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

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Schedule

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I graduated from the University of Minnesota in 1973 with a Bachelor of Science degree in Urban Studies and later a Masters degree in Business Administration from St. Thomas in 1991. As the Director of Regulatory Administration since April 2008, my current job responsibilities include oversight of the development, preparation and support of all the Company's regulatory requests for approval needed for resource plans, resource acquisitions, power plants and transmission lines in Minnesota, South Dakota, and North Dakota. Throughout my 33 year tenure with the Company, I have been employed in various positions responsible for the routing and siting of new energy facilities such as transmission lines and power plants, as well as the acquisition of regulatory approvals, including Certificates of Need for those facilities. Since 1994, I have been extensively involved in development of the Company's resource plans and represented the Company before state and federal regulators in various resource planning and Certificate of Need proceedings. My resume is included with my testimony as Exhibit___(JRA-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

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

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

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

Q. HOW HAVE YOU ORGANIZED YOUR DIRECT TESTIMONY?

A. My testimony is organized into discussion of capital improvements made to Existing Fossil Resources, Nuclear Supply and Renewable Resources, followed by our plans for Future Generation Projects. Generally, I describe the projects within each of the generation types in chronological order by facility. Some of these projects have only recently been completed or, are scheduled for completion yet this year. I will conclude with a brief mention of some of our forthcoming projects.

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

A. Projects completed prior to 2007 include:

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

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

- Allen S. King Plant Rehabilitation;
- High Bridge Repowering;
- Riverside Repowering
- Sherburne County Plant Improvements;
- Monticello Relicensing and Site Improvements; and the
- Grand Meadow Wind Project.

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

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

II. EXISTING FOSSIL GENERATION RESOURCES

ANGUS C. ANSON

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

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

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

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

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

BLACK DOG 1 & 2 REPOWERING PROJECT

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

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

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

BLUE LAKE

Q. PLEASE SUMMARIZE THE BLUE LAKE PROJECT.

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

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

ALLEN S. KING

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

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

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

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

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

A. Yes. In 2001, our Energy Supply division conducted condition assessments of both the boiler and the steam turbine. The boiler pressure retaining components were failing on a regular basis, reducing the availability, reliability, and capacity factor of the plant. Data showed that the frequency of the failures was rising at an increasing rate. Babcock and Wilcox ("B&W"), our consulting engineers, conducted an assessment of the boiler and found that the boiler floor was in poor condition: physically distorted and metallurgically weak. B&W also reported that the floor and the cyclone burners of the boiler were the longest surviving original components of all 1960's vintage cyclone-fired, supercritical boilers. All similar boilers built by B&W had floors and cyclones that had been replaced at least once, with some units having replaced some or all of those components twice. Based on this information and actual experience with plant performance, it was obvious that swift action was needed for the King Plant.

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

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

Q. HOW IS THE REHABILITATED KING PLANT OPERATING?

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

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 SO_2 and NOx emissions. The lime is used in the Dry Flue Gas Scrubber to remove SO_2 and the ammonia is used in the Selective Catalytic Reduction unit to remove NOx. At the King Plant, the pollution control equipment can achieve the permitted rates of 0.12 pounds SO_2 per million BTU (lb/mmBtu) and 0.10 lb NOx/mmBtu. Without the chemical reagents, SO_2 emissions would be on the order of 0.57 lb SO_2/mmbtu and 0.80 lb NOx/ 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.

Figure 1
NSPM Generation Ammonia Cost Trend

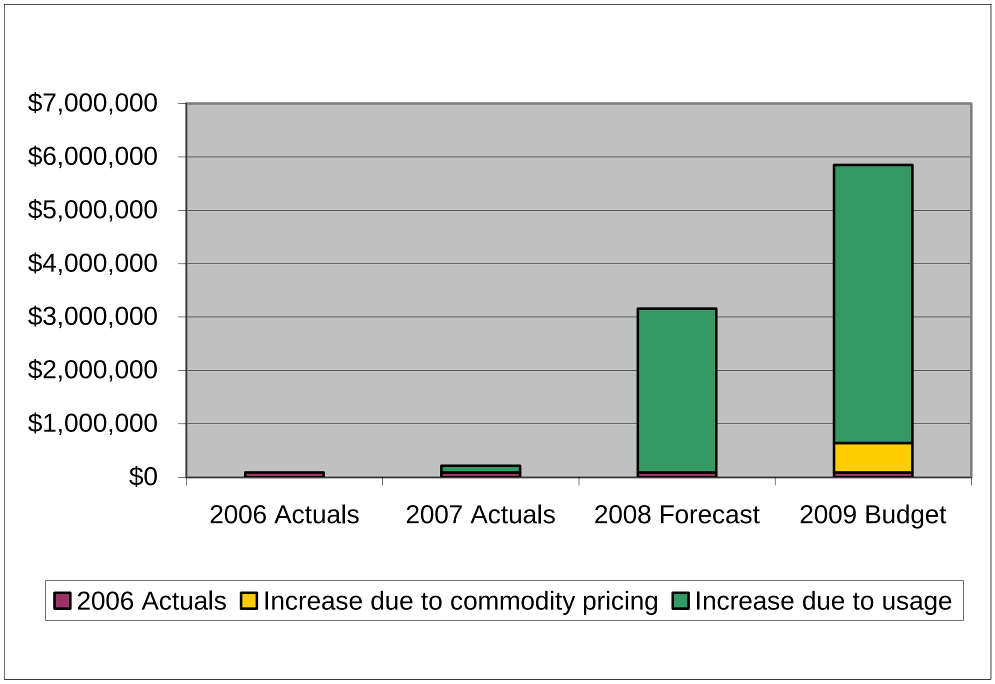
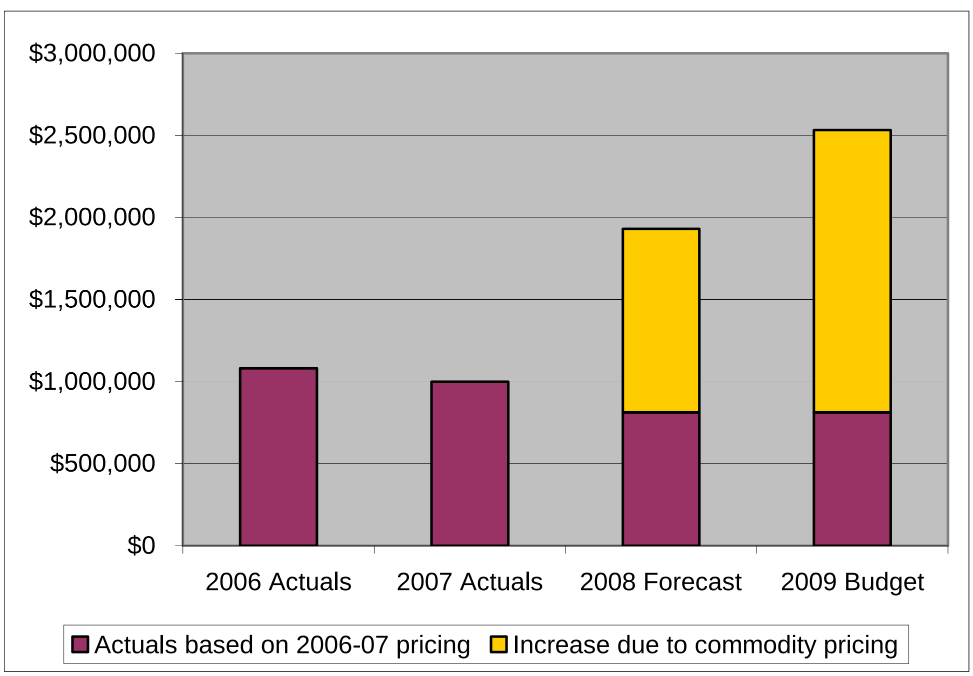


Figure 2
NSPM Generation Sulfuric Acid/Caustic Cost Trend

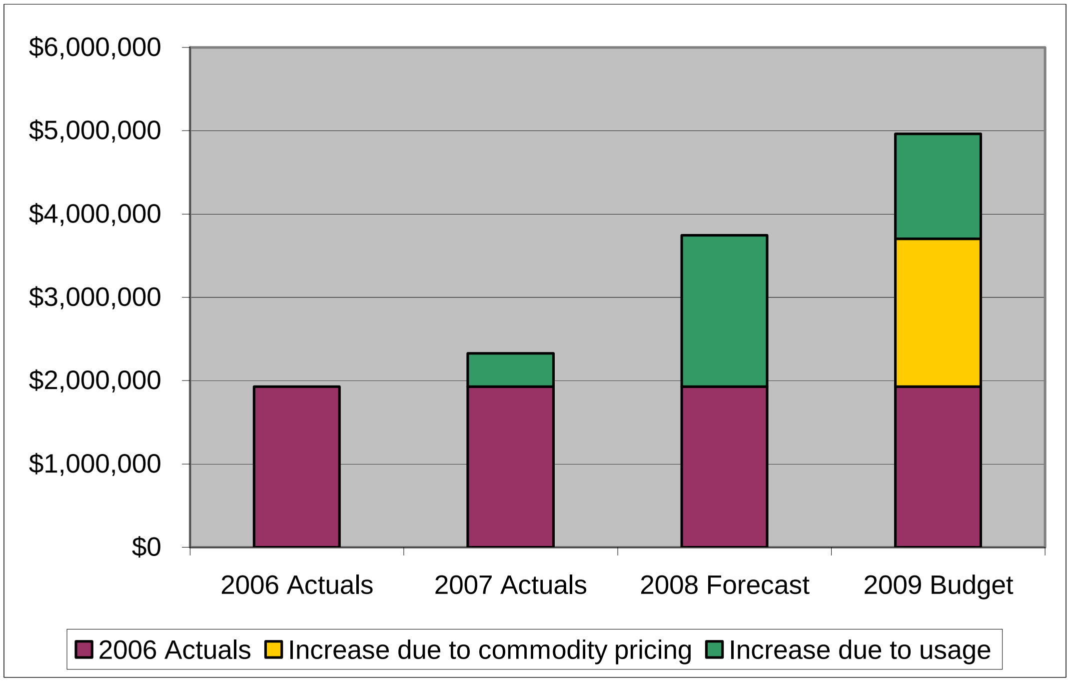


Q. HAVE YOU EXPERIENCED SIMILAR INCREASES IN THE USAGE AND COMMODITY COST OF LIME?

A. Yes. Usage of lime increased both at the King Plant with the installation of new pollution-control equipment and at Sherco, where we are increasing the removal rate of SO_2. The following chart indicates the cost trend of lime used in the operation of our generating plants.

Figure 3

NSPM Generation Lime Cost Trend



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

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

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

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

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

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

A. Yes. High Bridge is located in the heart of a densely populated metropolitan area. Most of our baseload plants, including our nuclear and large coal facilities, are located significant distances from our load centers. To facilitate the siting of these large baseload facilities outside of metropolitan areas, the Company must continue to maintain some resources within load centers to ensure transmission stability and minimize overall transmission congestion. Further, in the Midwest Independent Transmission Operator ("MISO") Day 2 environment, which began operation in April 2005, energy providers are directly assessed costs for the transmission congestion they impose on the system by delivering energy from generators to load. The High Bridge Plant location helps mitigate these costs for all customers.

RIVERSIDE

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

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

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

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

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

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

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

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

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

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

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

SHERBURNE COUNTY

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

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

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

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

Table 2
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)
Sherco Unit 1: Low NOx Burners /Separated Over Fire Air ("SOFA") Project and Damper Replacement Project	0.34	0.15	8,258	3,643	4,615
Sherco Unit 2: NOx Control -Damper Replacement Project	0.20	0.15	4,791	3,593	1,198
Sherco Unit 3: [d] NOx Control – Burner Mods/SOFA/Mill Optimization Project	0.35	0.18	11,160	5,740	5,421
Totals			24,209	12,976	11,234

[a] Based on pre-2006 data.
[b] Projected 2009 NOx year-end data.
[c] Using 2003-2007 average annual heat input (fuel-based values).
[d] Total values for unit 3 (includes both Xcel Energy and SMMPA shares)

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

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

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

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

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

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

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

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

Q. WHAT IS YOUR VIEW OF THE PERFORMANCE OF XCEL ENERGY'S NON-NUCLEAR GENERATING FLEET?

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

III. NUCLEAR SUPPLY

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE COMPANY'S THREE NUCLEAR UNITS.

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

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

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

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

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

A. CAPITAL IMPROVEMENTS

PRAIRIE ISLAND

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

A. The Company replaced the following major components:

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

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

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

Q. WHY WAS THE STEAM GENERATOR REPLACED?

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

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

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

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

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

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

A. Yes. Prior to making the decision, we evaluated the cost of replacement of both vessel heads compared to the additional on-going inspection costs. The net present values of the two approaches were quite similar when measured through the end of license life. However, if repairs were needed (estimate - $2-$3 million per repair) the cost benefit analysis would favor replacement. Based on industry experience, the probability of a repair would continue to increase through the end of the license. Therefore, we decided to replace both reactor vessel heads to significantly reduce the risk of needing such a repair, which had been required for other nuclear facilities.

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

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

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

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

Table 4

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

Q. PLEASE EXPLAIN THE REASON FOR DRY STORAGE.

A. Permanent disposal of spent nuclear fuel is the responsibility of the federal government. The Department of Energy ("DOE") is under contract with nuclear power plant owners to ultimately take title, remove and permanently dispose of spent fuel from the power plant sites. Until removed by the DOE, it is the nuclear power plant owner's responsibility to temporarily store spent nuclear fuel. This was originally done in the plant's spent-fuel storage pool. However, nuclear plants' spent-fuel storage pools were not sized to accommodate the amount of spent fuel produced over 20, 40 or 60 years of operation. Over the years, the Company has expanded the capacity of the spent-fuel storage pools at Monticello and Prairie Island to the maximum extent practical. In order to free up space in the spent-fuel storage pools, other means of storing spent-fuel storage were investigated; otherwise, the plants would need to shut down. Additional room for spent fuel is created by taking older and cooler spent fuel from the spent-fuel storage pools and placing it in dry storage systems on site, until such time as an off-site repository can be established.

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

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

B. PERSONNEL INCREASES

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

A. Recently the NRC enacted new regulations that take effect in October 2009 that establish requirements to ensure that personnel remain fit to safely and competently perform their duties. A key subpart of that regulation establishes requirements for managing personnel fatigue at nuclear power plants. The regulation requires us to implement new software tracking programs, train new operators and security staff to augment the existing staff at both plants, and negotiate these contractual changes with our labor unions. Affected work groups include operations, maintenance, radiation protection, chemistry, security, and individuals with fire brigade and emergency preparedness responsibilities. The primary impact will be to restrict work hours while providing minimum required periodic rest periods. The rule will have a significant impact on both normal operations and outage periods (forced, maintenance and normal refueling outages). On a total Company basis, our 2009 budget includes approximately $5.1 million in ongoing costs to support implementation of this new regulatory requirement.

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

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

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

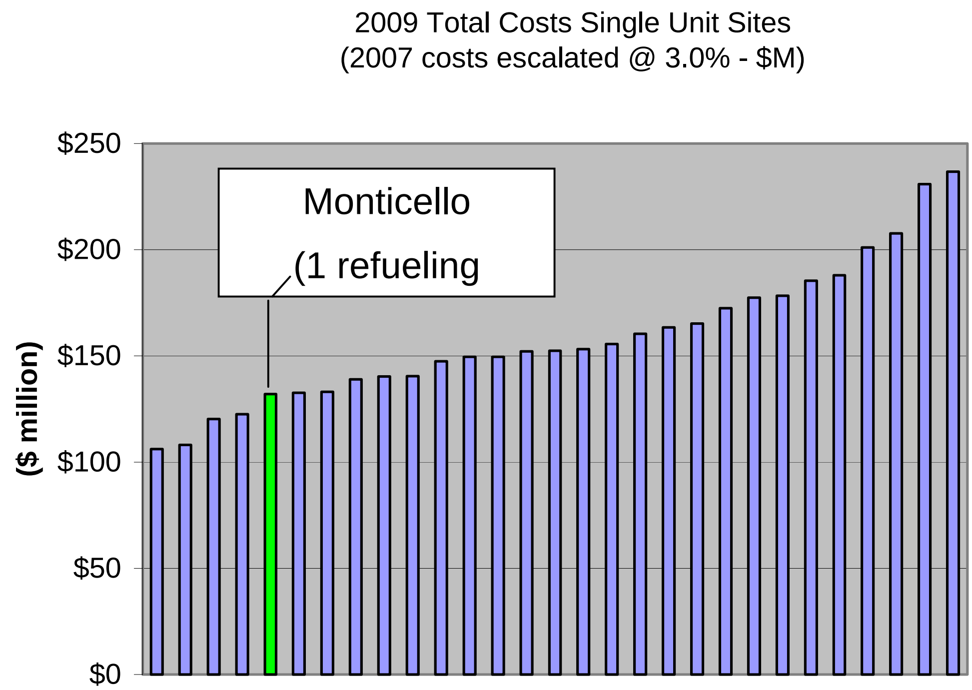
Q. EVEN WITH THESE COST INCREASES, ARE THE COSTS OF OPERATING THE COMPANY'S NUCLEAR PLANTS REASONABLE?

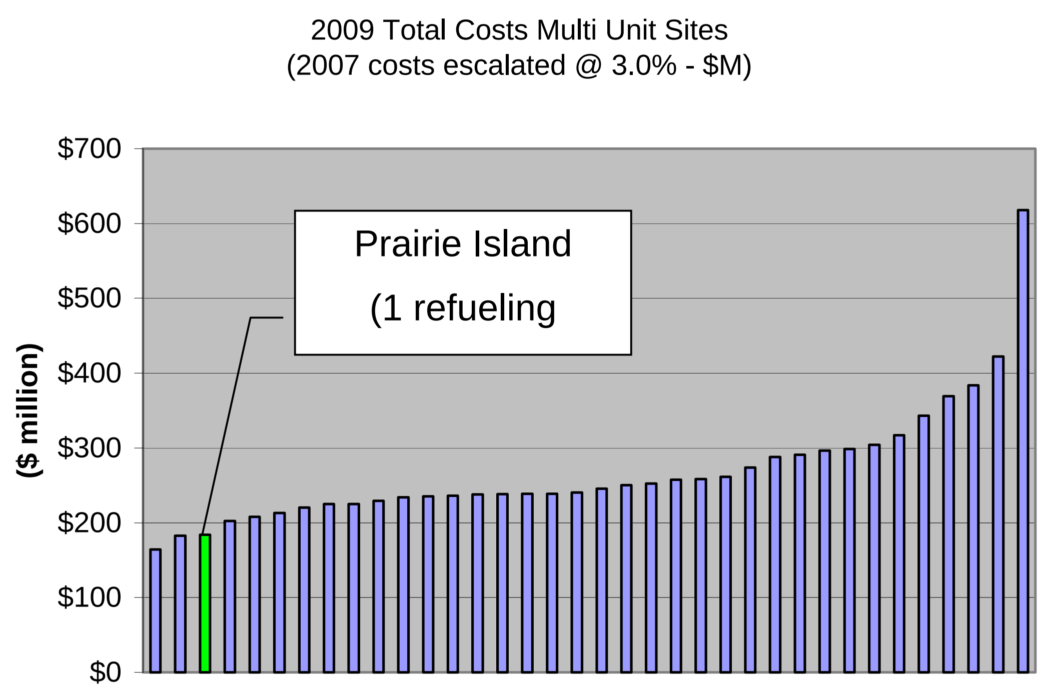
A. Yes. Our fleet remains one of the lowest cost operating fleets in the nation. However, we continue to face increased cost pressures for compliance with new regulations and meeting current industry standards, labor replacement, scarcity of qualified contractors, commodity escalation, security and fees.

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.

Figure 4

Comparison of 2009 Budgets with Estimated Industry Costs





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.

Q. PLEASE DESCRIBE THE GRAND MEADOW WIND PROJECT.

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

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

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

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

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

V. FUTURE PROJECTS

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

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

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

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

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

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

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

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

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

- Prairie Island License Renewal
- Prairie Island and Monticello Dry Fuel Storage
- Prairie Island and Monticello Extended Power Uprate
- Prairie Island Unit 2 Steam Generator Replacement

Q. PLEASE DISCUSS THE LICENSE RENEWAL COSTS.

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

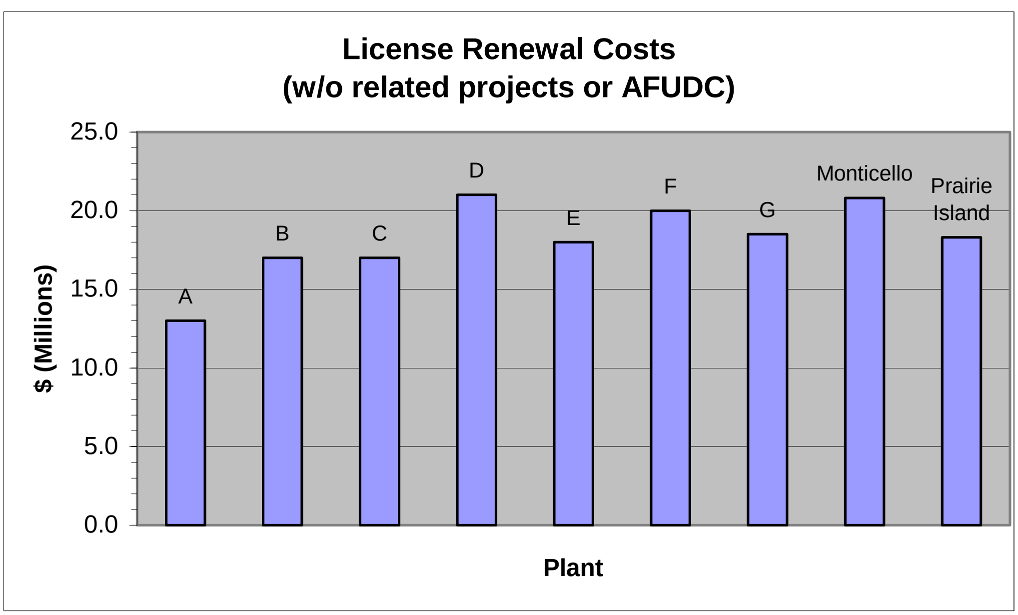
None of the Prairie Island license-renewal costs impact the test year revenue requirement.

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

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

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

Figure 5



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

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

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

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

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. In total, we have added a considerable amount of new generating capacity and made several critical improvements to the resources on the system since our last rate case in South Dakota, investing approximately $1.6 billion in generation plant in service since 2006. We believe we have done so in a cost effective manner and ensured efficient and reliable generation is available to serve customers while at the same time being environmentally responsible. We request Commission approval of the Application for a rate increase which is based in part on all of the generating investment since our last rate case in 1992 and the cost of operating that generation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

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 Utiltlies Commission for large capital projects including nuclear plant life extension and capacity upgrades, high voltage transmission liens, 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