Direct Testimony and Schedules
Laura McCarten

Before the South Dakota Public Utilities Commission
State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in South Dakota

Docket No. EL14-___
Exhibit___(LM-1)

Policy Testimony

June 23, 2014

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Schedules

I. INTRODUCTION

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, and media relations activities in South Dakota and North Dakota, and for legislative and media relations in Minnesota. I provide strategic leadership regarding the development and implementation of our initiatives to most effectively serve our retail customers and communities. My resume 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 and key factors driving this request and the importance of earning a reasonable return in this jurisdiction. 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;
- Revenue Requirements;
- Service to our Customers;
- Managing Costs;
- 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 reviewed all South Dakota Public Utilities Commission Rules and Orders from previous electric rate cases and other dockets to ensure we have complied with all requirements. My Exhibit___ (LM-1), Schedule 2, 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 DESCRIBE NSPM.

A. We provide safe, reliable, and clean energy at a competitive price to more than 1.4 million electricity customers in South Dakota, North Dakota, and Minnesota. NSPM is part of an integrated system of generation and transmission that serves the upper Midwest, including Xcel Energy's operations in Wisconsin and Michigan served by NSP-Wisconsin (collectively, the NSP System). Our combined system operations include power plants with a net maximum capacity of over 8,300 MW, more than 7,300 miles of transmission lines, and approximately 550 transmission and distribution substations.

The NSP System includes approximately 2,500 MW of renewable energy capacity, including wind, hydro, biomass, and solar resources. In addition, we will add 750 MW of wind power capacity to the NSP System by the end of 2015.

Q. DO YOU BELIEVE XCEL ENERGY'S INTEGRATED SYSTEM 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. PLEASE SUMMARIZE THE COMPANY'S REQUEST IN THIS PROCEEDING.

A. The Company is seeking to recover the costs of the investments we are making in our system to continue to meet our customers' needs and expectations for safe and reliable electric service. These investments are in our customers' interests, both in the near term and the long term, as reliable electric service is one of the highest priorities for our customers and vital to support a strong, growing economy.

In this case, Xcel Energy seeks authority from the Commission to increase our new incremental electric retail revenues by $15.6 million, or 8 percent. We base this request on a historical 2013 test year, adjusted for known and measurable changes over a 24-month period as allowed by the Commission's rules. The proposed revenue requirement reflects a return on equity (ROE) of 10.25 percent. Under our proposal, a residential customer using 750 kWh per month would see a monthly bill increase of about $8.49 per month or 9.71 percent.

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

A. Additional rate relief is necessary to recover the costs of long-term capital projects either already in-service or under construction, and to recover increases in operations and maintenance costs to ensure our plants and equipment are properly maintained. Our request includes investments associated with safe operations of our nuclear fleet as well as continued efforts to use cost-effective renewable resources on behalf of our customers.

We are still in a period of elevated system investment, reflective of the cyclical nature of refurbishment needs for utility infrastructure. This investment cycle has contributed to our need to file four rate cases in the past six years. In this case, we hope to establish a constructive outcome that advances our ability to plan for and invest in the long-term needs of our system while also ensuring that the impact of these investments is reasonable for our customers. As discussed in section VII of my testimony, a multi-year plan could be developed to help moderate rate impacts to customers while providing the financial resources needed to support the Company's investments.

In addition, it is important to earn a reasonable ROE in this jurisdiction.

Q. IS THE COMPANY CURRENTLY EARNING ITS LAST-AUTHORIZED ROE?

A. No. While the Company continues to manage costs, as discussed further below, the need for continued investment over a multi-year period, at a time of minimal sales growth creates a cycle of revenue deficiencies, which has required frequent rate cases. However, the allowed outcomes have not resulted in a reasonable opportunity to earn the authorized ROE. To illustrate, in 2011, our South Dakota actual weather normalized ROE was 3.9 percent; in 2012, it was 4.86 percent; and in 2013, it was 7.28 percent, an improvement resulting from our most recent rate case (Docket No. EL12-046). These returns are all significantly below the Commission-authorized returns.

Q. How does this case compare to your most recent rate case?

A. In many ways, this case is similar to our last case. We are continuing investments in our nuclear fleet to support continued operation through their extended license periods, in our coal plants to meet operational and regulatory requirements, and in our transmission and distribution infrastructure to improve reliability and capacity. Similarly, our investments in renewable energy will reduce customer costs and provide a hedge against future environmental regulation.

In addition, as with our last rate case, the slow sales growth combined with a peak period of investment means we cannot rely on sales revenue to keep pace with our investments and the rising costs of running our business.

Q. Recent news headlines suggest that the South Dakota economy is booming. Is this Xcel Energy's experience as well?

A. No. While there is significant new construction in South Dakota, we are not seeing corresponding increases in our sales. Some of the new customer base is being served by local cooperatives rather than Xcel Energy. In addition, improvements in energy efficiency and losses of load for some customers mitigate any sales growth. Our 2013 weather normalized sales increased 0.6 percent, compared to 0.3 percent in 2012, and 0.5 percent in 2011. This small level of electricity sales growth is not sufficient to support cost recovery of our investments, and so we must request a rate increase.

Q. Why is the Company continuing to invest in a slow sales environment?

A. As a regulated electric utility, we must manage our business for the short- and long-term benefit of our customers. We must make investments in the infrastructure necessary to provide service to our customers and fulfill our obligations to provide safe and reliable electric service even when sales growth cannot offset the additional costs associated with these investments.

Q. IS THIS FILING CONSISTENT WITH THE TERMS OF THE SETTLEMENT IN YOUR MOST RECENT RATE CASE AND COMMISSION POLICY?

A. Yes. In our last case (Docket No. EL12-046), we agreed not to file a request for an increase in base rates with an effective date prior to January 1, 2015; we will not implement our proposed rate increase in this case prior to that date. Also as part of that settlement, the Commission approved an Infrastructure Rider to allow the Company to recover the costs of discrete capital projects and to true up the costs included in that rider on an annual basis. The terms of the settlement anticipated that those projects would be moved into base rates in a subsequent rate case. Consistent with those terms, $8.481 million in costs currently being recovered through the Infrastructure Rider will be moved into base rates in this rate case.

Similarly, and consistent with Commission policy, we will also be rolling $558,000 for six projects from the Transmission Cost Recovery (TCR) Rider into base rates. As discussed in more detail by Company witness Mr. Charles R. Burdick, since the Infrastructure Rider and TCR Rider costs are already being collected, moving them into base rates is revenue neutral to both our customers and the Company.

Q. DOES THE COMPANY CONSIDER THE IMPACTS TO RATEPAYERS IN DEVELOPING ITS CAPITAL INVESTMENT STRATEGY?

A. We recognize the cost impact that these investments have on our customers and consider rate impacts when making these investments. However, as we discussed in our last case, much of our system is aging and we are continuing on our several-year cycle of refreshing and rebuilding our aging infrastructure to ensure reliable and cost-effective operations for our customers for the long-term.

As with our prior rate cases, we intend to work with the Commission and staff to moderate the cost impact of these investments and to help mitigate the frequency of future rate requests. For example, in our last case, the Commission approved the use of the Infrastructure Rider to allow the Company to recover the costs of its investments outside of base rate increases. Company Witness Mr. Burdick discusses the Company's alternative proposal to continue the Infrastructure Rider to recover the 2015 known and measurable cost for capital projects and property taxes. In addition, as I discuss in section VII of my testimony, a multi-year plan may be developed in the course of this proceeding to help moderate rate impacts to customers over a multi-year period.

III. CASE DRIVERS

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

A. Table 1 provides an overview of the major drivers for this rate increase request:

Table 1: Major Cost Drivers

2013 Test Year with 24 months Known and Measurable

Plant Related	$19.1	
Monticello EPU		2.8
Prairie Island Steam Generator		1.8
Other Nuclear Plant		3.9
Border Winds		0.6
Pleasant Valley Wind		0.8
Other Production		0.6
Transmission Capital		0.8
Distribution Capital		1.1
Common and General Capital (IT)		1.6
Property Taxes		3.5
Cap Structure		1.7
Other Rate Base		(0.1)
O&M	$6.0	
Nuclear O&M		1.8
Nuclear Outage Amortization		0.7
Transmission		0.3
Distribution		1.0
Pension and Insurance		0.7
IT		0.5
A&G and Other O&M		0.9
Net Other	($0.5)	
Less Amounts Currently Recovered Through Riders	($9.0)	
Deficiency, Net of Currently Collected Revenues	$15.6	

Infrastructure investments account for approximately 78 percent ($19.1 million) of the overall deficiency ($24.6 million, including $9.0 million currently recovered through riders), with nuclear capital and O&M costs alone comprising 45 percent ($11.0 million) of the overall increase. These cost drivers are further discussed in the Direct Testimony of Mr. Burdick.

A. Infrastructure

Q. YOU INDICATED THAT INFRASTRUCTURE INVESTMENTS ARE A KEY DRIVER OF THIS CASE. WHAT TYPES OF CAPITAL INVESTMENTS ARE PLANNED?

A. Since the last rate filing, we have implemented upgrades at our nuclear facilities, the Sherburne County generating facility Unit 3, the Black Dog generating station, and others.

The Company has continued a systematic program of capital investment in Monticello and Prairie Island to ensure safe and reliable operation. Such investment cannot be delayed or deferred, as the investments are required as part of our operating license renewals. The Monticello Lifecycle Management and Extended Power Uprate project, which was completed in 2013, will support continued operations at the plant through 2030, provide improved reliability and safety margins, and help mitigate future O&M increases. The replacement of Unit 2 steam generators at Prairie Island was completed in 2013 and will support operation through the license renewal period. In addition, we had numerous other capital projects going into service in 2013 to support continued operations and address new regulatory requirements, particularly in light of the events at the Fukushima Daiichi plant in Japan. These investments are further described in the Direct Testimony of Mr. Burdick.

The investments in our non-nuclear generation facilities and in the transmission and distribution systems are part of a long-term plan to refresh our system and accommodate evolving technologies, regulatory requirements, and customer needs, while ensuring continued system reliability. These efforts to keep our existing assets operating reliably and in compliance with regulatory requirements are a major focus of our investment strategy as many of our electric assets are 30-50 years old or older.

Q. CAN THE COMPANY POSTPONE SOME OF THIS CAPITAL WORK TO MITIGATE THE IMPACTS TO CUSTOMERS?

A. The Company continually assesses its infrastructure needs to determine the most cost-effective path to maintaining a reliable system. The completed and planned investments reflected in this rate request are those we have determined are necessary at this time. As noted above, many of the investments included in this case are related to our nuclear facilities. As part of the Nuclear Regulatory Commission's (NRC) review of our extended operating licenses, the Company and the NRC agreed to numerous commitments and improvements to ensure that the plants remained safe and reliable through the extended license periods. In addition, the environment today is much different than it was in the past and our work to maintain compliance in an every-changing regulatory environment has resulted in significant investments in capital, as well as O&M.

Q. DO THESE INVESTMENTS GO BEYOND GENERATION, DISTRIBUTION AND TRANSMISSION NEEDS?

A. Yes. In addition to refreshing our external systems, we have internal information technology investments that are needed to address evolving cyber security threats and requirements.

For example, to meet the needs and demands of today's security requirements and ensure the availability, integrity, and confidentiality of our information systems, we have had to implement multiple corporate security systems and technologies. The technologies implemented to date include: security forensic tools, intrusion prevention devices, data loss prevention software, and a security incident and event management system.

Further, our nuclear facilities have had to make considerable capital investments to comply with new regulations establishing cyber security requirements for digital computer and communication networks at nuclear plants.

Q. DO THESE INFRASTRUCTURE INVESTMENTS ADDRESS LOCALIZED CAPACITY AND GROWTH NEEDS?

A. Yes, our investment plan also addresses the service reliability and growth needs in our South Dakota service territory. We need to invest in new transmission and distribution infrastructure in order to refresh aging system components and to expand system capabilities, so that we can serve current customer needs and prepare for future growth and connection to power generation sources.

One specific example of these types of investments is the project to upgrade a portion of the 69 kV transmission line that runs between the Lawrence

Substation in Brandon to the West Sioux Falls Substation on the northern side of Sioux Falls. A portion of this transmission line will be upgraded to 115 kV to enhance contingency planning, improve reliability, and support customer demand.

A related distribution-level project is the construction of a new Falls Substation on the old Sioux Falls stockyards property. The segment of upgraded transmission line noted in the preceding paragraph runs adjacent to the existing Sioux Falls Substation by Falls Park. However, this existing substation is no longer adequate to meet current customer needs or future transmission needs, and it is not feasible to expand and upgrade this substation. Therefore, we plan to build a new Falls Substation on the old stockyards property, near the existing Sioux Falls Substation site. The customer load will be transferred from the Sioux Falls Substation to the new Falls Substation, and the old substation will be taken out of service and dismantled.

We planned these projects in phases in order to avoid disruption of service during construction and the ability to transfer load from the old to the new substation without disrupting service.

When these projects are complete, in 2015, we will have additional capacity to allow better, more reliable service to downtown Sioux Falls and the surrounding area.

Q. HOW WILL THESE INFRASTRUCTURE INVESTMENTS BENEFIT YOUR SOUTH DAKOTA CUSTOMERS?

A. These investments support safe, reliable service to our South Dakota customers. Maintaining and improving the operational characteristics of our system improves operational efficiency, reduces unplanned outages, and ultimately keeps costs low for customers.

In addition, all of our customers benefit by our planning and operation of an integrated system. Company assets needed to provide service to our South Dakota customers are part of a larger, interconnected network of assets owned by the Company and NSPW. Connection with this larger, regional network allows us to plan and operate our entire five-state system on an integrated basis.

Q. PLEASE EXPLAIN THE COMPANY'S RENEWABLES INVESTMENTS.

A. The Company anticipates adding two new wind facilities to rate base at the end of 2015, and to purchase the output from two other new wind facilities through power purchase arrangements. These facilities were selected as part of an extensive competitive bidding process in 2013 and will allow the Company to maintain compliance with the renewable objectives and standards in all of the jurisdictions, lower costs for customers long-term, and help protect customers from potential risks, including higher fossil fuel prices and carbon regulation.

B. Operations and Maintenance

Q. PLEASE EXPLAIN THE O&M INCREASES IN THIS CASE.

A. The Company has experienced growth in its O&M for this case over the last rate case. The primary reasons for this are increases in nuclear operations and maintenance expenses. As our nuclear facilities enter into their extended operating lives, the regulatory and operational requirements are fundamentally different than existed during the initial license periods. These new requirements, combined with new requirements resulting from the investigation into the disaster at the Fukushima Daiichi plant in Japan, have resulted increased O&M costs for these facilities. Other nuclear O&M increases result from additional security costs and nuclear fees.

Our nuclear outage expenses for 2012 and 2013 were higher due to longer than normal outages necessary to conduct extensive capital work simultaneously with the refueling work, performing periodic inspections, and to address emergent work.

Q. ARE THERE ANY OTHER REASONS FOR INCREASED O&M?

A. Yes. Additional increases in O&M largely fall into the following categories: nuclear, transmission, distribution, IT and pension. The nuclear O&M increases mostly stem from compliance with new regulatory requirements. The second largest increase relates to the distribution function and is driven by expenses related to storms, underground fault repairs, and O&M expense related to new capital projects. The increase in A&G and Other O&M can be attributed mainly to incentive pay and the known and measurable wage increases discussed in Mr. Burdick's Direct Testimony. Finally, pension costs are also contributing to the overall increase. The increase in pension costs is a function of accounting requirements to fund future obligations; there has not been any increase in employee benefits.

IV. SERVICE TO OUR CUSTOMERS

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. PLEASE PROVIDE AN EXAMPLE OF A TIME WHEN THE COMPANY HAS PROVIDED EXCELLENT SERVICE TO CUSTOMERS.

A. On April 9, 2013, the Sioux Falls area experienced a severe winter and ice storm that coated trees and power lines in a heavy layer of ice that ultimately resulted in about 53,600 customers experiencing one or more outages.

The impact of the storm was substantial. In some instances, the strong winds and weight of the ice brought down whole trees or large branches, denting vehicles, snapping utility poles, downing power lines, and making streets impassable. Meanwhile, adverse weather conditions continued and created new outages as crews worked to navigate the streets and fallen debris in dangerous conditions to restore service as quickly as possible.

In total, more than 380 distribution poles were replaced and 420 linemen from Xcel Energy, mutual aid utilities, and contractors worked 16-hour days to restore service to customers. All customers who were impacted, with the exception of those waiting for individual premise reconnection from electricians, were restored within four or five days.

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 79 and 94 minutes over the past five years, when normalized for storms.[1]

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 with Xcel Energy reported in these surveys for South Dakota customers has been at or above 94 percent. Further, over that same time frame, customers reported the overall value provided by Xcel Energy has been at or above 87 percent.

In addition, we track the number of Commission complaints initiated by our customers, and we track any customer contact with the Commission that identifies an instance when an internal business process or policy was not followed as we view those complaints as controllable and strive to continually review and identify those gaps. In 2013, there were just seven customer

[1] SAIDIs: 79.68 (2009); 80.56 (2010); 94.66 (2011); 82.68 (2012); 84.26 (2013)

contacts with Commission staff that fall within our controllable guidelines, compared to an average of 13 per year over the past five years.

Q. WHAT HAS THE COMPANY DONE TO HELP ITS CUSTOMERS REDUCE OR MANAGE THEIR ENERGY COSTS?

A. In January 2012, the Company launched a suite of conservation and load management programs designed to help business and residential customers save energy and money. For example, residential customers can receive cash rebates for ground source heat pumps and discounted prices for compact fluorescent bulbs at participating retailers. They can also receive bill discounts in exchange for allowing Xcel Energy to control central air conditioners and water heaters during times of peak demand. Business customers can receive cash rebates for installing more efficient lighting and bill discounts for curtailing load during peak times. Through these programs, participating customers realize significant bill savings; non-participants also benefit from the system savings and reduced emissions. Our conservation and load management programs can reduce the need for additional infrastructure and the use of our existing infrastructure, saving all customers money.

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

A. NSPM has been investing approximately $1 billion annually in our system for past several years, driving the need for frequent rate cases. While our electric rates in South Dakota may be higher now than some other utilities serving the region, we note that we are in the peak years of our infrastructure investment cycle and not all utilities are in the same phase of their investment plans. Our investments are not only needed to continue the level of service our customers expect, but many of these investments, such as our nuclear and wind projects, have positioned us well to mitigate price increases from future environmental regulations and increased fossil fuel prices.

While necessary infrastructure investments have put upward pressure on our rates, we still provide excellent value for our South Dakota customers, and our residential rates in the state are lower than the national average of approximately 12.21 cents per kWh.

V. REVENUE REQUIREMENTS

A. Test Year

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

A. The test year is 2013, adjusted to normalize the test year, properly reflect regulatory requirements, and account for appropriate known and measurable changes. As discussed by Mr. Burdick in his Direct Testimony, we include $4.2 million of incremental known and measurable changes for 24 months consistent with the Commission's rules. These incremental known and measurable changes include projects placed in service in 2014 or 2015 for the Monticello and Prairie Island Nuclear generating plants, Sherburne County and King generating facilities, and wind projects. It also includes other additional items such as property taxes.

Q. WAS THE COMPANY GRANTED ALL OF ITS KNOWN AND MEASURABLE CHANGES FOR 24 MONTHS FOR INCLUSION IN BASE RATES IN ITS LAST CASE?

A. No. The Company sought recovery of discrete known and measurable changes for a 24-month period after the end of the historical test year in our last case. As part of the settlement negotiated between the Company and the Commission staff, the Commission approved an Infrastructure Rider to allow a portion of our proposed project costs to be recovered from customers once they went into service.

Q. DOES THE COMPANY PROPOSE TO CONTINUE THE INFRASTRUCTURE RIDER IN THIS CASE?

A. The Infrastructure Rider was a tool used to recover the costs of several discreet projects in the last case. Because most of those projects are now in service, the Company proposes to move those costs currently being recovered through the Infrastructure Rider to now be recovered through base rates. However, the Infrastructure Rider was a useful tool and I discuss its potential continued use in Section VII below.

B. Rate of Return

Q. WHAT IS THE BASIS FOR THE COMPANY'S RECOMMENDED ROE OF 10.25 PERCENT?

A. Our proposed revenue requirement reflects an overall rate of return (ROR) on investment of 7.84 percent, based on an average common equity ratio of 53.86 percent and an ROE of 10.25 percent. Company witness Ms. Ann E. Bulkley provides a detailed analysis of the appropriate overall ROR and ROE for the Company.

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

A. Yes. An appropriate ROE and a supportive state regulatory framework are key contributors to our ability to raise significant capital at reasonable rates.

From 2005 through 2012, the Company invested approximately $7.6 billion in generation, transmission and distribution and expects to continue its relatively high level of investment with additional capital expenditures averaging slightly less than $1.2 billion per year from 2014 through 2017. We will need access to the capital markets to support this level of investment.

Given this magnitude of investment, we have a common interest with our regulators and customers in having the Commission set an appropriate ROE and allowing us 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.

C. Rate Design

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

A. The Company is not proposing significant changes to our current rate structures although we did make some refinements to improve the accuracy of class cost allocation to better reflect cost responsibility. We are proposing only those changes necessary to implement the proposed pro forma revenue requirements. The Direct Testimony of Company witness Mr. James P. Gilroy discusses these changes.

VI. MANAGING COSTS

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

A. The Company has worked diligently to reduce and control our costs in an effort to minimize our request for a rate increase, including the following actions:

- Limited the rate of medical cost increases by increased employee cost-sharing requirements, benefit reductions and renegotiation of vendor contracts;
- Set aggressive targets for business units to further limit O&M expenses;
- Deployed new technologies to gain operational efficiency and reduce costs;
- Reduced travel and employee expenses by implementing new procedures and limitations; and
- Controlled supply chain costs by forming strategic supplier relationships.

Q. PLEASE DESCRIBE SOME OF THESE COST MITIGATION EFFORTS IN MORE DETAIL.

A. In response to increasing costs and slow sales growth over the past several years, Xcel Energy Inc. and the NSP Companies have implemented aggressive cost control efforts to minimize the size of rate increases while continuing our efforts to provide quality service to our customers. Below I highlight seven of our cost management efforts:

1. *Master Services Agreement Initiative-* This program within our Energy Supply business unit seeks to reduce costs through volume purchasing, decrease overall service agreement transactions, and streamline contractual terms across individual plants and business units.

We estimate that the process of acquiring bids and negotiating longer-term contracts results in a cost reduction of two to seven percent for labor, materials, and equipment.

2. *Combustion Turbine Parts Exchange Program-* This industry-leading initiative focuses on reducing the expenses associated with the operation of our 20 natural gas-fired generating units and aims for better spare part pricing, reduced ownership costs, and fewer overhauls.

Among other benefits, our initial forecasted savings, excluding reduced inventory costs, is approximately $29 million over the next 10 years across Xcel Energy's fleet.

3. *Chemicals Supply Contract Program-* Through this program, the Company has re-negotiated or re-bid many of the contracts for the large quantity of chemicals used in our plants to reduce emissions and treat water.

These negotiation efforts have positioned us well for years to come as we have been able to re-negotiate many of our rates below market prices on a long-term basis.

4. IBM Contract Renegotiation - We renegotiated our contract with IBM for application and infrastructure support.

During this renegotiation, we were able to extend our contract with IBM from September 2015 to June 2019 and obtained expected cost savings of approximately $56 million over the next four years for Xcel Energy.

5. Strategic Sourcing Initiative- Our marketing and sourcing business units combined efforts to manage our demand-side management (DSM) projects which involved improving internal processes, consolidating suppliers, and taking advantage of competition between third-party suppliers.

Despite the fact that our DSM program is growing, we currently estimate that we could save $5 million in 2014 due to this initiative.

6. Materials Management- Our transmission and substation team have analyzed materials and processes used across Xcel Energy and identified opportunities to enhance efficiencies. The team brought forth several cost saving measures, including methods to effectively identify and use stranded materials, reduce overstocking of materials, and increase buying power.

This collaborative effort has achieved nearly $2.25 million in cost-savings over the past three years for Xcel Energy.

7. Nuclear Cost- Saving Efforts- Our nuclear facilities recently received an award in recognition of the fleet's efforts that saved $6.6 million in 2013. The savings are a result of coordinated contracts and various projects and programs including (1) Fukushima response savings related to contracting with other operators with common vendors, (2) in-processing for outages saving time and sharing best practices with other facilities, and (3) a safety culture assessment program.

VII. INFRASTRUCTURE RIDER

Q. PLEASE DESCRIBE THE EXISTING INFRASTRUCTURE RIDER.

A. The Infrastructure Rider is a useful tool that the Commission approved in our last rate case to address the Company's need to recover the costs of its investments and Commission Staff's concern that some projects proposed to be placed in-service late in the 24-month period may not be completed in the planned timeframe.

Q. DOES THE COMPANY PROPOSE TO CONTINUE THE INFRASTRUCTURE RIDER IN THIS CASE?

A. Because there are several projects included in our known and measurable changes in this case, we look forward to a constructive dialogue with Commission staff to potentially continue the use of this ratemaking tool for recovery of costs of new projects going into service in 2015, property taxes and other costs as appropriate. Recovery of costs through the Infrastructure Rider provides assurance to our customers that only those costs that are incurred will flow through the Rider, and provides the Commission an ongoing opportunity to review these costs in the established annual true-up process.

Q. COULD THE INFRASTRUCTURE RIDER BE USED TO RECOVER CATEGORIES OF COSTS NOT PRESENTLY IDENTIFIED IN THIS CASE?

A. Yes. We believe that the Infrastructure Rider may be continued and could be drafted to allow the addition of future infrastructure investments not presently included as known and measurable adjustments in this case. For example, between 2013 and 2015, the Company will experience a $2.3 million increase in Transmission Interchange costs on a South Dakota jurisdictional basis. These are costs for major NSP System transmission network upgrades that are owned by NSP-Wisconsin and then approximately 85% of those costs are shared with NSP-Minnesota through the Interchange Agreement. These major network upgrades enhance the transmission of electricity throughout the Upper Midwest region and therefore enhance reliability to South Dakota customers. We did not include these as a known and measurable 2015 adjustment at this time. However, the costs will be incurred in 2015 and may be appropriate for inclusion in an Infrastructure Rider or, in the alternative, could be included in base rates or the Transmission Cost Recovery rider. The Company will discuss this issue with Commission Staff as the case proceeds.

Q. DOES THE COMPANY SEE A POTENTIAL FOR A LONGER-TERM SOLUTION?

A. Yes. As I stated earlier in my testimony, we hope to establish a constructive outcome that advances our ability to plan for and invest in the long-term needs of our system while also ensuring that the impact of these investments is reasonable for our customers.

We believe a multi-year plan can be developed that moderates rate impacts while providing the financial resources needed to support the Company's infrastructure investments. A multiyear plan that covers several years can maintain intergenerational equity among rate payers receiving service during the term of the plan and also provide a predictable level of rate support that matches the most significant remaining years of the Company's infrastructure investment cycle. In addition, protective mechanisms may be included in any multi-year plan. For example, our current Infrastructure Rider includes a true-up process. A multiyear plan could also include true-up mechanisms or other preset audit provisions to assure that rates matched costs actually incurred.

Q. DOES THE COMMISSION HAVE AUTHORITY TO APPROVE A MULTI-YEAR PLAN?

A. Yes. A multiyear plan is within the scope and intent of the Commission's general authority regarding setting utility rates and is consistent with the intent of the 2012 legislation authorizing the Commission to implement Rate Phase-in Plans.

VIII. 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:

- *Charles R. Burdick,* who sponsors the overall revenue requirement for the rate case. Mr. Burdick sponsors the schedules supporting our income statement, rate base, revenue deficiency, and jurisdictional allocations.
- *Ann E. Bulkley,* of Concentric Energy Advisors, who sponsors testimony on the ROE and ROR, including, capital structure, and the cost of debt.
- *James P. Gilroy*, who sponsors our class cost of service study and tariff changes.

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

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This case requests the rate relief necessary to preserve system safety and reliability, both now and in the future. More specifically, this case is needed to allow recovery of:

- The costs of extending the life of our nuclear fleet and increasing power output at our Monticello nuclear plant;
- Other capital investment to support our business and keep our core plants, substations, poles and wires operating reliably for the future; and
- Increases in the cost of doing business.

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

A. We respectfully request that the Commission approve:

- Our requested rates that provide a net incremental increase of $15.6 million in revenues;
- An overall ROR on investment of 7.84 percent, based on an average common equity ratio of 53.86 percent and an ROE of 10.25 percent; and
- Our proposed rate design and tariffs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.