Direct Testimony and Schedules
Laura McCarten

Before the South Dakota 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 Utility Service in South Dakota

Docket No. EL11-___
Exhibit___(LM-1)

Policy Testimony

June 30, 2011

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Laura McCarten. I am Regional Vice President for Northern States Power Company ("Xcel Energy" or "Company"), a Minnesota corporation operating in South Dakota.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I began working for the Company in 1979 as a nuclear engineer, and spent several years in the Company's nuclear engineering department supporting the Prairie Island and Monticello nuclear power plants. Since the early 1990s, I have worked in several additional areas of the Company, including regulatory, special nuclear projects, electric and gas utility operations, and transmission. In my current position, I am responsible for regulatory, legislative, customer and community relations activities in South Dakota and North Dakota. I provide strategic leadership regarding the development and implementation of initiatives to effectively serve our South Dakota customers. In addition, I am responsible for large customer management and community relations in Minnesota. My résumé is included as Exhibit___(LM-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Xcel Energy.

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

A. My testimony provides an overview of our Application, summarizing the need for a general electric rate increase and introduces the Company-sponsored witnesses. I also provide testimony regarding the Company's investments in infrastructure improvements, our efforts to manage costs in a challenging economic environment, and compliance with increasing regulatory requirements. Finally, I sponsor Exhibit No.___ (NSP-1), Statement Q, in Volume 1, which is a description of the Company's utility operations, offered in compliance with SD Admin. R. 20:10:13:101.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. I present my testimony in the following sections:

- Overview;
- Case Drivers;
- Service to Our Communities;
- Revenue Requirements;
- Managing Costs Going Forward;
- Presentation of Witnesses; and
- Conclusion.

Q. ARE THERE ANY OTHER COMPONENTS OF THE COMPANY'S FILING THAT YOU WOULD LIKE TO HIGHLIGHT?

A. Yes. We are filing testimony, exhibits, and work papers in support of our request. In addition, we undertook a comprehensive review of all Commission Rules and Orders since our last electric rate case to ensure we have complied with all requirements. My Schedule 2, Exhibit___ (LM-1), lists the relevant Commission directives from the orders, the action the Company has taken to address each order directive, and the location in our rate case application of the Company's response.

II. OVERVIEW

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST IN THIS PROCEEDING.

A. Xcel Energy seeks authority from the South Dakota Public Utilities Commission (the "Commission") to increase our electric retail revenue by $14.6 million, or 9.28 percent. We base this request on a historical 2010 test year, adjusted for known and measurable changes as allowed by the Commission's rules. The proposed revenue requirement reflects a return on equity ("ROE") of 11 percent. Under our proposal, a residential customer using 750 kWh per month would see a monthly bill increase of $6.93 per month or 9.48 percent.

Q. WHAT IS CAUSING THE NEED FOR RATE RELIEF AT THIS TIME?

A. This rate request is necessary for us to:

- Maintain, improve, and replace infrastructure on our system.
- Manage cost increases related to general economic trends, at a time of expected reduced sales growth.
- Comply with new and increasing regulatory requirements.

More than half of our request is due to new infrastructure investment and support, while economic and compliance trends account for a significant portion of the remainder.

While we have worked hard to manage our costs, we have been unable to sufficiently offset these cost increases. Addressing this deficiency will allow us to maintain the high quality, reliable electric service expected by our customers. Even with the requested rate increase, I believe customers will continue to receive great value, as we are well positioned to meet the challenges of the future.

III. CASE DRIVERS

Q. WHAT ARE THE MAJOR COST DRIVERS FOR THIS RATE CASE?

A. The chart below provides an overview of the major drivers for this rate increase request:

Major Cost Drivers

Drivers	**Revenue Deficiency (Millions)**
Infrastructure	
Wind	$ 0.6
Nuclear	$ 1.8
Other Generation (incl. O&M)	$ 5.8
Transmission & Distribution (incl. O&M)	$ 2.4
Depreciation	$ 1.2
Total Infrastructure	$11.8
Economic Trends	
A&G	$ 1.3
Medical & Pension	$ 0.6
Other Capital Related	$ 5.8
Net Other Operating Costs	$ 0.4
Margin	($ 5.7)
Total Economic Trend	$ 2.4
Regulatory Compliance	$ 0.4
Total	**$14.6**

As indicated above, costs related to new investments, primarily in generation and transmission infrastructure, account for nearly three-fourths of our revenue deficiency before accounting for sales growth, while medical and pension cost increases and additional regulatory compliance costs account for much of the remaining deficiency.

A. Infrastructure

Q. YOU INDICATED THAT MAINTAINING, IMPROVING, AND REPLACING COMPANY INFRASTRUCTURE IS A KEY DRIVER OF THIS REQUESTED RATE INCREASE. PLEASE EXPLAIN.

A. We continue the extensive capital investment in our system identified in our prior rate case in order to maintain safe and reliable service to our customers. Between 2010 and 2016 we will invest more than $4 billion in our system for all generating resources; $2.5 million of that amount is for new generation or major refurbishments to existing plants. In addition, we are forecasting nearly $2 billion in transmission investment and another $1 billion in our distribution system. Some of the biggest components of these capital projects, and of this rate request, are the life extension projects at Monticello and Prairie Island nuclear generating plants and electric power uprate at Monticello. For Monticello alone, we will add an estimated $186 million in capital investments in May 2011 and more than $179 million in November 2011. Our nuclear projects provide substantial cost savings to our customers compared to alternative sources and, as emissions-free resources, will help us manage future environmental regulations.

Another key contributor to this growth is investment in our transmission and distribution systems to provide improved reliability and support customer demand. This investment includes the recent 41st Street bridge rebuild where the Corps of Engineers required the City of Sioux Falls to raise the bridge over the Big Sioux River and Xcel Energy thus needed to relocate three feeders to accommodate the project. Another important investment represented in this case was a new 50 MVA transformer at the Lincoln County substation. We also added a new feeder out of the Minnehaha County substation and prepared for the construction of a new Louise Avenue Substation. These investments will help us to keep ahead of the growth around southern Sioux Falls and they will help us to maintain our ability to reliably serve our customers in South Dakota.

Q. PLEASE DESCRIBE THE COMPANY'S WIND INVESTMENT.

A. The primary wind investment included in the rate case is the Nobles wind project that became operational in December 2010. The Nobles wind project is a 201 MW project located in Nobles County, Minnesota, and consists of 134 1.5 MW wind turbines.

The Company implemented the Nobles project in part to provide an additional resource in which to meet its renewable requirements in its NSPM jurisdiction, including the South Dakota renewable energy objective, S.D. Codified Laws § 49-34A-101. All of the states in which we serve have implemented renewable energy requirements or objectives. The Nobles wind project will help us meet these requirements and objectives in a timely and cost-effective manner.

Q. WHY DID THE COMPANY CHOOSE TO INVEST IN THE NOBLES PROJECT?

A. The Nobles wind project arose out of our ongoing efforts to acquire timely and cost-effective wind energy generation resources to serve our customers and to comply with the renewable requirements and objectives of the states in which we operate. To maintain a robust system and minimize impacts to our customers, we need a diversified portfolio of wind resources, including Company-owned resources. Prior to the Nobles project coming on-line, however, less than 10 percent of our wind resources were Company owned. The Nobles wind project helps bring more balance to our wind energy portfolio.

In order to meet the renewable requirements and objectives of the states in which we serve, we initiated a competitive bidding process in 2007. The Nobles wind project was selected pursuant to this process in which we evaluated 30 proposals submitted in response to a request for proposal ("RFP") for up to 500 MW of wind energy generation.

One indication of the reasonableness of the costs associated with the proposed project is that the costs compare very favorably with the viable projects from the RFP process. At the time the project was selected, we also compared Nobles to an estimated range of levelized power purchase agreement ("PPA") costs for projects as if offered and installed in the same time frame. We found that the levelized costs of the Nobles wind project were below our estimated PPA cost range and, in many cases, lower than actual pricing that had been offered. Additionally, most PPAs are bid as 20-year contracts, whereas Nobles was modeled using a 25-year life. Company ownership provides benefits in that the price will not reset to the prevailing market rate as would a PPA upon expiration. In addition, after 25 years, the initial capital investment of a Company-owned wind farm will be fully recovered with the potential to still provide energy.

Q. HAS THE NOBLES PROJECT BEEN SUBJECT TO REGULATORY REVIEW?

A. Yes. The Company identified its plan to invest in Company-owned wind resources in its 2007 resource plan, MPUC Docket No. E002/RP-07-1572 and received general Commission concurrence as part of its Renewable Energy Plan in MPUC Docket No. E002/M-07-1558. The Company subsequently filed for approval of the investment in Nobles from the Minnesota Public Utilities Commission. The Minnesota Public Utilities Commission approved the investment in its June 10, 2009 order in MPUC Docket No. E002/M-08-1437.

Q. ARE ALL OF THE INFRASTRUCTURE COSTS RELATED TO CAPITAL INVESTMENTS?

A. No, not all of the costs related to our infrastructure are capital investments; there is an operation and maintenance ("O&M") component as well. For example, there are additional O&M costs associated with planned outages at the Monticello and Prairie Island nuclear plants, costs that are necessary for the continued safe and reliable operation of those facilities. Likewise, an expanded transmission network will require higher O&M costs to plan for, operate, and maintain those facilities.

B. Economic Trends

Q. PLEASE ELABORATE ON THE ECONOMIC TRENDS AND CONDITIONS THAT AFFECT YOUR BUSINESS.

A. Like all businesses, general economic trends have impacts on our Company. In particular, we have seen impacts in the areas of pension and health care:

Pension. For the first time since 1994, we need to make contributions to the pension fund to comply with federal pension requirements and meet our responsibility to protect the interests of plan participants and beneficiaries.

Health Care. We are experiencing health care cost increases at levels much greater than general inflation; in fact, despite numerous initiatives to control those costs, we are experiencing health care costs about four percent higher than the general medical inflation rate of seven percent. These trends are influenced by the average age of our workforce, the number of dependents insured under our plan, and high-cost claims compared to the average business. These cost increases are further described in the Direct Testimony of Company witness Mr. Thomas E. Kramer.

C. Regulatory Compliance Requirements

Q. PLEASE DESCRIBE THE COMPLIANCE COSTS DRIVING YOUR REQUEST.

A. We are seeing new and increasing regulatory requirements in many areas of our business. These are primarily federal requirements, from entities such as the North American Electric Reliability Corporation ("NERC"), the Nuclear Regulatory Commission ("NRC"), and the Environmental Protection Agency ("EPA"). Additionally, key provisions of recent federal legislation, such as the Pension Protection Act, and Patient Protection and Affordable Care Act, are now coming into effect. While our compliance costs must be prudently managed, increased costs associated with compliance are unavoidable.

Q. CAN YOU PROVIDE EXAMPLES OF SUCH ADDITIONAL COMPLIANCE REQUIREMENTS?

A. Yes. For example, the NRC has imposed new requirements on the operation of our nuclear generation plants. Recent standards imposed or expanded by the NRC focus on the safety and security at our plants, including additional fitness for duty standards, more stringent security rules, cyber-security rules, and fire protection and emergency preparedness requirements.

Similarly, in 2007, NERC replaced its voluntary reliability guidelines with a new mandatory compliance regime under the authority of the Federal Energy Regulatory Commission. Since that time, NERC has developed a number of new standards to manage and ensure the reliability of the electric grid, and we are now responsible for compliance with over 300 specific NERC requirements. In addition, compliance in and of itself is not sufficient – we must be able to demonstrate and document compliance with each requirement. Non-compliance can lead to substantial financial penalties. As a result, we are adding personnel, developing new documentation procedures, and adding or developing new information systems to track detailed compliance information.

IV. SERVICE TO OUR COMMUNITIES

Q. DO YOU BELIEVE THE COMPANY'S SOUTH DAKOTA CUSTOMERS RECEIVE VALUE FOR THE RATES THEY PAY?

A. Yes. We provide excellent value to our South Dakota customers as a result of our development of a diverse, flexible and robust fleet of generation resources that provide reliable, reasonably priced energy services to our customers both now and over the long term. In addition, we have developed a reliable and safe transmission and distribution system, both of which will continue to provide good value to our customers in the future.

Q. HOW DO YOU MEASURE SERVICE TO YOUR SOUTH DAKOTA CUSTOMERS?

A. We measure our performance in providing reliable electricity service through industry standard indices, the most important being the System Average Interruption Duration Index ("SAIDI"). On average, customers in South Dakota have experienced total outage duration times between 75 and 83 minutes over the past five years, when normalized for storms.[1] Surveys show us that this level of performance is better than other utilities across the country and better than the average of the other regions within the Xcel Energy footprint.

Q. DO YOU BELIEVE YOUR SOUTH DAKOTA CUSTOMERS ARE SATISFIED WITH THEIR SERVICE?

A. Yes. We regularly survey all classes of customers and track satisfaction through our "Voice of the Customer" surveys. For the past five years the overall customer satisfaction reported in these surveys for South Dakota customers has been at or above 90 percent, giving South Dakota one of the highest customer satisfaction ratings of any of the jurisdictions that we serve. The current South Dakota customer rating through May 2011 is at 98 percent.

In addition, we track the number of Commission complaints initiated by our customers, and we have had only two formal complaints in the past five years. We also track any customer contact with the Commission that expresses dissatisfaction. Over the past five years, we averaged 35 customer contacts per year with Commission staff with only 13 customer contacts in 2010.

[1] SAIDIs: 82.45 (2006); 82.85 (2007); 75.84 (2008); 79.68 (2009); 80.56 (2010)

Q. DISCUSS WAYS IN WHICH THE COMPANY MEETS CUSTOMER EXPECTATIONS FOR RELIABLE AND REASONABLY-PRICED ELECTRIC SERVICE.

A. We have followed a prudent, balanced approach to replace aging infrastructure and build new facilities that are necessary to meet current and future system needs. Our approach has led to a very balanced mix of energy sources, which will help mitigate impacts to our customers resulting from potential negative cost or reliability issues associated with any specific energy source.

Over the last decade, we have made significant investments to modernize our fleet of power plants, thus maximizing the efficient and cost-effective use of existing sites and facilities. For example, we are making the investments needed to extend the lives of our Monticello and Prairie Island nuclear plants another 20 years (these life extensions were recognized for depreciation purposes in our last rate case, Docket No. EL09-009), and have plans for adding a new "virtual" nuclear power plant of about 235 MW by increasing the power production capabilities at these plants. In addition, we cost-effectively refurbished and repowered three old, but strategic coal fired plants in the Minneapolis/St. Paul metropolitan area.

While our resource planning and investment decisions have lead to cost-effective, reliable service, we have also undertaken various initiatives to reduce costs in many parts of our business as a result of process and technology efficiencies. Some of these initiatives are designed to better inform customers, through our website and customer mailings, of ways to keep their utility costs low and better manage their energy use. A recent example is our My Account site (Online Account Management program), which currently allows our South

Dakota customers to register their accounts for online access, view account summary information, view their usage, billing, and payment history, select among various payment methods, and view energy saving tips.

Q. PLEASE DESCRIBE THE XCEL ENERGY OPERATING SYSTEM.

A. Xcel Energy operates an integrated generation and transmission system to serve all our customers in the upper Midwest, including South Dakota, North Dakota, Minnesota, Wisconsin and Michigan. Our customers benefit from the economy of scale of a broad portfolio of generating resources including the large base load generators and the high voltage transmission network that we operate to deliver electricity to our customers in South Dakota. In addition, a central warehouse facility maintains a large inventory of spare parts and the scope of our purchasing gives us a purchasing power that enables us to obtain equipment such as transformers, poles and wire at the lowest possible cost.

Q. DO YOU BELIEVE THE INTEGRATED SYSTEM OF XCEL ENERGY HELPS TO MEET ITS CUSTOMERS' NEEDS?

A. Yes, our integrated system helps to provide cost-effective, reliable and safe service to all of our customers, including South Dakota. All of the customers across the five states of Xcel Energy's upper Midwest service area derive great benefits from the integrated system and a comprehensive approach to planning for and meeting customers' needs. The diversity of our energy supply is good for our customers because it reduces the risk of significant increases in customer bills due to cost, regulatory, or supply issues that can occur for any one energy source. Our customers also benefit by the fact that many significant business costs can be spread over a larger base, thus lowering the average cost of service.

Q. HOW DO XCEL ENERGY'S RATES IN SOUTH DAKOTA COMPARE TO ENERGY RATES IN THE REGION?

A. Our electric rates in South Dakota remain low. While necessary infrastructure investments have recently put upward pressure on our rates, we still provide excellent value for our South Dakota customers, and our residential rates in the state are significantly lower than the national average of approximately $0.115/kWh.

V. REVENUE REQUIREMENTS

A. Historical Earnings

Q. YOUR MOST RECENT ELECTRIC RATE CASE WAS BASED ON A 2008 TEST YEAR WITH KNOWN AND MEASURABLE CHANGES IN 2009. BOTH YEARS FELL DIRECTLY IN THE MIDDLE OF THE FINANCIAL DOWNTURN. HOW DID THE COMPANY RESPOND?

A. Both 2008 and 2009 were challenging years for us, given reduced sales due to the economic downturn. We worked hard to manage our costs, reducing and deferring employee base pay increases, driving down employee expenses and consulting costs, and delaying work. However, our cost management initiatives were not sufficient to offset the low sales in those years. In 2009, we reported an actual return on equity of 3.38% percent and a weather-normalized return on equity of 4.23% percent, much lower than our authorized return. Although sales improved in 2010, these sales were not sufficient to offset the costs related to implementing the previously-delayed work and the continued need to invest in our system. For the historic test year of 2010, we reported an actual return on equity of 2.95% percent and a weather-normalized return on equity of 2.64%, again much lower than our authorized return.[2]

Economic factors are stabilizing and slowly improving, and our efforts created efficiencies and cost controls that we continue to employ. Nonetheless, the need to continue to invest in our infrastructure and increased regulatory compliance costs have resulted in increased costs.

B. Test Year

Q. WHAT TEST YEAR DOES THE COMPANY PROPOSE IN THIS CASE?

A. The test year is 2010, adjusted to normalize the test year, properly reflect regulatory requirements, and account for appropriate known and measurable changes. As discussed by Company witness Mr. Kramer in his Direct Testimony, we have limited these known and measurable changes to a very discrete set of costs for purposes of this case. We have considered factors such as: 1) whether a signed contract was in place (e.g. union wage increases); 2) action had already been taken by the Company (e.g. employee expense reductions); and 3) major capital projects with an actual or projected 2011 in-service date.

C. Rate of Return

Q. WHAT IS THE BASIS FOR THE COMPANY'S RECOMMENDED ROE OF 11 PERCENT?

A. Our proposed revenue requirement reflects an overall rate of return ("ROR") on investment of 8.78 percent, based on an average common equity ratio of

[2] The actual return on equity shown on the Company's cost of service study is lower, at 1.33 percent, reflecting the requested higher ROE of 11 percent.

52.48 percent and a rate of return on equity ("ROE") of 11 percent. Mr. Daniel S. Dane provides a detailed analysis of the appropriate overall ROR and ROE for the Company.

Q. IS THE LEVEL OF RETURN ON EQUITY ESPECIALLY IMPORTANT IN LIGHT OF THE COMPANY'S PLAN FOR FUTURE INVESTMENTS?

A. Yes. While the Company is entitled to earn a fair return on equity as a part of this rate proceeding, an appropriate ROE and a supportive state regulatory framework are also key contributors to our ability to raise significant capital at reasonable rates. Our plan of investment in generation, transmission and distribution will result in approximately $7 billion of expenditures between 2010 and 2016. We will need to turn to the capital markets to support the level of investment that is needed.

Given the magnitude of investments we need to make, we have a common interest with our regulators and customers in having the Commission set an appropriate ROE and ensure we have a reasonable opportunity to earn that ROE. Absent these conditions, the cost of capital for the investments we need to make to serve our customers would be higher than otherwise necessary, increasing the rate impact on our customers.

D. Rate Design

Q. PLEASE DESCRIBE YOUR PROPOSED RATE DESIGN FOR THIS CASE.

A. The Company is not proposing significant changes to our current rate design. We are proposing only those changes necessary to implement the proposed test year 2010 revenue requirements, other technical and administrative updates necessary to keep the tariff structure current with that in the other retail jurisdictions within the NSP (MN) Company, and limited changes in design to make our rates better reflect the cost of service.

VI. MANAGING COSTS

Q. HAS THE COMPANY CONSIDERED THE IMPACT OF THIS PROPOSED INCREASE ON YOUR CUSTOMERS?

A. Yes. We recognize the impact this case has on our customers, and we have taken significant care in this request to be thorough and transparent in explaining and justifying our costs. That is why we have limited our request to only the minimal amount and this case only includes those items that are essential for cost recovery. These amounts are necessary to support the Company's operations and the Company commitment to ensuring adequate, efficient and reasonable service to our customers.

Q. HOW HAS THE COMPANY WORKED TO MANAGE COSTS AND AVOID THIS REQUESTED RATE INCREASE?

A. We have taken numerous steps to reduce and control our costs. For example, we have:

- Reduced travel and employee expenses from historic levels by implementing new procedures and limitations.
- Controlled supply chain costs by forming strategic supplier relationships. In addition, most areas are multiple sourced to ensure supply continuity and competition among suppliers.
- Limited the rate of medical cost increases by increased employee cost-sharing, benefit reductions, and renegotiation of vendor contracts.

- Managed and offset labor cost pressures by a number of workforce deployment initiatives, such as strict management of overtime, employee replacements and hires, and work-planning efforts.

We have controlled costs without compromising safety, reliability, or customer service. As mentioned above, the Company has consistently provided our South Dakota customers high levels of customer satisfaction, safety performance, and reliability. Although these efforts have not eliminated the need for a rate case, the rate increase requested would undoubtedly be higher without these cost controls in place.

Q. WILL THE COMPANY'S COST MANAGEMENT EFFORTS DELAY A FUTURE RATE CASE?

A. I previously explained how the Company has presented only a minimal rate case in this instance. While we make every effort to control costs on a daily and yearly basis, we recognize that necessary investments in capital projects, particularly with the Company's nuclear projects, and ongoing cost pressures for health care and similar expenses may necessitate the Company filing a rate case in 2012.

Q. PLEASE DESCRIBE XCEL ENERGY'S NUCLEAR OPERATIONS.

A. Xcel Energy owns and operates three nuclear units: one unit at Monticello, Minnesota and two units at Prairie Island in Welch, Minnesota. Monticello was originally licensed by the NRC in 1970. We received a renewed license for Monticello in 2006, extending its operating life until 2030. We are currently awaiting final NRC approval to implement the power uprate at the plant.

Prairie Island has two reactor units. The NRC licensed Prairie Island's two units in 1973 and 1974, respectively. We pursued renewal of the federal operating licenses to extend the Prairie Island operating lives until 2033 and 2034. We received the NRC decision granting the renewed license on June 27, 2011. We also plan to implement a power uprate at Prairie Island's operating units in 2014 and 2015.

Together, Monticello and Prairie Island continue to be Xcel Energy's most reliable baseload generation assets in Minnesota. We are making significant investments in our nuclear facilities to further maximize this low-cost resource for our customers.

Q. HOW WILL THESE PROJECTS BENEFIT YOUR SOUTH DAKOTA CUSTOMERS?

A. Our nuclear generating fleet provides the lowest cost energy of all of our generating resources. Continued and expanded use of these facilities is an integral part of the Company's future plans to provide low cost and reliable energy to our customers in South Dakota and throughout our system. The investments we are making now in the Monticello facility, including life cycle management work and power uprate, will provide lasting benefits for the next 20 years.

Q. ARE ALL OF THE CAPITAL COSTS FOR THE MONTICELLO POWER UPRATE/LIFE CYCLE MANAGEMENT WORK INCLUDED IN THIS RATE CASE?

A. Yes and no. Our pro forma test year includes a known and measurable adjustment for the Monticello power uprate/life cycle management project for 2011. This adjustment includes actual costs through April 2011 and the forecast of the remaining months of 2011. However, while some of the costs for these yet to be completed projects are known and measurable (costs of the Spring outage), some of these costs are subject to price fluctuation and continue to be recalculated, even in this short time period prior to the commencement of the Fall outage. For that reason, we recognize that differences will exist between the actual final costs and the cost estimates that will be reflected in base rates as a result of this case. By not including these final costs and not reflecting a full year's revenue requirements for those final costs, we recognize we will experience an immediate significant revenue deficiency in 2012 as a result of these projects. We project this deficiency to be approximately $1 million in 2012.

Q. HOW DOES THE COMPANY PROPOSE TO ADDRESS THIS REVENUE DEFICIENCY?

A. The Company proposes to recover the costs of the Monticello power uprate/life cycle management project that are not included in the base rates in a rate rider to go into effect in 2012. Company witnesses Mr. Kramer and Mr. Huso further discusses the proposed Nuclear Cost Recovery ("NCR") rate rider in their Direct Testimonies. Because these major investments would not otherwise be recovered in base rates, these growing costs go unrecovered in absence of a rider or another rate case in 2012.

Q. WHAT ARE THE BENEFITS OF ADOPTING THE COMPANY'S PROPOSAL?

A. The Monticello power uprate/life cycle management project is an integral part of our overall efforts to provide reasonably priced and reliable energy for our customers throughout our system. However, absent timely cost recovery, the Company will find it difficult to maintain the aggressive investment program that is needed to bring this and future projects forward and obtain capital to fund these projects. Timely cost recovery provides added confidence to our investors and creditors and ultimately leads to reduced rates for our customers.

Q. WHY DID THE COMPANY ELECT NOT TO FILE A RATE STABILITY PLAN UNDER S.D. CODIFIED LAWS § 49-34A-73?

A. We determined that the rate stability plan would not be a good fit for a project like the nuclear power uprate/life cycle management projects. The rate stability plan is intended to recover costs over a number of years during construction of major capital additions. In this case, however, a rate stability plan could have resulted in ratepayers paying significant costs of the Monticello project significantly in advance of the customers receiving the benefit of the work.

For example, if the Company were constructing a large new baseload coal plant, construction of that project would occur at a steady rate over several years. Recovery through a rate stability plan could be an appropriate mechanism to manage cost recovery and the significant outlay of funds to support the construction. In contrast, the work supporting the power uprate/life cycle management projects is conducted somewhat more sporadically as the work generally occurs only during outages. Initial work to support the Monticello power uprate/life cycle management project was implemented in the 2009 outage. Since Monticello is on an approximately 24-month refueling schedule, significant additional work did not occur until the next outage, in Spring 2011. To avoid the risk of an extensive outage and due to additional regulatory review of the license amendment application, final construction was delayed until the Fall of 2011. A rate stability plan could potentially have had customers paying costs related to project implementation at a time when no work was being performed.

Q. HOW DOES THE COMPANY'S PROPOSED RIDER MITIGATE THIS POTENTIAL MISMATCH?

A. In this case, we propose to implement the rider after the project is fully implemented. This proposal results in current ratepayers paying the current costs of service.

Q. WHY DID THE COMPANY CHOSE NOT TO INCLUDE ALL OF THE COSTS IN ITS BASE RATES?

A. In this case, we proposed known and measurable changes fitting into very discrete categories, as discussed by Mr. Kramer. We intend to update the Commission on the costs of the project within 60 days of the projects being completed. However, at present, the final outage to complete construction and implementation will not be finished until very late in 2011 and we will not know the final costs until the work is complete. Accordingly, we propose to true-up those final costs in the rider.

Q, WOULD THE RIDER APPLY TO ADDITIONAL FUTURE PROJECTS?

A. The NCR rider would only recover the costs of those projects expressly authorized by the Commission. Because the NCR rider would assist in delaying a future rate case, we request the ability to propose future NCR rider qualifying projects in the future.

VII. PRESENTATION OF WITNESSES

Q. WHO ARE THE WITNESSES FOR THE COMPANY IN THIS PROCEEDING?

A. In addition to my Policy Testimony, the Company sponsors the following witnesses:

- *Thomas E Kramer*, who sponsors the overall revenue requirement for the rate case. Mr. Kramer sponsors the schedules supporting our income statement, rate base, revenue deficiency, and jurisdictional allocations.
- *Daniel S. Dane,* of Concentric Energy Advisors, who sponsors testimony on the ROE and ROR, including, capital structure, and the cost of debt.
- *Michael A. Peppin*, who sponsors our class cost of service study.
- *Steven V. Huso*, who sponsors the general rate design in this case and tariff changes.

Together, these witnesses provide the information and advocacy needed to evaluate and approve our Application.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This rate request is needed to support infrastructure improvements to our system, fund cost increases in health care, pension, and other costs that are related to trends in the overall economy, and to ensure compliance with increasing regulatory requirements. We provide excellent value to our South Dakota electric service customers as a result of our prudent development of a diverse, flexible and robust fleet of generation resources that will provide reliable, reasonably priced energy services to our customers both now and over the long term. Our requested increase in rates is necessary to allow the Company to continue to provide adequate, efficient and reasonable electric service to our South Dakota customers.

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST TO THE COMMISSION.

A. We respectfully request that the Commission approve:

- Our requested rate increase of $14.6 million, which is 9.28 percent of present retail revenues,
- An overall ROR on investment of 8.78 percent, based on an average common equity ratio of 52.48 percent and an ROE of 11 percent
- Our proposed rate design and tariffs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Laura McCarten

Experience

2008-Present | Xcel Energy | Minneapolis, MN

Regional Vice President, NSPM

- For Xcel Energy's South Dakota service territory, responsible for regulatory and legislative interface and policy development, customer and community relations and public affairs, and provide strategic leadership on initiatives to effectively serve customers.
- For Xcel Energy's North Dakota service territory, responsible for regulatory and legislative interface and policy development, customer and community relations and public affairs, gas business development, and provide strategic leadership on initiatives to effectively serve customers.
- For Xcel Energy's Minnesota service territory, responsible for managing relationships with communities and large customer accounts, gas business development and our HomeSmart service.

2006-2008 | Xcel Energy | Minneapolis, MN

Director, Regional Transmission Development

1997-2005 | Xcel Energy | Minneapolis, MN

Director, Minnesota Community Services

1994-1997 | Xcel Energy | Mankato, MN

Regional General Manager

1992-1994 | Northern States Power | Minneapolis, MN

Manager, Regulatory Affairs

1979-1991 | Northern States Power | Minneapolis, MN

Nuclear Generation: Spent Nuclear Fuel Project Manager, Engineer

Education

1979 | University of Wisconsin | Madison, WI

Bachelor of Science in Nuclear Engineering

Professional Development

- Xcel Energy Leadership Advantage Program (2004)
- University of Michigan Business School, Strategic Marketing Planning (1998)
- University of Minnesota, Carlson School of Management, Minnesota Management Institute (1996)

Community Service

- Lignite Energy Council, Board of Directors
- Minneapolis Regional Chamber of Commerce, Board of Directors
- North Central Electrical League, Board of Directors
- Ordway Center for the Performing Arts, Board of Directors
- University Enterprise Laboratories, Board of Directors

SD Admin.R.	Description	Sponsoring Witness	Filing Location
20:10:13:26	Report to commission of tariff schedule changes on notice.	S. Huso	Volume 2
20:10:13:41.	Comparison of sales, services, and revenues.	S. Huso	Volume 2
20:10:13:42.	Comparison of rates.	S. Huso	Volume 2
20:10:13:43	Cost of service under the new rates.	M. Peppin	Volume 2
20:10:13:44	Analysis of system costs for a 12-month historical test year.	T. Kramer	Volume 2
20:10:13:47	Working papers to be filed.	Various	Volume 3
20:10:13:50	Attestation by chief accounting officer or other authorized accounting representative.	N/A	Volume 1
20:10:13:104	Testimony and exhibits.	Various	Volume 2

SD Admin.R.	Stmt	Schd	Description	Sponsoring Witness	Filing Location
20:10:13:51	A		Balance sheet	T. Kramer	Volume 1
20:10:13:52	B		Income Statements	T. Kramer	Volume 1
20:10:13:53	C		Earned surplus statements	T. Kramer	Volume 1
20:10:13:54	D		Cost of Plant	T. Kramer	Volume 1
20:10:13:55		D-1	Detailed plant accounts	T. Kramer	Volume 1
20:10:13:56		D-2	Plant addition and retirement for test period	T. Kramer	Volume 1
20:10:13:57		D-3	Working papers showing plant accounts on average basis for test period	T. Kramer	Volume 1
20:10:13:58		D-4	Plant account working papers for previous years	T. Kramer	Volume 1
20:10:13:59		D-5	Working papers on capitlizing interest and other overheads during construciton	T. Kramer	Volume 1
20:10:13:60		D-6	Changes in intangible plant working papers.	T. Kramer	Volume 1
20:10:13:61		D-7	Working papers on plant in service not used and useful	T. Kramer	Volume 1
20:10:13:62		D-8	Property records working papers	T. Kramer	Volume 1
20:10:13:63		D-9	Working papers for plant acquired for which regulatory approval has not been obtained	T. Kramer	Volume 1
20:10:13:64	E		Accumulated depreciation	T. Kramer	Volume 1
20:10:13:65		E-1	Working papers on recorded changes to accumulated depreciation	T. Kramer	Volume 1
20:10:13:66		E-2	Working papers on depreciation and amortization method	T. Kramer	Volume 1
20:10:13:67		E-3	Working papers on allocation of overall accounts	T. Kramer	Volume 1
20:10:13:68	F		Working capital	T. Kramer	Volume 1
20:10:13:69		F-1	Monthly balances for materials, supplies, fuel stocks, and prepayments	T. Kramer	Volume 1
20:10:13:70		F-2	Monthly balances for two years immediately preceding test year	T. Kramer	Volume 1
20:10:13:71		F-3	Data used in computing working capital	T. Kramer	Volume 1
20:10:13:72-75	G		Rate of return/Debt capital/Preferred stock capital/Common stock capital	T. Kramer	Volume 1
20:10:13:76		G-1	Stock dividends, stock splits or changes in par or stated value	T. Kramer	Volume 1
20:10:13:77		G-2	Common stock information	T. Kramer	Volume 1
20:10:13:78		G-3	Reacquisition of bonds or preferred stock	T. Kramer	Volume 1
20:10:13:79		G-4	Earnings per share for claimed rate of return	T. Kramer	Volume 1
20:10:13:80	H		Operating and maintenance expenses	T. Kramer	Volume 1
20:10:13:81		H-1	Adjustments to operating and maintenance expenses	T. Kramer	Volume 1
20:10:13:82		H-2	Cost of power and gas	T. Kramer	Volume 1
20:10:13:83		H-3	Working papers for listed expense accounts	T. Kramer	Volume 1
20:10:13:84		H-4	Working Papers for Interdepartmental Transactions	T. Kramer	Volume 1
20:10:13:85	I		Operating Revenue	T. Kramer	Volume 1
20:10:13:86	J		Depreciation expense	T. Kramer	Volume 1
20:10:13:87		J-1	Expense charged other than prescribed depreciation	T. Kramer	Volume 1
20:10:13:88	K		Income taxes	T. Kramer	Volume 1
20:10:13:89		K-1	Working papers for federal income taxes	T. Kramer	Volume 1
20:10:13:90		K-2	Differences in book and tax depreciation	T. Kramer	Volume 1
20:10:13:91		K-3	Working papers for consolidated federal income tax	T. Kramer	Volume 1
20:10:13:92		K-4	Working papers for an allowance for current tax greater than tax calculated at consolidated rate	T. Kramer	Volume 1
20:10:13:93		K-5	Working papers for claimed allowances for state income taxes	T. Kramer	Volume 1
20:10:13:94	L		Other taxes	T. Kramer	Volume 1
20:10:13:95		L-1	Working papers for adjusted taxes	T. Kramer	Volume 1
20:10:13:96	M		Overall cost of service	T. Kramer	Volume 1
20:10:13:97	N		Allocated cost of service	T. Kramer	Volume 1
20:10:13:98	O		Comparison of cost of service	M. Peppin	Volume 1
20:10:13:100	P		Fuel cost adjustment factor	T. Kramer	Volume 1
20:10:13:101	Q		Description of Utility Operations	L. McCarten	Volume 1
20:10:13:102	R		Purchases from affiliated companies	T. Kramer	Volume 1

Docket	Commission Order	Sponsoring Witness	Filing Location
EL09-009 Electric Rate Case	**Integrated Resource Plans--** Xcel Energy agrees to provide to the Commission the Company's Resource Plan (RP) filed with the Minnesota Public Utilities Commission (MPUC) for the integrated NSP System (Minnesota, Michigan, North Dakota, South Dakota and Wisconsin) at the same time the RP is filed with the MPUC. In addition to providing the RP to the Commission, the Company agrees to provide an alternative resource scenario that specifically meets, but does not exceed, combined Federal and South Dakota environmental and renewable requirements or objectives for the same time period addressed by the RP.	Complied	n/a
EL09-009 Electric Rate Case	**Curtailment-** The Company agrees to provide to the Commission copies of the monthly wind curtailment summary report filed in Minnesota showing actual total payments made for wind curtailment events separated into the following reason codes as identified in the Minnesota reports for wind curtailment: 1) Lack of firm transmission as described in Attachment C of the Midwest Independent System Operator (MISO) Open Access Transmission Tariff (ATC Constraint); 2) Low Load; 3) Transmission loading relief or MISO directive for reasons other than ATC Constraint; and 4) Other. This information will be submitted as confidential to Commission Staff. Additionally, the Company will provide Commission Staff a copy of the annual wind curtailment forecast filed with the MPUC.	Complied	n/a
EL09-009 Electric Rate Case	**Asset and Non-Asset based Margins-** South Dakota customers will be credited 100 percent of the jurisdictional portion of actual asset based margins and 25 percent of the jurisdictional share of non-asset based margins from intersystem sales as described in the Company's South Dakota Fuel lause Rider. For asset based margins sharing, the Company agrees a tracker will be developed and included in the monthly Fuel Clause Adjustment eports showing the monthly amount credited to South Dakota customers. The Company also agrees to establish a similar tracker for the nonasset based margins sharing credit. The retail share of the non-asset based margins will be computed annually after the close of the calendar year. The Company has agreed to provide both a fully allocated cost study and an incremental cost study showing the costs incurred to realize non-asset based margins.	Kramer	Volume 2
EL09-009 Electric Rate Case	**Shifts in Methods of Cost Recovery-** The Company will move into base rates all projects previously approved by the Commission for recovery under the TCR and ECR Riders. These shifts in cost recovery result in no material impact to ratepayers. Approximately $1.2 million previously collected in the TCR Rider and approximately $1.7 million previously collected in the ECR Rider will now be collected in base rates.	Kramer	Volume 2
EL09-009 Electric Rate Case	**Depreciation of Prairie Island Nuclear Generating Plant-** The Parties agree that the recognized depreciable remaining life for Prairie Island will be extended by 20 years over the current license life effective January 1,2010, to match the 20-year operating life extension that the Company has applied for at the Nuclear Regulatory Commission (NRC). If the NRC denies the requested life extension, the Company is entitled to recover costs that have been foregone by the implementation of the 20-year life extension in this proceeding.	Kramer	Volume 2
EL09-009 Electric Rate Case	**Amortization-** TheParties agree that amortizations being recovered in rates under the terms of the Settlement Stipulation include the following where the cost will be deferred and amortized over the periods shown: a. Private Fuel Storage (PFS) The Parties agree that the PFS deferred balance of $1,010,000 is to be amortized over six (6) years in an amount of $168,000 annually. Further, the Parties agree that the average unamortized balance of $505,000 will be included as a component of other rate base. b. Rate Case Expenses The Parties agree that the Rate Case deferred balance of $268,099 is to be amortized over five (5) years in an amount of $54,000 annually. Further, the Parties agree that the average unamortized balance of $134,000 will be included as a component of other rate base. c. S02 Emission Allowance Sales The Parties agree that the S02 Emission Allowance Sales deferred balance of negative (-) $219,000 is to be amortized over five (5) years in the amount of negative (-) $44,000 annually. Further, the Parties agree that the average unamortized balance of negative (-) $110,000 will be included as a component of other rate base. The Parties also agree to an annual S02 Emission Allowance Sales a most recent five (5) year average of emission allowance sales.	Amortization periods reflected in 2010 actuals, Kramer	Volume 2
EL09-009 Electric Rate Case	**Renewable Development Fund (RDF)**- The costs were denied	n/a	n/a