comply with Phase 1 of the Clean Air Interstate Rule (“CAIR”), we installed low NOx burners, ducting, dampers and controls on each of the three Sherco units starting in 2005 and completing this work in 2008. Under the CAIR, an affected unit could either reduce emissions through installation of control equipment or

1 purchase allowances in order to match our allowance allocations. In
 2 addition, these controls have been proposed as Best Available Retrofit
 3 Technology (“BART”) by the Minnesota Pollution Control Agency in
 4 their regional haze state implementation plan. With the installation of this
 5 equipment, we expect to be able to meet NOx regulations without
 6 installation of a selective catalytic reduction (“SCR”) on any units, thereby
 7 avoiding significant capital expenditures yet still complying with required
 8 standard. These projects are examples of investments that improve
 9 environmental performance. The effect of these projects on NOx
 10 emissions are shown in the table below. The cost for these improvements
 11 at Unit 1 was \$17.8 million, Unit 2 was \$3.5 million and Unit 3 was \$13
 12 million with Unit 3 being the last project to be in service in 2008.

13
 14 **Table 2**
 15 **Emissions Reductions from NOx Capital Projects at Sherco**

Projects	Pre-Project ^(a) Emission Rate (lb/mmBtu)	Projected ^(b) Post-Project Emission Rate (lb/mmBtu)	Pre-Project ^(c) Emissions (tons/yr)	Projected ^(c) Post-Project Emissions (tons/yr)	Projected Emissions Reduction (tons/yr)
<u>Sherco Unit 1:</u> Low NOx Burners /Separated Over Fire Air (“SOFA”) Project and Damper Replacement Project	0.34	0.15	8,258	3,643	4,615
<u>Sherco Unit 2:</u> NOx Control -Damper Replacement Project	0.20	0.15	4,791	3,593	1,198
<u>Sherco Unit 3:</u> ^(d) NOx Control – Burner Mods/SOFA/Mill Optimization Project	0.35	0.18	11,160	5,740	5,421
<u>Totals</u>			24,209	12,976	11,234

16 ^(a) Based on pre-2006 data.

17 ^(b) Projected 2009 NOx year-end data.

18 ^(c) Using 2003-2007 average annual heat input (fuel-based values).

19 ^(d) Total values for unit 3 (includes both Xcel Energy and SMMPA shares)

1
2 As part of our environmental improvements, we will also be installing a
3 sorbent injection system for Unit 3 in 2009 to reduce mercury emissions.
4 The cost of this is \$4.4 million.

5
6 2) ***Sherco 1 & 2 Cooling Tower Replacement:*** Unit 1's and 2's cooling
7 towers were experiencing deterioration of structural elements and support
8 structures, leading to the increasing probability of local failures of the
9 cooling towers. Environmental permits require operation of the cooling
10 towers at certain times of the year. These projects are good examples of
11 investments that are needed to maintain existing plant performance.
12 These two projects added \$11.6 million to plant in service in 2008.

13
14 3) ***Sherco Unit 3 Control Systems Replacement:*** The computer systems
15 for both the plant and environmental equipment had been in operation
16 since 1986, one year prior to the commercial operation date of Unit 3.
17 The control systems had become obsolete and spare parts and compatible
18 hardware was not available to keep the system operating. Replacement of
19 the control system in 2008 resulted in investment of \$13.1 million.

20
21 4) ***Sherco Ash Pond Work:*** Ash Ponds require continuous work and
22 improvements. In 2006 we capped approximately 44 acres of pond 2 to
23 meet permit requirements. This allowed us to reduce water infiltration
24 into the pond, the amount of leachate generated and provided protective
25 cover. Our environmental permit requires permanent capping to
26 commence within 18 months of reaching final elevation and to be
27 completed within 36 months. The cost of this project was \$4.2 million.

28

1 During 2008 and 2009, additional vertical pond expansion work to extend
2 existing pond storage capacity has and continues to be to economical until
3 a new pond is needed. These capital improvements added \$4.6 million to
4 plant in service in 2008

5
6 5) ***Sherco 2 Boiler Arch Replacement:*** Replacement of boiler tube
7 sections including boiler arch, sootblower openings, and boiler corners will
8 be completed this year. These areas have been the source of many leaks
9 and corrective action will lower future operating and maintenance costs
10 and improve unit reliability. This project will add \$17.8 million to plant in
11 service in 2009.

12
13 6) ***Other Capital Improvements for Units 1 and 2:*** During 2009
14 additional investments for Units 1 and 2 will include a new coal yard
15 scraper at approximately \$1 million, additional coal yard mobile equipment
16 and improvements, and Controllable Emissions Monitors (“CEMs”).
17 During outages we typically spend additional capital for improvements to
18 plant, replacing equipment as required for plant reliability. In total, these
19 improvements will add almost \$6 million to plant in service.

20
21 7) ***Sherco 3 New Landfill Cell 3A:*** The new cell is necessary for the
22 continued disposal of Sherco Unit 3 ash coming out of the air quality
23 control system (“AQCS”). In service is planned for 2009 at an investment
24 cost of \$3.1 million.

25
26 Q. WHAT IS YOUR VIEW OF THE PERFORMANCE OF XCEL ENERGY’S NON-
27 NUCLEAR GENERATING FLEET?

1 A. I believe our fossil generating resources have performed well and with
2 continued attention to sound operating and maintenance practices and timely
3 capital investments, as needed, will remain ready to serve the needs of all
4 customers. We have made significant investments to upgrade and extend the
5 useful life of key facilities that will benefit customers through improved
6 performance and availability. Maintaining high availability of our fleet
7 minimizes the need for market-based purchases to supply customers'
8 requirements, keeping overall rates lower than would otherwise be possible
9 without these investments.

10 **III. NUCLEAR SUPPLY**

11
12
13 Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE COMPANY'S THREE NUCLEAR
14 UNITS.

15 A. Monticello is a single-unit 585 MW reactor located in Monticello, Minnesota.
16 Monticello was originally licensed by the Nuclear Regulatory Commission
17 ("NRC") in 1970 for a 40-year period scheduled to expire in 2010. In 2006
18 and 2007, federal and state regulatory agencies approved license renewal for
19 Monticello, extending its operating life until 2030.

20
21 Prairie Island has two units, each rated at 550 MW and located in Welch,
22 Minnesota. The NRC licensed Prairie Island's two units in 1973 and 1974
23 respectively and, if not renewed, the current operating licenses will expire in
24 2013 and 2014 respectively. Application to renew the operating licenses at
25 Prairie Island until 2033/2034 was made in April 2008. The NRC decision is
26 expected in 2010. Additionally, the Company is seeking Certificate of Need
27 approval from the Minnesota Public Utilities Commission ("Minnesota

1 Commission”) to expand dry spent-fuel storage to support life extension at
2 Prairie Island. The Minnesota Commission decision is expected in late 2009
3 and will become effective at the close of the legislative session following the
4 issuance of its order if the Legislature takes no action before June 1, 2010.

5
6 Q. WHAT NUCLEAR RELATED COSTS ARE INCLUDED IN THIS RATE INCREASE
7 REQUEST?

8 A. I will address two areas of nuclear related costs included in this rate case dealing
9 with major and routine capital improvements as well as increased staff
10 requirements at our nuclear facilities. Prior to 2007, significant investment was
11 required at the Prairie Island Nuclear plant, including steam generator
12 replacement and new reactor vessel heads. Major capital investments at our
13 nuclear facilities, placed into service after 2006, included license renewal at
14 Monticello, a dry storage facility at Monticello and additional spent fuel storage
15 casks at Prairie Island. Additionally, I will address the personnel increase
16 needed to meet new NRC requirements.

17
18 **A. CAPITAL IMPROVEMENTS**

19
20 **PRAIRIE ISLAND**

21 Q. PLEASE DESCRIBE THE CHANGES MADE TO THE PRAIRIE ISLAND PLANT PRIOR
22 TO 2007.

23 A. The Company replaced the following major components:

- 24 • Prairie Island Unit 1 steam generator in November 2004;
25 • Prairie Island Unit 2 reactor vessel head in May 2005; and
26 • Prairie Island Unit 1 reactor vessel head in May 2006.

27

1 Q. COULD YOU EXPLAIN THE FUNCTION OF THE STEAM GENERATOR AT PRAIRIE
2 ISLAND?

3 A. Yes. In a pressurized water reactor, the steam generator is a major component
4 that converts the heat from the reactor into steam that is used to power the
5 steam turbine, which drives the electrical generator to produce the electrical
6 output of the plant. The steam generator is a series of over 3000 U-shaped
7 tubes which carry the high-temperature radioactive coolant inside these tubes,
8 heating the non-radioactive water on the outside of the tubes to create steam.
9 The steam generator also has significant safety functions to remove excess heat
10 from the reactor in several accident scenarios.

11

12 Q. WHY WAS THE STEAM GENERATOR REPLACED?

13 Through careful management of our steam generators at Prairie Island, they
14 have lasted 38½ years, longer than those at any other pressurized water
15 reactors where the average time before replacement was 20 years. They are
16 currently the longest-lasting original steam generators by the measure of
17 effective full power-years of operation and the second longest-lasting by
18 chronological years. However, we determined in 1999 that without
19 replacement we would see deterioration in performance of the Unit 1 steam
20 generator in the 2004 time-frame. In addition, Unit 1 would likely experience
21 longer and more costly outages associated with tubing and sleeving
22 reinforcement efforts. The cost when the project was approved in 2000 was
23 \$125.7 million and the final cost of the replacement in 2004 was \$125.2 million.

24

25 Without replacement, we expect to see deterioration in performance of the
26 Unit 2 steam generators in 2013 and beyond. Our future plans include

1 replacement of the steam turbine generators at Prairie Island Unit 2.

2
3 Q. COULD YOU EXPLAIN THE REASON FOR THE PRAIRIE ISLAND REACTOR VESSEL
4 HEAD REPLACEMENTS?

5 A. Yes. In the late 1990s, the NRC identified an industry-wide boric acid
6 corrosion failure mechanism affecting the reactor vessel heads of pressurized
7 water reactors that required rigorous inspections. The most serious incident of
8 this corrosion occurred in the reactor vessel head of the Davis-Besse nuclear
9 reactor. As a result of that significant corrosion, the NRC issued an order in
10 2003 requiring regular full view inspections of the reactor vessel heads of all
11 pressurized water reactors based on the age of the reactor vessel head.

12
13 Although neither Prairie Island unit had signs of corrosion, the age of the
14 reactor vessel heads would have required the additional operating and
15 maintenance (“O&M”) costs (estimated at \$4.5 million per inspection)
16 associated with the new inspection requirements commencing in 2005.
17 Consequently, the reactor vessel heads were replaced in both units in the
18 2005/2006 period.

19
20 Q. DID THE COMPANY PREPARE AN ANALYSIS OF THE BENEFIT OF REPLACEMENT?

21 A. Yes. Prior to making the decision, we evaluated the cost of replacement of
22 both vessel heads compared to the additional on-going inspection costs. The
23 net present values of the two approaches were quite similar when measured
24 through the end of license life. However, if repairs were needed (estimate - \$2-
25 \$3 million per repair) the cost benefit analysis would favor replacement. Based
26 on industry experience, the probability of a repair would continue to increase
27 through the end of the license. Therefore, we decided to replace both reactor

1 vessel heads to significantly reduce the risk of needing such a repair, which had
2 been required for other nuclear facilities.

3
4 All of these factors, combined with the significantly lower risk of a more costly
5 repair or shutdown associated with the reactor vessel head, drove our decision
6 to invest in the new vessel heads.

7
8 Q. HAVE THERE BEEN OTHER PLANT IMPROVEMENTS AT PRAIRIE ISLAND IN 2007
9 OR LATER?

10 A. Yes. Numerous capital improvements were made at Prairie Island and placed
11 in service during 2008, summing to \$41.8 million for thirty-seven various
12 projects. Described generally, these include replacement projects for electro-
13 hydraulic control systems (“EHC”) on Units 1 and 2 which provide the means
14 for controlling turbine-generator speed and electrical power output; a project to
15 increase electrical output by reducing feed-water flow measurement uncertainty
16 (“MUR”); 17 projects dealing with pumps, motors and other cooling related
17 equipment; and another 17 assorted projects involving security and monitoring
18 equipment and routine capital improvement projects.

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Table 3

2008 Prairie Island Capital Improvements

Project	\$ Millions
EHC	22.7
MUR	5.2
Pumps/motors/related cooling equipment	9.4
Security-related/Monitors/Miscellaneous	4.5
TOTAL	\$41.8

MONTICELLO

Q. PLEASE DESCRIBE THE CAPITAL INVESTMENTS MADE AT THE MONTICELLO NUCLEAR GENERATION FACILITY.

A. A number of projects have been underway at Monticello since 2007 totaling approximately \$72 million. Most notably is the license renewal project allowing extended plant operation through the year 2030. Total cost to renew Monticello’s operating license was approximately \$31.9 million including \$20.1 million for the NRC renewal process and \$11.8 million for license-renewal-related projects (Alternate Source Term and Improved Plant Technical Specifications).

Q. WERE THERE OTHER MAJOR PROJECTS UNDERTAKEN AT MONTICELLO?

A. Yes. In addition to the license renewal investment described above, a variety of other capital improvements were made. Over \$11 million was spent for a new technical support center to meet NRC requirements and improve the plant’s emergency response capability. We also upgraded pumps at the plant. Another

1 major expenditure was for the torus coating at \$5.4 million. Further plant
2 improvements involved upgrades to our computer system. Generally
3 described, the remaining amount of the \$72 million is made up of many minor
4 projects. A tabulation of the \$72 million plant-in-service projects is shown in
5 Table 4 below.

6
7 **Table 4**

8 **Monticello Capital Improvements**

Project	\$ Millions
License Renewal & related projects	31.9
Technical Support Center	11.0
Pumps/motors/related cooling equipment	6.5
Torus Coating	5.4
Computer System Upgrade	3.0
Other Miscellaneous Projects	13.8
TOTAL	\$71.6

9
10 Q. PLEASE EXPLAIN THE REASON FOR DRY STORAGE.

11 A. Permanent disposal of spent nuclear fuel is the responsibility of the federal
12 government. The Department of Energy (“DOE”) is under contract with
13 nuclear power plant owners to ultimately take title, remove and permanently
14 dispose of spent fuel from the power plant sites. Until removed by the DOE,
15 it is the nuclear power plant owner’s responsibility to temporarily store spent
16 nuclear fuel. This was originally done in the plant’s spent-fuel storage pool.
17 However, nuclear plants’ spent-fuel storage pools were not sized to
18 accommodate the amount of spent fuel produced over 20, 40 or 60 years of
19 operation. Over the years, the Company has expanded the capacity of the

1 spent-fuel storage pools at Monticello and Prairie Island to the maximum
2 extent practical. In order to free up space in the spent-fuel storage pools, other
3 means of storing spent-fuel storage were investigated; otherwise, the plants
4 would need to shut down. Additional room for spent fuel is created by taking
5 older and cooler spent fuel from the spent-fuel storage pools and placing it in
6 dry storage systems on site, until such time as an off-site repository can be
7 established.

8
9 Q. PLEASE EXPLAIN THE SPENT NUCLEAR FUEL STORAGE FACILITY THAT WENT
10 INTO SERVICE AT THE MONTICELLO PLANT IN 2008.

11 A. The storage facility is known as an Independent Spent Fuel Storage Installation
12 (“ISFSI”) by the NRC. The Company applied for and received approval for an
13 ISFSI at Monticello in order to operate that facility until the end of its renewed
14 operating license in 2030. Monticello’s ISFSI has been constructed and a total
15 of 10 containers were placed in the Monticello ISFSI in 2008. The facility
16 consists of a lighted area, approximately 400 feet by 200 feet, roughly 3.5 acres
17 in size, located adjacent to the reactor and generating building on the 2150 acre
18 plant site. In 2008, we booked approximately \$45.8 million to plant in service
19 for the ISFSI project.

20
21 **B. PERSONNEL INCREASES**

22 Q. PLEASE EXPLAIN THE NEED FOR ADDITIONAL PERSONNEL AT THE
23 MONTICELLO AND PRAIRIE ISLAND FACILITIES

24 A. Recently the NRC enacted new regulations that take effect in October 2009
25 that establish requirements to ensure that personnel remain fit to safely and
26 competently perform their duties. A key subpart of that regulation establishes
27 requirements for managing personnel fatigue at nuclear power plants. The

1 regulation requires us to implement new software tracking programs, train new
2 operators and security staff to augment the existing staff at both plants, and
3 negotiate these contractual changes with our labor unions. Affected work
4 groups include operations, maintenance, radiation protection, chemistry,
5 security, and individuals with fire brigade and emergency preparedness
6 responsibilities. The primary impact will be to restrict work hours while
7 providing minimum required periodic rest periods. The rule will have a
8 significant impact on both normal operations and outage periods (forced,
9 maintenance and normal refueling outages). On a total Company basis, our
10 2009 budget includes approximately \$5.1 million in ongoing costs to support
11 implementation of this new regulatory requirement.

12
13 Although the new rule will not be effective until October 2009, we are required
14 to be in compliance with the rule on its effective date. The \$5.1 million cost
15 estimate includes over eighty new personnel who have and are being added to
16 the affected workgroups to meet the October 1, 2009 requirement, with
17 administrative costs for added time and record keeping, as well as the cost of
18 software development to track work hours and aid in worker scheduling.
19 Assumptions for the number of additional personnel necessary to comply with
20 this new NRC requirement are guided by the NRC's "Regulatory Guide 5.73,
21 and the NEI document 06-11 Rev01".

22
23 Without consideration of any other staffing activity, the new work hour rules
24 indicate staff would be expected to increase at the Company's nuclear plants by
25 81 individuals as a result of Fatigue Management rule implementation as shown
26 in the following table.

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Table 5
Expected Staff Increases Resulting from FFD Implementation

	Operations	Maintenance	Security	Chemistry	Health Physics	Administrative	Total
Monticello	12	0	29	2	0	1	44
Prairie Island	12	11	9	4	0	1	37
Total	24	11	38	6	0	2	81

Q. EVEN WITH THESE COST INCREASES, ARE THE COSTS OF OPERATING THE COMPANY'S NUCLEAR PLANTS REASONABLE?

A. Yes. Our fleet remains one of the lowest cost operating fleets in the nation. However, we continue to face increased cost pressures for compliance with new regulations and meeting current industry standards, labor replacement, scarcity of qualified contractors, commodity escalation, security and fees.

As another comparison, since EUCG cost data is not yet available for 2008, we have attempted to evaluate our 2009 budgets with our best estimate of industry costs in 2009. Applying a conservative annual escalation of 3.0 percent per year to 2007 EUCG U.S. nuclear plant cost data, Figure 4 provides a comparison of 2009 operating budgets for Monticello and Prairie Island with the remainder of the industry. Even with these conservative escalations applied, it appears that our total site budgets remain among the lowest in the industry when compared to postulated nuclear industry plant costs.

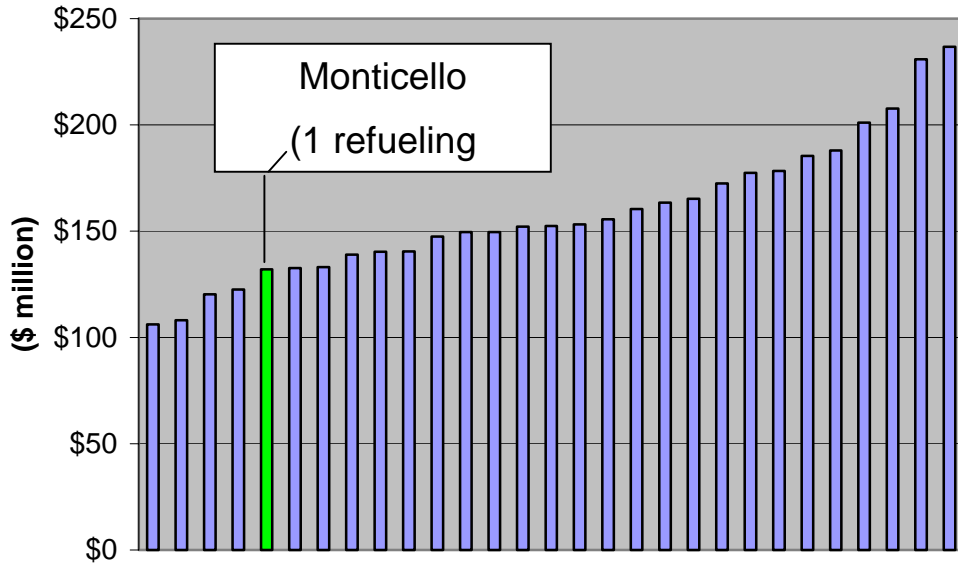
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Figure 4

2

Comparison of 2009 Budgets with Estimated Industry Costs

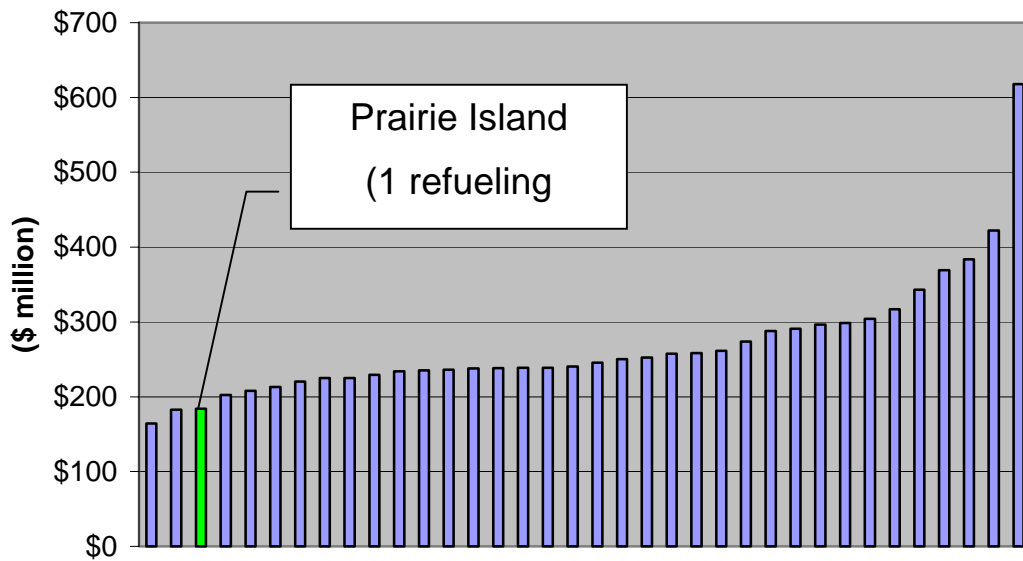
2009 Total Costs Single Unit Sites
(2007 costs escalated @ 3.0% - \$M)



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4

2009 Total Costs Multi Unit Sites
(2007 costs escalated @ 3.0% - \$M)



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IV. RENEWABLE ENERGY

Q. PLEASE DESCRIBE THE COMPANY’S EFFORTS TO ACQUIRE RENEWABLE ENERGY.

A. All states in the NSP System have mandated some form of renewable requirements or objectives. Renewable resources have proven to be a cost-effective resource for all of our customers. In 2007, for example, the average cost of wind on our system was \$32.16/MWh, while the average MISO market price was roughly \$55.00/MWh. Based on these sample prices, customers can see as much as \$23.00/MWh savings during certain times of the year. In addition, wind energy has no emissions.

Q. WHY ARE MOST OF THE CURRENT WIND ENERGY FACILITIES IN MINNESOTA?

A. While we were required by the Minnesota legislature to install our initial wind project in Minnesota, that requirement no longer exists, and, as I explain below, the selected projects was the least cost alternative.

Most of our wind resources have been contracted for through a competitive process. The sites where our wind energy is currently located were selected because the combination of wind speed (which helps determine capacity factor), available transmission, proximity to load, and other infrastructure produced the lowest cost wind energy. In addition to capacity factors and transmission access, the State of Minnesota adopted favorable incentives such as sales and property tax exemptions in the early 1990s to encourage wind development. All of these factors combined to produce low cost offers to supply wind energy and provide significant benefits for our customers today.

1 Q. PLEASE DESCRIBE THE GRAND MEADOW WIND PROJECT.

2 A. Our first Company owned wind project was completed through a turnkey
3 process in 2008 resulting in approximately \$218 million in additional plant
4 investment. The project consists of 67 - 1.5 MW turbines that will produce
5 100 MW and is located near Grand Meadow, Minnesota. The Grand Meadow
6 Wind Project is situated in a particularly good area for wind resources and
7 relatively uncongested transmission. A key development success in the Grand
8 Meadow project was having favorable position in the MISO interconnection
9 queue. As the MISO interconnection queue currently contains over 20,000
10 MW of wind projects in our area, and it is estimated that it will take many
11 years to study and interconnect all currently proposed projects. The ability to
12 interconnect the project quickly allowed us to take advantage of the Federal
13 Production Tax Credit on wind energy, which, at the time we contracted for
14 this project, was set to expire at the end of 2008. This tax benefit is worth
15 approximately \$20.00 per MWh for the first ten years, or more than 16 percent
16 of the cost of the Grand Meadow Wind Project.

17

18 Q. HOW MUCH WIND WILL XCEL ENERGY EVENTUALLY NEED TO PLACE ON THE
19 NSP SYSTEM?

20 A. To meet renewables requirements in all of our jurisdictions, we estimate that
21 we will have nearly 4,000 MW of wind on our system by 2020.

22

23 Q. WILL ALL OF THIS WIND BE LOCATED IN MINNESOTA?

24 A. No. Xcel Energy plans to develop wind facilities in wind-rich areas
25 throughout our multi-state service territory. Xcel Energy recognizes the
26 benefits of diversifying wind resources over as large an area as possible and is
27 affirmatively planning and investing in system improvements to this end.

1
2 **V. FUTURE PROJECTS**
3

4 Q. PLEASE DESCRIBE THE COMPANY'S FUTURE NON-NUCLEAR RESOURCE
5 ACQUISITION ACTIVITIES.

6 A. While outside the test period of the case, the Company would like to take this
7 opportunity to ensure the South Dakota Public Utilities Commission
8 ("Commission") is knowledgeable of other resource acquisition activities in
9 progress. These projects are as follows:

10 1) ***Nobles Wind Project:*** To be located in Nobles County, Minnesota.
11 This is a 200 MW facility that will be developed by enXco, the same
12 developer as the Grand Meadow Wind Project. Ownership of the
13 project will transfer to the Company in a progressive manner as the
14 project develops. Project completion is expected by the end of 2011.

15 2) ***Merricourt Wind Project:*** To be located in Dickey and McIntosh
16 Counties in North Dakota. This is a 150 MW facility that will be also
17 be developed by enXco with ownership transferring to the Company
18 in stages as the project develops. Project completion is expected by
19 the end of 2012.

20 3) ***Sherco Unit 3 Repowering:*** This project involves replacing the
21 GSU transformer, exciter and steam turbine and will result in an
22 increase of about 20 MW of which the Company will receive 59% or
23 around 12 MW because of our joint ownership of this unit with the
24 Southern Minnesota Municipal Power Agency. This project will also
25 be completed in 2012.

26 4) ***Bay Front Boiler #5 Gasification Project:*** The Bay Front Plant is
27 located in Northern Wisconsin and is owned by NSP-Wisconsin.

1 Two of the units at the plant have already been reconfigured to run on
2 biomass. Due to the age of the existing Boiler #5, the location and
3 forthcoming environmental regulations, it is no longer cost effective
4 to run this unit on coal and petroleum coke. As a result we are
5 planning to reconfigure the unit to run on readily available biomass
6 already in use at the site. This will add 124,000 MWh annually of
7 baseload output to our renewables portfolio.
8

9 Q. PLEASE DESCRIBE THE ONGOING CAPITAL INVESTMENTS PLANNED FOR
10 MONTICELLO AND PRAIRIE ISLAND.

11 A. These three nuclear units are critical components of our generation resource
12 portfolio. We are pursuing regulatory authorization to uprate the capacity of
13 Prairie Island and have already begun uprate work at Monticello. In total
14 between now and 2015, we will have invested an additional \$1.5 billion in these
15 units. Following is a list of the major projects:
16

- 17 • Prairie Island License Renewal
- 18 • Prairie Island and Monticello Dry Fuel Storage
- 19 • Prairie Island and Monticello Extended Power Uprate
- 20 • Prairie Island Unit 2 Steam Generator Replacement

21
22 Q. PLEASE DISCUSS THE LICENSE RENEWAL COSTS.

23 A. Once the renewed licenses are approved and issued, Prairie Island operating
24 licenses will extend an additional 20 years to 2033 for Unit 1, and to 2034 for
25 Unit 2. Keeping these two units in operation for an additional 20 years is a
26 clear benefit to our customers as our most recent resource planning study
27 showed a \$1 billion to \$2 billion present-value revenue requirement benefit.

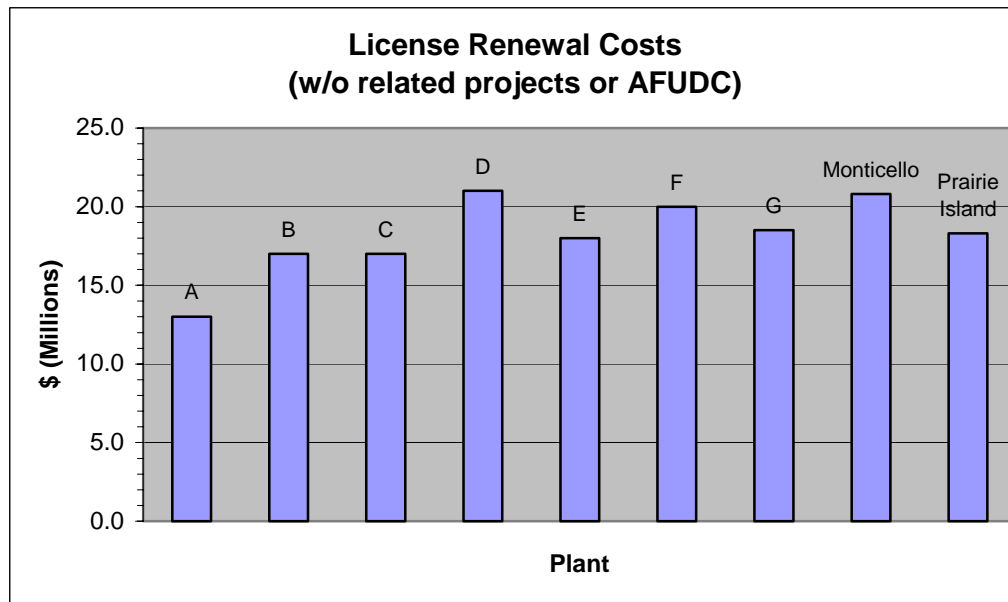
1 None of the Prairie Island license-renewal costs impact the test year revenue
2 requirement.

3
4 The total costs to be assigned to the license renewal project are estimated to be
5 \$26 million plus allowance for funds used during construction. (\$18.3 million
6 for the process of renewing the operating license with the NRC plus \$7.7
7 million of related projects equals estimated total project of \$26 million).

8
9 Q. HOW DO THE PRAIRIE ISLAND LICENSE RENEWAL COSTS COMPARE TO THE
10 COSTS FOR MONTICELLO LICENSE RENEWAL?

11 A. The total costs assigned to the license-renewal project at Monticello are \$31.9
12 million. This includes \$20.1 million for the process of renewing the operating
13 license with the NRC. The \$20.1 million cost for the license-renewal process
14 with the NRC would be comparable to \$18.3 million for Prairie Island. In a
15 survey of other nuclear license renewals, the costs for the license-renewal
16 process ranged from \$13 million to \$21 million (see Figure 5 below).

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18 **Figure 5**



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Q. WHAT IS THE STATUS OF DRY STORAGE AT PRAIRIE ISLAND?

A. At Prairie Island, the Company began utilizing dry storage in the early 1990s. To date, Prairie Island has filled and placed 24 dry-storage containers in the on-site ISFSI. It is currently estimated that five additional dry-storage containers will be filled and placed in the Prairie Island ISFSI to support plant operations until the end of its current operating licenses in 2013 and 2014. The Company is seeking approval for additional dry-storage capacity at Prairie Island to accommodate continued operation of the plant through 2033/2034 with an anticipated effective date in June 2010.

The costs of adding dry spent-fuel storage capacity needed to support 20 additional years of operation as a result of license renewal require an investment of \$211 million, or approximately \$10 million per year--a comparatively small cost to keep Monticello and Prairie Island operational.

Q. PLEASE EXPLAIN THE REASON FOR EXTENDED POWER UPRATES AT MONTICELLO AND PRAIRIE ISLAND.

A. As originally licensed, nuclear power plants had large conservatisms designed into their safety and operating analyses. The advent of improved nuclear instrumentation, controls, equipment and analytical techniques and many years of operating experience allow the reactors to produce more thermal output while maintaining or improving margins of safety. The resulting increase in thermal output from the reactor can be used to produce additional electrical output at a lower cost than new available generation alternatives. The NRC has recognized this conservatism, and as of October 2008, has approved 124

1 license amendments for power uprates at nuclear power plants across the
2 United States resulting in 5,640 MW of additional generation.

3
4 For Monticello, an additional 71 MW can be achieved while maintaining safe
5 and reliable operation (Monticello had previously been approved and achieved
6 a 34 MW power uprate in 1998). For Prairie Island, approximately 82 MW can
7 be achieved on each unit for a total of up to 164 MW while maintaining safe
8 and reliable operation. At a cost of \$2,011/kW installed at Prairie Island and
9 \$1,815/kW installed at Monticello, this is a comparatively low-cost method for
10 adding capacity relative to other forms of base load generation. Nonetheless,
11 the investments to achieve the additional output are significant.

12
13 Q. WITH TOTAL INVESTMENTS OF \$1.5 BILLION, WILL NUCLEAR POWER REMAIN A
14 LOW-COST GENERATION ALTERNATIVE?

15 A. Yes. Our investments in the plants (including original investment) to date have
16 been \$1.8 billion, much of which has been depreciated. So, while \$1.5 billion
17 seems like a significant investment to gain an additional 20 years of operational
18 capability, it is comparable to what we have historically invested in these three
19 units. We believe these are prudent investments on behalf of our customers.

20 21 **XIII. CONCLUSION**

22
23 Q. PLEASE SUMMARIZE YOUR CONCLUSIONS?

24 A. In total, we have added a considerable amount of new generating capacity and
25 made several critical improvements to the resources on the system since our
26 last rate case in South Dakota, investing approximately \$1.6 billion in
27 generation plant in service since 2006. We believe we have done so in a cost

1 effective manner and ensured efficient and reliable generation is available to
2 serve customers while at the same time being environmentally responsible.
3 We request Commission approval of the Application for a rate increase which
4 is based in part on all of the generating investment since our last rate case in
5 1992 and the cost of operating that generation.

6

7 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

8 A. Yes, it does.

1 effective manner and ensured efficient and reliable generation is available to
2 serve customers while at the same time being environmentally responsible.
3 We request Commission approval of the Application for a rate increase which
4 is based in part on all of the generating investment since our last rate case in
5 1992 and the cost of operating that generation.

6

7 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

8 A. Yes, it does.

Statement of Experience and Education

James R. Alders

Experience

April 2008 – present	Director Regulatory Administration
Jul. 1994 – April 2008	Manager Regulatory Administration
Nov. 1989 - Jul. 1994	Manager New Facility Permitting
Feb. 1984 - Nov. 1989	Administrator Routing & Siting
Aug. 1981 - Feb. 1984	Administrator Environmental Activities
July 1978 - Aug. 1981	Senior Environmental Planner
Nov. 1975 - July 1978	Environmental Planner

1994 to present

Managed Certificate of Need and Resource Planning proceedings before the Minnesota Public Utilities Commission for large capital projects including nuclear plant life extension and capacity upgrades, high voltage transmission lines, combustion turbines, and plant conversions.

1975 to 1994

Managed siting, routing, environmental review, and permitting for large, capital projects including high voltage transmission lines, power plants, ash landfills, and solid waste processing facilities. Represented company in public forums of all types including public hearings, regulatory proceedings, citizen advisory committees, legislative hearings, rule making proceedings, and environmental forums.

Education

1989 to 1991	University of St. Thomas, Graduate School of Business MBA
1971 to 1973	University of Minnesota Bachelor of Science Degree, Urban Studies