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Direct Testimony and Schedules
Timothy J. O'Connor

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-15-826
Exhibit___(TJO-1)

Nuclear Operations

November 2, 2015

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Timothy J. O'Connor. I am the Chief Nuclear Officer for Northern States Power Company, a Minnesota Corporation (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy). I am responsible for all nuclear activities in Minnesota at the Monticello and Prairie Island Nuclear Generating Plants.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 30 years of experience in the nuclear industry, including a diverse background in operations, maintenance, and engineering at both boiling and pressurized water reactors. Before joining Xcel Energy in 2007, I held a number of positions with increasing responsibility at Constellation Energy Group's Nine Mile Point station in New York, Public Service Enterprise Group's (PSEG) Hope Creek and Salem plants, and Exelon's LaSalle, Dresden, and Zion plants. My resume is attached as Exhibit___(TJO-1), Schedule 1.

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

A. The purpose of my testimony is to present and support the Company's capital and operation and maintenance (O&M) budgets for the Nuclear Operations business area, for purposes of determining electric revenue requirements and final rates in this proceeding.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. This case and our pending 2015-2030 Upper Midwest Resource Plan present important questions for the Minnesota Public Utilities Commission with respect to the future of Xcel Energy's nuclear generation. For more than 40 years, our Monticello Nuclear Generating Plant (Monticello) and our Prairie Island Nuclear Generating Plant Units 1 and 2 (Prairie Island) have provided 1,700 reliable MW electric (MWe or MW) of clean energy. Together these generation stations provide dependable baseload power to more than one million customer homes. Our recent investments in Monticello provide an additional 71 MW for customer use, while further extending the life of the plant to 2030 on a cost-effective basis.

In addition, safe, reliable, and carbon-free nuclear energy is critical to the Company's and the State's goals of supporting a more environmentally secure future, pending federal regulations, and existing State policy. The recently announced Clean Power Plan regulations demonstrate the fundamental value of our nuclear fleet. The jobs and economic benefits of these facilities, as well as their value in diversifying our fuel sources, provide further benefits to the Company and our customers.

At the same time that nuclear power presents both important energy resources and opportunities for the future, maintaining a fleet of nuclear power plants presents unique requirements, such as specialized safety needs and a very high level of regulatory oversight. Many of these issues were discussed in our most recent past rate case. As we discussed at that time, safety is the Company's first priority for nuclear generation, and is an ever-present consideration in any investment we make. In light of the 2011 incident at Fukushima Daichii, the

Nuclear Regulatory Commission (NRC) and the Institute of Nuclear Power Operations (INPO) have not only added regulations, standards, and fees that require additional investments in our plants, but also increased day-to-day regulatory oversight that increases the cost of sustaining nuclear power generation. The steps we have taken – including our recent 3:2:1 performance improvement initiative – have proven successful, as effective October 1, 2015 all three of our nuclear units were in the NRC's Column 1, the highest level of safety in their Reactor Oversight Process.[1] Operating in Column 1 is also significant for customers from a cost management perspective, because at that level the NRC requires the fewest inspections.

Our goals focus not only on meeting mandated requirements, but also on performance excellence. As discussed in our last rate case, the Company has moved strategically to improve equipment, improve human performance, maintain strong relationships with INPO and the NRC, and bring our plants into top quartile performance. We have added employees that are not only helping us meet our performance goals, but also reduce the cost of and reliance on external vendors. In light of these efforts, we have continued to see improvement in INPO's measures for tracking operational performance – the INPO index and the INPO Plant Performance Index – which I discuss later in my testimony. Now that we have increased our staffing and set up organizations to meet our ongoing needs and demands, we are also managing our O&M expenses to lower the rate of year-over-year growth that we have experienced in recent years.

[1] See Exhibit___(TJO-1), Schedule 12, which includes a summary of the NRC's Reactor Oversight Process and the columns used to rank safety performance of nuclear units.

To maintain healthy nuclear power plants and performance excellence, we must also address reliability of our aging equipment. Our recent Life Cycle Management/Extended Power Uprate (LCM/EPU) program at Monticello was a lengthy, difficult project for many reasons, including industry labor challenges, impacts of increased NRC oversight and requirements, and complexities of replacing the aging equipment of an existing plant. While we have cancelled our uprate for Prairie Island, the systems at that plant are also aging and will need attention in the coming years to continue reliable operations through Prairie Island's existing license period. The NRC's aging management program requires monitoring and planning for upgrades to refurbish equipment to "like new" condition or replace it. Some of those investments are discussed in this case, while others are on the longer-term horizon.

As we continually review the value of our nuclear generation at the Company, we see a theme emerging: While nuclear energy requires federal oversight and Company capital investments unique to this kind of generation, nuclear energy also provides an important quantity of reliable, clean, and safe electricity. As we look to the future, we need to make sure there is alignment between the value the Commission places on nuclear energy and the amount of capital we as a utility must invest in it.

My Direct Testimony outlines both the benefits of nuclear energy and the considerations and challenges the nuclear industry faces in the coming years. After discussing these issues and the purpose and mission of Xcel Energy's Nuclear Operations Business Unit (Nuclear), I discuss our current capital investment plan for the coming years, why the level of capital we propose to

invest in our nuclear plants is reasonable, and the kinds of projects that we plan to undertake. I illustrate in detail that we are making the right kind of smart investments in our nuclear facilities; balancing the need for safety and our obligation to manage to regulatory requirements with customers' interests in cost-effective energy.

Next, I discuss in detail the level of non-outage and then outage O&M expenses that we expect to incur in 2016, and again explain why it is necessary and wise to support this level of O&M costs. I address our overall maintenance plans and our upcoming planned outages, supporting the need for those efforts and the basis for our cost estimates to complete them.

Finally, I address the Commission's requirement that the Company must justify the Key Performance Indicators (KPIs) that form the basis of our incentive compensation to employees. I illustrate that our KPIs are appropriately challenging and developed to result in customer benefits.

Overall, the Company recognizes both the challenges and the opportunities inherent in nuclear energy. We are continually and appropriately calibrating our work in Nuclear to find the balance between regulatory expectation, plant safety and reliability needs, and cost. As discussed in my Testimony, our anticipated capital and O&M levels are reasonable and reflect an equitable balance between these considerations, and support rate recovery in this case.

Q. DO YOU PROVIDE ANY ADDITIONAL INFORMATION RELATED TO THE NUCLEAR OPERATIONS FUNCTION?

A. Yes. To prepare testimony for this case, we reviewed the discovery related to nuclear operations from the 2014 multi-year rate case. We incorporated some of this discovery into my testimony through expanded discussions and schedules. Appendix A also provides a list of relevant information requests from the Company's last rate cases in Docket Nos. E002/GR-12-961 and E002/GR-13-868, and indicates whether the responsive information is included in my testimony or schedules, or if it is provided in Appendix A. Where information was requested for a particular historical timeframe in the last case, the Company has provided information for an updated, comparable timeframe in relation to the filing date of this case.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. I first describe our current nuclear operations. I then describe our capital additions impacting 2016, 2017, and 2018, followed by a detailed description of our 2016 O&M expenses, and an overview of our 2017 and 2018 O&M expenses.

- *Section II* – Nuclear Operations Overview
- *Section III* – Capital Investments
- *Section IV* – Non-Outage O&M Budget
- *Section V* – Planned Outage O&M Budget
- *Section VI* – Completeness Information
- *Section VII* – Conclusion

II. NUCLEAR OPERATIONS OVERVIEW

A. Overview and Value Proposition

Q. PLEASE DESCRIBE XCEL ENERGY'S CORE 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 is a single-unit boiling water reactor rated for gross output at 671 MW, and was originally licensed by the Nuclear Regulatory Commission (NRC) in 1970. The NRC approved a renewed license for the facility in 2006, allowing the plant to operate through 2030. The Company recently completed the Life Cycle Management/Extended Power Uprate Project at Monticello, which added 71 MW of capacity (for a total of 671 MW) and supports continued operations through the extended license period.

Prairie Island is a two-unit pressurized water reactor, with each unit rated at 550 MW gross output capacity. The NRC licensed Prairie Island's two units in 1973 and 1974, respectively. The initial operating licenses were set to expire in 2013 and 2014. In 2011, the NRC approved renewed licenses for Prairie Island Units 1 and 2, extending their operating lives until 2033 and 2034.

In addition to NRC oversight, the Minnesota Public Utilities Commission (Commission) has also overseen proceedings in which the Company's investments and plans for Monticello and Prairie Island are reviewed.

Q. PLEASE DESCRIBE THE TOP PRIORITIES OF THE NUCLEAR ORGANIZATION.

A. Our top priority is operating at the industry's highest standards for safety and reliability. From a Company perspective, we also recognize that Nuclear needs to serve the overall Xcel Energy mission to provide our customers the safe, clean, reliable energy services they want and value at a competitive price.

Our mission in Nuclear is to foster a learning environment that promotes safe operations, continually raises operational performance to standards of excellence, promotes accountability for strong financial stewardship, and demonstrates leadership within the nuclear industry and the communities we serve. Nuclear is well aligned with Xcel Energy's mission given our focus on safety, our carbon-free energy, our plants providing output at 85-90 percent of capacity to serve base-load customers, and our efforts to hold our cost growth to a minimum, as discussed later in my testimony.

Q. GIVEN SOME OF THE COSTS SPECIFIC TO NUCLEAR, WHAT IS THE VALUE PROPOSITION FOR NUCLEAR FROM A CUSTOMER PERSPECTIVE?

A. We acknowledge that our nuclear cost structure contains some expenditures and investments that other generation sources do not have. However, customers receive considerable value for these incremental costs in the form of large quantities of reliable baseload energy, clean emissions, fuel diversity, cost-effective electricity, and jobs and economic development.

With renewable energy a growing priority in Minnesota and across the U.S., Nuclear offers more than 1700 megawatts of carbon-free generating capacity. In 2014, Nuclear provided almost 30 percent of the generation used by the NSP system in the upper Midwest, and nearly 21 percent of the State's

electricity with no greenhouse gas/carbon footprint. See Exhibit___(TJO-1), Schedule 2, which includes the latest Nuclear Energy Institute report on Nuclear Energy in Minnesota. Nuclear energy powers over one million households in our service territory.

Reliable Baseload Energy – Nuclear is a critical baseload generation source for NSP customers, generally running at 85-90 percent of its output capacity year after year. No other generation source is as reliable as Nuclear, as nuclear plants are designed to run at this output level, while other resource options are not. Nuclear generation provides the constant baseload output to which our system adds coal, gas and renewable energy as customer load varies.

As an example, during the three summer months of 2014, when NSPM system demand and peak load was at its highest, all three Company nuclear units ran at a combined 95 percent of output capacity, ensuring the reliable delivery of power to our customers. Similarly, for the first three months in 2015 (July-September), that Monticello had NRC approval to operate at full EPU power of 671 MWe the three Company nuclear units ran at a combined 96 percent of output capacity.

Clean Energy – Nuclear is a key element in the Company meeting the carbon reduction goals set by the state. Nuclear energy produces nearly 56 percent of Minnesota's emission-free electricity, and is unique in that it can do so virtually around the clock; see Schedule 2. As such, it is estimated that in 2014 Minnesota's nuclear facilities prevented the emission of 22 thousand tons of sulfur dioxide, 13.6 thousand tons of nitrogen oxides and 12.6 million metric tons of carbon dioxide. See Schedule 2, which includes NEI's summary of

emissions avoided in 2014 by the U.S. nuclear industry. And as public policy evolves toward the shutdown of coal plants due to carbon emissions, the value of nuclear energy becomes even higher.

Fuel Diversity – The Company's nuclear power plants provide the Company and its customers a hedge against changes in resource availability, fossil fuel prices, and future emissions regulations. Our nuclear units use a steadily available fuel at a consistent cost per MWh. The fuel assemblies in each nuclear unit's reactor contain the equivalent energy of approximately six million tons of coal used to produce electricity.

Cost-effective Resource – Even with recent investments to increase the output and extend the life of the Monticello nuclear plant to 2030, our Monticello plant continues to be cost-effective on the whole. As a general matter, the Company's nuclear energy provides our customers with cost-effective baseload electricity that is not easily replaced.

Jobs and Economic Development – The Nuclear Energy Institute estimates that "[m]ore than $315 million of materials, services and fuel for the nuclear energy industry are purchased annually from more than 1,150 Minnesota companies. Global and domestic growth in the nuclear energy industry each year adds thousands of high-paying, long-term jobs for American workers," see Schedule 2. As we noted in our last rate case, Xcel Energy currently has about 1400 employees working in or directly supporting our Nuclear business area.

B. Update from Prior Rate Case

Q. PLEASE REVIEW NUCLEAR'S STRATEGIES AS COMMUNICATED IN THE LAST RATE CASE.

A. In our last rate case, we discussed the following strategies related to resources and funding requested. In that case, we said Nuclear aimed to:

- Step change *plant performance* given industry demands (through our 3:2:1 program).
- Improve our *governance/oversight* structure to accommodate fleet performance versus just site performances independently.
- Work on our *staff succession/development plans* as a way to reduce the need for ongoing external hires for experience and retained knowledge.
- Improve *sourcing with fuel suppliers*, focusing on opportunities to lower our fuel costs on a per megawatt hour (MWh) basis.
- Focus on *shorter outages* to reduce not only outage expenses, but also improve fuel usage and increase our *output capability*.

Q. WHAT RESULTS HAVE BEEN ACHIEVED WITH RESPECT TO THESE STRATEGIES?

A. Since the Company's last rate case, the following results have been achieved for the strategies noted above:

- *Plant Performance* – The infrastructure we build today assures tomorrow's performance. We have changed performance on the regulatory front through improvements to our people, plants, and processes. All three units are back to NRC Column 1, and the inspection findings on human performance issues have been closed out by the NRC. That puts all our nuclear units back into normal oversight, which reduces the likelihood of additional inspections and findings that result in added costs and fees.

- *Governance /Oversight* – The revised governance structure we implemented has delivered fewer NRC findings and added to our level of regulatory margin (beyond minimal compliance). On the INPO front, our plants remain in good standing with the industry overall, in the upper two quartiles. Prairie Island had some challenges with equipment in the first half of 2015. However, those have been remediated and our plants have been extremely reliable in the summer for customers, and as NEI recently noted we had higher uprate capacity available at Monticello for most of the summer in 2015.
- *Staffing* – Our turnover and attrition have stabilized in the last few years due to our hiring efforts, and our succession plans are taking hold with replacements. This progress can be measured and tied to the result of our deployed strategies (and related costs).
- *Fuel Supply* – We have worked with fuel suppliers to restructure contracts and have delivered lower fuel costs that are showing up in the test year, as I discuss in more detail later in my testimony.
- *Outages/Output* – We have reduced the duration and cost of our planned refueling outages from the previous few years. We continue to focus on becoming more efficient and timely at outage management, and in doing so improve our competitive edge. We successfully obtained NRC approval of the final EPU levels at Monticello, which delivered higher output for the summer. Our plant equipment is working well and is very efficient when river temperatures fall below 78 degrees. Collectively, these results mean we are seeing increased outputs and related lower cost per MWh for customers, for carbon free energy.

C. Industry Developments

Q. PLEASE DESCRIBE RECENT NUCLEAR INDUSTRY DEVELOPMENTS THAT IMPACT NUCLEAR'S OPERATIONS, COSTS AND RESOURCE REQUIREMENTS.

A. We consider three recent industry developments to be especially impactful for purposes of this rate case: the extent of new NRC rulemaking, the heightened level of NRC inspections, and the success of industry group collaborations. I will discuss each of these in more detail.

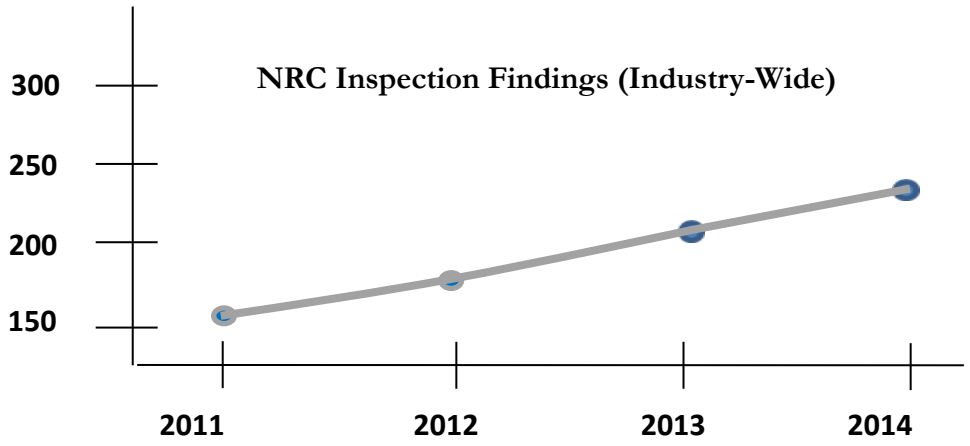
NRC Rulemaking & Impacts – It is important to recognize that the nuclear industry (including Xcel Energy) is in the heart of the biggest regulatory implementation of NRC rules ever witnessed. Exhibit___TJO-1, Schedule 3 is NEI's "cumulative effect" timeline chart, which shows 2015, 2016, and 2017 through 2018 as big years for new industry rules, with dozens of new requirements going into effect during that time period. These rules translate into mandated compliance work for us resulting from the incident at Fukushima (including flooding and seismic analysis), fire protection, used fuel storage, plant security, and "hardening" the grid for protecting both the regional system and our plants. This pervasive compliance implementation is the driver for the projects we have started for those areas in 2015 and going forward, and also for the additional oversight resources we noted in the last case.

With these new rules and guidelines in place, our plants are now safer. One example is the Fukushima program and the additional public safety it provides in the event severe external events such as floods or earthquakes should occur. Another specific project related to the new rules was replacement of the reactor coolant pump (RCP) seals at Prairie Island Unit 2. This seal project

was to combine into a single project the compliance work required by the NRC for fire protection and Fukushima external events protection, which otherwise would have been dealt with in multiple projects.

Increased NRC Inspections & Impacts – Exhibit___(TJO), Schedule 4, shows a list of the current level of inspections under the NRC's current rules. As these new rules have been implemented, the additional inspections on a yearly basis mean two things: First, we are constantly in inspection mode with our plants. Second, the industry is seeing an increase in compliance findings from these inspections. Chart 1 below shows the trend in NRC findings for the industry. Under these circumstances, it isn't an oddity when Nuclear has NRC findings – it is now the new norm. In addition, the threshold at which findings are issued is decreasing. Today, significance of findings is based on potential threats to safety – not actual reductions in safety. This is the new standard in the industry, which means extremely remote safety issue probabilities of less than one in 10,000,000 can still lead to the issuance of findings.

Chart 1



Industry Collaboration – The various industry groups to which we pay fees (NEI, the boiling water reactor (BWR) owners group, and the Electric Power Research Institute (EPRI)) have coordinated efforts that have been effective in the recent elimination of Fukushima requirements for containment vents and filtered ventilation systems. This requirement was anticipated to create a cost of about $45 million per reactor – so these collaborative efforts have delivered significant cost avoidance for our customers in the 2018/2019 time table. We need to continue participating in these groups actively to improve the financial position of all utilities, including the Company, in the nuclear industry.

D. Industry Trends and Challenges

Q. WHAT GENERAL TRENDS ARE YOU SEEING IN THE NUCLEAR INDUSTRY?

A. In recent years the industry has been faced with a number of trends that present both opportunities and challenges for the Company. From an opportunity perspective, Nuclear provides carbon-free energy that will aid Minnesota in meeting EPA Clean Power Plan obligations. As with other utilities that have recently made long-term investments in the reliability of their nuclear plants, our life cycle maintenance investments at Monticello allow the Company to continue to provide this reliable, cost-effective energy to customers through the current license period. Overall, industry investments in nuclear assets help us maintain safer, more reliable, environmentally sound, large sources of baseload energy.

Industry challenges also exist. I discussed some of the regulatory challenges above, including increasing NRC oversight and regulation for public safety measures after the Fukushima Daiichi accident. In addition, we are

contending with increasing standards for operational excellence and performance from the industry's oversight organization INPO;[2] permanent fuel storage issues; and labor resource challenges given the combination of an aging industry workforce nationwide, competitive demand for experienced nuclear personnel, and the uncertainty of long-term public policy commitments to nuclear energy in the U.S. We, along with the States we serve, continue to seek constructive ways to balance the cost of investing in aging technology at our nuclear plants with the important benefits of nuclear energy.

Q. CAN YOU ELABORATE ON SOME SPECIFIC TRENDS AND CHALLENGES FOR THE INDUSTRY AND THE NUCLEAR ORGANIZATION?

A. Yes. In addition to the industry developments I noted above, we are facing and must address a number of specific industry trends, focus areas, and challenges. They include system protection improvements, mitigating critical equipment risk, driving for higher output capacity, the possibility of global standards for nuclear utilities, and dealing with the tight staffing market in the industry. I will discuss each of these issues in turn.

System Protection Improvements – We are expected to harden our safety systems and provide the grid with emergency protection, not just for abnormal events but also to deliver protection beyond the original plant design basis. This requirement is coming from not only the NRC, but also from NEI and INPO. For example, NEI is urging all plants to comply with single phase protection from the grid to avoid mandated NRC regulated rules. INPO has established

[2] See Exhibit ___ TJO-1, Schedule 14 for background on Institute of Nuclear Power Operations (INPO) and its oversight role for the nuclear industry.

review visits for emergency response and emergency protection, focusing on the proficiency of teams and workers in those areas.

Mitigating Critical Equipment Risk – The industry is seeing a trend of reducing plant transient initiators by increasing aging management program requirements (shortening the frequencies for equipment replacements) and increasing preventative maintenance (PM) requirements. This means more items are being added to current maintenance workloads to mitigate equipment risk. Today we have more PM activities as an industry than any site's workforce can manage; therefore, there remains risk of equipment loss on the more critical items until we can complete all the PM work.

Higher Output Capacity – The nuclear industry's unit capacity factors are achieving output at 90 percent or better in 2015 – higher than the prior year-end level – due to improved availability from increased PM focus. This is in part the result of larger fleets leveraging their size and being able to deploy existing resources amongst multiple plants.

Global Standards – The World Association of Nuclear Operators (WANO), the international counterpart to INPO, is taking a larger role in overall nuclear policy and governance standards, which will have impacts on U.S. plants. Since Fukushima, most nuclear standards have emanated from the U.S., but that is changing as other nuclear utilities around the world take larger seats at the table. We can expect regulatory standards to be imposed by this global organization as requirements for U.S. plants in the future.

Tight Staffing Market – The level of experience in the national nuclear workforce continues to drop, pushing us to increase our pipelines of future personnel today to ensure we have sufficient succession plans for the key functional areas such as operations, maintenance, engineering, radiation protection and chemistry. In addition, we need pipelines for security forces and emergency preparedness personnel. Also, utilities have to take on larger training staffs to train internal employees, as well as educate external stakeholders at state/local emergency planning and regulatory agencies.

Q. WHAT ISSUES DO YOU BELIEVE ARE MOST CRITICAL FOR THE NUCLEAR ORGANIZATION TO ADDRESS IN THE NEXT FEW YEARS?

A. The industry challenges I noted, including the need to comply with ongoing and emergent NRC requirements, to address aging equipment and single point vulnerabilities, and to meet INPO's expectations for high-performing plants, will put pressure on our cost structure. We need to continue to work with the Department of Energy to resolve long-term fuel storage and disposal issues at a reasonable cost.[3] We also need to ensure we maintain a stable, qualified workforce given the industry's staffing challenges. Ultimately, we need to assess the long-term future of nuclear energy in the company's generation portfolio and consider the possibility of further license extensions beyond 2030-34.

[3] We have been successful in obtaining reimbursement of historic dry cask spent fuel storage costs from the U.S. Department of Energy (DOE) through litigation settlements. Such costs are incurred as capital additions by the Company, as noted later in this testimony, and DOE reimbursements are reflected in customer rates separately as directed by the Commission. The litigation settlements with DOE provide for reimbursement of costs through 2016, but do not address costs thereafter. Reimbursement of dry cask storage costs after 2016 is expected to be sought from the DOE through future claims.

E. Key Nuclear Strategies for the Long Term

Q. HOW DOES NUCLEAR PROPOSE TO ADDRESS THESE KEY ISSUES AND TRENDS?

A. We are in the process of developing and executing plans to address the industry and Company challenges noted above. In general, these plans include: compliance management to meet NRC requirements timely and as cost-effectively as possible without compromising safety; performance improvement initiatives to meet INPO expectations; commitments to effective workforce management; long-range planning to identify, prioritize, and fund capital investments needed; and resource planning discussions on generation alternatives, capital investment requirements, and net customer benefits of nuclear energy.

The long-range planning activities will be discussed in separate resource plan proceedings before the Commission, outside of this rate case. Our plans to address the other key issues and trends have been rolled into three strategic focus areas for Nuclear: safe operations, reliability, and cost optimization and higher performance standards. The impact of these focus areas on capital and O&M costs in this rate case are discussed below.

Q. PLEASE DISCUSS FURTHER THE SAFE OPERATIONS STRATEGIC FOCUS AREA.

A. The goal of this strategic focus area is to meet the NRC's expectations for public safety, by complying with our operating license, ensuring plant security and adequately planning for emergencies, safely conducting dry fuel storage, and anticipating what safety issues might be coming. The key result to be achieved is Column 1 status, without "greater than green" findings[4] or cross-cutting issues raised by the NRC and without significant operating events.

[4] See Exhibit___(TJO-1), Schedule 12, which includes a summary of the NRC's Reactor Oversight Process and the color coding used to designate findings from inspections and performance reporting.

Indirect factors to support public safety also include succession for our people pipelines and leadership development. These pipelines of new hires and developing staff across the functional areas enable the effective transfer of knowledge and experience. Sustained leadership helps assure tomorrow's safe operations are minimizing risk to the plant, to the Company and to customers. The following summarizes the three key elements of this focus area.

NRC Compliance – It is paramount that we not only comply with existing rules, but anticipate the new rules, as well as participate in the industry working groups where policy is being drafted. We are also seeing a clear increase in standards of compliance by all stakeholders, which means recognizing that dedicated support of the weekly inspections we now have is a real and ongoing resource need. Extra efforts are necessary for the larger inspections (such as Component Design Basis Inspection, tri-annual fire protection, design modifications, Corrective Action Program, Problem Identification and Resolution, security Force on force, security Hostile Base drill, Fukushima beyond design basis events). These require us to do program compliance self-assessments considering lessons learned, as the industry evolves, findings in the industry from the NRC, and industry guidelines from NEI. On average, preparation for and response to these key inspections can require $2.5 - $5 million per year, which is material. As discussed later in the Non-Outage O&M, Employee Labor and Nuclear-Related Fees sections of my testimony, this is driving higher staffing levels needed since 2012 to support inspections, and more NRC inspection fees.

We also have to identify the work that has risk (such as heavy loads movement) and interface with the three stakeholders requiring some level of

engagement for those risks – NRC, INPO, and Nuclear Electric Insurance Limited (NEIL, the industry insurer). Both the NRC and INPO have expressed their expectations that nuclear operators need to detect safety threats early. Finding our own issues first, before inspections or evaluations, is an important measure of the effective governance over our plants.

Finally, we expect to see increased attention by the NRC in inspections focusing on resolving licensing basis discrepancies among the design of the plants, the licensing requirements, and the actual physical condition of the plants. Post-Fukushima, we see tornado protection, flooding mitigation, and fire protection as clear areas of highest risk for licensing design basis reviews. Design basis protection standards have increased dramatically since the Fukushima incident, so that where we previously were required to address risk scenarios at 1 in 10,000 or 1 in 1 million likelihood of occurrence, we are now expected to address scenarios of 1 in 10 million up to 1 in 10 billion likelihood of occurrence. This has resulted in capital projects for these efforts to prepare, address, support the inspections/interfaces, and provide documentation and performance results that have been completed and continue, as noted in the Mandated Compliance grouping discussion in the Capital Investments portion of my testimony. This is also driving higher staffing levels needed since 2012 to support inspections, and more NRC inspection fees, as discussed later in the Non-Outage O&M, Employee Labor and Nuclear-Related Fees sections of my testimony.

Fuel Storage – With the Yucca mountain proposal on hold and no alternative permanent storage facility likely in any near term, the responsibility for interim dry cask storage transferred to the power plants for 60 years after plant

shutdown as ordered by the Commission in the recent triennial decommissioning filing. On-site dry cask storage has proven to be safe, and creates time for the federal government to deliberate on long-term storage matters without immediate consequence. However, the shift in interim fuel storage responsibility from the federal government is creating financial consequences for operating power plants, and is requiring the NRC to look at aging management programs and inspections for dry cask storage at those plants. This will lead to the NRC imposing Aging Management Program (AMP) requirements for dry cask storage. While dry cask canister designs will not change, new inspection tools will need to be developed to provide access to existing designs before casks are shipped to a permanent repository. Therefore, in addition to continuing dry cask storage costs (as noted in the Capital Investments portion of my testimony), we can expect the NRC to add new AMP requirements to storage facility license renewals implemented in 2016 for Prairie Island (and much later for Monticello). Further, longer on-site fuel storage requires security measures well beyond the operating life of the plant, increasing decommissioning costs.

Workforce Planning – To ensure safety, we must create staffing pipelines that sustain the licensed-required positions such as operators, chemistry technicians and radiation protection technicians. Since the extended time for training to meet regulatory qualification expectations for these roles can be up to two years, these pipelines have to be in active hiring mode continuously each year. Also, pipelines in other areas are only satisfying minimum staff levels and are not sufficient to operate the plants with the desired level of staff stability in the long term, assuming retirements and other attrition occur. Therefore, engineering, maintenance, and quality assurance areas must also be

actively hiring on an annual basis to feed their staff pipelines. Both the NRC and INPO have shown a focus on the importance of sustaining full staffing for integrated operations across all areas, rather than just key functional areas separately.

Finally, both the NRC and INPO consider leadership sustainability as an early warning flag for potential decline in performance and vulnerability to operating events and non-compliance. Sustainability in the leadership ranks requires a mix of internal candidates under development, as well as external hires from elsewhere in the Company or outside firms, to maintain a diverse experience base for effective operations to meet the expectations stated above. Both retention and other incentive programs are necessary to attract and sustain the required workforce numbers with the needed experience levels to operate, as well as to coincidentally develop the next leadership teams. Consequently, staffing is a constant focus for the Nuclear organization, and an essential element to achieve our performance objectives for our stakeholders.

Workforce planning initiatives have been a driver for higher staffing levels since 2012 to support inspections, as discussed later in the Non-Outage O&M, Employee Labor section of my testimony.

Q. PLEASE DISCUSS FURTHER THE RELIABILITY STRATEGIC FOCUS AREA.

A. The goal of this strategic focus area is for our units to operate with solid power plant production outputs – delivering high capacity factors, meeting system generation output expectations, and optimizing refueling outages. Results from achieving this goal are unit capability factors at 90 percent capacity, delivering a 14 million MWh production to the NSP system, and

performing refueling outages in less than 35 days. The following summarizes the three key elements of this focus area.

Capacity Factors – Achieving 90 percent capacity factors means optimizing our PM program and placing more focus on the true critical equipment items, along with finding the single point vulnerabilities. This will generate added maintenance activities and probably increase O&M costs slightly, as we add some means of system redundancy to minimize generation losses. Successful PM activities can reduce forced outage O&M costs from equipment issues, and also optimize our capital spend on the most critical equipment issues. Our goal is to enable higher capacity and in doing so lower cost per MWh generated, even with some level of higher O&M for added maintenance.

Mitigating Output Risks – The aging of nuclear plant equipment in a variety of areas will require added attention to maintenance expenses. Focus areas will include circuit boards, instruments, power supplies, solenoid valves and motor rewinds. Review of industry experiences and other power plant events will require more timely action by our plants to prevent similar issues occurring here. Also, as we verify and validate the extent of condition at our plants based on this knowledge, we will increase maintenance scopes to add preventative actions. Again, successful PM activities can reduce forced outage O&M costs from equipment issues, and also optimize our capital spend on the most critical equipment issues.

Outage Management – Nuclear is planning to create a centralized outage organization, dedicating full time resources from both internal staff and external contractors to plan, prepare for, organize, schedule and execute

refueling outages. With three reactors on different fuel cycles (ranging from 18 to 24 months), our nuclear fleet must be able to lay out the plans for the next three future refueling outages in parallel at any given time, as well as support any plant currently in a refueling outage and be prepared to handle a forced outage. Our goal is to optimize outage efficiency and drive planned outage costs downward over time. Some cost reduction benefits from this approach are anticipated in the 2016 outage at Prairie Island, as noted later in the Planned Outage O&M section of my testimony.

Q. PLEASE DISCUSS FURTHER THE COST OPTIMIZATION & HIGHER PERFORMANCE STANDARDS STRATEGIC FOCUS AREA.

A. The goals of this strategic focus area are to optimize fuel cycles, build alliances with the Utility Services Alliance, use strategic sourcing focusing on performance accountability, and implement organizational best practices. Achieving these goals will help keep the nuclear fleet as part of the combined Xcel Energy generation portfolio and maintain a large carbon-free generating option for the state of Minnesota. The following summarizes the four key elements of this focus area.

Fuel Cycles – As discussed in the Prairie Island EPU Change in Circumstance filing,[5] we have a plan underway to increase the fuel cycles for the Prairie Island units from 18 to 24 months beginning with the 2017 refueling outage at that plant. This requires licensing changes, instrument/set point changes in equipment, other maintenance changes, and engineering analysis and calculations. This fuel cycle optimization can eliminate two refueling outages over the remaining operating license life of the units. Although we expect

[5] Section A.2 of Supplemental Filing in Docket No. E002/CN-08-509, dated October 22, 2012.

some capital costs in the years 2015-2019 to complete the engineering for this fuel cycle change, we also expect fuel cost efficiencies and the elimination of two planned outages over the remaining life of the plant to more than offset those capital costs.

Building Alliances – We plan to take on both a participatory and a leadership role with the Utility Services Alliance (USA) to leverage the benefits of a larger fleet approach. USA enables companies with fewer nuclear units (like us) to share information and resources to operate as if they were part of a larger fleet. This should optimize costs as well as facilitate best practices to improve our timely responses to subtle declines in performance. These efforts require ongoing commitments to industry organizations, the cost of which is included in Nuclear-Related Fees as discussed in the Non-Outage O&M section of my testimony.

Strategic Sourcing – We plan to formulate and implement partnership approaches with certain suppliers to leverage their nuclear expertise, which we expect will strengthen Nuclear without having to increase our permanent employee level. This will require some dedication by both Nuclear and the suppliers to focus on key objectives, such as equipment performance and refueling outages, and will be supported by longer term arrangements with the suppliers. We expect the outcome of this effort will be higher vendor accountability for quality, which should enable cost effectiveness for materials and services procured from the vendors for both capital projects and O&M work.

Organizational Best Practices – Nuclear will develop and implement organizational best practices to raise the accountability standards for both teams and individuals. This will put our emphasis on not only building an optimal nuclear workforce, but also assuring that we fully utilize it. We plan to leverage our USA alliance to share best practices of all USA nuclear units (including ours) as if we operated as one larger fleet. This organizational information sharing is one enabler of our expectation to keep headcount at 2014 levels going forward, as discussed in the Non-Outage O&M, Employee Labor section of my testimony.

Q. GIVEN THESE VARIOUS DEVELOPMENTS, TRENDS, OPPORTUNITIES, AND CHALLENGES, HOW DOES NUCLEAR ENABLE AND SUPPORT THE FUNCTIONS AND BENEFITS OF NUCLEAR ENERGY DESCRIBED ABOVE?

A. Nuclear makes both capital investments and incurs O&M expenses to support the ongoing operation, safety, and reliability of the Company's nuclear power plants. These investments include year-over-year plant maintenance work, replacement of aging equipment and systems, general operations, storage of spent fuels, compliance with evolving NRC mandates, and other, more unique projects such as operating license extensions and amendments. Having discussed the context in which we work, I will now discuss our capital investments and O&M trends.

III. CAPITAL INVESTMENTS

A. Overview

Q. FOR 2012-14, WHAT WERE NUCLEAR'S KEY STRATEGIC GOALS AND FOCUS DRIVING YOUR CAPITAL INVESTMENTS?

A. As discussed earlier in my Direct Testimony, our focus from 2012 through 2015 was on improved plant performance, improved fleet performance, staff succession and development, sourcing, and outage lengths. At the same time, we were undertaking major capital projects at our Nuclear facilities in 2012 through 2014, including completion of the Monticello LCM/EPU program, the Prairie Island Steam Generator project, and various ongoing projects to support the life extension of Prairie Island and comply with increasing NRC requirements resulting from the incident at Fukushima and the NRC's evolving approach to regulatory oversight.

Q. AND HOW DID YOUR CAPITAL INVESTMENTS IN THAT TIME PERIOD BREAK INTO CAPITAL BUDGET GROUPINGS THAT REFLECTED THOSE GOALS?

A. For long-range planning purposes, Nuclear's Projects department groups projects around a common theme to assist in the analysis of budget plans, assignment of project management resources, and benchmarking across the industry. These capital budget groupings enable the application of common practices among similar projects. The groupings (excluding fuel loads) can be described as follows:

- *Dry Cask Storage* is work associated with on-site dry spent fuel storage and loading campaigns, including the Independent Spent Fuel Storage Installation (ISFSI) and related NRC-mandated aging management programs given the lack of a permanent federal repository for spent fuel.
- *Mandated Compliance* includes regulatory, security, and license commitment activities required by Federal or state regulators (normally the NRC), including industry commitments made to the NRC.

- *Reliability* activities improve equipment reliability or reduce maintenance activities, and include life cycle management programs and projects.
- *Improvements* include activities that improve system and equipment performance and operation (for example, digital upgrades), and can reduce O&M costs.
- *Facilities & General* includes facility work such as building improvements, roof replacements, road repairs and general plant additions such as small tools and equipment.
- *Strategic* work involves large and unique projects intended to support and enhance the operations of our plants over their useful lives. Examples of Strategic projects are the completed Monticello LCM/EPU project and the Prairie Island Steam Generator replacement.

Q. FOR THE YEARS 2012-2014, CAN YOU PROVIDE A SUMMARY OF HOW YOUR INVESTMENTS FELL INTO THOSE CAPITAL BUDGET GROUPINGS?

A. Yes. Table 1 below provides a summary of Nuclear's budgeted capital additions compared to actual amounts for the years 2012-2014.

Table 1

Nuclear Capital Additions – Actual vs. Budget 2012-2014 Including AFUDC - $ in millions						
NSPM Electric Utility Nuclear	**2012 Budget**	**2012 Actual**	**2013 Budget**	**2013 Actual**	**2014 Budget**	**2014 Actual**
Dry Cask Storage	$16.7	$0.0	$76.7	$63.9	$23.7	$26.2
Mandated Compliance	37.8	30.5	18.9	26.6	69.4	76.9
Reliability	18.5	26.2	51.6	41.0	59.6	42.8
Improvements	4.5	3.0	8.4	18.4	15.3	17.5
Facilities & General	7.1	10.6	5.0	3.9	25.0	26.5
Completed Strategic Projects:						
Monticello LCM /EPU	41.4	20.9	299.4	384.2	54.2	0.1
PI Steam Generator	--	--	285.1	284.5	2.3	(8.6)
Subtotal – Projects	$126.0	$91.2	$745.0	$822.5	$249.5	$181.4
Nuclear Fuel	114.9	97.9	132.5	142.5	61.3	63.0
Total Nuclear Additions	$240.9	$189.1	$877.5	$965.0	$310.8	$244.4

Q. CAN YOU EXPLAIN WHY THE PERCENTAGES OF YOUR INVESTMENTS IN THESE GROUPINGS CHANGED OVER THESE THREE YEARS?

A. Yes. As shown by Table 1 above, in 2013 we largely completed very substantial capital projects related to the Monticello LCM/EPU Program and the Prairie Island Steam Generator Replacement. These two projects combined totaled approximately $669 million in capital additions that were addressed in our prior rate cases and other proceedings before the Commission. Because these projects were largely completed in 2013, our investments dedicated to Strategic projects declined in kind. Currently we do not have any Strategic projects underway.

Each of the nuclear capital budget groupings now in use has a strategic driver that can change the need for investment year by year.

- Dry Cask Storage is driven by the Federal government's delay in providing a permanent, long-term spent fuel storage facility, and the Company's requirement to store spent fuel on site in the interim. The

timing of spent fuel storage is also designed to enable a full core offload for each unit at any time, compliant with license requirements.

- Mandated Compliance is driven by the requirements of the NRC or other regulators as a condition of maintaining our license to operate the plants.
- Reliability is driven by the fact that the Company's nuclear plants are all over 40 years old and require ongoing capital investment to maintain reliable operation through equipment upgrades and replacement to address aging and obsolescence issues.
- Improvement enables us to capture opportunities for improved output or operational performance and efficiency, which can provide a payback for the investment through higher output or lower operating cost.
- Facilities and General include ongoing activities to maintain plant building and properties, and provide small tools and equipment to support normal plant operation.
- Fuel is necessary to operate the reactors and provide the steam to generate power.

While we group our capital projects in the categories noted above, we also have several strategic objectives that our capital investments are striving to achieve:

- The Mandated Compliance grouping is intended to implement new NRC regulations for the industry, often with a safety implication (such as Fukushima external events and fire protection).
- Some Reliability and Improvement projects are intended to (a) eliminate license design basis issues which distract or complicate our

NRC inspections, and (b) reduce vulnerability to NRC inspection findings.

- The LCM projects in the Reliability grouping focus on aging equipment management issues such as generators and transformers.
- Other Reliability and Improvement projects are intended to improve equipment and system reliability, with dual goals of ensuring plant safety and avoiding unplanned reductions in generation output.
- The Fuel and Dry Cask Storage groupings address the needs for procuring new fuel to operate the reactors, and for storing old/used fuel on-site until a federal repository is established.

After completion of the Monticello LCM/EPU and Prairie Island steam generator replacement, ongoing capital investment is still needed to maintain plant reliability and to comply with regulatory requirements. We recognize that the capital investment made to date and required in the future for our nuclear plants is substantial. However, we believe that investment is warranted given the value of safe, carbon-free, reliable, base-load generation that these plants deliver to provide the power for more than one million customer homes. Our long-term capital investment plan balances regulatory requirements, equipment risk, funding capabilities, and customer benefit.

Q. HOW DID YOUR ACTUAL TOTAL CAPITAL INVESTMENTS OVER THE YEARS 2012-2014 COMPARE TO YOUR BUDGETS?

A. For 2012, the total capital project additions of $91 million were $35 million less than the budget of $126 million. This was entirely due to delays in the Monticello LCM/EPU project and the Prairie Island dry cask storage work originally planned for 2012. The Monticello project had initially planned to

complete some work in 2012 but ultimately did not complete it until the 2013 refueling outage at the site. The Prairie Island cask loading work was moved to the next year, 2013.

For 2013, the total capital project additions of $822 million were $77 million higher than the budget of $745 million. This was entirely due to cost increases in the Monticello LCM/EPU project, as discussed in our last rate case. Actual additions for all other projects in 2013 came in at a combined 98.3 percent of budget for the year.

For 2014, the total capital project additions of $181 million were $68 million less than the budget of $249 million. Almost all ($65 million) of this decrease was due to the timing of the Monticello LCM/EPU project and the final cost of the Prairie Island steam generator project. The 2014 Prairie Island budget was developed before we became aware of final project cost underruns that were ultimately experienced due to monitoring vendor spend and holding vendors accountable for contract terms and performance. These savings were passed through to customers as agreed in our last rate case.

These 2014 underruns were unusual situations for completed strategic projects, and are not reflective of our ongoing capital work for reliability and other groupings. Actual additions for all other projects in 2014 came in at a combined 98.4 percent of budget for the year.

These variances in project additions do not include fuel. Our fuel capital additions in each of the years 2013-2014 have exceeded budget. On a combined basis, actual capital additions for the three years 2012-2014 were

within approximately 2.3 percent of budget including Strategic projects, and within approximately 2.1 percent of budget when including all projects and fuel.

Q. LOOKING AT THIS HISTORY, WHAT DO YOU CONCLUDE?

A. Throughout the past several years, Nuclear has faced unanticipated challenges at the plants and in the industry as described earlier in my testimony. However, we have continued to make the investments necessary to meet the Company's overall goals of providing safe, reliable, environmentally sound energy that meets our customers' needs and expectations. As a result, in 2013-2014 we in-serviced capital project additions in the aggregate for all groupings other than Strategic (which no longer is in use) at slightly more than 98 percent of the level of our initially anticipated budgets. Further, when combining the three years 2012-2014 together, our total capital additions (including Strategic projects and even fuel) are within about 2 percent of the aggregate budget for those years. Therefore, the Commission can have confidence that our actual capital investment levels on behalf of customers will meet our anticipated budgets.

Q. WHAT ACTIVITY HAS OCCURRED WITH RESPECT TO THESE CAPITAL BUDGET GROUPINGS SO FAR IN 2015?

A. Overall, Nuclear is on track to complete the 2015 capital additions identified in our last rate case. We have also brought to conclusion several projects that carried over from the 2012-2014 timeframe. In particular, cost reductions to the Prairie Island Steam Generator project were recorded in 2015 related to vendor credits, based on resolution of the issues discussed in our last rate proceeding. Further, as of the conclusion of our last rate case, the estimated

total cost of the Monticello LCM/EPU Program was approximately $748 million with AFUDC. However, we incurred some costs in 2014 and 2015 related to the final ascension of Monticello to full uprate levels. These and other additional Monticello LCM/EPU costs are included in rate base without a return, as directed by the Commission in prior proceedings. The final total cost of the Monticello LCM/EPU project was $750.7 million, including AFUDC.[6]

Q. LOOKING AHEAD, WHAT ARE YOUR CAPITAL FORECASTS FOR 2016-2018 BY CAPITAL BUDGET GROUPING?

A. Table 2 below provides a summary of Nuclear's budgeted capital additions for the years 2016-2018.

Table 2
Nuclear Capital Additions 2016-2018
Including AFUDC ($ in millions)

NSPM Electric Utility Nuclear	2016 Budget	2017 Budget	2018 Budget
Dry Cask Storage	$19.4	$0.0	$90.0
Mandated Compliance	83.8	29.8	35.2
Reliability	53.6	76.3	165.6
Improvements	4.6	0.6	3.1
Facilities & General	7.3	0.8	0.8
Subtotal – Projects	$168.7	$107.5	$294.7
Nuclear Fuel	76.1	172.6	71.9
Total Nuclear Additions	$244.8	$280.1	$366.6

Q. CAN YOU EXPLAIN WHY TABLE 2 ABOVE DOES NOT REFLECT A STRATEGIC CAPITAL BUDGET GROUPING?

[6] This includes $749.8 million in actual additions through Sept. 30, 2015 and $0.9 million in forecasted additions for post-ascension testing and analysis through Dec. 31, 2015.

A. Yes. Now that we have completed our large strategic projects (including the Monticello LCM/EPU and the Prairie Island Steam Generator replacement) that are no longer incurring costs after this year, we will no longer utilize the Strategic project grouping. Each of these strategic projects was addressed in our last rate case and they are not resulting in any new test year additions for 2016 through 2018.

Q. WHAT KEY PROJECTS WILL YOU BE INVESTING IN OVER THE TIME PERIOD 2016-2018?

A. Our single largest project over the next several years is our Prairie Island Unit 1 Generator replacement scheduled for 2018. Fuel is also a key capital investment in any given year. We have dry cask loading campaigns scheduled at Monticello in 2016 and 2018 and at Prairie Island in 2018. We also have significant multi-year mandated compliance projects for the Fukushima program and the fire protection program in 2016-2018.

Q. WHAT OTHER PROJECTS DO YOU EXPECT TO DRIVE YOUR INVESTMENTS OVER THESE YEARS?

A. Overall, we anticipate future investments in projects in each of these capital budget categories. While we are making larger investments in mandated compliance items in 2016, as I discuss later, we anticipate lower costs in that grouping after 2016 for the Fukushima program as it winds down and for the multi-year fire protection compliance projects. After 2016, we will increase our focus on reliability needs as noted above.

Table 3 below summarizes nuclear capital expenditures by capital budget grouping (excluding AFUDC) for the test years 2016-2018 in comparison to actuals for 2012-2014 and the forecast for 2015.

Table 3

Actual 2012-2014 and Forecasted 2015-2018 Capital Expenditures Excluding AFUDC - $ in millions							
NSPM Electric Utility Nuclear	**2012 Actual**	**2013 Actual**	**2014 Actual**	**2015 Fcst**	**2016 Budget**	**2017 Budget**	**2018 Budget**
Dry Cask Storage	$36.0	$33.9	$19.4	$18.0	$22.2	$20.5	$33.1
Mandated Compliance	25.8	37.8	71.8	84.7	52.6	40.7	29.7
Reliability	76.0	61.5	57.7	72.8	78.3	90.1	134.1
Improvements	12.2	16.2	11.3	2.9	2.5	1.3	3.0
Facilities & General	7.2	6.7	24.3	7.9	3.6	0.9	0.9
Strategic Projects (completed)	10.4	312.7	0.3	(0.4)	--	--	--
Subtotal – Projects	$167.6	$468.8	$184.8	$185.9	$159.2	$153.5	$200.8
Nuclear Fuel	142.4	89.9	154.3	90.4	118.5	117.6	62.3
Total Nuclear Cap Ex	$310.0	$558.7	$339.1	$276.3	$277.7	271.1	$263.1

These expenditures accumulate as projects progress, AFUDC is added, and the total costs are placed in service as capital additions, as discussed in the next section of my testimony. As illustrated in Table 3 above, Nuclear's capital expenditures have largely remained and are expected to remain within a $150-200 million range (excluding fuel) for each year between 2012 and 2018, depending on the varying needs of the Nuclear facilities and the overall Company budget during those years. The outlier is, of course, 2013, when we made substantial additional investments in the Monticello LCM/EPU program and the Prairie Island steam generator project.

Table 4 below summarizes nuclear capital additions by capital budget grouping for the test years 2016-2018, in comparison to actuals for 2012-2014 and the

forecast for 2015. The additions in Table 4 include both capital expenditures and accrued AFUDC.

Table 4

Actual 2012-2014 and Forecasted 2015-2018 Capital Plant Additions Including AFUDC - $ in millions							
NSPM Electric Utility Nuclear	**2012 Actual**	**2013 Actual**	**2014 Actual**	**2015 Fcst**	**2016 Budget**	**2017 Budget**	**2018 Budget**
Dry Cask Storage	$0.0	$63.9	$26.2	$24.8	$19.4	$0.0	$90.0
Mandated Compliance	30.5	26.6	76.9	64.1	83.8	29.8	35.2
Reliability	26.2	41.0	42.8	135.5	53.6	76.3	165.6
Improvements	3.0	18.4	17.5	3.0	4.6	0.6	3.1
Facilities & General	10.6	3.9	26.5	3.3	7.3	0.8	0.8
Completed Strategic Projects:							
Monticello LCM /EPU	20.9	384.2	0.1	3.4			
PI Steam Generator	--	284.5	(8.6)	(2.7)			
Subtotal – Projects	$91.2	$822.5	$181.4	$231.4	$168.7	$107.5	$294.7
Nuclear Fuel	97.9	142.5	63.0	144.4	76.1	172.6	71.9
Total Nuclear Additions	$189.1	$965.0	$244.4	$375.8	$244.8	$280.1	$366.6

While capital additions are directly affected by our capital expenditures, the capital additions trend may not mirror the capital expenditure trend. The capital expenditure trend reflects the progress of the project's spend through the months, whereas the capital addition trend reflects the total cost at the conclusion of the construction or implementation process when the asset is placed in service. The difference between capital expenditures and capital additions reflects the varying lengths of time required to complete different projects. For example, the expenditures in 2013 on the Monticello LCM/EPU and Prairie Island steam generator projects was only a portion of the amount of the total additions placed in service that year, due to spend in earlier years as well. However, Company witness Ms. Lisa H. Perkett addresses

how the Company's overall capital additions over time align with budgeted capital additions in any given year.

Q. WHAT KINDS OF CHANGES COULD OCCUR THAT MAY LEAD TO A RE-PRIORITIZATION OF YOUR CAPITAL INVESTMENT NEEDS AND CHANGE THE PERCENTAGES THAT YOU INVEST IN EACH CAPITAL BUDGET GROUPING?

A. There are several reasons why we may need to reprioritize capital investments in any given year or over the course of several years.

Management does its best to predict the progression in which projects are completed, which ones will be completed in each year, and how much in additions will flow into rate base for the test year. However, given new regulatory requirements, emergent equipment issues, changing business priorities, and constraints on corporate funding availability, it is difficult to plan precisely in advance which individual projects will be completed in each future year. In addition, complications in engineering and design, challenges in vendor bidding or performance, and constraints for resource scheduling can cause the timing and cost of individual project additions to change in any year from that assumed in the budget. That said, the 2016 test year capital budget is our current best estimate of the capital work needed in the coming year. Even if the individual projects making up the budget may change slightly, it remains reasonably representative of the capital investment needed for Nuclear in 2016.

Q. WHY IS THE ABILITY TO CHANGE THE MIX/MAKEUP OF CAPITAL INVESTMENT GROUPINGS FOR NUCLEAR IMPORTANT TO THE COMPANY AND YOUR CUSTOMERS?

A. At any given time, it is Nuclear's priority to ensure we are investing in our Nuclear generation wisely on behalf of customers. It would not be prudent to invest in a project that is no longer needed, or to delay a project that becomes essential, simply to align with a capital plan that was developed before circumstances changed. This is particularly true as safety, mandated compliance, or plant reliability needs change over time.

Q. IS IT NECESSARY FOR NUCLEAR TO ADJUST ON A REGULAR BASIS THE CAPITAL PROJECTS PLANNED?

A. Yes, for the reasons noted above. As a particular example, we had initially planned to perform the Electric Generator Replacement Project for Prairie Island Unit 1 (now planned for 2018) in 2016. Given limitations on corporate capital funding capabilities in 2016-17, Nuclear evaluated opportunities to delay its capital spending and identified this $70+ million project as the best opportunity to significantly reduce our capital spend in those years.

This delay carries with it some risk, both from a business standpoint for generation reliability, and from a regulatory standpoint for possible NRC oversight. The generator is past its intended life of 40 years. The plant will do an inspection of the generator during the 2016 refueling outage to assess its condition and minimize the risk associated with delaying the replacement to 2018. This risk can be defined as loss of generation due to equipment failure with the possibility of a forced outage during a peak demand period. Also, certain failures could create threats or challenges to plant safety. Should those occur, they would be considered to be an initiating event in the NRC's Reactor Oversight Process, which could generate a safety or potential safety finding, possibly changing the plant's column status. Our continual

assessments are necessary to ensure we are undertaking the right projects at the right times.

Q. SHOULD CUSTOMERS BE CONCERNED THAT SPECIFIC CAPITAL PROJECT PLANS EVOLVE?

A. No. It is in our customers' interests that Nuclear applies the funding available to the risk-significant projects prioritized from most to least risky. We make changes to the specific projects we implement during the course of a year to address emerging issues or perform like-kind replacements for previously planned projects. In this way, we better serve our business and our customers' most pressing needs in a cost-effective way. When the need arises to accelerate a project, we assess the situation to make sure we are doing so for the right reasons and in a prudent manner. Similarly, we assess potential project delays or cancellations to make sure we are still meeting business and customer needs in a reasonable way.

Overall, the 2016, 2017 and 2018 capital addition budgets are representative of the amount of capital investment being made available to Nuclear to address the regulatory requirements and equipment needs of our plants. Further, as the previous Table 4 shows, more than half of the capital additions in 2016 are for Dry Cask Storage and Mandated Compliance projects that must be done to ensure refueling outages can be completed and NRC requirements are met in a timely manner. We are committed to deliver on the projects needed to meet our performance goals established by various stakeholders (the NRC, INPO, the industry, and the Company) and sometimes we have to shuffle the list of projects to do so. That is a normal part of managing our business.

Q. EVEN IF YOUR INVESTMENT GROUPING PERCENTAGES CHANGE FROM THE CURRENT FORECAST, WILL NUCLEAR STILL MANAGE ITS OVERALL CAPITAL INVESTMENTS TO ITS OVERALL BUDGET?

A. Yes. Our planned capital investments – during the term of this multiyear rate plan and beyond – are intended to ensure our plants operate to the end of their licenses. Ultimately, we must invest as necessary to meet our overall goals of safe, reliable Nuclear energy generation to ensure we meet customer demand and NRC expectations.

Q. SO WHAT DO YOU CONCLUDE ABOUT NUCLEAR'S 2016 – 2018 CAPITAL INVESTMENT FORECASTS?

A. I conclude that our capital forecasts represent an accurate and reasonable picture of our necessary investments planned over these years. Therefore, these forecasts can be relied on to set just and reasonable rates for our customers.

B. Capital Budget and Investment Planning Process

1. Reasonableness of Overall Capital Budget

Q. PLEASE MAKE THE BUSINESS CASE FOR THE NUCLEAR CAPITAL PROGRAM.

A. Nuclear generation provides the Company's customers with carbon-free, base-load energy to combine with other fossil sources like gas, and renewable sources like wind and solar. Nuclear's high capacity base production allows renewable resources – which cannot be expected to run consistently given their nature – to be optimized for customers through a diverse portfolio of competitive, carbon-free energy.

Operating our nuclear plants requires capital investments to meet the needs

for fuel management, comply with NRC license requirements, and replace/upgrade equipment so that the units can function reliably in normal operations, deal appropriately with any unusual situations, and provide adequate safety protections. The cost of these investments is estimated, benchmarked for industry comparability, and leveraged though vendor procurement sourcing, with the objective to deliver the best value to customers.

Q. HOW DOES THE NUCLEAR AREA ESTABLISH A REASONABLE CAPITAL BUDGET FOR EACH YEAR?

A. Nuclear's capital investment requirements are identified and established through development of a long-term asset strategy. Due to the complexity of executing projects for an operating nuclear power plant, they are typically identified many years in advance. Our plans are subdivided into the categories discussed previously to help understand the priorities. In addition, we look at capital needs through the end of each unit's current operating license. This long-term view helps ensure that the overall planning and timing of our capital investments support safe, compliant and reliable operation. Each year we re-evaluate our capital needs during the annual budget cycle.

The appropriate annual capital budget for Nuclear is based on a partnership between corporate management of overall finances and the business needs we identify for our constituents. Company witness Mr. Gregory J. Robinson explains how the Company establishes overall business area capital spending guidelines and budgets based on financing availability, specific needs of business areas, and overall needs of the Company.

At the same time, Nuclear employs a "bottom-up" approach to capital budget development, meaning that we look at the needs and potential needs of our plant and then assess how much it would cost to address each of them. We listen to our nuclear employees – engineers, operators and maintenance staff – and strive to address the issues they raise by getting their input and plotting a course of action. The decision-making on capital investments needs is undertaken by the Nuclear executive management team, in collaboration with Xcel Energy governance processes, and ultimately approved by the Board of Directors of the Company.

As noted previously, our capital budgeting process evaluates and balances requirements, risks, opportunities, and funding capabilities. It includes four major elements:

- Identification of NRC license requirements, including regulations and inspection findings;
- Evaluation of equipment and plant health issues to meet business plan operational goals (such as safety system availability, generation capacity, forced loss rate, fuel reliability and chemistry control);
- Prioritization of potential capital projects based on risk and urgency considering factors such as age of equipment, operating risk and need, and regulatory risks; and
- Consideration of the relative funding available from the corporation given the needs and requirements of all business units and stakeholders.

A number of governance and oversight functions exist to support these capital budget development efforts at both the Nuclear department and corporate Xcel Energy level. They include:

- Corrective Action Program (CAP) process, which includes self-identified issues and findings from NRC inspections of original plant design;
- Long Range Planning (LRP) process;
- Plant Health Committee (PHC) at each plant site;
- Project Review Group (PRG) at each plant site, and an Executive PRG for the nuclear fleet;
- Technical Review Board (TRB) at each plant site;
- Investment Review Committee (IRC) for Xcel Energy; and
- Financial Council for Xcel Energy.

Ultimately, these processes appropriately balance the needs of our nuclear plants with the need for cost-effective electric generation for our customers, arriving at a reasonable budget for Nuclear in each year. I explain this governance and oversight process in more detail below.

2. Nuclear Capital Planning Process & Governance

Q. PLEASE DESCRIBE THE PROCESS TO EVALUATE NRC LICENSE REQUIREMENTS, AND POTENTIAL CAPITAL PROJECTS NEEDED TO ADDRESS THEM.

A. NRC license requirements are entered into the Corrective Action Process (CAP) and evaluated regularly by the Engineering and Regulatory Affairs functions. CAP is an NRC-mandated license compliance program. The evaluations include not only plant license requirements but also the NRC's new rules and regulations, Regulatory Issue Summaries, Task Interface Agreements, and other communications. The CAP process is quite extensive and complicated. About one-half of our engineering resources are dedicated

to the CAP program, reviewing safety licensing documentation so the plant can operate in compliance with NRC requirements.

If deviations from NRC requirements are identified, and capital funding is required to resolve the deviation, then a project request is initiated using Nuclear's "Project Review and Approval Process" procedures. The request is also added to the long range plan using Nuclear's "Long Range Planning (LRP)" procedures, as I discuss later.

Q. PLEASE DESCRIBE THE PROCESS TO EVALUATE EQUIPMENT AND PLANT HEALTH ISSUES, AND POTENTIAL CAPITAL PROJECTS NEEDED TO ADDRESS THEM.

A. Equipment and plant health issues are entered into the CAP process, which establishes how we document and track resolution of conditions deviating from desired plant performance levels. The CAP process ensures that deviations from performance expectations are promptly identified, evaluated, corrected through actions commensurate with safety significance, and verified as a closed issue.

The Plant Health Committee (PHC) is the cornerstone for plant improvements in equipment reliability. The PHC is an industry best practice developed from INPO's excellence standards. The PHC's primary focus is to understand the site's existing equipment reliability issues, prioritize these issues and ensure that the site resources are aligned to support resolution consistent with their priority. The process ties together material condition evaluations, work identification and approval, and the business planning process. One

output of the PHC is providing inputs to the long range plan (LRP), which outlines current and future project expenditures as I describe later.

PHC inputs are forwarded to the Project Review Group (PRG) for consideration. The PHC recommends projects to PRG, which then ensures that capital projects are properly ranked and thus re-evaluates priorities of previously authorized capital projects, as required.

Q. PLEASE DESCRIBE THE PROCESS TO PRIORITIZE POTENTIAL CAPITAL PROJECTS IDENTIFIED, BASED ON RISK AND URGENCY.

A. Capital projects are prioritized in accordance with Nuclear's *Prioritization Guidelines*, which provide guidance for ranking projects based on various criteria for risk and urgency. The prioritization guideline is integrated into the planning, implementation, and budgeting processes for capital projects. For the current year, the prioritization guideline works to manage capital spend to the approved budgets, to evaluate the impact of emergent issues, and to communicate these impacts to the affected process owner. For future years, the procedure works to formulate project budgets and to identify potential adjustments to optimize whenever possible. The PHC validates[7] or assigns the prioritization ranking for capital projects in accordance with Prioritization Guidelines. As I noted earlier, the site's PRG reviews the risk and urgency rankings of all recommended projects for the plant, and continually re-evaluates priorities of previously authorized projects, as required, to allocate (and re-allocate) available capital funding for that site's plant.

[7] Each plant has a Technical Review Board (TRB) which reviews proposed modifications to improve plant health, identify best alternatives, establish issue priority ranking per Prioritization Guidelines and report the results of the TRB to the plant's PHC.

Q. PLEASE DESCRIBE THE PROCESS TO CONSIDER AND ASSIGN FUNDING TO NUCLEAR CAPITAL PROJECTS BASED ON CORPORATE NEEDS, REQUIREMENTS, AND FINANCING CAPABILITY.

A. The LRP establishes a multi-year baseline project plan for the plant based on the plant's strategy and prioritization of work through the end of licensed life. A phased funding approach is used to develop project cost estimates and further classify the projects on the LRP as Study, Design, or Implementation Phase expenditures. A project must be identified on the LRP to be included in the annual capital budget. During creation of the annual budget, each site's PRG uses the LRP to determine which capital projects will be proposed for a given year. The PRG ensures proposed projects are subjected to effective business evaluations and management review at key decision points prior to committing significant resources. PRG ensures projects meet corporate financial objectives. At the time of the annual budget creation, the fleet-wide Executive Project Review Group (EPRG) reviews and approves the LRP for each site and for the combined fleet for the five-year budget period, which is then submitted for corporate review and approval by Xcel Energy through the Investment Review Committee and/or Finance Council.

Ultimately, the collective process operates as an effective decision making function of the Company's leadership team. The PHC determines the appropriate technical solution for issues raised; the PRG assesses risk and determines the appropriate cost alternatives for the issues, and the EPRG looks at broader business area and Company risk and makes a final decision to approve capital spending (subject to corporate funding constraints). This process creates an independent view from each site for oversight of safety and cost.

Q. PLEASE DESCRIBE THE PROCESS TO BUILD THE BUDGETS FOR SPECIFIC CAPITAL PROJECTS, IN-SERVICE DATES, AND AMOUNTS OF CAPITAL ADDITIONS BY YEAR.

A. We have a well-defined, tactical process to capital budgeting, along with strategic oversight and decision-making accountability.

From a process standpoint, project requests that are approved by the PHC are assigned a Project Manager. The Project Manager develops or revises the initial project estimate as described in *Project Management Manual* procedures. Cost estimating is based on the industry standard[8] included in PRG procedures. These standards provide for varying levels of estimates as a project proceeds through the three-phase funding approach, comprised of study, design and implementation phases. The PRG reviews the initial cost estimate and approves or rejects the project for LRP addition. The LRP includes the annual project cash flows.

Project Management procedures align with industry practices[9] including the development of a Project Management Plan. The Project Management Plan preparation should start in time to permit initial approval by the milestone date identified in the standard project milestones table of Project Management procedures. The standard project milestones are used as an input to establish the in-service dates. The Project Management Plan defines how the project will be implemented, monitored, controlled and closed. Included in the

[8] AACE International, formerly the Association for the Advancement of Cost Engineering, prepares professional practice guides (PPG) for engineers such as PPG#7, *Cost Engineering in the Utility Industries*. *See* ACEE INTERNATIONAL, www.aacei.org (last visited Oct. 21, 2015).

[9] The Project Management Institute (PMI) and INPO both provide guidance on project management procedures. *See* PROJECT MANAGEMENT INSTITUTE, www.pmi.org (last visited Oct. 21, 2015); INSTITUTE OF NUCLEAR POWER OPERATIONS, www.inpo.info (last visited Oct. 21, 2015).

Project Management Plan are Cost and Funding as well as an Implementation Strategy. The Cost and Funding section of the Project Management Plan estimates costs and resource impacts including design implementation, materials, internal resources, procedure updates, simulator updates, disposal costs, NERC compliance requirements and NRC fees. The Implementation Strategy section of the Plan provides what will be required to accomplish the project scope and achieve the desired deliverable. The Implementation Strategy should include all preparations and restraints, and identified resources, vendors, and other experts.

Project planning also uses benchmarking and performance contracts with vendors to more effectively predict and control project costs. We benchmark other companies and do comparative analysis for industry-wide work like the Fukushima external event program. This benchmarking enabled us to align our Fukushima program costs with what other companies were experiencing in their similar work. We also work with our vendors on larger projects like the steam generator replacement at Prairie Island to build in performance milestones and hold them accountable for the quality, cost and timeliness of their work. In 2013-14, this resulted in our ability to obtain vendor credits for the steam generator project that reduced the final project cost and saved customers money.

After the capital expenditure budgets by project are prepared and expected in-service dates are established, all of the projects are accumulated by month and year and the aggregate capital budgets are reviewed by the Nuclear management team in the governance process discussed previously. The combination of project-specific reviews and approvals, and overall alignment

with strategic decision making, provides accountability for a reasonable level of capital investment for Nuclear.

Q. HOW DOES THIS PROCESS TIE BACK TO THE OVERALL COMPANY BUDGET?

A. Once individual capital projects are developed using the processes and procedures I have described, they are rolled up to total budgeted capital costs by capital budget groupings. Often the desired initial fleet capital budget request exceeds the Company's spending guidelines, which then requires review meetings with functional managers, directors, and vice presidents to assess the requested budget and determine the appropriate course of action given funding availability. These leaders evaluate the risks of options available and make judgments on the course of action to take.

Because this happens throughout the Company for all business areas, a higher or lower percentage of the Company's overall resources may be allocated to Nuclear in any given year, depending on the priority of needs throughout the Company. Once the balancing and budgeting process is completed, Nuclear may be able to maintain the list of projects "as is," or may need to adjust the capital investment plan within the established budget thresholds.

Q. DO YOU BELIEVE THAT NUCLEAR'S PROCESS RESULTS IN CAPITAL BUDGETS FOR 2016-2018 THAT REPRESENT A REASONABLE LEVEL OF COSTS FOR CUSTOMERS TO INCUR?

A. Yes. This process results in a reasonable budget that is representative of the capital investment needed to meet Nuclear's prioritized requirements and plant needs for the test year. In each year, Nuclear capital additions are reasonable and necessary to maintain the stability, safety, reliability, and

compliance of our nuclear plants in service of our customers. The capital budgets for this period are reasonable given the life cycle status of our plants (in particular Prairie Island), based on industry comparisons with costs of similar projects, and considering inputs of independent validations of the need for these projects.

3. Capital Budget Updates & Oversight of Emergent Work

Q. IS IT POSSIBLE TO PLAN PRECISELY FOR ALL INDIVIDUAL PROJECTS THAT WILL NEED TO BE DONE IN FUTURE YEARS?

A. Not entirely. As I discussed previously, the capital budgeting process identifies a list of potential projects that must be prioritized based on risk and urgency. This list is continually updated, and given the fact that the budget is prepared six to eighteen months prior to the budget period, priorities can certainly change in that timeframe. For example, many projects have long lead times for engineering, design, scoping, resource appropriation and scheduling, and consequently the timing of the final work can shift between the budget preparation and project completion.

In addition, new priorities can arise, from emerging regulatory requirements (like the Fukushima program) or equipment issues (such as the reactor cooling pump seals that led to forced outages at Prairie Island in 2014-2015). These changing priorities require Nuclear to continually reassess the relative ranking of risk and urgency for all projects, and new priorities can rank ahead of previously identified ones. When total corporate funding capabilities are limited, which they usually are, that can mean that some projects are delayed to make room for the new priority projects that are identified after the budget was prepared. Accordingly, while the total capital spend for Nuclear may stay

close to constant, the individual projects funded in a particular year can change over time as new priorities arise.

Q. HOW DOES NUCLEAR MANAGE ITS OVERALL CAPITAL BUDGET WHEN PRIORITIES CHANGE?

A. LRP procedures establish the process to systematically plan for capital expenditures for long term operation of the Xcel Energy Nuclear plants. It supports making operation, resource allocation and risk management decisions to maximize fleet value to stakeholders, while maintaining and improving safety and reliability for the public and plant staff. The LRP process works in conjunction with the PRG and Prioritization Guideline procedures. Periodically, it may be necessary to reallocate and reforecast capital expenditures, as unforeseen problems encountered are difficult to fix, and often require final implementations that differ from initial conceptual plans. When new projects arise, the site PRG will initially perform the reallocation of plant prioritization and will update the capital forecast with the new funding information. Before the funds are authorized to reallocate capital spend, however, the Site Vice President and the Vice President, Nuclear Capital Projects must concur with the PRG recommendations and approve the revised capital forecast. The sites are accountable to the Nuclear leadership team via EPRG, and the Nuclear leadership team is accountable to the Company's Financial Council. These accountabilities effectively reallocate resources as part of managing our business.

Q. WHAT DOES NUCLEAR DO TO MANAGE CAPITAL COSTS WHEN THEY EXCEED ORIGINAL BUDGETS, OR WHEN UNPLANNED PROJECTS BECOME CRITICAL PATH?

A. We have a process that tracks changes in individual projects, but also provides overall governance with accountability to total capital investments made.

From a process standpoint, when changes are identified that will impact project budget, scope, schedule or quality, the resolution and approval are documented on Project Impact Notice/Project Scope Change Request form in accordance with Project Management Manual procedures. If the change is significant, PRG procedures require that a change to the project funding authorization be prepared and submitted to PRG for approval. If at any time during a project's execution the total cost is projected to exceed an authorization threshold requiring additional corporate review and approval, then the responsible Project Manager shall ensure the project is presented to Nuclear EPRG or Xcel Energy corporate Investment Review Committee or Finance Council for approval as governed by corporate policies/procedures. Project Impact Notice/Project Scope Change requests that are attributable to a vendor are analyzed against the vendor's contract and the vendor will be held accountable to said contract requirements.

We have also learned important lessons about ensuring proper communications with stakeholders and our Commission when large project costs exceed initial estimates. During the Monticello LCM/EPU proceedings, we also gained a better understanding of regulatory expectations regarding communications and updates if a large project should have a material increase in project estimates. We work closely within our internal governance process and with our regulatory group to ensure appropriate communications going forward.

1 *4. Major Capital Projects*

2 Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

3 A. It is my understanding that amendments to the multi-year rate plan statute in
4 Minnesota require a utility to "provide a general description of the utility's
5 major planned investments over the plan period." To comply with this
6 requirement, we have identified the major Nuclear capital projects we believe
7 fall under this category of investments, and describe those projects below.

8

9 Q. HOW DID NUCLEAR IDENTIFY THE PROJECTS THAT FALL WITHIN THIS
10 CATEGORY OF INVESTMENTS?

11 A. For purposes of ratemaking, we define "major capital projects" that contribute
12 to our overall major planned investments as unique projects that will require a
13 greater than normal quantity of Nuclear resources to complete.

14

15 Q. WHAT MAJOR CAPITAL PROJECTS DOES NUCLEAR ANTICIPATE COMPLETING
16 OVER THE PERIOD OF THIS MULTI-YEAR RATE PLAN?

17 A. We anticipate undertaking nine major capital projects during the period 2016
18 through 2018. These projects, depicted in Table 5 below, include:

19

Table 5
Major Capital Projects

Capital Grouping	Project	Number of Major Projects in 2016	2017	2018
Dry Cask Storage	Dry Fuel Storage Loads (Both Plants)	1		2
Mandated Compliance	Fukushima Program (Both Plants)	1	Continued	Continued
	NFPA 805 Fire Protection (PI)	1	Continued	Continued
	Physical Security Upgrade (Monticello)	1		
	Cyber Security Model (Both Plants)	1		
Reliability	Reactor Coolant Pump Replacements (PI)	1	Continued	Continued
	Cooling Tower Replacement (PI)		1	Continued
	Electric Generator Replacement (PI)			1
Facilities & General	Turbine Building Crane Upgrade (PI)	1		

Some of these projects, including the Fukushima program, NFPA 805 Fire Protection, and Reactor Coolant Pump Replacements will continue over multiple years, with portions of the project placed in service as they are put into use each year. The major capital projects we expect to complete during the plan period, as well as the additional key projects we anticipate completing in 2016-2018, are discussed in more detail under each plan year, below.

C. 2016 Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NUCLEAR CAPITAL ADDITIONS BUDGET FOR 2016.

A. The total NSPM Nuclear 2016 capital additions are budgeted to be $169 million for projects and $76 million for fuel. Table 6 below sets forth the anticipated capital additions for 2016 by capital budget grouping:

Table 6

2016 Nuclear Capital Budget Groupings	Total NSPM 2016 Additions Including AFUDC ($ in millions)
Dry Cask Storage	$19.4
Mandated Compliance	$83.8
Reliability	$53.6
Improvements	$4.6
Facilities & General	$7.3
Subtotal – Projects	$168.7
Nuclear Fuel	$76.1
Total Nuclear Capital Additions	$244.8

Q. WHAT ARE THE PRIMARY DRIVERS OF THE 2016 CAPITAL ADDITIONS PLACED INTO SERVICE BY THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. Project additions include $84 million for mandated compliance work, $54 million for equipment reliability, and $19 million for dry cask storage. Fuel additions are an ongoing capital requirement over the refueling cycles of each plant.

The mandated compliance work reduces fire risk and fire-induced loss of cooling to the reactor, implements new post-Fukushima standards for industry external event mitigation for extreme circumstances beyond license requirements, and addresses security threats to nuclear plants, both physical and cyber/computer. The reliability work is in support of ensuring high generation output, in pursuit of our goal of producing over 90 percent of our capacity.

1 *1. Dry Cask Storage*

2 Q. WHAT ARE DRY CASK STORAGE PROJECTS?

3 A. Dry Cask Storage projects are associated with on-site dry spent fuel storage
4 and loading campaigns, such as the Independent Spent Fuel Storage
5 Installation (ISFSI). Because the Federal Government has not yet identified a
6 permanent, long-term spent fuel storage facility, the Company must store
7 spent fuel on-site in the interim. The timing of spent fuel storage is also
8 designed to enable a full core offload for each unit at any time, compliant with
9 NRC license requirements and the Commission's Certificate of Need
10 requirements. Because of the longer on-site storage now required, we will
11 need to implement several aging management programs for the storage casks,
12 including continued/extended licenses from the NRC.

13

14 Q. PROVIDE AN EXAMPLE OF A KEY DRY CASK STORAGE PROJECT NUCLEAR
15 OPERATIONS ANTICIPATES PLACING IN SERVICE IN 2016.

16 A. The only Dry Cask Storage project being placed in service in 2016 is
17 Monticello Cask #16, carried over from the 2013 fuel storage loading
18 campaign due to license compliance issues from vendor performance in 2013,
19 which increased project costs. We did not seek recovery of the incremental
20 costs related to these compliance issues in our prior rate cases. However, we
21 worked with the NRC in 2014 and 2015 to determine what actions are needed
22 to complete the loading of Cask #16 and place it in service in the storage
23 facility on site. The focus of this discussion was ensuring storage canister
24 integrity and safety for long-term storage.

25

26 Pending results of our discussions with the NRC and further investigation, we
27 propose including these costs in our 2016 capital additions for final rates,

subject to revision as more information becomes available. I discuss this 2016 project addition in more detail later in my testimony.

Q. WHAT IS THE 2016 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $19.4 million for Dry Cask Storage project additions during the 2016 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. Earlier in my testimony I discussed the capital budgeting process and how we identify, prioritize and assign funding to specific projects, and estimate expenditures and in-service dates by year.

With respect to this specific project, the budget for additions represents the accumulated capital expenditures and AFUDC incurred over time for the Monticello Cask #16 project that is expected to be completed and placed in service during 2016. The additions budget includes actual capital expenditures incurred through June 30, 2015 of $14.1 million, expenditures projected through 2016 of $3.5 million, and AFUDC accruing over the period 2013-2016 of $1.8 million. I discuss these costs in more detail later in my testimony.

Q. WHAT ARE THE TRENDS IN DRY CASK STORAGE PROJECT ADDITIONS OVER THE LAST THREE YEARS, AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Dry Cask Storage project additions have ranged from $19-26 million per year in 2014 to 2016. After no dry cask projects were in-serviced in 2012, cask additions were $64 million in

2013 and $26 million in 2014. Forecasted additions for 2015 are $25 million. The budget for Dry Cask Storage additions in 2016 is about $19 million.

Q. WHAT IS DRIVING THESE VARIATIONS BY YEAR IN CASK ADDITIONS?

A. Dry Cask Storage project additions are different each year based on the specific needs for fuel storage at each site as refueling outages are completed, the spent fuel storage pools are filled, and ISFSI licensing approvals and activities proceed. While some capital expenditures occur each year (see Table 3 above), some years – such as 2012 and 2017 – have no Dry Cask Storage capital additions at all (see Table 4 above).

As noted, the 2016 additions relate solely to the in-servicing of Cask #16 at Monticello. The 2015 additions include the relicensing of the Prairie Island ISFSI facility and Prairie Island Casks #39-47. The 2014 additions related to Monticello Casks #17-20 and Prairie Island Casks 30-38. The $64 million for 2013 additions was higher than in later years due to two projects in-servicing large amounts that year – Monticello Casks #11-15 and Prairie Island Casks #30-38. Smaller amounts for those projects were also in-serviced in 2014.

Q. DO YOU EXPECT THESE VARIATIONS TO CONTINUE?

A. Yes, because the level of work required to complete dry storage installations will continue to vary each year. The dry storage containers authorized by the Commission will continue to be loaded periodically until 2031 in order to support nuclear plant operations at Monticello until 2030 and at Prairie Island until 2034. The licenses for the dry storage installations will also have to be periodically amended in order to continue to comply with NRC regulations. As I noted previously, we can also expect the NRC to add new AMP

requirements to storage facility license renewals implemented in 2016 for Prairie Island (and much later for Monticello), which will add more costs to fuel storage.

In addition to NRC requirements, another Certificate of Need will be required from the Commission to add the additional storage capacity necessary to support plant decommissioning. In the most recent Triennial Decommissioning Accrual filing with the Commission, we identified that the earliest that all spent fuel could be removed from our plant sites is 36 years after plant shutdown. In that proceeding, the Commission: (a) found that based on the Federal Government's past performance, 36 years may be overly optimistic; and (b) ordered that we collect the required funds to support safe spent fuel management for 60 years after plant shutdown. We will continue to take all required actions to ensure the continued safe operation of these fuel storage facilities are compliant with NRC licenses and Commission requirements. The activities needed to meet these requirements will cause varying amounts of dry cask additions over the years.

a) Key 2016 Dry Cask Storage Project:
Monticello Dry Fuel Storage (DFS) Load Cask #16

Q. PLEASE DESCRIBE THE PROJECT.

A. The Monticello 2013 DFS – Load Cask #16 project relates to the procurement, loading and transfer of one cask (#16) containing fuel assemblies from the site's spent fuel pool in the plant to dry cask storage in the site's ISFSI facility, including costs to resolve the dye penetrant weld examination issues.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. This project completes the transfer and storage of the spent fuel in Cask #16 to the ISFSI. Cask loading and storage is part of our long-term fuel disposal process at our plants. Used fuel is regularly removed from the reactor and placed in the spent fuel storage pool to discharge fuel assemblies that have reached the end of their useful lives. The spent fuel storage pool does not have enough space for all used fuel. Because the Federal government is not removing spent fuel from the Monticello site, our on-site dry fuel storage provides sufficient spent fuel storage space over time, allowing continued plant operation in compliance with the plant's operating license and used fuel storage license.

Q. PLEASE DESCRIBE THE PROJECT COSTS IN MORE DETAIL.

A. The 2016 capital addition for this project is $19.4 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, employee travel expenses associated with the project, and other costs such as equipment rental. The additions placed in service include AFUDC accrued during the project's duration. The costs include activities for engineering of program phases, construction of implementation work, and procurement of materials. The budgeted capital addition for 2016 represents the costs associated with the design, engineering, management, oversight, procurement, loading and placement of Cask #16, including those costs incurred to resolve the dye penetrant weld examination issues.

Q. IS THIS THE SAME COST THE COMPANY ORIGINALLY BUDGETED FOR THIS WORK?

A. No. The budgeted amount for the Monticello Dry Cask #16 project has increased over time. The original budget for the 10-cask loading campaign planned for 2013 was about $4 million per cask.

The original budget for capital expenditures was established prior to project commencement in 2013 based on the planned scope, estimated cost, and established activity schedule for the project (which initially included loading 10 casks at Monticello, Casks #11-20). AFUDC is accrued on actual expenditures according to Company policy, compliant with FERC guidelines, while the project is in progress. Our initial plan was to complete loading all of Casks #11-20 in late 2013. The initial capital budget for this work was exceeded due to technical issues caused by vendor performance in 2013, as I discuss later.

The remaining expenditures forecasted for this project are therefore based on our projection of the work necessary to address the Cask #16 technical issues with the NRC, which we currently anticipate will take until at least mid-2016 to resolve. We have filed an exemption request with the NRC to approve our work on the cask as sufficient to mitigate the vendor performance issues noted. Our forecasted cost assumes the NRC will approve our exemption request by mid-2016, and we can place Cask #16 in service in the test year.

That said, the NRC has indicated it may take some time to review our exemption request and act on it, so we may not have a final disposition from the NRC until the end of 2016. Because of the uncertainty in the steps and timeline in bringing the Cask #16 issue to closure, at this time we are including the costs in our proposed final rates (but not in our proposed

interim rates) to allow the NRC review and vendor dispute processes to play out.

Finally, we also face the risk of the NRC requiring additional inspections in the future on Casks 11-15, which have been placed in the IFSFI storage facility. No costs for these additional inspections, should they be required, are included in our capital budgets or O&M expenses for this rate case.

Q. DESCRIBE THE CASK LOADING PROCESS AND THE COMPLIANCE ISSUES ENCOUNTERED.

A. During a nuclear plant refueling, spent (used) fuel is removed from the reactor core and placed in the spent fuel pool for temporary storage. The spent fuel pool has limited capacity, and fuel must eventually be removed from the pool to make room for the next refueling. The plant is required to keep enough room in the spent fuel pool to accommodate a full reactor core offload. Fuel removed from the pool is loaded into metal dry shielded canisters, which have two lids that are each welded, one on top of the other. The canister loading process is facilitated by a specialized transfer cask that the canister is placed in during loading. The transfer cask is procured from our vendor AREVA. Inert gases are injected into the sealed casks to prevent degradation of the spent fuel during interim storage. The casks are loaded and sealed in the reactor building, and then transported to, and inserted into the ISFSI storage module located outside the plant. Ultimately, the loaded casks are to be moved off-site by the Department of Energy once a permanent Federal storage site is approved and available. Until then, the spent fuel is stored on-site in casks in the ISFSI storage facility.

With respect to Dry Cask #16 at Monticello, our dry cask loading vendor, TriVis, Inc., failed to follow all of its procedures for post-weld examinations of loaded casks. These examinations are surface evaluations for cracks. Examination procedures required placing dye on the welds for at least 10 to 15 minutes before checking for cracks; however, TriVis workers did not adhere to the required wait time. The preliminary NRC findings from their investigation of this issue faulted both TriVis contractors (who conducted the work) and Xcel Energy (which is responsible for oversight) for these improper examination procedures. The preliminary findings stated that the vendor not only failed to follow the required waiting times, but also inaccurately documented the waiting times to make them appear to be consistent with the requirements of its examination program procedures.

Q. WHAT WERE THE COMPANY'S OPTIONS WITH RESPECT TO ADDRESSING THESE FINDINGS?

A. We needed to address the NRC's findings, either (i) through re-performing the dye penetrant weld examinations, which was not feasible or practical because some welds were not easily accessible, or (ii) by obtaining an NRC exemption to the requirement for the dye penetrant examinations based on undertaking alternative examination methods and providing additional information to the NRC. Until then, the cask in question must remain staged within the plant rather than inserted into the on-site ISFSI facility. After evaluating our alternatives for resolving the issue, we decided we would perform an alternative examination method on the cask welds and request approval of an exemption from the NRC. We consider this the safer option with less nuclear risk.

Q. WHY DOES THE COMPANY BELIEVE THIS IS THE RIGHT APPROACH?

A. We took several steps to evaluate our options. First, we took prompt action to ensure that all of the Dry Cask containers these two technicians inspected (#11-16) were safe and did not pose a risk to the public. This action included an extent of condition review which determined that the containers were safe and leak tight, based on review of empirical test data for our employees' helium pressure leak tests on the casks. The NRC agreed with our conclusion, but may require additional evidence or inspections to be fully satisfied.

Additionally, we have worked with the Electric Power Research Institute (EPRI) to develop an alternate weld examination method called Phased-Array Ultrasonic Testing that allows us to look deep into the numerous weld layers on the canister, similar to how a doctor can look inside a patient using x-rays or a CAT scan, to examine the quality of the welds and look for imperfections that may not have been identified due to the improper dye penetrant tests. The results of this phased-array testing on canister #16 showed that the welds are structurally sound and provide us further confidence that all of the Dry Cask Storage canisters from the 2013 loading campaign will maintain their integrity in order to protect public health and safety. As a result, at this point we are satisfied that the welds on Casks 11-16 are safe.

Q. PLEASE PROVIDE DETAIL REGARDING THE ADDITIONAL COSTS INCURRED AS A RESULT OF THIS ISSUE.

A. Our primary additional costs relate to interim storage of Cask #16, investigation of alternate weld examination and NRC approval processes, and moving the loaded cask to the ISFSI facility.

During the period that an alternative method was developed and performed, we have kept the cask on the reactor building floor inside the specialized transfer cask provided by AREVA, which provides both radiation shielding during the loading process and indoor storage protection. Consequently, until the issue is resolved, we have had to retain the transfer cask longer than originally planned **[TRADE SECRET BEGINS** …

… **TRADE SECRET ENDS]**. There is a limited supply of transfer casks available to the industry, and utilities have generally found it to be more cost-effective to procure them through rental from outside vendors rather than building or buying their own. Thus we have had to incur substantial additional rental costs, totaling **[TRADE SECRET BEGINS** …

… **TRADE SECRET ENDS]** based on current forecasts. We have mitigated some of those cost increases and negotiated a discount from the initial contract terms with AREVA by implementing a broader scope of work between our two sites from that vendor.

We have also incurred and will continue to incur costs for the alternative weld examination method and the NRC exemption process. These items have added approximately $6 million to the project beyond our original budget. Finally, once we obtain the exemption we will incur incremental costs to move the loaded cask into the ISFSI facility and demobilize equipment at a cost of approximately $1 million beyond the level we would have incurred had Cask 16 been part of a larger loading campaign (instead of a stand-alone load of one cask).

Q. WHY HAS THE COMPANY INCLUDED THESE ADDITIONAL COSTS IN ITS RATE REQUEST?

A. The costs for loading spent fuel are a reasonable cost of service for customers, even at the higher amount for Cask #16. We are including the costs in our proposed final rates (but not in our proposed interim rates) to allow the NRC review and vendor dispute processes to play out.

At the same time, we are initiating claims against the vendor, although it is not yet clear whether we will ultimately recover costs from the vendor. Under circumstances where the amount of vendor recovery is not fully known, we typically include the costs in proposed rates subject to refund to customers for amounts recovered from vendors. We believe this is the appropriate course of action in this case. We are continuing to take action to address the situation, and will keep our regulators informed.

Q. WHAT MEASURES WERE TAKEN TO REVIEW THE QUALITY CONTROL PROGRAM OF THE DRY CASK VENDOR AT MONTICELLO?

A. As part of the Spent Fuel Dry Cask Loading campaign at Monticello in 2013, the company contracted with TriVis to perform work associated with that campaign. The Company hired TriVis because it had successfully performed this type of work for another utility and also had in place a Quality Control Program compliant with NRC regulations (commonly referred to as an Appendix B program).[10] In our view, accountability for compliance with NRC requirements belongs to TriVis under such circumstances, and we plan to hold TriVis legally accountable to the extent possible. While it is incumbent upon

[10] Nuclear quality assurance employees audited TriVis' weld examination program procedures and found them to be compliant with NRC Regulations 10 CFR 50 Appendix B - *Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.*

us to ensure all work performed at our nuclear facilities is completed properly, the purpose of NRC-approved Quality Control Programs such as TriVis' is to enable Company employees to focus on day to day operations rather than actually perform quality control functions our vendors have been approved to perform. Such reliance and accountability is standard industry practice when using vendors with approved Appendix B programs. We believe we acted responsibly in selecting the vendor, had appropriate supervision protocols in place, and took appropriate remedial measures when the vendor's performance issues were identified.

Q. HOW IS THE COMPANY PROCEEDING IN ITS DISCUSSIONS WITH THE NRC ON THE CASK WELD ISSUES?

A. The NRC provides the option of pursuing Alternative Dispute Resolution (ADR) to resolve potential issues – in this case, non-binding mediation. Mediation is an informal process in which a trained neutral and independent mediator works with parties to help them reach resolution. The mediator has no stake in the outcome and no power to make decisions. Mediation gives us and the NRC an opportunity to discuss issues, clear up misunderstandings, be creative, find areas of agreement, and reach a final resolution of the issues.

Q. WHAT IS THE STATUS OF THE ADR PROCESS WITH THE NRC?

A. Representatives from the Company, the NRC, and an independent mediator conducted an ADR session in Chicago on October 15, 2015. The session resulted in a preliminary agreement that will be finalized and communicated through an order from the NRC. We will provide updates on the terms of the agreement and our commitments thereunder in the rate case discovery process.

Q. WHAT IS THE CURRENT STATUS OF THIS PROJECT?

A. The project is in the implementation phase. The storage canister (cask) #16 has been loaded with spent fuel and is on the refueling floor of the site reactor building awaiting disposition. A request for NRC exemption from the requirements of the storage canister technical specifications was submitted on September 29, 2015. Once the request is approved by the NRC, the canister will be moved to the ISFSI and placed in-service as a capital addition. Our current expectation is that this in-servicing will occur in the summer of 2016.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. Yes. NRC approval of the exemption request described above is required. At this time we are anticipating the NRC will take until mid-2016 to approve our request. However, there is no specific timetable and the NRC may provide us with further information requests, questions, or analysis to which we need to respond before approval can be obtained.

2. Mandated Compliance

Q. WHAT PROJECTS ARE INCLUDED IN THE MANDATED COMPLIANCE GROUPING?

A. Mandated Compliance projects include regulatory, security, and license commitment activities required by Federal or state regulators (normally the NRC), including industry commitments made to the NRC. They are driven by the requirements of the NRC or other regulators as a condition of maintaining our license to operate the plants. Mandated Compliance work is intended to implement new NRC regulations for the industry, often with a safety implication (such as Fukushima external events and fire protection).

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY MANDATED COMPLIANCE PROJECT SCHEDULED TO GO IN SERVICE DURING THE 2016 TEST YEAR.

A. The largest Mandated Compliance project with 2016 additions is Nuclear's program to comply with the NRC's external event orders issued after they reviewed the Fukushima incident in Japan in 2011. I discuss this 2016 project addition in more detail in the next set of questions in my testimony, along with two other key Mandated Compliance projects related to compliance with NRC requirements for fire protection and cyber security.

Q. WHAT IS THE 2016 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $83.8 million for Mandated Compliance project additions during the 2016 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. Earlier in my testimony I discussed the capital budgeting process and how we identify, prioritize and assign funding to specific projects, and estimate expenditures and in-service dates by year.

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Mandated Compliance projects that are expected to be completed and placed in service during 2016. We first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project revised, the cost estimate can be updated over the period the project is progress. The capital additions budget

for 2016 represents the total of expenditures incurred, and AFUDC accrued over the project duration, that are expected to be completed and placed in service during the year 2016.

We have also benchmarked several Mandated Compliance projects that are common across our industry, such as Fukushima program spend as I discuss later in my testimony. Further, we have received industry data from NEI that shows average mandated/regulatory spend per reactor.

Q. WHAT ARE THE TRENDS IN MANDATED COMPLIANCE PROJECTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Mandated Compliance project additions are fairly consistent from 2014 to 2016 at about $64-84 million per year. The 2016 budget for Mandated Compliance additions of $84 million is higher than the forecasted 2015 additions of $64 million and the actual 2014 additions of $77 million placed in service those years. The 2016 additions are significantly higher than the $27-30 million placed in service for Mandated Compliance in 2012-2013.

Q. WHAT IS DRIVING THESE TRENDS?

A. The 2016 additions are largely related to complying with the NRC's Fukushima program, the NRC's fire protection requirements, the NRC's requirements for addressing physical security threats at Monticello, and the NRC's cyber security initiatives. Each of these Mandated Compliance projects is explained in more detail later in my testimony. The 2015 additions include compliance projects for Fukushima and fire protection, but also include projects for the NRC's tornado/missile protection initiative, and the NRC's

fuel oil train separator requirements. The 2014 additions included fire protection and cyber security projects, but also projects required under Prairie Island license renewal and Monticello's resolution of NRC flooding protection issues.

The lower level of Mandated Compliance additions in 2012-2013 is due to no additions in those years for Fukushima (as the NRC's orders came out in March 2012), and lower levels of additions for cyber security and phased fire protection work being completed in those years.

a) Key 2016 Mandated Compliance Project: Fukushima Program

Q. PLEASE DESCRIBE THE PROJECT.

A. This project is the Company's initiative to comply with NRC orders in response to increasing public safety at U.S. nuclear reactors after reviewing the 2011 incident at the Fukushima Daiichi plant in Japan. In March 2012, the NRC issued a set of Orders[11] that all U.S. nuclear plants will need to comply with to continue to operate. NRC Orders EA-12-049 ("FLEX") and EA-12-051 (Spent Fuel) are required to be implemented at both of the Company's plants. Additionally, the NRC issued a Request for Information[12] that required all plants to re-evaluate the plant with respect to a set of external

[11] NRC Orders EA-12-049 (Mar. 12, 2012), ORDER TO MODIFYING LICENSES WITH REGARD TO REQUIREMENTS FOR MITIGATION STRATEGIES FOR BEYOND-DESIGN-BASIS EXTERNAL EVENTS; EA-12-051 (Mar. 12, 2012), ORDER MODIFYING LICENSES WITH REGARD TO RELIABLE SPENT FUEL POOL INSTRUMENTATION; and Order EA-13-109 (June 6, 2013), Order Modifying Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation Under Severe Accident Conditions.

[12] NRC's REQUEST FOR INFORMATION PURSUANT TO TITLE 10 OF THE *CODE OF FEDERAL REGULATIONS* 50.54(f) REGARDING RECOMMENDATIONS 2.1, 2.3, AND 9.3, OF THE NEAR-TERM TASK FORCE REVIEW OF INSIGHTS FROM THE FUKUSHIMA DAI-ICHI ACCIDENT (Mar. 12, 2012).

hazards using modern day methods and techniques (referred to as hazard evaluations). External hazards include seismic (earthquake), flooding, and tornado projectile "missile" risks.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. It is necessary to ensure compliance with the requirements of the NRC's Orders and Request for Information. Compliance in the timelines given is mandatory to continue operation at the Company's nuclear plants. From a public safety perspective, the NRC considers the Fukushima program warranted to ensure the public is appropriately protected from external events that could threaten the safe operation and shutdown of nuclear plants.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The Fukushima program is a multi-year project for both sites. The capital additions planned for 2016 are $36.2 million (including AFUDC), after additions in 2014-2015 and continuing additions in 2017-2019. The program has been categorized into five groups at each of the Company's nuclear plants:

- Spent Fuel Pool Instrumentation;
- FLEX Hazard Evaluation & Equipment Implementation;
- FLEX Equipment Storage Building;
- Regional/National Communications/Response Center; and
- Reliable Hardened Vent (Monticello only).

Each of these groups of Fukushima program activities has NRC due dates based on a unit's refueling outage schedule in relation to the issuance dates of the NRC's orders. Thus the completion schedule for program activities at each of our plant sites is different, with FLEX and Spent Fuel activities due

for completion at Monticello prior to plant restart from the spring 2015 outage, at Prairie Island Unit 2 prior to restart from its fall 2015 outage, and at Prairie Island Unit 1 prior to restart from its fall 2016 outage.

The project costs include employee labor, outside contractors, materials and equipment, employee travel expenses, and other costs associated with regulatory compliance. The additions placed in service include AFUDC accrued during the project's duration. The costs include activities for engineering of program phases, construction of implementation work, procurement of materials, and NRC regulatory compliance.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. We benchmarked other companies' operating experience to date to calibrate the scope and costs of the Fukushima program. We gathered estimated figures from vendors for the various program elements' cost components: construction, equipment, engineering and implementation costs. In-service dates were developed to support the site's refueling outages where Order compliance is required to be complete and documented. We added appropriate contingencies due to uncertainty of costs in the early stages of the project, and to ongoing guidance from the NRC and other companies as to program compliance expectations. We have continually refined our program budgets as the project goes through the project management process. Our current forecast of the entire Fukushima program is comparable to industry benchmarking data, which averaged over $30 million in capital costs per reactor.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Monticello has implemented the FLEX (with an exception for missile protection of the existing hard pipe vent) and Spent Fuel Orders. Monticello successfully completed its Fukushima program work in less time and at lower cost than the industry norm. Prairie Island has also in-serviced the Spent Fuel compliance project and is currently anticipating an in-service date on the FLEX Storage building in the fall of 2015.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. Yes. The NRC defined program requirements in its orders, required us to submit plans to comply with the orders, and approved our Fukushima project work plans. The NRC will be certifying that program work is done and auditing compliance with the FLEX and Spent Fuel Orders at each plant as the projects proceed. The NRC considers compliance with its Fukushima external event orders to be mandatory. In the event of non-compliance (or possibly untimely compliance), the NRC has the authority to terminate the plant's operating license and shut the units down. Further, if the NRC determines non-compliance to be willful, it has the authority to seek enforcement actions – including criminal charges – against officers and employees involved.

b) Key 2016 Mandated Compliance Project:
Fire Protection Program at Prairie Island

Q. PLEASE DESCRIBE THE PROJECT.

A. Nuclear's fire protection requirements under operating licenses are codified in Federal regulations (referred to as Appendix R[13]). However, Appendix R

[13] Federal Regulation 10 CFR 50, Appendix R.

provides some requirements that cannot readily be met regarding the separation of safety related equipment in the event of a fire. As this became an industry issue, the NRC offered nuclear operators a choice to comply with fire protection standards under one of two alternatives, at the operator's option. One option is the deterministic model under Appendix R. The other option is following the risk-informed, performance-based approach established by the National Fire Protection Association (NFPA) under its Standard No. 805.[14] Implementation of an NFPA 805 program requires an NRC License Amendment Request (LAR). Implementation of all approved LAR projects is a condition of maintaining an operating license in good standing. The NRC has granted extensions of fire protection program compliance under NFPA 805 without regulatory findings (for non-compliance with Appendix R). The NRC compliance process for fire protection under NFPA 805 is then defined with the LAR approval schedule.

We evaluated the options for each of our sites. Monticello has proceeded with Appendix R requirements as its fire protection program. Prairie Island elected NFPA 805 requirements to provide more time to resolve its fire protection risk issues, and avoid potential non-compliance and NRC findings during the time it would take to comply fully with the Appendix R program. The NFPA 805 project scope at Prairie Island includes development of a fire protection model (evaluating risk to reactor core damage) and performance of 32 plant modifications to implement fire protection elements, which will be completed in stages through 2020. This NFPA 805 modeling complies with NRC regulations for fire protection.

[14] NFPA 805: Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants was originally issued in 2001 and has issued revised editions four times since then, with the latest in 2015.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. The NRC allowed the choice of fire protection programs under either Appendix R or NFPA 805. Our analysis determined that the NFPA 805 risk-informed approach was more cost effective to mitigate the risks of reactor core damage frequency and large early radiation release, and to ensure the safe shutdown of the Prairie Island plant in the event of a fire. Using an Appendix R at Prairie Island would be cost prohibitive and uneconomical to address pending fire protection nonconformances (now being addressed throughout the NFPA 805 program) through the NRC's significance determination process.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2016 capital addition for this project is $18.2 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, employee travel expenses, and other costs associated with regulatory compliance. The costs include engineering and construction work for fire model development and implementation, and regulatory compliance activities for LAR preparation and submittal.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. Industry operating experience and benchmarking of NFPA 805 pilot plants were initially used for high level project cost estimates. Vendor estimates, additional industry operating experience, and our own experience, were used to refine the initial estimates and determine the program budget for the LAR preparation, submittal, fire model development, and administrative implementation costs. As each modification approaches implementation, the cost estimates will be further refined as specific scope and resource needs are

finalized to meet NRC requirements for fire protection. The project duration and scope has expanded over time as the NRC has reviewed our implementation plans, issued requests for additional information, and provided additional guidance on their compliance expectations for fire protection. We continue to monitor the fire protection modifications made and costs incurred by other nuclear utilities to ensure our project costs are in line with the industry.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project is currently responding to NRC Requests for Additional Information. Upon resolution of all outstanding requests, the NRC will issue a Safety Evaluation Report signifying the approval of the related License Amendment Request(s). Capital additions for fire protection modeling are going into service in two phases, with about $23.8 million of actual additions in 2012 and another $15.9 million of budgeted additions in 2016. Additions for fire protection modifications are also going into service in a phased approach, including $3.7 million in 2014, $4.8 million in 2015 and $2.3 million in 2016. Modeling is expected to be completed in 2016, but additional modifications are planned to continue in phases through 2021. Once the Safety Evaluation Report is approved (see below for timing), the phased modifications will continue to be installed. Many of the modifications require refueling outages to install. Also, since these outages have limits as to the amount of equipment that can be safety modified during the outage period, the fire protection modifications will take until 2021 for all phases to be completed.

Of the 32 program modifications in scope, 16 were not yet in design phase, nine were in the design phase, none were in the implementation phase, and seven were completed as of August 2015. Of the 16 not yet in design phase, nine have been approved by the site PRGs with funding beginning in the fall of 2015, and the other seven scheduled to go through the PRG process in early 2016. Implementation planning and scheduling is underway. The draft Change Management Plan is currently being prepared and is under review.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. Yes. The NRC must approve Prairie Island's License Amendment Request(s) for NFPA 805 program activities through the approval of the related Safety Evaluation Report. With satisfactory response to the NRC's information requests, we expect approval through the Safety Evaluation Report. Based on the NRC's 2-year review metric, issuance of that report can be expected by April 30, 2016. In the meantime we continue to proceed on our implementation timetable, putting phases of the fire protection project into service as completed. Upon the NRC's approval through issuance of the Safety Evaluation Report, the NFPA 805 Transition License Condition will be in effect, which allows a transition period to implement programmatic changes and facility modifications.

c) Key 2016 Mandated Compliance Project:
Monticello Security Physical Upgrade

Q. PLEASE DESCRIBE THE PROJECT.

A. The purpose of this project is to ensure the Monticello plant meets the NRC's Force on Force security threat requirements of our licensed design basis. This project provides protections required to permanently address the

waterborne security threats to the plant's approved design basis, as part of closing a recent NRC security finding. In addition, the project changes the plant's physical security infrastructure in order to remove compensatory actions that the NRC required to be implemented to ensure security as a result of construction of the flooding bin wall at the site.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. This project delivers compliance with NRC license requirements by improving our safety posture for physical security threats, and provides long-term O&M cost reduction by removing additional security officer posts that were required to be implemented at the site as a compensatory measure, to resolve the NRC flooding issue at the plant. It also strengthens certain security detection and assessment capabilities for the site. Further, it assures the effectiveness of the site security response plan to meet NRC expectations for waterborne threats.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2016 capital addition for this project is $13.2 million, including AFUDC. The project costs include employee labor, outside contractors, and materials and equipment. The costs include engineering and construction work for installation of bullet resistant barriers and associated electrical components, as well as activities to address the waterborne security threat under the plant's design basis.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The project cost budget was determined by first developing a conceptual scope of all required physical upgrades. Material costs for the upgrades were determined by pricing standard materials from historic and catalog data, and

by vendor input for non-standard equipment and materials. Construction costs for installation of the upgrades were developed with the input of the responsible work groups supporting the project, as well as historical operating experience for similar project work. Engineering and project personnel costs were estimated based on scope and complexity of the engineering products required to technically assess and justify the upgrades to plant security features.

The conceptual scope of physical upgrades was the result of modeling the site and then optimizing the security design using standard structures. This resulted in an outcome that was more cost effective and provided more effective security protection.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Development of the engineering change package for the project is nearly complete. Major equipment has been ordered and contracted. Construction and installation of upgrades is in progress. Completion of interim configuration of security features was completed in September 2015. The new security configuration will be tested by an NRC Force on Force drill in late 2015. Final project completion is planned for 2016.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. No additional NRC approvals are needed for this project. The NRC's inspection findings on waterborne security threats to the plant were the basis for our security upgrades. The NRC has closed the inspection findings after completing a thorough follow-up inspection of our proposed corrective actions. As always, the NRC will continue to monitor the effectiveness of our

1 security through periodic inspections and drills, such as the Force on Force
2 drill that will occur in late 2015.
3
4 d) Key 2016 Mandated Compliance Project:
5 Cyber Security Programs at Both Sites
6 Q. PLEASE DESCRIBE THE PROJECT.
7 A. Nuclear's Cyber Security requirements are codified in Federal regulations[15]
8 and are designed to provide high assurance that digital computer,
9 communication systems and networks are adequately protected against cyber-
10 attacks up to and including the design basis threat established by regulations.[16]
11 The regulations specifically require operating licensees to implement a cyber
12 security plan (CSP) that satisfies the requirements of the regulations in
13 accordance with an NRC-approved cyber security plan implementation
14 schedule.
15
16 Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?
17 A. Evolving cyber technology in a digital world has created new risks for hostile
18 threats to interfering with nuclear operations. To mitigate these risks, the U.S.
19 Congress is asking the NRC to order the nuclear industry to protect its
20 existing systems and apply new rules for system add-ons and changes. The
21 Federal requirements – and our cyber security plan – are intended to protect
22 our nuclear plants against radiological sabotage due to cyber security events.
23 Compliance with the requirements is mandatory to continue operation under
24 the license in good standing.
25

[15] Federal Regulation 10 CFR 73.54.
[16] Federal Regulation 10 CFR 73.1(a)(1)(v).

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2016 capital addition for this project is $6.2 million, including AFUDC. The Cyber Security project costs include employee labor, outside contractors, materials and equipment, software, hardware, and employee travel expenses associated with the project. The costs include activities for engineering of program phases, implementation of new security procedures, construction of plant modifications to enhance security controls, and procurement of materials.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The project cost estimate was completed by comparing the state of the current Cyber Security program to the latest Federal regulatory requirements. We performed benchmarking of other companies' experience in the industry, when regulatory guidance was unclear for requirements. The in-service date was set to align with the required program implementation date set forth in the operating license amendment.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. We have completed our assessment of the Federal regulatory requirements against the current program. Work is ongoing to implement programmatic controls via procedure generation, and changes to the plant facilities to ensure compliance with regulatory controls.

Q. WERE /ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. Yes. NRC approvals were required for implementation of the Cyber Security program compliant with the guidance provided in the industry guidelines

provided by the Nuclear Energy Institute (NEI).[17] Our compliance plan was submitted to the NRC as a license amendment and has been approved, with amendments, to fully implement the program by December 31, 2016. We expect the NRC to perform ongoing compliance audits with cyber security requirements, and make adjustments to such requirements based on industry lessons learned as new threats are discovered. These adjustments may create new NRC requirements we will have to address.

3. Reliability

Q. WHAT ARE RELIABILITY PROJECTS?

A. Reliability projects improve equipment and generation reliability by reducing safety system unavailability and forced losses in production output, reducing the need for maintenance activities, and implementing life cycle aging equipment management/ replacement programs. They are driven by the fact that the Company's nuclear plants are all over 40 years old and require ongoing capital investment to maintain reliable operation through equipment upgrades and replacement. In effect, these projects are intended to make the plants "like new" under the renewed/extended operating licenses to 2030 for Monticello and 2033-2034 for Prairie Island. That is what our license says, and what we are committed to do.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY RELIABILITY PROJECT SCHEDULED TO GO IN SERVICE DURING THE 2016 TEST YEAR.

A. The largest Reliability project with 2016 additions is a multi-year program to replace and/or rebuild reactor coolant pumps at Prairie Island under our longer-term LCM efforts. I discuss this 2016 project addition in more detail

[17] NEI 08-09 (rev.6) - Cyber Security Plan for Nuclear Power Reactors (April 2010).

later in my testimony, along with two other key Reliability projects at Prairie Island, related to heater drain tank pump speed controls and motor rewinds/replacements. Motors are the latest transient initiation system noted by the NRC, which drives inspection findings under their Reactor Oversight Process. Also, aging equipment is the largest operational complaint by our employees at the plants. These Reliability projects reflect our response to obsolescence of equipment and our commitment to keep O&M costs from growing due to constant repairs.

Q. WHAT IS THE 2016 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $53.6 million for Reliability project additions during the 2016 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. Earlier in my testimony I discussed the capital budgeting process and how we identify, prioritize and assign funding to specific projects, and estimate expenditures and in-service dates by year.

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Reliability projects that are expected to be completed and placed in service during 2016. Our budget allotment to Reliability projects comes first from our strategy to meet operating performance goals set consistent with excellence standards from the NRC and INPO, as I discussed earlier.

For specific projects, we first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project revised, the cost estimate can be updated over the period the project is progress. The capital additions budget for 2016 represents the total of expenditures incurred, and AFUDC accrued over the project duration, that are expected to be completed and placed in service during the year 2016.

Q. WHAT ARE THE TRENDS IN RELIABILITY PROJECTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Reliability project additions have fluctuated from year to year based on the specific projects undertaken in each year. The 2016 budget for Reliability additions of $54 million is significantly lower than the forecasted 2015 additions of $135 million but higher than the actual additions of $43 million in 2014, $41 million in 2013, and $26 million in 2012.

Q. WHAT IS DRIVING THESE TRENDS?

A. Our major capital investments in the prior strategic projects for Monticello's LCM/EPU and at Prairie Island in 2012-2013 diverted resources and funding from our capabilities to complete many Reliability projects in those years. After completion of those strategic projects, our capital investment focus in 2014-2016 shifted to mandated Fukushima projects, which were coming due under NRC requirements, and preparation for LCM Reliability projects at Prairie Island that needed to be done regardless of the 2012 cancellation of the EPU project at that site. Of the $135 million in 2015 Reliability additions, $69

million relates to PI LCM projects going into service with the fall outage this year, and $66 million relates to other Reliability projects being placed into service in 2015. We expect to place a smaller portion of projects in service in 2016.

From a broader view, the nuclear industry is seeing a trend to commit more capital investment to equipment reliability – through replacement and refurbishment – to attain performance excellence and cost efficiencies. High production output of 90 percent of capacity or more is consistent with top quartile operations. Our reliability commitment to attain and maintain output to those levels ensures the delivery of 1700 megawatts of clean carbon-free energy to our customers, and leverages our cost per MWh over a larger base of production output.

a) Key 2016 Reliability Project:
PI Reactor Coolant Pump Replacements

Q. PLEASE DESCRIBE THE PROJECT.

A. The reactor coolant pump replacement project is to replace the four reactor coolant pumps at Prairie Island, two for each unit (numbers 11 and 12 for Unit 1, and numbers 21 and 22 for Unit 2). This project addresses not only plant reliability but also nuclear safety.

Reactor Coolant Pump (RCP) internals are a single point vulnerability for the plant, which is defined as a critical component whose failure results in a reactor trip, turbine trip, or loss of generation capacity. Failures in RCP internals would have a direct consequence of plant trips and loss of generation output. The assemblies for RCP internals as currently installed in three of the

pumps (11, 12 and 22) are original equipment with 40+ years of operation and are showing signs of mechanical wear. Metal filings from the aging pumps become debris in the water flow, which reduces the effectiveness of RCP seals that contain reactor fuel, and present a direct safety risk for leaks.

Because of the complex work involved, and high radiation dose in this equipment, we will plan to rebuild each of the four pumps and related assemblies during the next four scheduled maintenance/refueling outages in 2016 and 2018 for Unit 1, and in 2017 and 2019 for Unit 2. This 2016 addition is the rebuilding of the first set of RCP pump components at Unit 1.

Q. HOW WERE ISSUES WITH THE REACTOR COOLANT PUMPS IDENTIFIED?

A. In the fall 2014 outage at Prairie Island, we implemented a new design for RCP seals intended to reduce the probability of an event causing nuclear fuel damage, to improve the reliability of the seal package, and to extend the operating life of the seals before replacement. The new design was necessary to reduce the NRC's core damage concerns from a post-Fukushima perspective. These seals are less tolerant than the previous design, and proved to be much more susceptible to damage from foreign materials (such as metal fragments from the normal wear of pumps and other components in the cooling water flow).

The 2014 outage scope included the replacement of the seal for both RCP pumps at Unit 1 (there are two RCP pumps for each unit). Once installed, the new seal on one of the pumps experienced damage after several weeks and began to leak reactor cooling water.[18] Once the leakage reached a certain

[18] The leaks were confined to a limited area and no contamination outside the containment area occurred.

level, the unit was required to be shut down to identify and correct the problem. The leak was repaired in a first forced outage/shutdown in late 2014, and a new seal was installed.

After a few weeks the replacement seal began leaking again, the unit was shut down via a second forced outage in early 2015, and a new replacement seal was installed.

After plant startup, the newly replaced seal experienced damage and began leaking again. The unit was shut down via a third forced outage in spring 2015 and a different seal design was installed. This new seal design has remained in service without failure since the third forced outage.

Q. DESCRIBE HOW THIS MULTI-YEAR PROJECT ADDRESSES THE ISSUES EXPERIENCED ON RCP COMPONENTS.

A. After the RCP seal failures, we asked our vendor Westinghouse to perform analysis on the components and system dynamics. Their analysis concluded that pump #12 is showing performance issues and that given the age of all of the plant's RCP pumps, it is likely they will all eventually experience more wear and as a result have more foreign material cause issues in future operations.

Given this likelihood, we evaluated the options for heading off equipment issues in this area of single-point vulnerability, and developed a multi-year, phased LCM program to replace the components for each of the plant's four RCP pumps. This program is intended to mitigate the risk of aging equipment failures in the future, ensure reliable and safe operation of the plant through

the end of its license, and enable event-free performance. Other companies have already completed similar pump replacements and we consider it prudent to complete this work given that our pumps are among the oldest in the industry.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT AT THIS TIME?

A. The benefits of this project include assurance that all of the site's reactor cooling pumps are refurbished to meet minimum equipment standards after operating the original plant components for 40+ years. As with the benefits of many reliability projects, the RCP replacement program reduces the risks of unplanned equipment failure, the related extended loss of generation during the repair period and potentially higher replacement power costs, and regulatory scrutiny in the event of equipment failure that threatens plant safety. Rebuilding these pumps helps us achieve generation at 90 percent or more of capacity while mitigating threats to fuel integrity or other radiation leaks.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2016 capital addition for this project is $11.4 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, and some employee travel expenses associated with the project. The costs include activities for engineering of program phases, construction of implementation work, and procurement of materials. A significant portion of the costs will be for replacing RCP internal components, which include an impeller, shaft, diffuser adapter, turning vane diffuser, labyrinth seals, radial bearing, the main pump flange/radial bearing support, thermal barrier, and thermal barrier heat exchanger.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The first pump being replaced in the project was identified as a key contributor for the seal failures of RCP equipment at Prairie Island that led to multiple forced outages in 2015.

As a recently created project, the initial budget was developed as an early, higher-level, range of magnitude estimate for the replacement of the four pumps and related internal assemblies. These early estimates will continue to be refined through the project management process, described earlier in my testimony, which is ongoing until the project implementation commences during the fall 2016 outage at the plant. This process includes the competitive bidding of materials and services procured from vendors.

Range of magnitude estimates are prepared using vendor cost data and industry experience when available.

Q. HAVE ADDITIONS BEEN PLACED IN SERVICE FOR THIS WORK PRIOR TO THE TEST YEAR 2016?

A. Yes. Total capital additions for RCP seals and pump replacement work of $6.9 million in 2013 and $8.6 million in 2014 (including AFUDC) are included in beginning rate base for the test year 2016.

Q. WERE THE 2015 ADDITIONS FOR RCP WORK IDENTIFIED AS STEP PROJECTS IN THE LAST RATE CASE?

A. No. None of the RCP work capitalized in 2015 was anticipated in the prior rate case, and consequently no additions were included as 2015 Step projects in that case.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The phased pump replacement project was formally initiated in July 2015 and is still in the planning phase. This project is a high priority for equipment reliability and the design phase is commencing in 2015. The first phase of implementation occurs in fall 2016 outage at Unit 1.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. No.

b) Key 2016 Reliability Project:
PI Heater Drain Tank Pump Speed Controls

Q. PLEASE DESCRIBE THE PROJECT.

A. This project replaces the obsolete drive system for the heater drain tank pumps for both Prairie Island Units. The existing motors, magnetic drive couplings, control panel, and level transmitter will be replaced. These components have required significant maintenance support, present a constant threat to generation reliability, and represent a single point vulnerability as a transient initiator that challenge reactor and fuel safety. The new system will consist of a variable frequency drive based system and direct coupled motors. Additionally, two channels of new level transmitters will be added to increase redundancy and eliminate the single point vulnerability. These improvements notably reduce threats to our generation reliability.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. The existing heater drain tank pump system is one of the leading causes of reactivity events at the plant, and addressing such events is a significant maintenance burden. Reactivity events are transient initiators that challenge

reactor and fuel safety. Replacement parts and support for the system are no longer available from original equipment manufacturers. This project updates the system to eliminate the causes of the related reactivity events, eliminates the maintenance burden associated with the frequent failures and design issues, and replaces obsolete equipment.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2016 capital addition for this project is $10.4 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, employee travel expenses associated with the project, and other costs such as equipment rentals. The costs include engineering and construction work for replacement of the drive system for the heater drain tank pumps. Construction includes component replacement such as magnetic drive couplings, control panels and level transmitters, and the addition of two channels of new transmitters.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The project cost budget was determined by developing detailed man-hour estimates for each of the various labor work groups supporting the project. These estimates were developed using inputs from each of the responsible work groups and historical project data. Construction and installation estimates were based on construction walk-downs performed with the 60 percent level engineering package. Major materials, equipment, and engineering support estimates were developed based on vendor proposals or contracts. The resulting estimate was then validated by a professional estimator. The in-service dates were developed based on the refueling outages in which this project would be installed. Each of the in-service amounts is

based on the associated cost of installing each Unit in that year. Physical installation costs were individually estimated for each Unit to reflect the differences in layout, lengths of cable and conduit runs etc. Shared costs common to all four pump replacements (engineering, project management, etc.) were equally split among each Unit to develop the final in-service amounts.

In addition, when the project was initiated, we benchmarked the work against the Kewaunee nuclear station, which had recently revised its heater drain tank pump controls. Although there are some differences in scope and quantities between that plant and ours, the benchmarking data supports our cost estimates for the work at Prairie Island.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project is in the engineering design phase with the engineering package at approximately 90 percent complete. The project is on track with its schedule for implementation in 2016 and 2017.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. No.

c) Key 2016 Reliability Project:
PI Motor Rewinds / Replacements

Q. PLEASE DESCRIBE THE PROJECT.

A. The purpose of the LCM project is to address aged motors throughout the Prairie Island plant by a combination of rewinds and replacement. Industry program guidelines and equipment manufacturers (such as for the common

H54 motor) recommend refurbishment of motors at 10-15 years and rewinds every 30-40 years. Most motors within the program at Prairie Island have been in service for 42 years and are due for refurbishment or rewind. This is a multi-year program, with capital additions in 2015 and the test year 2016, continuing in 2017-2018, and beyond.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. This is a key equipment reliability project that is critical to reliable plant operation through end of the plant's license in 2033-2034 by addressing preventative maintenance needs that are coming due to rewind aged motors. Industry history and trends have shown that at 35 years, motor failures frequently occur even with robust preventative/diagnostic plans. With most of our motor components exceeding that age, this program is needed to mitigate the high risk that would otherwise exist for failures. As with most reliability projects, the motor program reduces the risks of unplanned equipment failure, the related extended loss of generation during the repair period and potentially higher replacement power costs, and regulatory scrutiny in the event of equipment failure that threatens plant safety.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2016 capital addition for this project is $6.2 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, employee travel expenses associated with the project, and other costs such as equipment rentals. The costs include materials, engineering and construction work for motor replacements, and implementation work associated with industry/manufacturer recommendations for motor refurbishment/rewinds.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. This is an LCM project intended to get the plant in line with industry recommendations on motor equipment health. We evaluated the costs of rewinding/rebuilding the motors versus buying them new. In many cases we found it less costly to rebuild the motors to like new condition, as we expected to be better able to control cost and scope as well as building exact spares, since many of the motors did not have original equipment manufacturer components available that matched our exact form, fit and function. This approach is similar to best practices followed by the industry, including similar work done in the Exelon and Duke nuclear fleets.

The project cost budget was determined by developing detailed man-hour estimates for each of the various labor work groups supporting the project (construction, engineering, etc.). These estimates were developed using inputs from each of the responsible work groups and historical operating experience. Vendor estimates were obtained for material and rewind costs. The in-service dates were developed to support and align with the plant's refueling outages or motor availability for out of service. Initial estimates have been refined as operating experience is developed from other motor replacements in the plant.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Motor refurbishments and rewinds for 2015 are currently in production. New motor purchases and rewind services for 2016 and 2017 have been contracted. New 2016 motors will begin to be manufactured in August/September 2015. New 2017 motors will begin to be manufactured on August/September 2016.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. No.

4. Improvements

Q. WHAT ARE IMPROVEMENT PROJECTS?

A. Improvement projects improve system and operational performance and operation (for example, digital upgrades), and can reduce O&M costs. They enable us to capture opportunities for improved output or operational performance and efficiency, which can provide a payback for the investment through higher output or lower operating cost.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY IMPROVEMENT PROJECT BUDGETED TO GO IN SERVICE DURING THE 2016 TEST YEAR.

A. The total amount of Improvement project additions budgeted in 2016 is only $4.6 million for both plant sites, and thus no individual projects are considered key for that year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. Earlier in my testimony I discussed the capital budgeting process and how we identify, prioritize and assign funding to specific projects, and estimate expenditures and in-service dates by year.

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Improvement projects that are expected to be completed and placed in service during 2016. We first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a

budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project revised, the cost estimate can be updated over the period the project is progress. The capital additions budget for 2016 represents the total of expenditures incurred, and AFUDC accrued over the project duration, that are expected to be completed and placed in service during the year 2016.

Q. WHAT ARE THE TRENDS IN IMPROVEMENT PROJECTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Improvement project additions can fluctuate from year to year based on the specific projects undertaken in each year. The 2016 budget for Improvement additions of over $4 million is comparable with other low addition years like 2015 and 2012, which each have about $3 million in additions. The 2016 additions are lower than the actual additions of about $18 million in both 2014 and 2013.

Q. WHAT IS DRIVING THESE TRENDS?

A. The nature of Improvement projects is that they are completed as opportunities to improve arise and have funding capability given other priorities. In 2012, 2015 and 2016, when fewer Improvement projects were completed, other projects had higher priority in our balancing of risk and opportunity. In 2013 and 2014, we completed several larger Improvement projects which had a higher relative priority. In 2013, the larger projects completed at Monticello related to remote camera monitoring and alternate spent fuel pool work, and at Prairie Island related to turbine oil reservoir filters and control room recorder replacements. In 2014, a very large project was completed at Prairie Island for spent fuel pool system protection.

1 *5. Facilities and General*

2 Q. WHAT ARE FACILITIES AND GENERAL PROJECTS?

3 A. The Facilities and General grouping includes facility work such as building
4 improvements, roof replacements, road repairs and general plant additions
5 such as small tools and equipment. They are ongoing activities to maintain
6 plant buildings and properties, and provide small tools and equipment to
7 support normal plant operation.

8

9 Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FACILITIES AND GENERAL PROJECT
10 SCHEDULED TO GO IN SERVICE DURING THE 2016 TEST YEAR.

11 A. The largest Facilities and General project with 2016 additions is an upgrade to
12 the turbine building crane at Prairie Island. I discuss this 2016 project
13 addition in more detail later in my testimony.

14

15 Q. WHAT IS THE 2016 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS
16 GROUPING?

17 A. The Nuclear Operations business unit has established a budget of $7.3 million
18 for Facilities and General project additions during the 2016 test year.

19

20 Q. HOW DID YOU ESTABLISH THAT BUDGET?

21 A. Earlier in my testimony I discussed the capital budgeting process and how we
22 identify, prioritize and assign funding to specific projects, and estimate
23 expenditures and in-service dates by year.

24

25 Overall, the budget for additions represents the culmination of capital
26 expenditures incurred over time for various Facilities and General projects
27 that are expected to be completed and placed in service during 2016. We first

establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project revised, the cost estimate can be updated over the period the project is progress. The capital additions budget for 2016 represents the total of expenditures incurred, and AFUDC accrued over the project duration, that are expected to be completed and placed in service during the year 2016.

Q. WHAT ARE THE TRENDS IN FACILITIES AND GENERAL PROJECTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Facilities and General project additions have fluctuated from year to year based on the specific projects undertaken in each year. The 2016 budget for Facilities and General additions of $7 million is significantly lower than the actual 2014 additions of $26 million, slightly higher than the actual 2013 additions of $4 million and forecasted 2015 additions of $3 million, and slightly less than the actual 2012 additions of $11 million.

Q. WHAT IS DRIVING THESE TRENDS?

A. In general, Facilities and General additions tend to be the smallest capital project grouping, except when significant projects are a priority. Two significant Facilities projects were recently completed at Prairie Island, in 2014 for a new site administration building, and in 2012 for a new receiving warehouse. In 2016, more than half of the Improvements additions are for the upgrade to Prairie Island's turbine building crane. Excluding these significant projects, the Facilities and General additions have been very

consistent at about $3 million to $4 million per year.

As discussed in our last rate case, the 2014 site administration building investment enabled reductions in O&M costs (utilities and maintenance) from the previous construction trailer system used by the plant.

a) Key 2016 Facilities and General Project:
PI Turbine Building Crane Upgrade

Q. PLEASE DESCRIBE THE PROJECT.

A. This project upgrades the electrical components and controls on the Turbine Building cranes at each unit (#11 for Unit 1 and #21 for Unit 2) to support the generator replacement outage and ensure reliable crane operation through the end of the plant's life. The scope of the project includes the replacement of the common power distribution system to both cranes, and the control and drive systems on both cranes. This project is a good example of our effort to improve our plant systems for efficient outages and control our O&M costs.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. The existing crane controls are obsolete and are no longer supported by the manufacturer. The cranes have experienced significant failures in the past which have delayed work during outages and caused higher costs. Additionally, the radio control cards have failed on one crane and cannot be repaired. This project upgrades the crane with a variable speed drives system which allows for more precise lifts, restores radio control functionality, extends crane life through the remainder of the plant's life, and mitigates the risk of crane failures delaying outage critical path during generator replacement.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2016 capital addition for this project is $4.7 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, and other costs such as tool/equipment rentals. The costs include engineering and construction work for upgrading the electrical components and controls for both units' Turbine Building Cranes. This includes cost associated with the common power distribution system, control/ drive systems and implementation of the all associated work.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The cost Budget was determined by developing detailed estimates for each of the major areas supporting the project: Project Management and Support, Engineering, Work Order Planning and Procedures, Materials, Installation, Tooling, etc. Labor costs were developed by developing man-hour estimates performed by the responsible work group and comparing similar size/scope projects. The final labor estimates were than calculated using current billing rates and contract rates with escalation for out-years. Proposals for major contracted efforts (engineering, materials, and installation support) were obtained to develop budgets for these items. Miscellaneous materials, tool rentals, and shipping costs were estimated using site guidance based on historical project experience. In-service dates were determined based on estimated project schedules and available implementation windows which would align with supporting the generator replacement outages.

We have already completed the first phase of this crane project on Prairie Island Unit 2, and are on schedule and within budget thus far.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The first phase of installation for the Unit 2 crane and power distribution system common for both units at the plant has been completed. Installation of the second crane for Unit 1 is scheduled for early 2016 and is on track with the project schedule.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. No.

6. Fuel

Q. WHAT ARE FUEL PROJECTS?

A. Fuel capital additions relate to the nuclear fuel loaded into the reactor to provide the heat energy that turns the turbine and powers the plants' generators. In fossil plants, fuel such as coal is delivered to the plant, stored on-site as inventory, and then loaded in the plant to burn. For nuclear plants, we contract with outside vendors to purchase uranium (called yellowcake), convert the uranium to a gaseous state, enrich and fabricate the uranium gas into fuel pellets and assemblies usable in the reactor, and install the fuel assemblies during refueling outages. In-house fuel engineers also design the fuel process at each site, working to optimize the type of fuel, configuration of assemblies, and reloading plans.

Because this process takes almost two years from beginning to end, and because the fuel lasts for multiple years until it is fully used up, nuclear fuel expenditures are considered capital work. The various fuel expenditures are accumulated in CWIP, AFUDC is accrued, and the fuel is considered placed in service when loaded in the reactor during the unit's refueling outage. Fuel is then consumed over approximately three refueling cycles, and one-third of

the fuel assemblies are removed and replaced in each refueling outage. Fuel is amortized over the period it is loaded in the reactor, which for three refueling cycles would be 4.5 to 6 years (based on cycles of 18 to 24 months, respectively). Each unit's fuel is loaded as an addition every other year, so with three units we would alternate years with two Fuel projects when Monticello and Prairie Island both have a refueling, with years with one project when only Prairie Island has a refueling.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FUEL PROJECT SCHEDULED TO GO IN SERVICE DURING THE 2016 TEST YEAR.

A. The test year 2016 has only one fuel project with capital additions, the reload for Prairie Island Unit 1.

Q. WHAT IS THE 2016 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $76.1 million for the PI Unit 1 fuel project addition during the 2016 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. The budgeting for nuclear fuel additions is different than the process described earlier in my testimony for other capital projects. The costs incurred for uranium purchase, conversion, and enrichment are tracked using segregated units of measure and applied to refueling loads using an average cost methodology. Engineering and fabrication costs are accounted for on a project-specific basis.

See additional details in Exhibit___(TJO-1), Schedule 5, regarding the nature

of capital fuel expenditures, the process used to estimate and track nuclear fuel costs, the number of assemblies in each fuel reload, and the specific types of fuel costs included in budgets for capital fuel expenditures and additions over various periods including the test year 2016.

Q. WHAT ARE THE TRENDS IN FUEL PROJECT ADDITIONS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, fuel project additions fluctuate from year to year largely based on whether they include a refueling for a single unit or for two units. Comparing single refueling years, the 2016 budget for fuel additions of $76 million is higher than 2014 additions of $63 million but lower than 2012 additions of $98 million. Comparing dual refueling years, 2015 forecasted additions of $144 million are fairly consistent with $142 million of 2013 additions.

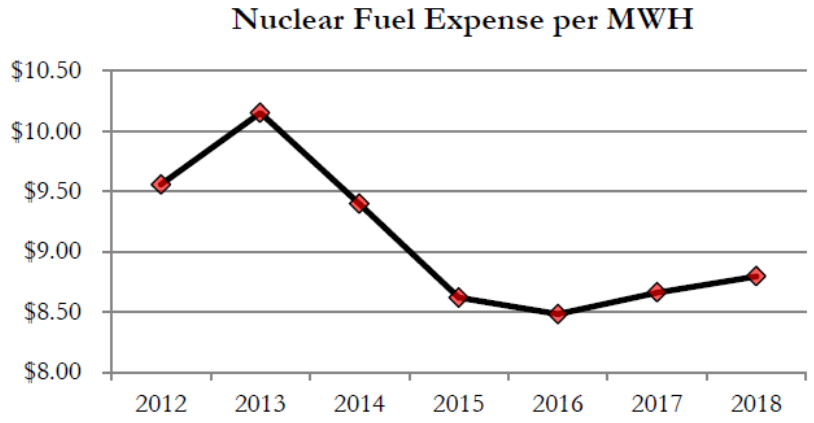
Q. WHAT IS DRIVING THESE TRENDS?

A. The average additions per refueling trended as follows through 2014: $65 million in 2012 to $71 million in 2013 and $63 million in 2014. Each fuel load varies as to the number of assemblies installed in the reactor. In addition, the reduction in 2014 reflected successful contract negotiations with vendors on uranium purchases and conversion, enrichment and fabrication services. The 2014 amounts also reflect the impact of lower market prices for uranium due to increased supply available after Japanese nuclear plants shut down as a result of the Fukushima incident there. We made an accelerated strategic purchase in 2014 to capitalize on a unique market pricing opportunity that we identified, which provided a one-time benefit that year.

Average fuel additions per refueling have increased since 2014, from $63 million in that year to $72 million in 2015 and $76 million in 2016. Again, these reflect differences in the number of fuel assemblies installed each year. These changes also reflect the lower market pricing in general since Fukushima and lower contract pricing, but do not include a recurrence of the one-time strategic purchase we made in 2014 that lowered costs that year.

From a customer perspective, our fuel management efforts have paid dividends in the form of lower fuel costs per megawatt hour (MWh) as we have efficiently planned fuel reloadings and successfully negotiated contract pricing and capitalized on market opportunities in recent years. Chart 2 below summarizes our amortized cost of capital fuel additions, expressed as fuel expense per MWh, over the periods 2012-2014 (actual), 2015 (forecast), 2016 (budget) and 2017-2018 (preliminary budget).

Chart 2



These reductions are significant for customers, and bring us closer to industry best in fuel costs per unit. Our industry benchmarking shows that plants with

higher production capacity, and/or are part of larger fleets, can have fuel costs that approach $7 per MWh.

See additional details in Schedule 5, regarding the nature and specific types of fuel costs included in capitalized fuel expenditures, additions and amortized costs over various periods including 2016.

Q. ARE NRC APPROVALS NEEDED FOR FUEL PROJECTS?

A. Yes. Our Monticello plant is seeking NRC approval for new fuel types and the extended flow window used for fuel configurations under EPU conditions at the site.

D. 2017 Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NUCLEAR CAPITAL ADDITIONS BUDGET FOR 2017.

A. The total NSPM Nuclear 2017 capital additions are budgeted to be $107 million for projects and $173 million for fuel.

Q. WHAT ARE THE PRIMARY DRIVERS OF THE 2017 CAPITAL ADDITIONS PLACED INTO SERVICE BY THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. Project additions include $76 million for equipment reliability, and $30 million for mandated compliance work. Fuel additions are an ongoing capital requirement over the refueling cycles of each plant, and in 2017 we have two fuel reloadings, one at each plant.

1. Dry Cask Storage

Q. WHAT IS THE 2017 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. There are no capital additions scheduled for 2017 for Dry Cask Storage projects. As discussed earlier in my testimony, this is due to the changing needs and availability of fuel storage at each site each year. No dry cask storage projects are planned to be placed in service in 2017, but both sites have dry cask storage work planned for 2018 as I discuss later in my testimony.

2. Mandated Compliance

Q. WHAT IS THE 2017 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $29.8 million for Mandated Compliance project additions during the 2017 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Mandated Compliance projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY MANDATED COMPLIANCE PROJECT PLANNED TO GO IN SERVICE DURING THE 2017 PLAN YEAR.

A. Nuclear has continuing investment in 2017 for the major 2016 Mandated Compliance projects discussed earlier in my testimony, for the Fukushima program and fire protection requirements. Capital additions budgeted in 2017 for those projects are $12.5 million and $9.1 million, respectively.

None of the remaining 2017 additions for Mandated Compliance are considered key on their own. Of course, continued compliance with NRC requirements is important and we will continue work in that regard.

3. Reliability

Q. WHAT IS THE 2017 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $76.3 million for Reliability project additions during the 2017 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Reliability projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY RELIABILITY PROJECT PLANNED TO GO IN SERVICE DURING THE 2017 PLAN YEAR.

A. Nuclear has continuing investment in 2017 for the 2016 Reliability projects discussed earlier in my testimony, for the LCM programs at Prairie Island including reactor coolant pump replacements, heater drain tank pump speed controls, and motor rewinds/replacements. Capital additions budgeted in 2017 for those projects are $9.2 million, $10.0 million, and $9.2 million, respectively.

In addition to those continuing investments, we are budgeting $16.2 million in 2017 capital additions for the first phase of a multi-year LCM program to replace cooling towers at Prairie Island. I discuss this 2017 project addition in more detail in the next set of questions in my testimony.

a) Key 2017 Reliability Project:

PI Cooling Tower Replacement Program

Q. PLEASE DESCRIBE THE PROJECT.

A. The objectives of this project are to: (1) ensure cooling water compliance with state environmental regulations under National Pollutant Discharge Elimination System (NPDES) permits issued by the Minnesota Pollution Control Agency; and (2) facilitate adequate cooling water availability to continue operation of the plants at 100 percent of output capacity. The primary project scope of the Cooling Tower Header Replacement Project is to replace the hot water distribution header system at Prairie Island with an updated design and materials. A secondary requirement is to ensure the cooling tower structure is sufficient to support new/revised header loads through the end of tower life, assuming regular preventive maintenance activities are carried out. The project includes replacement of piping, support structures and forced-draft equipment used in the plant cooling process.

There are four cooling towers at the plant site, and this is a multi-year program commencing in 2017 and continuing into 2018 and beyond.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. The benefits of the project are to improve cooling equipment reliability for plant operations, eliminate the risks of de-rating the unit in the event of cooling issues from equipment failures, and reduce maintenance repairs that would continue to be necessary without this replacement project. Upgrading the cooling towers also ensures compliance with NPDES permitting requirements, which will maintain compliance with State and Federal environmental laws. In short, this project keeps us environmentally

responsible and puts our cooling equipment in good working condition for the long run.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2017 capital addition for this project is $16.2 million, including AFUDC. The project costs will include employee labor, outside contractors, materials and equipment, and other costs such as tool/equipment rentals. The costs include engineering and construction work for replacement of each of the cooling tower headers at the plant site. Costs are expected to consist largely of outside vendor installation services and tower materials.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The project's work scoping document was created and reviewed by Nuclear management. The approved scoping document was used to develop detailed requests for quotes and proposals from multiple vendors for tower header replacement (services and materials). Internal labor cost estimates were developed using inputs from each of the responsible work groups supporting the project and historical operating experience. The in-service dates were developed to support and align with the plant's refueling outages or motor availability for out of service. Initial estimates will be refined as vendor proposals are received and approved, and as operating experience is developed as the multi-year project commences.

We have done internal benchmarking of similar cooling tower work performed on the Company's Sherco and King coal plants. We also had the vendor for the Prairie Island materials procurement and construction project provide an order of magnitude cost estimate for the complete structural

overhaul of our cooling towers. Benchmarking data from those two sources was used to prepare the high level estimates for this project's total costs, including site/contract engineering, field oversight, management and administrative overheads, and contingencies.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project has just completed the scoping phase and is now entering the design phase. The implementation phase is scheduled to begin in 2017.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. No.

4. Improvements

Q. WHAT IS THE 2017 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $0.6 million for Improvement project additions during the 2017 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Improvement projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY IMPROVEMENT PROJECT PLANNED TO GO IN SERVICE DURING THE 2017 PLAN YEAR.

A. The total amount of Improvement project additions in 2017 is only $0.6 million for both plant sites, and thus no individual projects are considered key for that year.

5. Facilities and General

Q. WHAT IS THE 2017 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $0.8 million for Facilities and General project additions during the 2017 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Facilities and General projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FACILITIES AND GENERAL PROJECT PLANNED TO GO IN SERVICE DURING THE 2017 PLAN YEAR.

A. The total amount of Facilities and General project additions in 2017 is only $0.8 million for both sites, and thus no individual projects are considered key for that year.

6. Fuel

Q. WHAT IS THE 2017 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $172.6 million for Fuel project additions during the 2017 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Fuel projects. See additional details in Schedule 5, regarding the nature of capital fuel expenditures, the process used to estimate and track fuel costs, the number of assemblies in each fuel reload, and the

specific types of fuel costs included in budgets for capital fuel expenditures and additions over various periods including 2017.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FUEL PROJECT PLANNED TO GO IN SERVICE DURING THE 2017 PLAN YEAR.

A. During 2017 we plan to complete two large fuel refueling projects, one at each site during the scheduled outages that year. Monticello's fuel addition for 2017 is $95.6 million and Prairie Island's is $77.0 million.

E. 2018 Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NUCLEAR CAPITAL ADDITIONS BUDGET FOR 2018.

A. The total NSPM Nuclear 2018 capital additions are budgeted to be $295 million for projects and $72 million for fuel.

Q. WHAT ARE THE PRIMARY DRIVERS OF THE 2018 CAPITAL ADDITIONS PLACED INTO SERVICE BY THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. Project additions include $166 million for equipment reliability, $90 million for dry cask storage work, and $35 million for mandated compliance work. Nearly half the reliability additions relate to one project, the replacement of the electric generator at Prairie Island, as I discuss in greater detail below. Fuel additions are an ongoing capital requirement over the refueling cycles of each plant, and in 2018 we have one fuel reloading at Prairie Island.

1. Dry Cask Storage

Q. WHAT IS THE 2018 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $90.0 million for two Dry Cask Storage project additions during 2018: the loading of four spent fuel casks (#41-44) at Prairie Island and 14 casks (#17-30) at Monticello. Capital additions budgeted in 2018 for those projects are $41.3 million and $48.7 million, respectively.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Dry Cask Storage projects.

Q. PROVIDE AN EXAMPLE OF A KEY DRY CASK STORAGE PROJECT PLANNED TO GO IN SERVICE DURING THE 2018 PLAN YEAR.

A. There are only two Dry Cask Storage projects being placed in service in 2018, as I noted previously. I discuss both of these 2018 project additions in more detail in the next section of my testimony.

a) Key 2018 Dry Cask Storage Project:
Prairie Island Load of Casks 41-44

Q. PLEASE DESCRIBE THE PROJECT.

A. This project relates to the procurement, loading and transfer of nine casks (type TN-40HT) containing 360 fuel assemblies from the site's spent fuel pool in the plant to dry cask storage. This is a multi-year project, and the 2018 addition is for the in-servicing of four of the nine casks in this program. Two of the casks (#39-40) were previously in-serviced in 2015. The remaining casks in this program (#45-47) will be in-serviced in later years.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. This project is necessary to enable timely refueling of the Unit 1 and Unit 2 reactors at Prairie Island. Space needs to be available in the spent fuel storage pool to discharge fuel assemblies from the reactor that have reached the end of their useful life. Spent fuel storage space in the pool is limited by our NRC operating license, the physical design of the plant, and the federal government's inability to remove spent fuel from the site into permanent storage elsewhere. Dry fuel storage allows sufficient spent fuel storage space to be available over time, thereby allowing continued plant operation in compliance with the plant's operating license and used fuel storage license.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2018 capital addition for this project is $41.3 million, including AFUDC. This project accumulates costs over time and in-services the casks as they are placed in service, at the time spent fuel is loaded into them. The amount of the partial in-service in 2018 represents the costs associated with the design, engineering, management, oversight, procurement, loading and placement of four casks (#41-44).

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget for the PI Cask 39-47 Program was developed by reviewing the experience and costs of procurement, loading and placement of the first 38 casks in the site's Independent Spent Fuel Storage Installation (ISFSI) from 1994 through 2014.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. This project is in the implementation phase. Two casks (#39-40) have been

delivered, loaded and transferred to the site's ISFSI. The remaining seven casks are nearing the completion of fabrication and will be held for later shipment to the site. Current plans are to load four of these casks in 2018 (#41-44), and the remainder (#45-47) at a later date.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. Yes. The Prairie Island spent fuel storage system has a site specific license[19] held by Xcel Energy. NRC approval of license amendments was required to permit use of these TN-40HT casks. These approvals have been obtained.

b) Key 2018 Dry Cask Storage Project:
Monticello Load of Casks 17-30

Q. PLEASE DESCRIBE THE PROJECT.

A. This project relates to the procurement, installation, loading and transfer of 14 dry fuel storage canisters containing 610 fuel assemblies from the spent fuel pool in the plant to dry cask storage. The capital addition for 2018 includes four casks (#17-20) delayed from loading in 2013, in addition to 10 casks (#21-30) scheduled for loading after the site's 2017 refueling.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. This project is necessary to enable the timely refueling of the reactor at Monticello. Space needs to be available in the spent fuel storage pool to discharge fuel assemblies from the reactor that have reached the end of their useful lives. Spent fuel storage space in the pool is limited by our NRC operating license, the physical design and the federal government's inability to remove spent fuel from the site into permanent storage elsewhere. Dry fuel

[19] Site specific license SNM-2506, issued under Federal Regulation 10 CFR 72.

storage allows sufficient spent fuel storage space to be available over time, thereby allowing continued plant operation.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2018 capital addition for this project is $48.7 million, including AFUDC. The project includes the costs of loading the last four canisters (#17-20) delayed from the 2013 Monticello dry cask storage program, and the costs of loading casks #21-30. This project accumulates costs as incurred over time and in-services the casks as they are placed in service, at the time spent fuel is loaded into them and they are placed into the ISFSI at the site. The amount to be in-serviced in 2018 represents the costs associated with the design, engineering, management, oversight, procurement, loading and placement of 14 dry fuel storage canisters (#17-30). The costs of materials purchased for casks 17-20 were placed in service as plant held for future use in 2014, once it was determined that their loading would be delayed until the issues with cask #16 were resolved.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget for the 2018 fuel storage load at Monticello was developed by reviewing the experience and costs of procurement, installation and loading of the first 15 dry fuel storage canisters in the site's ISFSI from 2008 through 2013.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. This project is in the implementation phase. A contract has been issued for the procurement, installation, loading and transfer of the dry fuel storage canisters in 2018. The vendor has started the design and procurement process

and fabrication of the equipment will begin in 2016.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. Yes. The Monticello spent fuel storage system has a general license held by our outside contractor AREVA-TN. AREVA is presently in the process of timely renewing its Certificate of Compliance with the NRC under Federal regulations.[20]

2. Mandated Compliance

Q. WHAT IS THE 2018 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $35.2 million for Mandated Compliance project additions during the 2018 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Mandated Compliance projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY MANDATED COMPLIANCE PROJECT PLANNED TO GO IN SERVICE DURING THE 2018 PLAN YEAR.

A. Nuclear has continuing investment in 2018 for the major 2016-2017 Mandated Compliance projects discussed earlier in my testimony, for the Fukushima program and fire protection requirements. Capital additions budgeted in 2018 for those projects are $7.3 million and $4.6 million, respectively. The information provided for the first two years of these programs in 2016-2017

[20] Federal Regulation 10 CFR Part 72, Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High Level Radioactive Waste, and Reactor-Related Greater than Class C Waste (Docket Number 72-1004).

describes the major project work done for these continuing capital investments in 2018.

The remaining Mandated Compliance additions in 2018 are mainly for a number of security projects required by the NRC, none of which are considered key individually. They include security for the ISFSI dry cask storage facilities at each plant site, and other security modifications required by the NRC. The NRC continues to develop and issue guidance on these emerging security requirements, and we expect capital expenditures and additions in 2018 and beyond to comply with such requirements.

3. Reliability

Q. WHAT IS THE 2018 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $165.6 million for Reliability project additions during the 2018 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Reliability projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY RELIABILITY PROJECT PLANNED TO GO IN SERVICE DURING THE 2018 PLAN YEAR.

A. The most significant project planned for 2018 is the major planned investment in LCM Reliability work at Prairie Island to replace the main electrical generator for Unit 1. This project has a budgeted addition of $74.4 million

that year. I discuss this 2018 project addition in more detail in the next set of questions in my testimony.

In addition, Nuclear has continuing investment in 2018 for the 2016-2017 key Reliability LCM projects at Prairie Island discussed earlier in my testimony, for reactor coolant pump replacements, motor rewinds/ replacements, and cooling tower replacements. Capital additions budgeted in 2018 are $10.5 million for the third phase of the four-year reactor coolant pump replacement program, $3.7 million for the ongoing motor rewind/replacement program, and $19.3 million for the second phase of the four-year cooling tower replacement program. The information provided for the first two years of these programs in 2016-17 describes the major project work done for these continuing capital investments in 2018.

a) Key 2018 Reliability Project:
PI LCM Replacement of Electric Generator

Q. PLEASE DESCRIBE THE 2018 PRAIRIE ISLAND ELECTRIC GENERATOR PROJECT.

A. This project replaces the Unit 1 electric generator at Prairie Island that currently has a high risk of degraded operation, such as was experienced in 2013 on the plant's Unit 2 generator, due to 40+ years of use. The project installs a new generator/exciter that will operate reliably through the end of plant life. The project will design, fabricate, and replace the following Unit 1 components: main electrical generator stator/rotor, lead box, exciter, seal oil skid, generator monitoring instrumentation, and hydrogen control/monitoring components.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. The Project installs a generator/exciter and auxiliaries that will operate reliably through end of plant life, after operating these original plant components for 40+ years. As with many reliability projects, the benefit of this project is reducing the risks of unplanned equipment failure, the related extended loss of generation during the repair period and potentially higher replacement power costs, and regulatory scrutiny in the event of equipment failure that threatens plant safety.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2018 capital addition for this project is $74.4 million, including AFUDC. The project costs will include employee labor, outside contractors, materials and equipment, and other costs such as tool/equipment rentals. The costs include engineering and construction work for replacement of the main electrical generator for Prairie Island Unit 1. Costs are expected to be largely outside vendor installation services and generator equipment/materials. The majority of the costs may be broken down as follows:

- Generator manufacturer – design, fabricate, and replace generator;
- Provide heavy lift of generator during installation;
- Xcel Energy engineering; and
- Other construction support (non-manufacturer).

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The project budget was largely developed via a competitive bidding process with outside vendors which resulted in the receipt of proposals to design, manufacture, and install a new generator exciter. Budgetary input was also solicited from Nuclear's engineering and construction groups supporting the

project. These inputs, as well as others, were compiled by project management staff, who created a multi-year project budget.

This project was originally scheduled for the plant's 2016 outage but was deferred to 2018 to accommodate Company capital funding constraints. This resulted in refinement of earlier cost estimates to update scope, schedule and budget from the 2016 timeframe to 2018.

In addition, the electric generator for the other Prairie Island unit (Unit 2) is being replaced during the fall 2015 refueling outage. Cost estimates for that project were helpful in determining estimates for the 2018 generator replacement at Unit 1.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project's design and equipment manufacturing phases are near completion. The generator exciter has been shipped from the manufacturer and is scheduled to arrive on site in September 2015. Installation is planned during the Unit 1 refueling outage scheduled for 2018.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. No.

4. Improvements

Q. WHAT IS THE 2018 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $3.1 million for Improvement project additions during the 2018 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Improvement projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY IMPROVEMENT PROJECT PLANNED TO GO IN SERVICE DURING THE 2018 PLAN YEAR.

A. The total amount of Improvement project additions in 2018 is only $3.1 million for both plant sites, and no individual projects are considered key for that year.

5. Facilities and General

Q. WHAT IS THE 2018 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $0.8 million for Facilities and General project additions during the 2018 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Facilities and General projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FACILITIES AND GENERAL PROJECT PLANNED TO GO IN SERVICE DURING THE 2018 PLAN YEAR.

A. The total amount of Facilities and General project additions in 2018 is only $0.9 million for both sites, and thus no individual projects are considered key for that year.

6. Fuel

Q. WHAT IS THE 2018 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $71.9 million for fuel project additions during the 2018 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital and project budgeting process I discussed earlier in my testimony for 2016 Fuel projects. See additional details in Schedule 5, regarding the nature of capital fuel expenditures, the process used to estimate and track fuel costs, the number of assemblies in each fuel reload, and the specific types of fuel costs included in budgets for capital fuel expenditures and additions over various periods including 2018.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FUEL PROJECT PLANNED TO GO IN SERVICE DURING THE 2018 PLAN YEAR.

A. During 2018 we plan to complete only one fuel project, a refueling at Prairie Island during its scheduled outage that year. All of the budgeted fuel additions for 2018 relate to this project.

IV. NON-OUTAGE O&M BUDGET

A. Overview and Trends

Q. HOW IS YOUR TESTIMONY ORGANIZED IN THIS SECTION?

A. I first provide a discussion of the overall request for our non-outage O&M expenses and briefly describe the initiatives that we are taking in an attempt to reduce our cost growth (with a goal of 0-2 percent increases annually) while at

the same time improve safety, reliability, and performance. I then discuss the major cost categories included in the test year with a discussion of the drivers behind any changes. The O&M expenses related to our planned maintenance/refueling outages are discussed in Section V of my testimony.

Q. WHAT IS INCLUDED IN YOUR O&M BUDGET?

A. We split non-outage O&M items into two general cost categories associated with operating our nuclear plants: site costs (costs directly controlled by us) and non-site costs (costs not under our direct control). Non-outage site costs include employee labor, non-employee contractors and consultants, material costs, employee expenses, and other expenses. Non-site costs consist of the nuclear-related fees and security costs and are considered non-outage in nature.

Q. HOW DOES THE COMPANY SET THE NON-OUTAGE O&M BUDGET FOR THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. As an Xcel Energy business area, Nuclear Operations follows the budget process established by the corporate Financial Performance and Planning group, as discussed in the testimony of Company witness Mr. Greg Robinson. The starting point for that area developing the O&M spending guidelines is the most recent five-year financial forecast. Specifically, the starting point for the 2016-2020 Budgets was the most recent five-year (2015-2019) forecast. The Financial Council reviews this information, considering Xcel Energy's business plans and a number of other factors. After considering this information, the Financial Council establishes overall growth target guidelines for the new five-year O&M budgets, which each business area is expected to meet.

Once overall O&M spending guidelines are determined and communicated, the Nuclear Operations budgets are built from the "bottom up" by individual components, such as employee labor, contract labor, consulting costs, and materials expense by budget managers. In the example of labor, current salary and headcount data is fed from our payroll system to our budgeting system. Planned headcount additions over the five year period are added to the budget system based on current workforce plans; projected merit increases are applied by the corporate budgeting group, based on the assumptions provided in the corporate budget instructions, and approved by Human Resources. The budgets are built in detail, and not based simply on prior year costs, to which an inflation factor could be applied. However, the corporate budget instructions provide cost escalation factors to apply, if needed, for those costs to which inflation-based growth is appropriate to apply. The Nuclear Operations business area reviews the budgets submitted by department managers at each of the three sites with the responsible Vice President. As part of our effort to meet corporate targets, adjustments are usually made after the site reviews before being submitted for review with the Chief Nuclear Officer.

Q. DOES THE NUCLEAR OPERATIONS BUSINESS UNIT EVER NEED TO CHANGE THE COMPOSITION OF O&M AMONG NON-OUTAGE CATEGORIES, OR BETWEEN OUTAGE AND NON-OUTAGE DURING THE FINANCIAL YEAR?

A. Yes. Since the budgets are prepared about eight months in advance of the budget year, emergent items routinely arise that require a reprioritization of authorized spend levels. Examples of these emergent O&M items are forced outages and extensions to planned outages. In the Nuclear Operations area, a budget manager completes a form to request approval to spend money on an

unbudgeted item. The manager can propose to use budgeted dollars from a different line item in his/her own budget, or ask for help in identifying savings from another department to cover the emergent cost. For a more costly unforeseen event such as a forced outage, there may be a need to find budget savings on a broader scale, such as in other departments at that site, or across the entire Nuclear Operations business area.

When planned outage costs rise, Nuclear Operations is still expected to manage to its overall O&M target/budget, including both non-outage and outage costs. Thus, in the event that planned outage costs vary from budget, we may need to reprioritize and adjust non-outage costs in order to meet our O&M commitments for the year. In general, the corporate expectation is that each business unit (including Nuclear) should offset or absorb unplanned O&M costs and in so doing hold our cost levels to the budgeted targets used to determine customer rates.

Q. PLEASE EXPLAIN HOW THE NUCLEAR OPERATIONS BUSINESS UNIT MONITORS NON-OUTAGE O&M EXPENSES AFTER THE BUDGET IS CREATED.

A. Like all business areas, Nuclear is accountable for managing to its O&M budget for the year. The budget managers in each department are required to evaluate their ability to meet their budget as part of the monthly forecast process, with the help of the Nuclear Finance staff. This allows the business area to compare the approved budget with updated forecasts of spend, including actuals to date and estimates through end of year, that reflect changes in business operations that could not have been anticipated at the time the budget was first approved. Each site holds monthly financial meetings where budget managers describe the results for the current month

compared to the forecast, any changes to expected year end results, and risks (of higher costs) or opportunities (for lower costs) that have not yet been reflected in the forecast. In addition, a meeting is held monthly with the Chief Nuclear Officer (CNO) and direct reports to review the status of financial performance of the entire Nuclear business area, and to assess what actions may be needed to manage to the overall O&M budget.

A recent example of our cost monitoring and accountability is the forced outage costs incurred in 2015. We incurred nearly $20 million in forced outage O&M costs in early 2015, and implemented initiatives to reduce other O&M costs so that the overall annual expense level approximated budget levels. These initiatives included delays in filling employee vacancies, reductions in use of contractors and consultants, and cutbacks in employee travel and related expenses.

Similarly, we continue to work with our outside vendors to build more accountability for the cost and performance of their work. As I noted in the Capital Investments section of my testimony, we work with our vendors to build in performance milestones and hold them accountable for the quality, cost and timeliness of their work. In 2015, we have engaged a vendor to help us manage our planned outage at Prairie Island, which we expect to enable us to hold the duration and cost of our outage to planned levels.

Q. HOW DOES THE COMPANY DETERMINE ITS FORECAST OF CHANGES NEEDED FROM THE NON-OUTAGE O&M BUDGET?

A. The Company's ongoing financial governance process allows a business area to adjust, on a continuing basis, its business plans and financial forecasts. For

example, a business area (such as Nuclear) may face cost increases or new items not anticipated at the time the budget was created, or may need to reduce, delay, or accelerate spending in response to emerging new priorities, or unforeseen or changed circumstances. The monthly forecasting process allows those changes to be properly reflected in our business plans and forecasts. However, each business area is responsible for managing to their original O&M budget as approved, so when unforeseen costs occur, the business area makes every attempt to absorb them within their budget by reprioritizing other work. If they are unable to do so, the business area can request to increase their O&M forecast. Variances and updated forecasts are reviewed monthly with the Xcel Energy Financial Council. Generally speaking, it is expected that each business area do their best to manage to its approved budget levels. For Nuclear, that has resulted in several cost mitigation initiatives in 2015 (as I noted previously, and will discuss in greater detail below) with the goal of offsetting the impact of forced outages experienced that year.

Q. HOW DOES THE COMPANY'S NON-OUTAGE O&M BUDGET PROCESS AND GOVERNANCE COMPARE TO INDUSTRY PRACTICE?

A. Based on the experience of our financial staff with other companies, and our interactions with other companies within and outside of the utility industry, we believe our budget process and governance is consistent with the financial governance in practice for large companies in the U.S. The 5-year planning horizon, annual budget cycle, monthly forecasting process, and corporate oversight are typical elements of a well-controlled budgeting and financial governance process.

Q. WHAT IS THE COMPANY'S NON-OUTAGE O&M BUDGET FOR THE 2016 TEST YEAR?

A. As shown in Table 7 below, our 2016 test year non-outage O&M expenses are budgeted at $281.3 million, lower than our actual 2014 actual costs by $1.4 million, or 0.5 percent. This represents a 0.2 percent average annual decrease over the two-year period.

Table 7
Nuclear Operations Non-Outage O&M Costs
($ in millions)

	2012 Actual	2013 Actual	2014 Test Year Budget Requested	2014 Actual	2015 Forecast	2016 Test Year Budget	Avg Annual % Change: 2014 Actual to 2016
Site Costs (Non-Outage)							
A. Internal Labor	130.3	139.5	155.5	151.7	158.7	154.4	0.9%
B. External Labor (Contractors & Consultants)	30.0	40.2	26.8	34.6	26.0	26.4	-11.8%
Subtotal Workforce Costs	160.3	179.7	182.3	186.3	184.7	180.8	-1.5%
C. Materials & Chemicals	16.2	16.2	14.9	16.3	14.8	15.1	-3.6%
D. Employee Expenses	3.9	5.7	4.9	5.7	2.8	4.6	-10.1%
E. Other	4.8	4.9	5.6	6.7	5.7	8.2	11.6%
Non-Outage Site Costs Total	185.2	206.4	207.6	215.0	208.0	208.7	-1.5%
Non-Site Costs							
F. Nuclear-related fees	31.9	31.5	35.2	36.9	37.5	39.2	3.2%
G. Security	26.7	27.8	29.0	30.8	31.8	33.4	4.2%
Non-Site Costs Total	58.6	59.3	64.2	67.7	69.3	72.6	3.7%
Total Non-Outage O&M	**243.8**	**265.7**	**271.8**	**282.7**	**277.3**	**281.3**	**-0.2%**

Q. HOW ARE THE COMPANY'S LONG-TERM NON-OUTAGE O&M COSTS TRENDING?

A. From 2012 through the 2016 budget, our non-outage O&M expenses are increasing by an average of 3.8 percent annually. The calculated percentage changes by year, and average annual percentage changes over various two- and four- year periods, for non-outage O&M expenses is attached as Exhibit___(TJO-1), Schedule 6.

However, these expenses increased by an average annual rate of 8.0 percent per year from 2012 to 2014, and are decreasing by an average of 0.2 percent per year from 2014 to 2016. In those same periods, non-outage site costs (mainly workforce related) grew by an average of 8.0 percent per year in 2012-2014 and are declining by 1.5 percent per year from 2014-2016, and non-site costs (fees and security) increased by an average of 7.7 percent per year in 2012-2014 and are projected to increase 3.7 percent per year in 2014-2016.

Q. WHAT IS DRIVING THESE TRENDS?

A. The increase in total non-outage costs since 2012 has been primarily driven by the cost increases for our internal labor and in non-site fees and security costs.

Labor costs increased over the period 2012-2014 for the following three reasons: (1) we have added employees to meet regulatory and safety requirements; (2) we have increased compensation in order to attract and retain in-house expertise; and (3) we have increased our overall headcount in order to drive the performance excellence that will allow for long-term efficiency and stability. The added employees are in support of the staffing and workforce planning initiatives discussed earlier in the Update from Prior Rate Case and Key Nuclear Strategies sections of my Nuclear Operations Overview testimony, respectively.

However, from 2014 to 2016, we are maintaining essentially the same employee headcount. Our current headcount levels compare favorably to our counterparts in the industry, as demonstrated by Electric Utility Cost Group (EUCG) survey data shown in Exhibit___(TJO-1) Schedule 7. The chart on that schedule shows Monticello to be in the top quartile (lowest) for staffing,

and Prairie Island in the second quartile, relative to other nuclear plants in the U.S.

With respect to non-site costs for nuclear-related fees and security, we continue to see consistent growth in these costs of 6 percent per year on average since 2012, driven largely by outside forces beyond our control, as most fees are assessed by governmental agencies, and security staffing is subject to NRC oversight and requirements. Non-site cost increases are mainly in security and fees related to emergency preparedness and payments made to the Prairie Island Indian Community, as discussed below in my testimony.

Our overall total non-outage O&M costs in 2016 are actually budgeted to be less than actual 2014 levels. This is consistent with the Xcel Energy's long-term strategic goal of "bending our cost curve" and limiting the rate of cost growth to a level of 0-2 percent per year over time.

Q. HOW DID ACTUAL 2014 NON-OUTAGE O&M EXPENSES COMPARE TO THE BUDGET FOR THAT PERIOD?

A. As Table 7 above shows, actual non-outage O&M costs for 2014 were $10.9 million more than budget. The variance from budget was mainly due to unanticipated forced outages and regulatory inspection work. Forced outages at both plants (for which no budget was provided) increased costs by $6.8 million. Another $5.2 million was incurred for support of the one-time NRC inspections related to a regulatory finding related to emergency preparedness for flooding.

These variances correspond with 2014 increases in site costs of $7.4 million (including workforce costs of $4.0 million) and non-site costs of $3.5 million (including fees of $1.7 million and security of $1.8 million). Workforce cost variances include cost increases in contractors/consultants of $7.8 million, offset by labor savings of $3.8 million. Although we built up staff levels throughout the year 2014, much of that growth came later in the year and we had to rely on contractors to perform the work of vacant positions, as well as to serve specialty needs of the forced outages experienced during year.

As I noted earlier in my discussion of staffing and workforce planning initiatives, these staffing increases supported the effort to assess and prepare for our improvement in regulatory compliance. These investments in people were successful in improving both sites' NRC column ratings in 2014 and 2015. We are now committed to holding our headcount flat and redeployed employees as needed to continue the reduction in contractors going forward. This is reflected above in Table 7, where our 2015-2016 forecast/budget for contractors is about $26 million, significantly less than the actual costs of $35 million in 2014 and $40 million in 2013.

Q. IS THE COMPANY ENGAGED IN ANY EFFORTS TO CONTROL ITS NON-OUTAGE O&M EXPENSE GROWTH?

A. Yes. To manage labor costs, we are in the process of evaluating our long-term organizational structure and staffing levels to identify ways we can avoid staff increases in the future. In this regard, we are benchmarking other plants in the industry, which should help us identify and design a more centralized standard organization which we expect to deliver productivity and efficiency gains in relation to our current structure. We are also working to capture

productivity and efficiency from improved work processes and improvement in technology. We need to recognize, however, that we already compare favorably to the industry in our staffing levels, as I noted previously in reference to the EUCG staffing survey in Schedule 7.

To manage forced outage costs, we are developing preventative maintenance strategies to help identify the risks of aging components, and reduce single-point vulnerabilities, in areas where critical equipment could fail and cause unplanned shutdowns.

With respect to non-site cost growth, we are doing our best to manage the costs of security requirements in the long-term, and actually are sponsoring several capital projects that are aimed at making plant modifications to reduce the need for security officers (subject to NRC approval). Also, we have entered into a long-term contract with a security firm in our effort to manage and control costs over the contract term.

B. Non-Outage O&M Budget Categories – 2016 Test Year

1. Employee Labor

Q. PLEASE DISCUSS THE NON-OUTAGE EMPLOYEE LABOR INCLUDED IN THE NUCLEAR BUSINESS UNIT'S O&M TEST YEAR.

A. Non-outage employee labor expenses included in the test year are approximately $154.4 million and include all regular pay for Nuclear employees, including base pay, premium pay and overtime consistent with applicable bargaining agreements. It does not include annual incentive pay.

Q. WHAT ARE THE MAJOR TRENDS IN EMPLOYEE LABOR OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As shown in Table 7 above, internal labor costs increased 7.1 percent from $130 million in 2012 to $140 million in 2013, increased 8.7 percent to $152 million in 2014, are forecasted to increase 4.6 percent to $159 million in 2015, and are budgeted to decline 2.7 percent to $154 million in 2016.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. As I mentioned earlier in my testimony, labor is increasing over the period 2012-2016 mainly due to hiring more employees and raising base pay levels annually commensurate with market-based merit increases. Company witness Ms. Ruth Lowenthal describes the determination of appropriate compensation levels in her Direct Testimony. Staff levels increased approximately 10 percent in 2013 and 2014 from year-end 2012 levels, and are projected to remain at the year-end 2014 level through 2015 and 2016. Our long-term strategy is to reduce reliance on outside contract resources and build permanent internal staffs to do our work wherever efficient and cost-effective. Merit pay increases averaging 2.8 percent were provided through 2015 and are assumed for 2016. In addition, labor costs in 2015 include higher levels of overtime and premium pay time due to several forced outages experienced that year, that are not budgeted to recur in 2016.

As I noted earlier in my testimony, these additional employees hired in 2012-2014 accomplished multiple objectives. Adding people pipelines were in support of our strategic staffing and workforce planning initiatives, and provided stability in anticipation of normal attrition. And we need to deploy new resources in regulatory support functions to prepare for and resolve

issues arising from NRC inspections and INPO evaluations.

Q. PLEASE EXPLAIN THE DIFFERENCE IN EMPLOYEE LABOR FROM 2014 ACTUAL COSTS TO THE 2016 TEST YEAR BUDGET IDENTIFIED ABOVE IN TABLE 7.

A. The labor budget in 2016 is increasing $2.7 million or 1.8 percent from 2014 levels. The majority of labor cost increases from 2014 to 2016 are merit pay increases earned by employees in 2015 and 2016, at an average of 2.8 percent in each of those years. The average headcount in 2016 is budgeted to remain approximately the same as year-end 2014 levels.

Offsetting these increases are reductions in overtime/premium pay in 2016 vs. 2014. These costs are expected to decrease from 2014 to 2016 since the number of forced outages experienced in 2014, are not assumed to recur at that level in the 2016 labor budget.

Q. PLEASE EXPLAIN WHERE THE CHANGES IN EMPLOYEE COUNTS ARE BUDGETED TO OCCUR IN 2016 COMPARED TO 2014 ACTUALS.

A. Overall, the total average headcount in 2016 is budgeted to remain approximately the same as year-end 2014 levels. However, in 2016 our budget anticipates increased staffing in some areas, offset by decreases in other areas. The following are examples of changes in headcount of various departments between year-end 2014 and 2016:

- Operations and Engineering are budgeted to increase mainly due to open "pipeline" positions that are intended to bring in new staff, train them with hands on experience, and create "bench strength" for future opportunities that arise to fill existing positions. Nuclear operators have a two-year training cycle that must be completed before working

in line positions. These pipeline positions anticipate and prepare us for tomorrow's needs.

- Nuclear Oversight Services includes both quality assurance and audit functions for Nuclear. NOS is increasing its staffing to add auditor positions to monitor compliance with NRC requirements, is moving quality assurance from other departments, and is filling vacancies that existed at year-end 2014.
- Emergency Planning is increasing its staff primarily to fill vacancies that existed at year-end 2014. These positions are critical to deliver readiness for new NRC Fukushima program requirements, including training and practice scenarios for external events beyond the scope of the plants' original design basis.
- Procedures/Document Control/Site Administration positions are expected to decrease as part of our overall effort to optimize staff efficiency.

Q. PLEASE DESCRIBE THE CHALLENGES THE NUCLEAR ORGANIZATION FACES WITH RESPECT TO MAINTAINING ITS EMPLOYEE WORKFORCE, AND WHAT YOU ARE DOING TO ADDRESS THOSE CHALLENGES.

A. It remains a significant challenge to recruit and retain technically experienced nuclear employees. The compensation levels necessary to recruit and retain experienced nuclear employees is ever increasing based on the limited number of nuclear plants in the U.S. and the highly competitive practices employed by other nuclear companies in pursuit of the same experienced personnel. We are doing our best to provide market-competitive compensation through base pay, sign-on bonuses, relocation reimbursements, incentive programs, and (for key employees) retention awards.

The supply of possible nuclear employees is becoming more limited as well. With the industry being more than 40 years old, many experienced nuclear personnel are well along in their careers and will be in a position to retire in the next 5-10 years. We are building a succession plan of employees to replace these experienced staff members, and transfer the knowledge they now have so it can be carried forward.

Further, the lack of clear long-term public policy support for nuclear energy in the U.S. is limiting the entry of new employees into the industry. In addition, the younger members of the workforce do not find the nuclear industry attractive, for a number of reasons. They consider nuclear technology "old" in comparison to more interesting technologies in other industries. They are reluctant to make the personal sacrifices that nuclear often requires, such as being on call 24/7 for plant events or emergency preparedness, and nearly round-the-clock demands of plant outages (planned and forced). And they are hesitant to join an industry that may not have a future for career development, given the uncertainty in public policy support of nuclear in the long-term. We are doing our part to attract new, younger employees to nuclear through our internship, "pipeline," and rotational programs, particularly in the operations and engineering areas.

Finally, given the nuclear industry's openness in sharing issues and their resolution, plants with new performance issues are able to identify and recruit personnel who have worked at other plants who have successfully resolved issues. With our recent performance improvement efforts in exiting NRC Column 3 at Monticello and Column 2 at Prairie Island, other companies are targeting our employees as candidates to help them improve performance at

their sites. These other companies are offering signing bonuses and retention incentives to attract and retain experienced employees from other nuclear companies. We need to do the same.

Q. IN PAST RATE CASES, THE COMPANY HAS SOUGHT RECOVERY OF THE NUCLEAR EMPLOYEE RETENTION PROGRAM COSTS. IS THE COMPANY SEEKING TO RECOVER THE COSTS OF THIS PROGRAM IN THIS CASE?

A. No. To limit the number of contested issues, we are not seeking recovery of Nuclear retention program costs (approximately $900,000 in 2016) in this case. However, these costs remain critical to attracting and retaining quality Nuclear employees in the current marketplace, and we will continue to incur these costs in 2016 and beyond.

Q. WHY HAS THE COMPANY CONTINUED TO UTILIZE A NUCLEAR RETENTION PROGRAM?

A. We have continually experienced a high degree of turnover in upper-level management positions and in skilled workers. In mid-2012, we identified that there had been 36 changes at the senior level, manager and above, in the prior two years. We have continued to see losses in senior management positions, including the losses of our prior Chief Nuclear Officer (CNO) and Site Vice President (Site VP) at Prairie Island in 2012 and the losses of our Site VP at Monticello and three key managers in 2015. These losses through competition with other companies weaken an already stretched nuclear executive management team and exacerbate the challenge we continually face in stabilizing our workforce. Because these are highly-skilled, highly-recruited, and in-demand employees, we initiated in 2012 and continue today the nuclear

retention program to combat the threat of losing more of these valuable employees.

Q. WHY IS NUCLEAR EMPLOYEE RETENTION SO IMPORTANT?

A. The ability to retain key managers enables the Company to maintain long-term sustainable operations, succession planning, provides consistency, builds efficiency, and supports a high-level of operational performance at our facilities. Without continuity in these key positions, the nuclear facilities cannot operate as effectively and efficiently as other facilities that have not experienced similar levels of attrition at the upper management level.

Q. WHO IS ELIGIBLE FOR THE COMPANY'S NUCLEAR RETENTION PROGRAM?

A. We have identified over 30 key positions as eligible for the nuclear retention program. These positions were defined as critical positions by INPO and we followed INPO guidance in selecting the positions to be included. We relied on INPO guidance and industry knowledge to identify key roles in our operations, particularly with respect to the recent steam generator replacement project and dry cask project going into service in 2013 and 2014, respectively.

This retention program includes both cash compensation and long-term incentives (LTI). Retention values are based on the pay grades of the positions included in the program. Generally, the majority of the cash payouts is time-based (earned over a period up to three years), and the remaining cash bonuses are performance-based. All payments require the employee to remain with Xcel Energy through the designated time period. The performance goals have various expected achievement dates based upon the scheduled plant outages associated with key capital projects or nuclear licensing renewals.

Q. WHAT CRITERIA DOES THE COMPANY USE TO DECIDE WHETHER TO MAKE A PAYMENT UNDER THE NUCLEAR RETENTION PROGRAM?

A. Retention awards are paid when retention time periods and specified performance criteria are met. In some cases performance criteria was not met and the related payment was not made. For example, the 2012 Prairie Island site refueling outage was not completed on time per the project schedule and the performance criteria related to the 2013 Monticello EPU outage was not met, so neither of those performance awards was paid.

Q. DO YOU AGREE WITH DEPARTMENT WITNESS MR. DALE LUSTI'S COMMENTS IN THE DOCKET REGARDING THE COMPANY'S REPORT ON THE OPERATION AND PERFORMANCE OF ITS 2014 INCENTIVE COMPENSATION PLAN[21] THAT THE NUCLEAR RETENTION PROGRAM MAY BE AN "END RUN" AROUND PERFORMANCE INCENTIVES?

A. No. As discussed above, our retention program is a necessary part of our overall nuclear compensation strategy. Retention programs are well-established in the nuclear industry, and our plan's design is similar to what other companies are using to compete in today's marketplace for experienced nuclear managers. In order to maintain a stable base of experienced leaders, our Nuclear organization needs to use retention awards along with AIP – as other companies do – to compete with other companies to attract and retain these managers.

Further, although we have some performance elements to our retention program, the program serves a different purpose than the performance incentive program. The goal of a Nuclear retention program is to attract

[21] Docket Nos. E002/GR-92-1185, G002/GR-92-1186, and E002/M-15-522 (May 29, 20915).

employees and motivate them to stay with the Company. While this does not mean the employees will be permitted to continue to work indefinitely if their performance is substandard, good employees will "leave money on the table" if they move to different employment. In contrast, the focus of the Annual Incentive Plan is more specific to annual performance. Both elements of compensation are necessary to maintain a competitive overall Nuclear employee package.

Q. IS THE NUCLEAR RETENTION PROGRAM WORKING?

A. Yes. Since implementing the retention program for those critical positions, we have experienced turnover in fewer positions. And during this period, Prairie Island's performance has improved.

Q. DOES THE COMPANY PLAN TO CONTINUE TO USE A RETENTION PROGRAM?

A. Yes. We have incorporated other retention provisions in our employee agreements to help attract and retain qualified personnel. The benefits of maintaining our employee base are clear both on an operational basis and a cost basis as we avoid the costs related to recruiting and training replacement employees or hiring additional contractors to fill the gaps. We have expanded the program and it now includes both attraction and retention components. The expanded hiring, retention and performance program has individually-developed performance criteria specific to the job placement and skills of the individual employees.

2. Non-Employee Contractors and Consultants

Q. PLEASE EXPLAIN THIS BUDGET CATEGORY.

A. Contractors can be a cost-effective resource in some circumstances. We use contract labor (managed by site employees) for peak projects. Also, where we are unable to complete permanent hires to meet certain needs (or find it uneconomic to do so), we bring in contractors to supplement our ongoing work and fill in gaps until permanent positions can be filled. Contractors are used primarily to perform O&M project studies, engineering support and design, preventative maintenance studies, and regulatory project studies. We find the specialized expertise that contractors bring cheaper to buy than to qualify and maintain internally. Examples of specialty expertise include HVAC (heating, ventilation and air conditioning), heavy equipment servicing, certain engineering analysis, and reactor core fuel design.

Q. WHAT ARE THE MAJOR TRENDS IN NON-EMPLOYEE CONTRACTORS AND CONSULTANTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows, contractor/consultant costs increased from $30 million in 2012 to $40 million in 2013, declined to $35 million in 2014 and $26 million in 2015, and are budgeted increase slightly to $26.4 million in 2016. In general, our long-term strategy is to rely less on contractors and use permanent employee resources where possible. Our goal is to use contract labor (managed by site employees) for peak projects, to supplement our ongoing work in specialty areas where it is uneconomic to keep full-time resources on staff, and to fill in gaps until open permanent positions can be filled. The decreases expected in 2015 and planned for 2016 compared to 2012-2014 levels show our anticipated success in achieving our strategy and goals.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. Contractor/consultant costs increased from $30 million in 2012 to $40 million in 2013, when we had not yet increased to our higher employee target levels and still had to rely on outside resources to complete our work. We had some specific needs for contractors in 2013, given our 3:2:1 performance improvement initiative,[22] as discussed in our last rate case, and support needed to address NRC findings in three areas: (1) Monticello emergency preparedness related to flooding; (2) Prairie Island's diesel generators; and (3) human performance issues at both sites. We were able to lower contractor costs in 2014 to $35 million, as we increased employee staff levels and completed the NRC flooding inspection and our 3:2:1 initiative. Our forecast anticipates further decreases in contractor costs in 2015 to $26 million, reflecting our cost-reduction effort that year to help offset the unexpected costs of several forced outages by releasing contractors that were not working on short-term critical projects. The budget for 2016 has slightly increased to $26.4 million or 1.6 percent over the 2015 forecast.

3. Materials Costs

Q. PLEASE EXPLAIN THIS BUDGET CATEGORY.

A. Materials costs include tools, equipment and other resources to maintain and operate our nuclear generating facilities. They include items such as chemicals used in the nuclear generation process, radiological supplies, overhaul supplies not meeting capitalization thresholds, computer supplies, intake screen parts, boiler fuel oil, and ammunition used by on-site security personnel. The

[22] The 3:2:1 initiative was discussed in our last rate case. Its goal – improving up to 3 performance quartiles over 2 years (2013-14) and operate more as 1 fleet vs. individual plants – was our effort to accomplish a step change in performance improvement, in six major areas: safety systems, machine/equipment performance, independent assessments, regulatory margins with NRC, leadership effectiveness, and sustainability pipeline.

materials costs included in O&M are generally those consumed in the operating process or small in amount, and are in addition to materials capitalized in construction projects.

A key element of materials for nuclear utilities is the regulatory scrutiny and rules for equipment components and parts in use at our plants. Replacement and repair parts must meet regulatory qualification requirements for safety tolerances. Given the fact that most nuclear plants are 40+ years old, the original equipment manufacturers (OEM) may no longer be in business or produce the same components. The availability of replacement OEM components from vendors, or the time needed to qualify new components as acceptable, can create plant licensing basis and shutdown risks due to non-conformance with requirements.

Q. WHAT ARE THE MAJOR TRENDS IN MATERIALS COSTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows, materials costs are fairly constant in 2012-2016 at a level of $15 million to $16 million. Our actual costs have been about $16 million in each of 2012-2014, and we are forecasting/budgeting lower costs of about $15 million in 2015 and 2016.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. With consistent plant operation of three nuclear units, many of the chemicals, supplies and inventoried parts and materials needed to operate our three nuclear units remain constant over time and represent a base level of cost that does not fluctuate notably, as seen for 2012-2014.

The decreases in 2015-2016 from 2012-2014 levels are primarily due to a change in the Minnesota sales tax laws. Effective July 1, 2015, Minnesota discontinued the Capital Equipment Refund (which affects sales taxes for both capital and O&M) and now provides a sales tax exemption mechanism. Instead of paying sales tax on certain materials and then asking for a refund, the Company must provide an exemption certificate to its vendors in order to exclude the sales tax upon purchase. Accordingly, we have reflected lower levels of material costs in both 2015 and 2016.

However, maintaining lower materials costs may be challenging as we need to provide adequate resources to maintain the level of plant operation and performance improvement for which we are striving, and to allow for increased maintenance as our infrastructure (such as piping, breakers, etc.) ages. Also, the impact of future volatility in commodities prices, and their impact on materials costs, is unknown at this time. Further, we have recently experienced issues with the isotopes lithium-7 and depleted zinc, which are generally high in price while low in availability, which drives supply down and demand (and prices) up.

Q. WHAT ARE THE LONG-TERM TRENDS FOR BASE COMMODITIES?

A. In general, industrial commodity prices have been sliding downward since mid-2014 and as of mid-2015 had dropped to their lowest level since the 2008 global financial crisis. Causes for this slump include growing concerns over an economic slowdown in the Euro Area and China, rising supply of oil and key metals, and a strong U.S. dollar. Since most commodities are traded in U.S. dollars, a strong dollar reduces the purchasing power of customers globally. The decline in oil prices has led to general decline in other commodities,

including metals. Prices in electrical steel, stainless steel and aluminum prices have been declining. In addition to the drop in energy commodities, other factors contributing to low steel prices include chronic oversupply in the domestic market and the availability of cheap imports. Copper prices are down because of weak Chinese demand and uncertainties around the economic fate of the Eurozone.

4. Employee Expenses

Q. PLEASE DISCUSS WHAT EMPLOYEE EXPENSES ARE INCLUDED IN THE NUCLEAR OPERATION BUSINESS UNIT'S 2016 TEST YEAR O&M BUDGET.

A. Employee expenses are comprised mainly of the costs for Nuclear employees to travel both within and outside the Company's service territory for business reasons. The most common need for travel is for: staff travel (by car) between plant sites and fleet headquarters to provide support and oversight; meetings with regulatory and oversight agencies such as NRC and INPO; meetings and initiatives with industry groups such as NEI, EEI, and USA; performing industry benchmarking with and quality reviews (including INPO) for other nuclear utilities; and vendor oversight for quality assurance (which can involve international travel). We critically review employee expenses and are working hard to optimize the benefit of such travel in consideration of the associated costs.

Q. WHAT ARE THE MAJOR TRENDS IN NUCLEAR EMPLOYEE EXPENSES OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows, employee expenses increased from $3.9 million in 2012 to $5.7 million in 2013, remained flat in 2014 at $5.7 million, are forecasted to decline significantly to $2.8 million in 2015, and are budgeted to

rise to $4.6 million in 2016.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. A base level of employee expenses is necessary for staff travel between sites, as part of interacting with regulators (NRC) and industry oversight functions (INPO), and to participate in industry groups and initiatives. The base level can fluctuate upward with more fleet headquarters staff or cross-site support, with increased levels of regulatory and industry oversight activity, and with increased participation in industry groups and initiatives.

In 2012 and 2015, we exercised discretion and intentionally reduced our face-to-face participation in industry groups and initiatives, which lowered the level of employee travel expenses in those years, as we sought to manage our overall O&M costs in those years.

In 2013 and 2014, we intentionally increased our level of participation in those activities, recognizing that in the long-term we needed to do our part in not only keeping up with industry current issues, trends and learnings, but also shaping the future of nuclear energy through network-building and collaboration with our peers. Thus, in those years our travel and employee expenses increased.

In 2016, our budget assumes a base level of regulatory and oversight travel activity, but slightly less participation in industry groups/initiatives than in 2013-2014 (while more participation than in 2015). The NRC has expressed concern with the lower levels of attendance and their regional industry working groups in 2015, and requested we address that issue. These groups

are proactive look-ahead sessions to keep abreast of new NRC polices, and enable timely and effective compliance.

With our "one fleet" initiative to foster stronger support among all three locations (the two plants and the corporate headquarters), we now expect more staff travel between sites for this support in 2015 and beyond. Providing this cross-site support also reduces our reliance on contractors – one of our strategies as I discussed earlier, when we can supplement site resources with help from our other sites.

In addition to travel costs, employee expenses for relocation costs were higher in 2013 and 2014 as we sought to attract industry talent to add staff under our 3:2:1 initiative to improve governance and oversight, and to provide bench strength for key management roles. Since we reduced the level of hiring in 2015, relocation costs are very low that year, and are expected to return to a more normal level by 2016.

5. Other Expenses

Q. PLEASE DISCUSS WHAT OTHER EXPENSES ARE INCLUDED IN THE NUCLEAR OPERATION BUSINESS UNIT'S 2016 TEST YEAR O&M BUDGET.

A. "Other" O&M expenses are comprised mainly of information technology and support costs (such as software licensing and hardware maintenance), utility costs (i.e. electricity and gas used by the sites), rents (for equipment and facilities), facility and site maintenance costs, fleet vehicle transportation costs, permits, office supplies and printing costs. Also, through mid-2015, sales tax refunds for materials purchases qualifying for tax exemption were recorded as reductions to Other O&M.

Q. WHAT ARE THE MAJOR TRENDS IN OTHER O&M EXPENSES OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows, Other O&M Expense costs were increased from just under $5 million in 2012 and 2013 to $6.7 million in 2014, and are budgeted to rise to $8.2 million in 2016.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. After being fairly flat in 2012 and 2013, Other O&M Expense increased in 2014 primarily due to higher information technology costs (mainly software licenses) and reclassification of contractor costs within Nuclear. The reclassification was for building-related site maintenance expenses such as lawn care, janitorial, snow and trash removal, and maintenance of the buildings in order to provide better transparency for our true contractor support for staff augmentation and specialty services as part of our goal to reduce our dependency on these external resources.

Compared to 2014 levels, Other O&M Expense is increasing in 2016 due largely to the end of sales tax refunds previously available to Nuclear, that are now reflected as an exemption at the time of materials purchases, as discussed earlier in the Materials Costs section of my testimony.

6. Nuclear-Related Fees

Q. WHAT ARE INCLUDED IN NUCLEAR-RELATED FEES?

A. Nuclear fees include industry specific fees and dues. Fees are assessed by the industry's Federal regulatory oversight agency (NRC), by the industry's operational oversight organization (INPO), by governmental emergency preparedness and management agencies (FEMA for Federal and various state

agencies), and consistent with agreements with the Prairie Island Indian Community. Dues are assessed by various industry organizations and groups. Table 8 depicted below lists out the various components of Nuclear Fees and the changes by year.

Table 8
Nuclear Fees

$ in millions	2012 Actual	2013 Actual	2014 Test Year Budget	2014 Actual	2015 Fcst	2016 Test Year Budget	Avg Chg per Year 2014 to 2016
NRC	20.2	17.8	20.1	22.3	21.4	21.9	-0.9%
FEMA/ State EP	4.6	5.9	6.8	5.6	6.8	6.9	11.6%
INPO	2.8	3.1	3.0	3.0	3.1	3.0	0.0%
EPRI	2.3	2.3	2.5	2.6	2.5	2.7	1.9%
PI Indian Community	-	-	-	1.5	1.5	2.5	33.3%
NEI & Other Industry Groups	2.0	2.4	2.8	2.2	2.2	2.2	0.0%
Total Nuclear Fees /Dues	31.9	31.5	35.2	36.9	37.5	39.2	3.1%

Q. WHAT ARE THE MAJOR TRENDS IN NUCLEAR-RELATED FEES OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Tables 7 and 8 above show, Nuclear fees were fairly consistent at just under $32 million in both 2012 and 2013, increased significantly to nearly $37 million in 2014, are forecasted to increase, slightly to nearly $38 million in 2015, and are budgeted to increase to about $39 million in 2016. Overall, fees and dues in the test year 2016 are increasing an average of 3.1 percent per year from actual 2014 levels.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. Both NRC fees and FEMA/state emergency preparedness (EP) fees have fluctuated in various years, with NRC fees accounting for most of the 2014 increase and the 2015 decrease. In addition, a ratemaking change to remove

Prairie Island Indian Community (PIIC) fees from a rate rider recovery mechanism in 2014[23] has shifted those costs to Nuclear O&M from an amortization account, which accounts for some of the 2014 increase in O&M as well. The 2016 increase is driven by higher fees for NRC, FEMA/EP and PIIC.

Q. PLEASE EXPLAIN THE DIFFERENCE IN NUCLEAR-RELATED FEES FROM 2014 ACTUAL COSTS TO THE 2016 TEST YEAR BUDGET IDENTIFIED ABOVE IN TABLES 7 AND 8.

A. Two areas are driving increases in fees and dues from 2014 to 2016: FEMA/state emergency preparedness fees and Prairie Island Indian Community fees. NRC fees are actually declining in that period, and all other fees and dues are either flat or increasing less than 2 percent. I will explain the drivers for the larger changes in the next set of questions in my testimony.

Q. PLEASE EXPLAIN THE VARIATIONS IN NRC FEES OVER THE YEARS, IN PARTICULAR THE DECREASE IN 2016 FROM ACTUAL 2014 LEVELS.

A. NRC fees consist of two components, fixed fees assessed on a per-reactor basis, and inspection fees, which vary based on work the NRC does for each operator. Table 9 below summarizes the changes in these two components from 2014 to 2016.

[23] *See* ORDER APPROVING STATE ENERGY POLICY RIDER, AS MODIFIED, Docket No. E,G002/M-03-1544 (April 6, 2004) (approving inclusion of the Prairie Island Settlement payments in SEP rider); December 11, 2013 ORDER in Docket No. E002/M-13-959 (setting electric SEP rate to $0).

Table 9
Nuclear Fees – NRC

$ in millions	2014 Actual	Current 2015 Billing Level	Full Year 2015 Forecast	2016 Test Year Budget	Assumed 2015 Change from Current*	Assumed 2016 Increase from 2015*
NRC Reactor Fees	16.3	15.1	15.0	15.5	-0.7%	3.3%
NRC Inspection Fees	6.0	6.4	6.4	6.4	0.0%	0.0%
Total NRC Fees	22.3	21.5	21.4	21.9	-0.5%	2.3%

*Includes projected reactor fee increase of 2.5 percent per year effective at start of fiscal year on Oct.1

Q. PLEASE EXPLAIN THE VARIATIONS IN NRC REACTOR FEES.

A. The 2016 test year budget for reactor fees assumes current billing levels will change, normally upward, as each fiscal year progresses. The NRC's fiscal year ended September 30. We assume that reactor fee levels will increase for the fourth quarter of 2015, and again in the fourth quarter of 2016, at 2.5 percent each year. The 0.7 percent decrease in total 2015 reactor fees from current billing levels reflects the combined effects of the NRC's announced decrease of 1.3 percent through Sept. 30, 2015, an assumed increase for 4th quarter 2015 of 2.5 percent, and a true-up recorded in 2015 for the decrease in fee levels for the fourth quarter of 2014 (which was not known at year-end 2014). Ignoring this true-up recorded in 2015, the increase for 2016 would be our assumed level of 2.5 percent per year from current billing levels.

We base our assumed level of 2.5 percent annual increases in reactor fees on the best information available, considering NRC communications, history and experience. However, the NRC's assessed reactor fees are intended to cover all of their agency costs other than those funded by inspection fees, and when NRC budgets include unique drivers (such as one-time programs like

Fukushima, or expected staffing increases), past history is not necessarily predictive of future fee changes. For example, for their fiscal year ending September 30, 2014, the NRC increased its reactor fees 19.0 percent and for the fiscal year ending in September 2015 it decreased them 1.3 percent.

Q. PLEASE EXPLAIN THE INCREASES IN NRC INSPECTION FEES FROM 2014.

A. The 2016 test year fees for NRC inspections are budgeted to continue at the current levels we are being billed in 2015. This level represents an annual average increase from actual inspection fees in 2014 of 3.3 percent. As I noted earlier in my testimony, the number of NRC inspections and their extent continues to rise since the Fukushima accident. Our current level of inspection billings in 2015 is already higher than 2014 actuals and we project this higher level of inspections to continue into 2016. Depending on inspections that have not yet been scheduled or requested, the 2016 inspection schedule could actually be larger and at higher cost than current 2015 (and 2016 budget) levels.

Q. PLEASE EXPLAIN THE VARIATIONS IN FEMA/EP FEES, IN PARTICULAR THE INCREASE EXPECTED FROM 2014 ACTUALS TO 2016.

A. There are four main elements of emergency planning fees: one at the national level, Federal Emergency Management Agency (FEMA); and three at the local level, Minnesota Department of Public Safety (Homeland Security and Emergency Management), Wisconsin Radiological Emergency Planning Program, and Pierce County in Wisconsin (Office of Emergency Management). We base our assumed level of annual increase/decrease in these costs on the best information available, which typically includes communications directly from the applicable agency, historical rates of

increase, and any knowledge of unique drivers such as one-time programs or expected staffing increases. The 2016 increases can be summarized as shown in Table 10 below.

Table 10
Nuclear Fees - FEMA/Emergency Preparedness (EP)

$ in millions	2014 Actual	Current 2015 Billing Level	Full Year 2015 Forecast	2016 Test Year Budget	Assumed 2015 Increase from Current	Assumed 2016 Increase from 2015
FEMA	1.1	1.2	1.2	1.2	0.0%	0.0%
Minnesota EP	3.7	4.4	4.7	4.7	6.8%	0.0%
Wisconsin EP	0.6	0.8	0.8	0.9	0.0%	12.5%
Pierce County WI EP	0.2	0.1	0.1	0.1	0.0%	0.0%
Total FEMA/EP Fees	5.6	6.5	6.8	6.9	4.6%	1.5%

The increases in Minnesota and Wisconsin EP fees are driven by additional regulatory rules and training requirements for emergency planning and preparedness. The NRC requires communities supporting nuclear plants to perform regular drills to practice preparedness for hostile actions (such as an attack on the plant) and responses to external events (such as flooding or tornado threats).

Q. PLEASE DESCRIBE THE PIIC FEES, IN PARTICULAR THE INCREASE IN 2016 FROM 2014-2015 LEVELS.

A. Minnesota legislation passed in 2003 (Statute 216B.1645, subdivision 4, *Settlement with Mdewakanton Dakota Tribal Council at Prairie Island*) states in part:

> The commission shall approve a rate schedule providing for the automatic adjustment of charges to recover the costs or expenses of a settlement between the public utility that owns the Prairie Island nuclear generation facility and the Mdewakanton Dakota Tribal Council at Prairie Island, resolving outstanding disputes regarding the provisions of Laws 1994, chapter 641, article 1, section 4. The

> settlement must provide for annual payments, not to exceed $2,500,000 annually, by the public utility to the Prairie Island Indian Community …

Under these statutory provisions, the Company paid the PIIC various levels of fees, depending on their nature as recurring or non-recurring, under the settlement agreement. The Company paid the PIIC $2.25 million per year from 2003 through 2012, $2.15 million in 2013, and $1.45 million in 2014 and 2015. Through 2013 the fees were recovered through a rate rider recovery mechanism that was discontinued in 2014 when the recovery process in Minnesota was changed to base rates.[24] Accordingly, as it became a base rate cost in 2014, the fees were reassigned to Nuclear O&M beginning that year.

In 2015, the PIIC advised the Company that (a) its position when the settlement agreement was entered in 2003, was under the assumption that Yucca Mountain permanent spent fuel storage facility would be up and operating by 2025, and (b) since the federal government terminated the Yucca Mountain program in 2010, circumstances have changed and the terms of the settlement agreement should be renegotiated. The Company reached agreement to new terms with the PIIC in the summer of 2015, subject to Commission approval, to increase the fees due PIIC to the $2.5 million maximum level allowed under statute, effective in 2016.[25]

7. Security Costs

Q. WHAT ARE SECURITY COSTS?

A. Security costs reflect the contract labor workforce we procure to meet the

[24] December 11, 2013 ORDER in Docket No. E002/M-13-959.

[25] *In the Matter of the Petition of Northern States Power Company for Approval of an Amendment to the 2003 Settlement Agreement with the Prairie Island Indian Community,* PETITION FOR APPROVAL OF AMENDMENT TO 2003 SETTLEMENT AGREEMENT, Docket No. E002/M-15-922 (October 15, 2015).

security post requirements of the NRC. Posts are manned 24 hours per day, 7 days a week, using 5 shifts per day. This has resulted in Security being the largest single functional workforce in the Nuclear organization. The number of security officers manning each post is based on coverage requirements set by the NRC. The specific logistics of each plant must be mapped to the NRC's requirements, and coverage levels must be maintained. If any unusual security issues are noted, additional "compensatory" posts may be required on a temporary basis until a permanent security remedy can be designed and implemented, subject to NRC approval. The Security O&M item excludes the internal security management team that oversees the contract workforce. The costs are paid to an outside security firm based on the number of officers required per post and the contracted labor and benefit rates agreed to with the Company.

The NRC's security requirements under our operating license are quite extensive and unique for nuclear plants. Our plants must file a security plan that addresses those requirements, including provisions for various contingencies (such as hostile threats or radiation release) and compensatory actions when appropriate. The security plan has to provide a satisfactory response to real and potential threats, and must be able to operate concurrent with a nuclear radiation release should that occur.

The NRC requires self-assessment of security effectiveness, and also performs inspections. Issues found from either self-assessments or inspections must be remedied initially through compensatory measures, and followed up with a longer term permanent remedy. Our goal is to comply with requirements but

seek cost-effective means to do so, which can involve capital modifications to reduce compensatory measures where feasible.

Q. WHAT ARE THE MAJOR TRENDS IN SECURITY COSTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows, Security Contractor costs have increased each year, rising by 4 percent in 2013 and 11 percent in 2014, a forecasted 3 percent in 2015, and a budgeted 5 percent in 2016.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. The increases in security costs in all years is due mainly to increases in contracted labor and benefit rates for officers, and in some years to increases in the number of security posts based on NRC requirements (including compensatory measures). Table 11 below shows the major components that are driving the increases in security costs from actual 2014 to test year 2016.

Table 11
Security Increase Breakdown: 2014 Actuals to 2016 Test Year
($ in millions)

2014 Actual Security Contractor Costs	**$30.8**
[TRADE SECRET BEGINS…	
	…TRADE SECRET ENDS]
2016 Test Year Security Contractor Costs	**$33.4**

The consistent increases in security costs over time reflect the national Congressional concern over the enhanced security of nuclear plants, not only to provide protection for external events post-Fukushima, but also for hostile threats to plant and public safety.

Q. HOW DO NUCLEAR'S OVERALL O&M COSTS COMPARE TO OTHER COMPANIES IN THE INDUSTRY?

A. The total O&M costs at Prairie Island and Monticello continue to compare favorably to other facilities across the United States. Schedule 7 provides comparison charts for total operating costs in 2013 and 2014 for single unit sites like Monticello and dual unit sites like Prairie Island. Total operating costs include all of our O&M, including non-outage and outage. This data is provided by the EUCG based on surveys of industry companies, including Xcel Energy. We do not have comparison data for periods after 2014 at this time. These comparisons show the cost of our plants to be lower than most plants on a total dollar basis for operating costs.

C. Multi-Year Rate Plan Non-Outage O&M Costs

Q. WHAT IS THE LEVEL OF O&M EXPENSE NUCLEAR SEEKS TO RECOVER FOR THE 2017 AND 2018 PLAN YEARS?

A. Company witness Mr. Chandarana explains the basis of the Company's overall approach to its O&M expense requests for the 2017 and 2018 Plan Years and Company witnesses Mr. Charles Burdick and Mr. John Mothersole explain the basis for the Company's selection of the particular factors used in our rate requests for these years.

Q. WHILE THE COMPANY PROPOSES USING THESE FACTORS, ARE THERE SPECIFIC DRIVERS OF NUCLEAR 2017 AND 2018 NON-OUTAGE O&M BUDGETS?

A. Yes. As shown in our 2017 and 2018 supporting information, provided in Volume 6 of our Initial Filing, Nuclear is forecasting changes in its non-outage O&M expenses for Plan Year 2017 in the following areas:

- An increase in labor of $3.7 million (2.4 percent) due largely to annual merit increases in base pay.
- An increase in fees of $0.9 million (2.3 percent) due mainly to annual increases in fees assessed by NRC and FEMA/state emergency planning agencies.

Nuclear is also forecasting changes in its non-outage O&M for Plan Year 2018 in the following areas:

- An increase in labor of $4.2 million (2.6 percent) due largely to annual merit increases in base pay.
- An increase in fees of $0.8 million (2.0 percent) due mainly to annual increases in fees assessed by NRC and FEMA/state emergency planning agencies.

These forecasted increases for 2017-2018 are comparable with the relatively consistent level of annual increases in merit pay and nuclear fees for 2016, as discussed earlier in my testimony.

V. PLANNED OUTAGE O&M BUDGET

A. Overview and Trends

Q. HOW DOES THE COMPANY SET THE PLANNED OUTAGE O&M BUDGET FOR

THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. Planned outages refer to regularly scheduled refueling outages during which we also perform off-line maintenance to the plant. The first step in developing the budget for planned outage costs is to identify the scope and schedule of refueling outages. The schedule for a planned outage in a given cycle is determined by the unit's fuel reloading needs, which as discussed earlier in my testimony has a target of every other year at each unit. Monticello has historically been on a 24-month fuel cycle and Prairie Island has been on an 18-month cycle. Recently we have performed refuelings at Monticello in the spring of odd years, and at Prairie Island in the fall of even years for Unit 1 and the fall of odd years for Unit 2. This schedule is based on continuous operation of the plant, and can change depending on unplanned outages and their impact on the fuel operating cycles. The scope of a refueling outage includes routine activities (the activities completed during every refueling outage), periodic activities (activities that occur on a defined schedule but not necessarily every refueling outage) and other one-time or special activities.

The specific scope of each refueling outage is driven by both NRC license requirements (such as the plant's Technical Specifications) and industry-defined programs. Industry expert groups such as INPO, NEI and equipment owner groups provide best practices in critical equipment preventative maintenance and safety systems protection, which are key inputs to outage scope. These groups are part of the industry trends and strategies I referred to earlier in my testimony. In addition, the new extended licenses' aging equipment management inspections, evaluations, and replacements are inputs

to the outage scope definition.[26] Another set of inputs comes from plant operating and safety risk needs and reliability preventive measures for cycle-to-cycle operations. All of these activities are estimated individually and then aggregated to create the initial outage budget.

The refueling outage budget process is dynamic, with planning that remains fluid until the day the outage starts, and then adapts to emergent issues that may arise during the outage (typically based on inspections). Initial cost estimates for completion of the work are based on historical estimates, adjusted for labor or material cost changes that are known, or estimated using escalation for inflation. After initial planning, we solicit vendor bids for work scopes with performance criteria.

Activities in the refueling outage scope are controlled internally under our work order process. A work order will define the work to be completed, the resource (internal or contract) responsible to prepare for and complete the work, and the materials needed to support the work. Updated information on estimated labor and material costs are incorporated as the work order progresses through the planning process leading up to the actual refueling outage.

Planned outage budgets are reviewed in Nuclear's financial governance process, with regular (daily/weekly) reviews at the plant site, and monthly reviews through the business area and Xcel Energy corporate forecasting process.

[26] Examples of added outage scope from aging equipment management programs are new inspections required for Monticello, new steam dryer components added to the plant in 2011-13 as part of the EPU/LCM project, new core shroud and related legs, and upgraded baffle plates. These add scope to all planned outages at that site going forward.

Q. WHEN DOES THE PLANT START THE OUTAGE PLANNING PROCESS?

A. A long range plan exists which lays out the major activities for each outage for at least six years. The detailed planning process starts two years in advance of the refueling outage and before the prior refueling outage on that same unit has been completed. As an example, as Prairie Island performs its Unit 2 outage in the fall of 2015, the scoping for the Unit 1 outage in the fall of 2016 will be nearing final completion and planning will be commenced to ensure readiness for the 2016 outage. Work performed in the previous refueling outage will help define portions of the work for that unit's next refueling outage via lessons learned for better efficiency and selection of work scope.

We continue to look for ways to improve outage performance to reduce our planned outage duration and cost. For the fall 2015 outage at Prairie Island, we are implementing some of these improvement initiatives. One example includes the creation of a "team room" approach that includes representatives from site departments to manage all scheduled activities continuously, at a detailed level, to ensure progress and work execution continues to be implemented in accordance with the schedules. This group is also responsible for resolving emergent issues and driving solutions and actions to ensure we maintain schedules. Other improvement initiatives include scaffold design improvements and increased oversight of the efficient use of contractors.

Q. HOW DOES THE PLANT PLAN A SPECIFIC OUTAGE'S WORK SCHEDULE?

A. An overriding consideration in planning every outage is concern for plant shutdown safety, and managing the unique outage configuration scenarios that mandate security and protection. A key stakeholder concern is to ensure continuous nuclear fuel cooling when a nuclear reactor is shut down for an

outage. Post-Fukushima, stakeholders have a new focus and a much more conservative perspective on safety and compliance. Accordingly, all outage work is evaluated with safety as the most important concern.

The planning process for outage work activities follows industry best practices and includes numerous milestones that are uniquely set for each outage. These include pre-outage planning milestones, identification of major maintenance and projects, a review of scope changes based on the previous outage, and extensive engineering and project planning milestones. Several of the milestones will result in updated inputs into the final outage budget development. Although efforts are made to maintain budget, scope changes do occur and emergent issues due to plant needs or regulatory requirements arise that require deviations from budget to ensure safety, compliance and reliability are not compromised.

For the non-outage work and capital work, we review the requirements for those activities and evaluate how the necessary work will most efficiently fit into the outage schedule. Work activities that can safely be done on-line are performed outside of outage timeframes to minimize the outage duration and cost. There is always some risk of an unintended consequence when performing work while a unit is on-line that could result in unit shutdown. We also consider that doing the work while the unit is shut down can improve the available access to plant equipment and afford the opportunity to reduce radiation doses to the workers while accomplishing the work. All of these factors are considered in developing an outage's work plan.

Q. HOW DOES THE COMPANY PLAN FOR EMERGENT WORK DURING OUTAGES?

A. Historically, the Company had used a zero-based budgeting philosophy for outages and did not budget for emergent work. We budgeted for the work required, provide an allowance of 10-15 percent emergent work in our personnel resource allocations, and assumed for budgeting purposes that work and work scope would remain as planned. We are expected to remain on schedule and on budget for all outages, even when we encounter emergent work. When we encounter unplanned work, we evaluate the schedule and budget to determine how we can manage to the budget given current work requirements. However, the sites do not compromise on safety or reliability. If emergent equipment issues arise that could directly or indirectly pose a safety risk at the plant, the work will be performed and unplanned costs will be incurred.

The additional work to be done for emergent issues presents cost/benefit considerations. We view adding resources and cost to the outage scope for emergent issues to be cheaper and more cost-effective in the long term in comparison to waiting for the issue discovered to cause problems down the road and react at that time. Also, in many cases we cannot wait to address issues discovered due to safety concerns or regulatory requirements.

We have been challenged to manage within our 10-15 percent allowance for emergent work in the past. Most other nuclear units who can manage at 10 percent or less have invested more in aging equipment management and are further along in their life cycle management equipment upgrade and replacement efforts. We believe that investment in LCM projects, particularly at Prairie Island, will enable us to minimize emergent issues encountered in future outages.

Q. CAN YOU PROVIDE AN EXAMPLE OF EMERGENT WORK THAT ARISES DURING AN OUTAGE?

A. Yes. For example, the NRC requires compliance with the American Society for Mechanical Engineers (ASME) code[27] to inspect a certain population of plant components. If an indication is found during these initial inspections, the ASME code requires us to increase the population of components to be inspected. Similarly, we have periodic inspections for specific equipment components required by the NRC and mechanical engineering code at 5 or 10 year intervals. Should issues be identified during these periodic inspections, we need to perform work to address the equipment concerns identified.

Many ASME inspections involve what is called the military engineering sample approach. In this approach, a small sample of the population is inspected and if failures are found, the sample size is expanded. If further failures are found, the sample size is continually increased until eventually a 100 percent sample may be necessary. Examples of inspections using this approach are snubbers, relief valves, flow accelerated corrosion, and welds.

When equipment failures are identified through inspections, we are bound by the NRC corrective action process, whereby all failures must have an extent of condition determination, with expanded inspection scopes occurring when conditions dictate. Aging relays is a good example, where one failure identified in a recent outage led to the replacement of 28 relays, none of which were in the initial planned outage scope.

[27] The American Society of Mechanical Engineers (ASME) develops and issues codes and standards covering a breadth of topics, including pressure technology, nuclear plants, elevators / escalators, construction, engineering design, standardization, and performance testing.

Q. HOW ARE EMERGENT ISSUES REFLECTED IN BUDGETS, AND IMPACTING THE ABILITY TO MANAGE TO INITIAL PLANNED OUTAGE BUDGETS?

A. Historically, we have not budgeted for these types of additional inspections or emergent issues beyond planned scope, and while trying to manage to the original outage budgets, we have recently experienced overruns due in large part to emergent work issues. These types of issues continue to put a strain on our budgets because they are emergent and unplanned.

Industry practice is to provide for contingency in all project work. Our historical practice of not providing contingency for non-scope work makes us an outlier from industry best practice. Consequently, in the budgets for Prairie Island's outages in 2015 and 2016, we have provided a level of contingency for emergent issues based on what we have been experiencing in recent planned outages.

Q. HOW DOES THE COMPANY CATEGORIZE COSTS INCURRED DURING A PLANNED OUTAGE?

A. During a planned refueling/maintenance outage, there are three types of costs incurred:

- Outage work, with costs tracked separately via work orders and special codes;
- Capital projects, with costs tracked in separate capital work orders. These projects and their costs are subject to Capital Asset Accounting policies and oversight; and
- Non-outage, non-capital work, which is accounted for as a regular O&M expense.

The Company tracks outage costs consistent with the Commission's requirements for outage cost deferral/amortization. Exhibit___(TJO-1), Schedule 8, which is the Company's Planned Outage Policy, incorporates these requirements.

Costs incurred during an outage can only be included as incremental outage costs if they meet the Commission's deferral/amortization requirements, and can only be capitalized if they meet the Company's capitalization policies (which are based mainly on the requirements of FERC accounting regulations). The Commission has confirmed our method of deferral and amortization of outage costs in the Company's last several general rate cases.

All costs not meeting the Commission's outage requirements or the Company's policies using FERC capitalization requirements are accounted for as non-outage O&M expense.

Q. HOW DOES THE COMPANY ADDRESS POTENTIAL CHANGES IN THE PLANNED OUTAGE O&M BUDGET AS THE PLANNING PROCESS PROCEEDS?

A. As I discussed earlier, the initial estimates of work schedule, scope and cost are updated during the outage planning process, right up until the start of the outage, and are impacted by emergent issues encountered during the outage. The planned outage O&M budget is revised periodically during the planning process based on changes needed in maintenance activity scope, the updates to the sequence of outage work activities, and the cost of various resources needed to perform the latest work activities.

After initial planning, potential scope and work changes are considered and the impact on outage duration, schedule and cost evaluated. Regular challenge boards meet at the site and fleet level to identify opportunities to improve job performance, optimize the work schedule, and redeploy resources with the goal of doing the right level of work with minimal increase to planned outage cost.

We recognize that we need to balance the refueling and maintenance requirements of the plant with our ability to fund those activities given all Nuclear priorities and the limited O&M resources for the Company as a whole. The final outage budget considers both needs and available resources.

Q. PLEASE EXPLAIN HOW THE NUCLEAR OPERATIONS BUSINESS UNIT MONITORS OUTAGE O&M EXPENDITURES DURING THE OUTAGE TIMEFRAME.

A. Once the outage commences, the scope and schedule of outage refueling and maintenance activities are monitored by outage project management personnel to ensure the nature, timing and sequence of activities are properly understood and appropriately planned. From a cost perspective, we use a daily outage tracking process to monitor the resources in place and planned to be on site, assess which are needed for each day's activities, which can be redeployed to other outage jobs if possible, and which can potentially be put on temporary standby or given days off until their work comes up in the outage queue. This tracking and monitoring enables us to avoid costs of unnecessary contract staff remaining on site when their work is rescheduled, and to avoid outage overtime and premium pay for internal labor when possible.

We oversee the work of contractors in the field, and continually review resource mobilization and demobilization curves for work planned. We use our Nuclear Oversight Services (NOS) group to oversee quality assurance for work performed. We have roving human performance teams to assure safety and compliance. This collective effort is designed to lead to efficiency, productivity, and optimal costs.

Beginning in 2015, we have also engaged an outside firm to assist us in managing the overall planned outage project at Prairie Island. This vendor has been given performance criteria for both cost and schedule and is accountable for oversight of outage activities and resources. We anticipate that this additional monitoring and oversight will enable us to be as efficient as possible in delivering outage results on schedule and on budget.

That said, discovery of equipment issues, and any safety concerns identified during inspections and startup, creates emergent work that adds time, resources and costs to the outage in relation to plan. While we do our best to predict these unforeseen changes from plan, ultimately we must address the issues encountered and bear the costs required to resolve them.

Q. HOW DOES THE COMPANY MANAGE INCREASES IN ACTUAL COSTS EXPERIENCED FROM THE PLANNED OUTAGE O&M BUDGETS?

A. Outage costs have exceeded budgets in the last several refuelings due to the emergent and startup issues encountered at both plants, as I mention in more detail later in my testimony. Post-Fukushima, we operate in a very conservative safety environment that creates stops and starts in our returning

the unit to service based on the proper evaluation of issues identified. These are the norm for Nuclear safety in today's world.

Nonetheless, planned outage costs are part of the O&M budget that Nuclear is expected to manage to, as is every other Company business area. When we experience increases in planned outage costs from budget, we need to evaluate what opportunities we have to offset the higher outage costs in order to have overall O&M track with the budget expected for the year. Given the timing of Prairie Island's fall outages, it is often very difficult to find offsetting cost reductions before year-end. Also, given the priority of much of Nuclear's work, there is often little discretionary spend to defer or eliminate in our budgets. Including a contingency for emergent issues in our 2015 and 2016 Prairie Island outages will help us provide for work needed to address unanticipated items, such as those experienced in 2014 and early 2015 as I discuss later.

Q. HOW DOES THE COMPANY'S MANAGEMENT OF ACTIVITIES FOR PLANNED OUTAGES COMPARE TO INDUSTRY PRACTICE?

A. Our scheduled outage planning process follows the industry process through use of standard milestones used to measure progress for planning. These milestones are discussed in our outage procedures and are measured in a "t minus" approach where we plan and oversee progress toward a critical milestone point. Under this approach, off-line maintenance work and capital projects during a planned outage have milestones for scope freeze and design modifications to be completed. Our procedure for outage preparations, Refueling Outage Management, is based on best industry practices shared

through INPO as well as the EPRI.[28] Oversight of external contractors used during all projects is achieved through the guidance provided in our Contractor oversight procedure, which is based on industry guidance taken from INPO.

Q. HOW DOES THE COMPANY'S MANAGEMENT OF COSTS FOR PLANNED OUTAGES COMPARE TO THE INDUSTRY?

A. Like us, all nuclear utilities have regular refueling outages during which they perform off-line maintenance work and construction projects. We regularly have an opportunity to benchmark other nuclear companies' experience with outage costs – formally and informally – through our industry groups, quality reviews, and interaction with peers. We have found two common areas of comparison that drive outage cost, the duration of an outage and the cost per outage day.

Duration – Some companies perform refueling outages every year, and with annual off-line maintenance opportunities and smaller reloads of fuel these companies can reduce outage duration to as low as 20 days. Companies with large fleets of plants with two-year fuel cycles, and centralized outage teams that travel from site to site in their fleets can complete outages without significant emergent issues in 30 to 35 days, with industry top quartile durations at 28 to 30 days. All companies experience longer outages when they have emergent issues to address.

Non-regulated merchant plants can perform outages in 20-25 days by concentrating increased resources in a shorter timeframe, at a much higher

[28] Electrical Power Research Institute's (EPRI) document 1022952, *Effective Refueling Outages* (www.epri.com).

cost per day, in order to get the units back online as soon as possible. Market prices at the times of those outages may justify the higher cost. However, these shorter outages would be cost prohibitive to customers of a regulated utility like ours. Consequently, we believe that a goal of planned refueling/maintenance outages of 30 to 35 days would be best in class for companies with two-year refueling cycles like Xcel Energy. However, given construction projects with longer critical paths, required inspections and startup testing with likely emergent issues to address, and our small fleet of two sites, we are currently targeting 40 days or better as an efficient outage, with minimal emergent issues. As I discuss in my testimony later, we are building budgets based on outages of **[TRADE SECRET BEGINS**…

…**TRADE SECRET ENDS]** for 2015 and 2016 at Prairie Island due to expected emergent issues given the age of the plant and equipment maintenance issues anticipated from inspections being done in those outages. This is consistent with the two most recently completed planned outages, at Prairie Island in fall 2014 (with a duration of 44 days) and at Monticello in spring 2015 (48 days). Our assumed duration, including contingency for emergent issues, is also consistent with benchmarking we have done with other Utility Service Alliance (USA) utilities on 18 recent refueling outages, which had actual outage durations averaging 9 days longer than initial work schedule.

Cost per Day – In our recent outages without major capital projects (like EPU or steam generator replacement), we have experienced costs of slightly more than $1 million per planned outage day, with a higher cost per day for the initial portion of the schedule, and a slightly lower cost per day as outages went longer than planned. The reduction in cost per day for extended outages

is due to the release of resources not needed to resolve the specific issues being addressed in extended periods beyond the original target schedule. Based on our benchmarking of other companies, we believe that $1 million per planned outage day is exceptional performance for short outages of 30 to 35 days. More commonly, most other companies are now incurring costs closer to $1.1 million to $1.3 million per outage day. Benchmarking we have done with other USA utilities on their recent planned outages indicated that the actual cost per day for 18 outages averaged $1,166,000 with an average duration of about 41 days. For those outages, the initial outage budget assumed an average cost per day of $1,443,000 with the average scheduled outage duration of about 32 days. As I noted previously, the average cost per day declines as an outage extends beyond its initial schedule.

The Company's outage amortization process includes pre-outage planning costs in total qualifying outage costs, which generally run $3 million to $4 million each outage. In our benchmarking data above, pre-outage planning costs are not included in other companies' "cost per day" measure. Consequently, our total outage costs in comparing to other companies will be approximately $100,000 per outage day higher from including pre-outage planning costs.

As shown in Table 12 below, our forecast of costs for the fall 2015 outage is **[TRADE SECRET BEGINS**… …**TRADE SECRET ENDS]** per day, and the budget for the 2016 outage is **[TRADE SECRET BEGINS**… …**TRADE SECRET ENDS]** per day. The two most recently completed outages in 2014 and 2015, had costs of $1,002,000 and $1,008,000 per day, respectively. As I noted earlier, our budgeted cost per

day is also slightly lower than recent actual experience of 18 outages at 10 USA utilities we have benchmarked with an average cost of $1.166 million per day.

Table 12
Planned Outage Cost per Day
($ in millions)

Unit/Year	PI Unit 1/ Fall 2014	MT/ Spring 2015	PI Unit 2/ Fall 2015	PI Unit 1/ Fall 2016
Outage Duration (Days)	44	48	TRADE SECRET BEGINS... ...TRADE SECRET ENDS]	TRADE SECRET BEGINS... ...TRADE SECRET ENDS]
Total Outage O&M Cost	$44.1	$48.4	$45.6	$43.0
Outage Cost per Day	$1.002	$1.008	TRADE SECRET BEGINS... ...TRADE SECRET ENDS]	TRADE SECRET BEGINS... ...TRADE SECRET ENDS]

In the long term, our objective is to maintain a cost of about $1 million per planned outage day, which we have accomplished already, while working the duration downward through efficiency and effective labor/resource management. This is why we have used strategic sourcing to engage an outside firm to oversee outage management beginning in 2015. With the added benefits of effective aging equipment management and LCM replacements, our goal is to target step changes toward shorter outage durations over time.

Q. HOW ARE THE COMPANY'S LONG-TERM PLANNED OUTAGE O&M COSTS TRENDING?

A. Table 13 below shows the trend for Outage O&M for our nuclear plants from 2012-2016.

Table 13
Net Nuclear Planned Outage O&M Costs
($ in millions)

	2012 Actual	2013 Actual	2014 Actual	2015 Forecast	2016 Test Year Budget	Annual Average % Change: 2014 to 2016
Planned Outage O&M Costs - Nuclear Operations Spend	$87.5	$113.6	$48.0	89.8	45.5	
Deferral of Current Year Outage O&M Costs	(87.5)	(115.6)	(48.2)	(89.9)	(45.5)	
Outage O&M Amortization	58.0	71.5	88.8	80.3	69.7	
Net Nuclear Outage O&M	**$58.0**	**$69.5**	**$88.6**	**$80.2**	**$69.7**	**-10.7%**

Overall outage spend varies by year based on whether one or two outages is performed. Prairie Island generally alternates outages for its Units 1 and 2 each year, resulting in one outage per year at that site, and in odd years (2013 and 2015) Monticello has its outage in addition to Prairie Island's. However, in 2012 Prairie Island had outages at both units. In addition, spend can be periodically skewed upward when required 5 and 10 year inspections occur.

On a cost per outage view, the average annual spend is in the $43 million to $48 million range in that period except for 2013, when the average spend per outage rose to about $58 million due to the long construction outages that year for Monticello's EPU/LCM project and Prairie Island's steam generator replacement project. With an 18-24 month amortization process for the spend between outages, that trend has resulted in an increase in amortized outage costs from less than $60 million in 2012 to $69 million in 2013 and $89 million in 2014, followed by a decrease down to about $80 million in 2015 and $70 million in 2016. As discussed in the next section of my testimony, the scope and therefore the cost of each outage is driven by the level of planned

maintenance, inspections, emergent work, and critical path construction projects performed during the outages each year.

It should be noted that outage spend in Table 13 above is on an annual cash flow basis for all work done on any outage being planned or performed that year. The outage spend includes pre-outage planning work that is deferred, sometimes into the next calendar year, and is then amortized along with the cost of work performed during the outage.

B. Planned Outage O&M Budget Components – 2016 Test Year

Q. WHAT REFUELING OUTAGES IS THE NUCLEAR BUSINESS AREA INCLUDING FOR COST RECOVERY IN THE 2016 TEST YEAR?

A. The Commission has authorized the use of a deferral and amortization process to spread the costs of our scheduled refueling/maintenance outages over the period between outages. Under this approach, four planned refueling outages have costs that are amortized into the 2016 test year. They are the 2014 outage at Prairie Island Unit 1, the spring 2015 outage at Monticello, the fall 2015 outage at Prairie Island Unit 2, and the fall 2016 outage at Prairie Island Unit 1. Table 14 below summarizes the impact of amortization of these outages' costs in 2016.

Table 14
Planned Outage O&M Costs Included in 2016 Amortization Expense
($ in millions)

Unit/Year	PI Unit 1/ Fall 2014	MT/ Spring 2015	PI Unit 2/ Fall 2015	PI Unit 1/ Fall 2016	Total 2016 O&M
Outage Duration in Number of Days	44	48	TRADE SECRET BEGINS... ...TRADE SECRET ENDS]	TRADE SECRET BEGINS... ...TRADE SECRET ENDS]	
Total Outage O&M Cost	$44.1	$48.4	$45.6	$43.0	
Portion included in 2016 Amortization Expense	$18.2	$24.2	$23.8	$3.6	$69.7

The Company tracks these costs consistent with the Commission's requirements for outage cost deferral/amortization. Schedule 8 is the Company's policy incorporating these requirements and Company witness Ms. Anne E. Heuer explains the amortization of these planned outage costs in her Direct Testimony.

I will now discuss each of those outages affecting the 2016 test year further. Two of the outages were completed prior to summer 2015, and include actual costs through July 2015. The other two will take place in the fall of 2015 and 2016 and are based on estimated costs. Attached as Exhibit___(TJO-1), Schedule 9 is a detailed breakdown of the actual planned outage costs incurred for the 2014 and spring 2015, and Exhibit___(TJO-1), Schedule 10 provides an estimate of the planned outage costs for fall 2015 and 2016.

1. Prairie Island Unit 1 – Fall 2014 Outage

Q. PLEASE DISCUSS THE OUTAGE'S DURATION AND TOTAL COST INCURRED.

A. The scope of the 2014 outage at Prairie Island Unit 1 included fuel reloading, a list of off-line maintenance projects and inspections, and several capital

projects that were safer to schedule while the unit was off-line. At the time of our last rate case, our estimated costs for this outage were $41.5 million and the outage schedule was 36 days in duration (with no contingency for emergent issues). Emergent issues arose from inspection results and startup testing. Inspection issues identified included required diesel repairs, a reactor coolant system letdown valve, reactor coolant pump piping and supports, residual heat removal sump valves, electrical bus load sequencer and feedwater heater tube sheet. Startup testing issues included reactor coolant pump seals and containment fan coil unit excessive vibrations and flange leakage. Resolution of these emergent issues raised the final outage costs to $44.1 million and extended the outage duration to 44 days. The most significant items affecting outage duration were reactor coolant system clean up early in the outage (adding about 2 days), valve repairs that did not pass pre-startup testing (adding about 4 days), and water clean-up before syncing to the grid at startup (adding about 2 days).

2. Monticello – Spring 2015 Outage

Q. PLEASE DISCUSS THE OUTAGE'S DURATION AND TOTAL COST INCURRED.

A. The scope of the 2015 outage at Monticello included fuel reloading, a list of off-line maintenance projects and inspections, and several capital projects that were safer to schedule while the unit was off-line. At the time of our last rate case, our estimated costs for this outage were $41.5 million and the outage schedule was 35 days in duration (with no contingency for emergent issues). Emergent issues arose from inspection results and startup testing. Inspections during the outage identified issues with valves, turbine controls and heat exchangers which required repair work to be done to ensure high reliability until the next refueling outage. Startup testing identified issues with turbine

speed control adjustments, additional high pressure safety system tests, motor-generator voltage control tuning and nuclear instrumentation adjustments. In addition, we identified license design basis issues and required extended time to implement Fukushima program modifications. Resolution of these emergent issues raised the final outage costs to approximately $49 million and extended the outage duration to 48 days. The most significant items affecting outage duration were: valve repair difficulties, given the work location and productivity impacts (adding about 5 days); resolving license design basis legacy issues related to the diesel generators, to add safety-related pump redundancy (adding about 4 days); oil flushing and testing to remedy EPU control valve operation issues (adding about 3 days); and extended time needed to implement Fukushima program modifications, to avoid associated safety risks (adding about 2 days).

3. Prairie Island Unit 2 – Fall 2015 Outage

Q. PLEASE DISCUSS THE OUTAGE'S DURATION AND TOTAL ESTIMATED COST.

A. The scope of the fall 2015 outage at Prairie Island Unit 2 includes fuel reloading, a list of off-line maintenance projects and inspections, and several capital projects that were safer to schedule while the unit was off-line. As of August 2015, the planned outage scope had a critical path schedule of **[TRADE SECRET BEGINS**…

…**TRADE SECRET ENDS]**. The forecast for outage cost is $45.6 million, including about $2.5 million in contingency for emergent issues.

Q. PLEASE DESCRIBE THE SCOPE OF THE 2015 OUTAGE AT PRAIRIE ISLAND UNIT 2 IN COMPARISON TO PRIOR/OTHER OUTAGES.

A. This 2015 outage is shorter in duration and lower in cost than the last refueling for this unit in the fall of 2013, which lasted 104 days and had O&M outage costs of $58.5 million. The 2013 outage for this unit included a very large capital project for the replacement of the steam generator. While each outage has unique inspections and projects, the planned scope and duration for the 2015 outage is more comparable to the fall 2014 outage at the other Prairie Island Unit 1, which lasted 44 days and had O&M outage costs of $44.1 million. In 2014, we replaced the generation step-up (GSU) transformer for Unit 1. In 2015, we will be replacing the similar GSU transformer, along with the Main Electric Generator and exciter, for Unit 2. The 2015 outage will also include LCM replacement of containment cooling equipment (fan coil units) and 10-year reactor vessel inspections required by both ASME code and the NRC.

Q. WHAT IS THE CURRENTLY ANTICIPATED SCHEDULE FOR THE FALL 2015 OUTAGE?

A. This outage was occurring as testimony went to print, with commencement scheduled for **[TRADE SECRET BEGINS**…

…**TRADE SECRET ENDS]**. Our generation production planning schedule assumed the unit would be off-line for **[TRADE SECRET BEGINS**…

TRADE SECRET ENDS].

Q. HOW WERE THE ESTIMATED O&M COSTS FOR THE FALL 2015 OUTAGE DETERMINED?

A. As I noted earlier in my testimony, the work plan for each outage starts at the conclusion of the prior outage for the unit, and captures input from a number of sources (inspections required, equipment age and maintenance needs, risk and reliability analysis, etc.). Using this information, a plan is developed to scope out the work needed and the desired sequence of activities for efficient execution of an outage schedule. Resources needed are estimated in man hours, the use of internal vs. external staffing is evaluated, and materials and equipment costs are projected.

Q. WHY IS THIS A REASONABLE ESTIMATE OF THE OUTAGE O&M FOR THIS OUTAGE?

A. The refueling outage budget process is dynamic, and planning remains fluid until the day the outage starts because it needs to adapt to emergent issues that may arise during the outage. The forecast for the fall 2015 outage was based on the best estimate of cost for scheduled activities and included a contingency for emergent issues anticipated as of August 2015. This estimate is consistent with our recent experience with comparable outages, as I noted earlier in my testimony. Further, our forecasted total O&M cost of $45.6 million for this outage is actually lower than our USA benchmarking results, where 18 recent outages were planned at an average cost of about $46 million and came in with actual costs averaging about $48 million.

4. Prairie Island Unit 1 – 2016 Outage

Q. PLEASE DISCUSS THE 2016 OUTAGE'S EXPECTED DURATION AND TOTAL ESTIMATED COST.

A. The scope of the fall 2016 outage at Prairie Island Unit 1 includes fuel reloading, a list of off-line maintenance projects and inspections, and several capital projects that were safer to schedule while the unit was off-line. At this point in the planning process, we anticipate using approximately the same critical path schedule as our fall 2015 outage for Unit 2, at **[TRADE SECRET BEGINS**…

…**TRADE SECRET ENDS]**. The forecast for outage cost is $43.0 million, including about $4.3 million in contingency for emergent issues.

Q. PLEASE DESCRIBE THE SCOPE OF THE 2016 OUTAGE AT PRAIRIE ISLAND IN COMPARISON TO PRIOR/OTHER OUTAGES.

A. While each outage has unique inspections and projects, the planned scope and duration for this outage is very comparable to the fall 2014 outage at this same unit, which lasted 44 days and had O&M outage costs of $44.1 million. That outage's duration was extended, and costs increased, due to emergent issues addressed after identification through inspections and startup testing. The 2014 planned outage for this unit included replacement of the generation step-up (GSU) transformer, a turbine inspection and the 10-year reactor vessel inspection. The 2016 outage includes additional reactor vessel inspections and major inspections of the main electrical generator that is planned to be replaced in 2018. The 2016 outage also includes containment cooling system replacements (similar to what was done on Unit 1 in 2015) and reactor cooling pump replacements (the first phase of the four-year program, as I discussed previously).

Q. WHAT IS THE CURRENTLY ANTICIPATED SCHEDULE FOR THE 2016 OUTAGE?

A. Commencement of this outage is currently planned for **[TRADE SECRET BEGINS**… …**TRADE SECRET ENDS]**. Our generation production planning schedule assumed the unit would be off-line for **[TRADE SECRET BEGINS**…

…**TRADE SECRET ENDS]**.

Q. HOW WERE THE ESTIMATED O&M COSTS FOR THE 2016 OUTAGE DETERMINED?

A. As I noted earlier in my testimony, the work plan for each outage starts at the conclusion of the prior outage for the unit, and captures input from a number of sources (inspections required, equipment age and maintenance needs, risk and reliability analysis, etc.). Using this information, a plan is developed to scope out the work needed and the desired sequence of activities for efficient execution of an outage schedule. Resources needed are estimated in man hours, the use of internal vs. external staffing is evaluated, and materials and equipment costs are projected. As of late 2015, outage planning for the Unit 1 outage in 2016 was less developed and detailed than the Unit 2 outage that was commencing in fall 2015. More detailed work planning is to be completed for the 2016 outage at Unit 1 after conclusion of the Unit 2 outage in 2015. With improvement in our outage planning and execution process over the coming year, our budget assumes we can deliver the 2016 outage at Prairie Island Unit 1 at about $ 2.6 million less than the 2015 outage for Unit 2.

Q. WHY IS THIS A REASONABLE ESTIMATE OF THE OUTAGE O&M FOR THIS OUTAGE?

A. The refueling outage budget process is dynamic and planning remains fluid until the day the outage starts, and needs to adapt to emergent issues that may arise during the outage. The budgeted costs of the fall 2016 outage represents our best estimate of planned activities, and provides a contingency for emergent issues reasonably anticipated as of August 2015. This estimate is consistent with our recent experience with comparable outages, as I noted earlier in my testimony, and actually assumes some cost savings in comparison to recent outages. Further, our budgeted total O&M cost of $43 million for this outage is also lower than our USA benchmarking results, where 18 recent outages were planned at an average cost of about $46 million and came in with actual costs averaging about $48 million.

C. Multi-Year Rate Plan Outage O&M Costs

Q. WHAT IS THE LEVEL OF OUTAGE O&M EXPENSE NUCLEAR SEEKS TO RECOVER FOR THE 2017 AND 2018 PLAN YEARS?

A. Over our last several rate cases, the Commission has approved a method of deferring and amortizing Nuclear Outage O&M expenses between outages. Company witness Ms. Anne Heuer explains that process. Company witness Mr. Charles Burdick explains that the amount of the Nuclear Outage O&M amortization is expected to decline during the course of this multiyear rate plan, and that the Company proposes to use its forecasted amortization amounts for purposes of establishing 2017 and 2018 Outage O&M expense. I support our budgeted annual Outage O&M expenses on an amortized basis, which are summarized below in Table 15.

Table 15
Nuclear Planned Outage O&M Forecasts – 2016-2018

Nuclear Operations Planned Outage O&M Amortization Expense ($ in millions)	**2016**	**2017**	**2018**	**Change 2017 vs. 2016**	**Change 2018 vs. 2017**
Outage O&M – Amortized	$69.7	$68.9	$66.6	(1.1%)	(3.4%)

Q. ARE THERE SPECIFIC DRIVERS THAT YOU HAVE IDENTIFIED FOR NUCLEAR THAT WILL IMPACT THE EXPENSE LEVELS FOR 2017 AND 2018 OUTAGE O&M BUDGETS?

A. Yes. As shown in our 2017 and 2018 supporting information, provided in Volume 6 of our Initial Filing, Nuclear is forecasting changes in its outage O&M expenses for Plan Years 2017 and 2018 in the following areas:

- Our 2017 amortized outage O&M budget is decreasing from 2016 levels due to the effects of the lower cost outage at Prairie Island in 2016 having a higher weighting in 2017 amortization vs. 2016. This 2016 outage is occurring in the fall and thus has only a few months' amortization in 2016 vs. a full year of amortization in 2017.
- Our 2018 amortized outage O&M is decreasing from 2017 levels due to anticipated lower average costs of planned outages in 2017 and 2018 in comparison to outages amortized into 2017 costs. We anticipate that we will be able to improve our outage planning and execution as I discussed previously, and accordingly have reflected cost decreases in our outage spend budgets for 2017 and 2018.

VI. COMPLETENESS INFORMATION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to address the Nuclear Operation Key Performance Indicators (KPIs) for purposes of the Annual Incentive Program (AIP), as required by Order Point 29 in the Commission's May 8, 2015 Order in Docket E002/GR-13-868. Company witness Ms. Ruth K. Lowenthal discusses the AIP more broadly.

Q. PLEASE EXPLAIN HOW THE NUCLEAR OPERATIONS BUSINESS UNIT FITS WITHIN THE COMPANY'S OVERALL AIP.

A. As explained by witness Ms. Lowenthal, the Company's AIP has three components: individual, business area, and corporate. For the individual component, employees have performance goals tied to job functions. The business area and corporate components use KPIs to measure goals. Each business area, including Nuclear, uses a scorecard that identifies priorities, KPIs, and target goals.

Q. WHAT ARE THE 2015 AIP GOALS FOR THE NUCLEAR OPERATIONS BUSINESS UNIT SCORECARD?

A. The 2015 Nuclear business unit scorecard is focused on three broad priorities: ensuring safety, improving operating performance, and delivering cost competitiveness. Each of these priorities is measured by one or more weighted KPIs. In Nuclear's 2015 scorecard, we had eight KPIs in these three priority areas, as listed in Exhibit___(TJO-1), Schedule 11.

Q. PLEASE IDENTIFY AND EXPLAIN THE KPI MEASURES FOR THE NUCLEAR BUSINESS UNIT FOR 2015.

A. The second page of Schedule 11 lists the nature and metrics associated with each of our KPIs for 2015. The following summarizes these eight KPIs for the year:

Safety Priorities (weighted 30 percent)

- *OSHA Injury Rate* – Measures workplace safety incidents for employees
- *NRC Reactor Oversight Process (ROP) Rating* – Tracks status of plants in NRC safety performance based on results of inspections and review of performance reporting

Operational Excellence Priorities (weighted 40 percent)

- *INPO Index* – Provides a composite index of plant operating performance using various industry measures
- *INPO Plant Performance Index (PPI)* – Represents a predictive measure of plant performance between INPO evaluations; used as a tool to monitor trends vs. industry excellence expectations.
- *Outage Duration* – Tracks length of scheduled refueling / maintenance outages.

Cost Competitiveness Priorities (weighted 30 percent)

- *PTT Index* – Tracks alignment with other Xcel Energy business units and measures Nuclear's support of the project.
- *Capital Budget/Schedule* – Measures Nuclear's success of in-servicing key capital projects at each plant on-schedule and on-budget.
- *Operational Savings* - Measures cost savings delivered from Supply Chain (procurement) function from contract administration and vendor pricing.

Q. HOW WERE THE KPI GOALS FOR THE NUCLEAR ORGANIZATION DETERMINED?

A. We looked at our past operational performance, how we aligned with industry benchmarks and metrics, and determined what we need to focus on and measure to better serve our customers. Each year, we identify which areas

have performance gaps to improve upon, and which need to remain an area of focus. Consequently, in any year some goals may carry forward into the succeeding year, some goals may become a lower relative priority, and some new goals may be added as a new area of focus.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE GOAL SETTING PROCESS FOR ONE OF THESE KPIS?

A. Yes. In our safety priorities, we have a 2015 KPI to improve the combined average of our NRC Reactor Oversight Process (ROP) ratings for the three nuclear units. As explained in Exhibit___(TJO-1), Schedule 12, the NRC has a rating system that reflects the results of its plant inspections and reviews of regular performance reporting. Over the past few years, each of our nuclear plants has had inspection or performance reporting findings which lowered its respective ROP rating below the highest level (Column 1). At the time we set AIP KPI goals for 2015, Monticello was in Column 3, and Prairie Island was in Column 2 for Unit 2 and Column 1 for Unit 1, for a combined average of 2.0. We set our minimum/threshold scorecard level for this KPI at an average of Column 2 for all units, representing no improvement but also no further degradation. (Note that only one "white" finding results in a downgrade from Column 1 to Column 2, and only one "yellow" finding result in a Column 3 rating.) We set our maximum performance for this goal at the highest safety rating provided by the NRC, Column 1 for all three units, which would require significant improvement for both units with findings/issues. We set our target in-between minimum and maximum, at an average of 1.3, which would require notable improvement in 2015, either by both units improving at least one rating, or Monticello improving its Column 3 rating all the way up to Column 1.

Q. WHICH KPI GOALS FOR 2015 ARE THE SAME AS THE GOALS FROM 2014?

A. Employee safety remains a constant area of focus for Xcel Energy and Nuclear, and thus the OSHA KPI has stayed in our AIP scorecard for several years now. Similarly, our managing of capital project costs and in-servicing has been a renewed focus area since our Monticello LCM/EPU project was completed in 2013, and that KPI has carried forward from the 2014 Nuclear scorecard to 2015.

Q. WHAT KPIS FOR 2015 ARE DIFFERENT FROM PAST KPI LEVELS?

A. Several new goals have been added in 2015 to replace 2014 goals, although several of the underlying areas being measured are related. In 2014, we were completing our 3:2:1 performance improvement initiative and thus had six KPI goals that year related to the six "tiles" tracked by that initiative. In 2015, those six 3:2:1 goals were replaced with three new KPIs in operational excellence, the NRC safety KPI, and two cost competitiveness KPIs for PTT and Supply Chain. These new KPIs in 2015 reflect our ongoing monitoring and adjustment of goals to where we need focus and improvement.

Q. HAS THE NUCLEAR GROUP EVER NOT ACHIEVED ITS SCORECARD/KPI GOALS?

A. Yes, as recently as last year in 2014. That year, we did not meet target for three of our nine KPIs for the Nuclear AIP scorecard. We came in below minimum/threshold for equipment performance, and below target for regulatory margin and leadership effectiveness. While we understand that we set aggressive goals for ourselves in most areas, we were disappointed that we did not achieve the target parameters for those KPIs in 2014. Nonetheless, we continue to set aggressive goals for performance with the objective of

improving our operations and achieving top quartile performance in the industry.

Q. DO YOU AGREE WITH DEPARTMENT WITNESS MR. DALE LUSTI'S COMMENTS IN THE DOCKET REGARDING THE OPERATION AND PERFORMANCE OF THE COMPANY'S 2014 INCENTIVE COMPENSATION PLAN[29] THAT NUCLEAR HAS REVISED ITS KPIS OVER TIME TO ELIMINATE METRICS THE BUSINESS UNIT WAS UNABLE TO ACHIEVE?

A. No. The Nuclear KPIs do evolve each year, but it is because we attempt to incent our employees to focus on the most important priorities for Nuclear and to close the most important performance gaps that exist in the current period.

Overall, Nuclear's external oversight (by the NRC and INPO) is particularly intense and pervasive. The constant regulatory inspections and reviews of the NRC, and the regular cycles of INPO performance evaluations and feedback, constantly result in observations and expectations on areas for improvement, and we update our scorecard KPIs each year to align with those evolving performance gaps.

While we do not achieve our KPI goals in each year, this fact speaks primarily to the level of challenge inherent in our goals in each year. However, this does not mean our KPIs should remain static regardless of whether they were achieved. Notably, we have accountabilities to the NRC and INPO whether or not we put the same KPIs in our scorecard each year, and we are expected by those groups to continue performance improvement efforts until they are

[29] Docket Nos. E002/GR-92-1185, G002/GR-92-1186, and E002/M-15-522 (May 29, 2015).

satisfied. As a result, we focus the KPIs on the most important goals for each year to make sure our employees in turn focus on the most pressing objectives in their own performance that can support improvement in Nuclear's overall performance.

Q. CAN YOU PROVIDE FURTHER EVIDENCE THAT NUCLEAR'S KPIS FOR 2012 THROUGH 2014 KEPT NUCLEAR EMPLOYEES APPROPRIATELY ACCOUNTABLE FOR PERFORMANCE IMPROVEMENTS?

A. Yes. I have attached as Exhibit___(TJO-1), Schedule 13 a summary of the 2012 and 2013 Nuclear KPIs that Mr. Lusti notes were eliminated after each of those years. This schedule shows (a) how these KPIs have continued into elements of future KPIs and scorecards, requiring accountability until performance improvement resulted, and (b) what results have actually been achieved over time for the KPIs that Mr. Lusti noted as eliminated. This summary demonstrates that we are continuing to monitor KPI performance areas for improvement and have delivered improvement in areas where performance was at one time below expectations – even if the area does not remain a specific stand-alone KPI on our AIP scorecard.

Q. BASED ON YOUR REVIEW, WHAT DO YOU CONCLUDE ABOUT THE INCENTIVE METRICS USED BY THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. The goals for Nuclear are based on protecting employee and public safety, improving on past operating performance, attaining a higher standing in comparison to industry benchmarks, and delivering cost competitiveness for the Company's customers. As Company witness Ms. Lowenthal explains, in order to serve as true incentives, KPIs must be set at levels that require outstanding performance, but not so high that they are unattainable. I believe

the Nuclear KPI levels meet this requirement. We must work incredibly hard to achieve our KPI levels, and even with the best of efforts, we still may not achieve our desired results. Nuclear's goals in the Annual Incentive Program are set appropriately and sufficiently challenge the Company and its employees to meet them.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Nuclear capital investments and O&M budget presented in this rate case. Xcel Energy's Nuclear fleet provides more than 1700 MW of safe, reliable, carbon-free baseload generation that serves more than one million customer homes and is critical to the Company's and the State's goals of supporting a clean energy future. Our capital investments focus on plant reliability and improvements, and the fuel, storage, and compliance requirements necessary to continue to operate these plants into the future. Our O&M expense budgets reflect the operating costs needed to effectively run, maintain, and refuel our fleet of nuclear plants. We have managed our O&M activities to keep the rate of future cost growth low and to operate our plants as efficiently as possible.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Timothy J. O'Connor
Chief Nuclear Officer

Tim O'Connor is Chief Nuclear Officer for Xcel Energy. He is responsible for all Xcel Energy nuclear activities in Minnesota at the Monticello and Prairie Island nuclear generating plants (operated by NSP-Minnesota and its parent company, Xcel Energy).

Mr. O'Connor joined Xcel Energy in 2007 as the site vice president of the Monticello plant. He has 32 years of commercial nuclear experience with both boiling and pressurized water reactors. His increasing responsibilities throughout his career have included site vice president at Constellation Energy Group's Nine Mile Point station in New York; vice presidential roles at the Public Service Enterprise Group (PSEG) Hope Creek and Salem plants; plant manager at LaSalle station; and operations manager at Dresden and Zion plants. He has also worked in management positions in maintenance, operations, and engineering. Mr. O'Connor also held a position with the Institute of Nuclear Power Operations (INPO) as an evaluation team manager on a reverse loaned assignment.

Mr. O'Connor received his mechanical engineering degree from Marquette University in Milwaukee.

Northern States Power Company

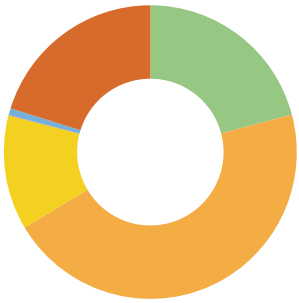
Nuclear Energy in Minnesota

Reliable, Clean and Safe Nuclear Energy

Minnesota's three reactors generate nearly 21 percent of the state's electricity while emitting no greenhouse gases. These nuclear energy facilities safely produce electricity while protecting our air quality and the environment. Based on national averages, each reactor employs between 400 and 700 highly skilled workers, has a payroll of about $40 million and contributes $470 million to the local economy.

Nuclear energy is vital to ensuring a reliable supply of electricity, now and for the future—helping to maintain a diverse energy mix that keeps electric rates as low as possible and ensures that consumers are not overly reliant on just one or two sources of electricity.

Sources of Electricity in Minnesota



Source: U.S. Energy Information Administration, 2013

Jobs and Economic Benefits

- Nuclear energy facilities in Minnesota employ more than 1,300 highly skilled employees.
- More than $315 million of materials, services and fuel for the nuclear energy industry are purchased annually from more than 1,150 Minnesota companies. Global and domestic growth in the nuclear energy industry each year adds thousands of high-paying, long-term jobs for American workers.

Clean Air Energy

- Nuclear energy produces nearly 56 percent of Minnesota's emission-free electricity and is the only clean-air source that can produce large amounts of electricity around the clock. The state's nuclear energy facilities prevent the emission of tens of thousands of tons of air pollutants.

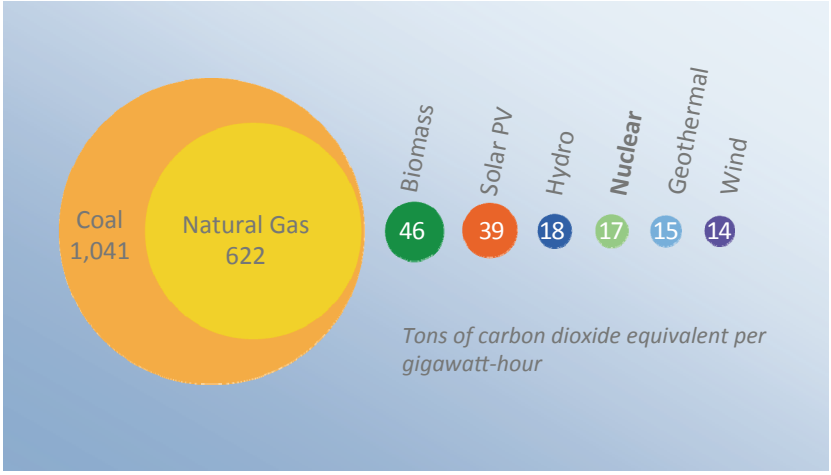
Clean Air Energy continued on back page

Nuclear Energy Facilities

Facility[1]	Company	Location	Generating Capacity (MW)	Electricity (billion kWh)	3-Year Capacity Factor (%)[2]
1. Monticello (BWR)	Xcel Energy	Monticello	633	3	74.6
2. Prairie Island 1 (PWR)	Xcel Energy	Red Wing	521	4.6	91.1
3. Prairie Island 2 (PWR)	Xcel Energy	Red Wing	519	3.1	79.8
		State Totals	**1,673**	**10.7**	**81.8**

[1]PWR: Pressurized Water Reactor, BWR: Boiling Water Reactor
[2]A facility's capacity factor is the percentage of how much electricity it produces compared to the maximum it could produce around the clock.

Life-Cycle CO_2 Emissions by Electricity Source



Source: "Life-Cycle Assessment of Electricity Generation Systems and Applications for Climate Change Policy Analysis," Paul J. Meier, University of Wisconsin-Madison, August 2002

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Clean Air Energy *continued from front page*

- Numerous studies demonstrate that nuclear energy's life-cycle greenhouse gas emissions are comparable to renewable energy, such as wind and hydropower, and far less than coal or natural gas-fueled power plants.
- More than 10 million metric tons of carbon dioxide are prevented by Minnesota's nuclear energy facilities, which equals what would be released in a year by more than 2 million passenger cars.

2013 Emissions	Quantity Prevented in Minnesota
Sulfur dioxide (SO_2)	21,192 short tons
Nitrogen oxide (NO_x)	11,755 short tons
Carbon dioxide (CO_2)	10.54 million metric tons

Used Fuel Management

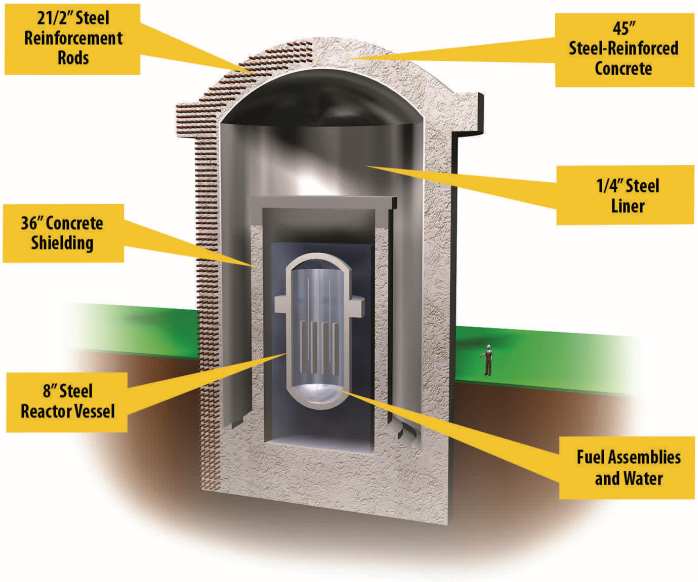
- Nearly 1,290 metric tons[3] of used nuclear fuel are stored at nuclear plant sites in Minnesota. All of this fuel is safely and securely managed in steel-lined, water-filled concrete pools or in concrete and steel containers awaiting consolidated storage and disposal by the U.S. Department of Energy.
- As of 2013, Minnesota has contributed more than $441.9 million to the Nuclear Waste Fund.

[3]*Source: ACI Nuclear Energy Solutions, 2013*

Used fuel at nuclear energy facilities is managed securely in steel-lined concrete pools filled with water.

After a cooling period, nuclear energy facilities store used fuel safely and securely on site in steel and concrete vaults.

U.S.-Style Reactor Features Multiple Layers of Safety



Committed to Safety

- America's 100 nuclear energy facilities are among the safest and most secure industrial facilities. Multiple automatic safety systems, the industry's commitment to comprehensive safety procedures and stringent federal regulation keep nuclear energy facilities and neighboring communities safe.
- The independent U.S. Nuclear Regulatory Commission regulates and monitors plant performance in three areas: reactor safety, radiation safety and security.
- After more than a half-century of commercial nuclear energy production in the United States—more than 3,900 reactor years of operation—there have been no radiation-related health effects linked to the operation of nuclear energy facilities. Numerous studies, including those from the National Cancer Institute and the United Nations Scientific Committee on the Effects of Atomic Radiation, show that U.S. nuclear power plants effectively protect the public's health and safety.
- The industry has developed a diverse, flexible mitigation approach (FLEX) to address the major problem encountered at Fukushima: the loss of power to maintain effective cooling. More than $2 billion of safety enhancements have been made since 2011, including the purchase of about 1,500 pieces of backup equipment.

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Emissions Avoided by the US Nuclear Industry (State by State)

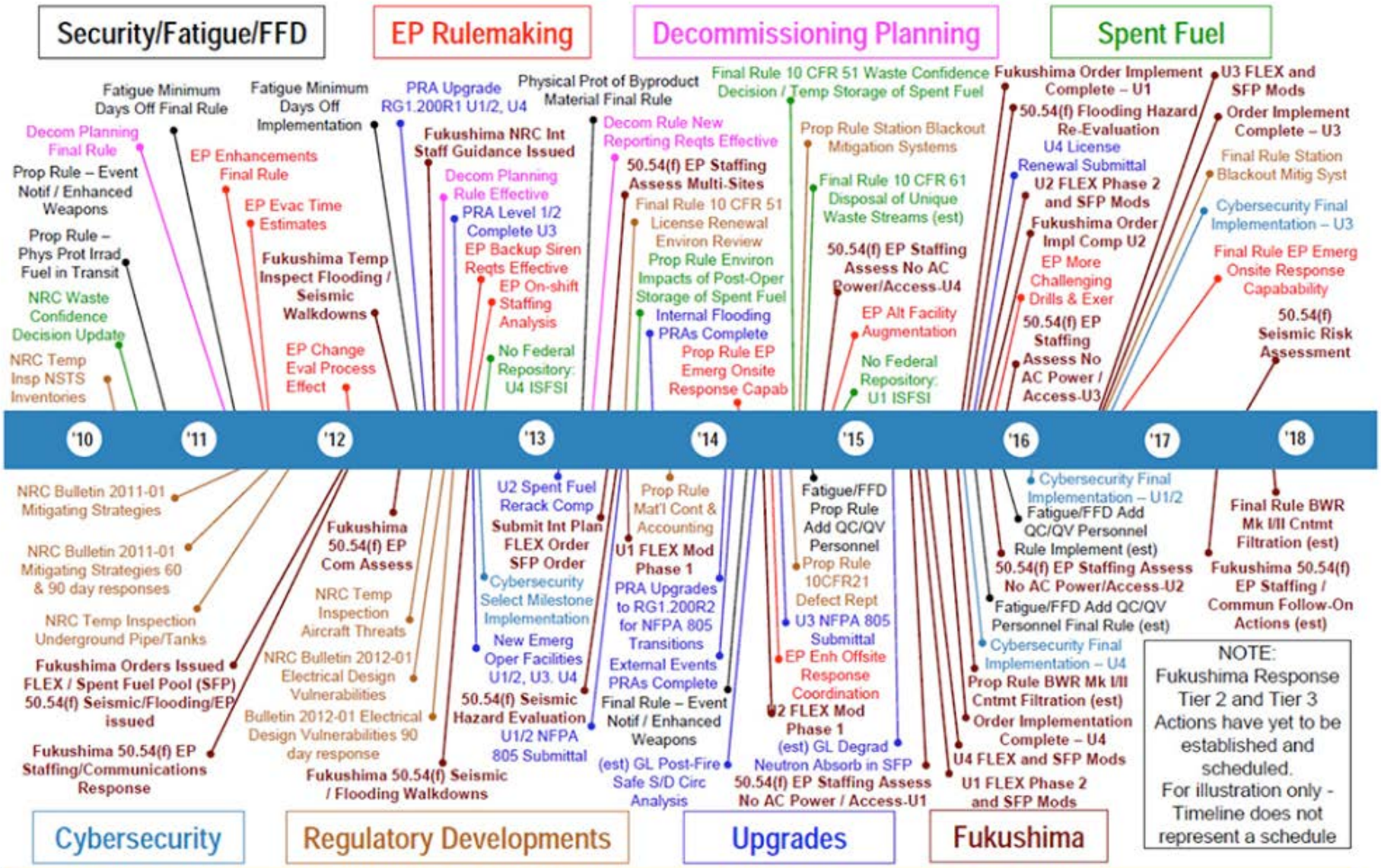
State by State, 2014

State	Sulfur Dioxide (Short Tons)	Nitrogen Oxides (Short Tons)	Carbon Dioxide (Million Metric Tons)
Alabama	65,057	27,095	33.55
Arizona	10,184	26,613	24.07
Arkansas	15,746	11,562	10.00
California	38	471	6.87
Connecticut	3,091	2,839	7.77
Florida	13,526	8,576	16.03
Georgia	40,048	15,712	23.05
Illinois	180,124	75,180	79.96
Iowa	7,203	4,444	4.12
Kansas	10,920	5,901	7.32
Louisiana	18,823	13,822	11.96
Maryland	26,877	11,361	11.52
Massachusetts	1,126	1,034	2.83
Michigan	62,157	24,671	26.85
Minnesota	22,042	13,599	12.61
Mississippi	11,038	8,105	7.01
Missouri	14,067	4,961	8.84
Nebraska	17,523	10,811	10.03
New Hampshire	1,984	1,823	4.99
New Jersey	59,038	24,957	25.31
New York	10,717	10,525	21.45
North Carolina	22,046	18,050	29.95
Ohio	34,830	12,804	15.17
Pennsylvania	147,496	62,350	63.23
South Carolina	28,209	23,096	38.33
Tennessee	48,867	20,798	24.10
Texas	42,713	13,470	27.64
Vermont	988	907	2.48
Virginia	16,263	13,315	22.10
Washington	4,574	5,847	7.08
Wisconsin	20,206	7,428	8.80
Total	957,521	482,130	595.03

Source: Emissions avoided by nuclear power are calculated using regional fossil fuel emissions rates from the Environmental Protection Agency and plant generation data from the Energy Information Administration.
Updated: 5/15

NEI's Summary of Industry "Cumulative Effects"

from Nuclear Regulatory Initiatives and Impacts – with Fukushima



NRC Inspections Scheduled for Xcel Energy Nuclear Plants

Three-Year Inspection Cycle 2013-2015

Key for Column Headings on Page 2

- **IP#** - NRC Inspection Procedure number
- **Inspection** – Description of NRC inspection
- **Hours** – Estimated number of hours to be spent by NRC staff on this inspection, each time it is conducted during three-year cycle
- **MT** – Number of times this inspection is scheduled to be conducted at the Monticello plant during the three year inspection cycle
- **PI** - Number of times this inspection is scheduled to be conducted at the Prairie Island plant during the three year inspection cycle

Note: Hours include only time for NRC staff, and do not reflect time needed by Xcel Energy employees and contractors to prepare for, support and report on inspections.

Number of Times Each Inspection Procedure is Scheduled to be Performed at Each Site (2013-2015)

IP #	Inspection	Hours	MT	PI
50001	Steam Generator Replacement Inspection	350	0	1
60855.1	Operation of an Independent Spent Fuel Storage Installation at Operating Plants	100	3	4
71003	Post-Approval Site Inspection for License Renewal	2052	0	4
71111.05	Fire Protection	240	1	1
71111.07	Heat Sink Performance	46	1	1
71111.08	Inservice Inspection Activities	100	2	5
71111.11	Licensed Operator Requalification Program - Biannual	96	2	1
71111.17	Evaluations of Changes, Tests, and Experiments and Permanent Plant Modifications	212	1	1
71111.19	Post Maintenance Testing	97	0	1
71111.20	Refueling and Other Outage Activities	92	0	1
71111.21	Component Design Bases Inspection	408	2	2
71111.22	Surveillance Testing	100	0	1
71114.01	Exercise Evaluation	74	1	1
71114.02	Alert and Notification System Testing	8	2	2
71114.03	Emergency Preparedness Organization Staffing and Augmentation System	10	2	2
71114.05	Correction of Emergency Preparedness Weaknesses and Deficiencies	15	2	2
71114.06	Drill Evaluation	20	0	0
71114.07	Exercise Evaluation - Hostile Action (HA) Event	98	1	0
71114.08	Exercise Evaluatino - Scenario Review	16	1	0
71124.01	Radiological Hazard Assessment and Exposure Controls	38	5	5
71124.02	Occupational ALARA Planning and Controls	64	6	4
71124.03	In-Plant Airborne Radioactivity Control and Mitigation	20	2	4
71124.04	Occupational Dose Assessment	28	2	4
71124.05	Radiation Monitoring Instrumentation	44	2	3
71124.06	Radioactive Gasesous and Liquid Effluent Treatment	34	3	4
71124.07	Radiological Environmental Monitoring Program	30	2	2
71124.08	Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation	38	1	2
71151	Performance Indicator Verification	14	14	15
71152	Problem Identification and Resolution - Biannual	288	2	2
92709	Licensee Strike Contingency Plans	100	2	3
95001	Supplemental Inspection for One or Two White Inputs in a Strategic Performance Area	40	1	3
95002	Supplemental Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area	200	1	0
2201/004	Inspection of Implementation of Interim Cyber Security Milestones 1-7	64	1	1
2515/177	Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal & Containment Spray System	100	1	0
2515/182	Review of the Implementation of the Industry Initiative to Control Degradation of Underground Piping - Phase 1	64	2	2
2515/182	Review of the Implementation of the Industry Initiative to Control Degradation of Underground Piping - Phase 2	64	2	2
2515/186	Inspection of Procedures and Process for Responding to Potential Aircraft Threats	40	1	1
2515/187	Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns	40	1	1
2515/188	Inspection of Near-Term Task Force Recommendation 2.3 Seismic Walkdowns	40	1	1
2515/189	Inspection to Determine Compliancer of Dynamic Restraint (Snubber) Program with 10 CFR 50.55a	32	0	1

Northern States Power Company

Nuclear Fuel Process

The following summarizes how nuclear fuel expenditures and additions are determined.

Commodities - Nuclear fuel commodities (uranium, uranium conversion services and uranium enrichment services) are purchased as needed under contracts in force at the time of purchase to meet future reload specific energy requirements. These commodities are fungible. The uranium content of the new nuclear fuel assemblies received are provided by the nuclear fuel fabrication vendor at the time the new nuclear fuel assemblies are shipped to the nuclear plant site.

Processing - Each processing stage (uranium mining, uranium conversion services, uranium enrichment services and fuel assembly fabrication) in the nuclear fuel construction period has contractually agreed upon lead times for the delivery of the prior processing stage's unfinished nuclear materials. Consequently, a typical construction period for new nuclear fuel assemblies ranges from 18 months to 24 months.

Service Providers - Westinghouse Electric Co., LLC provided the nuclear fuel fabrication and engineering services required to manufacture the new nuclear fuel assemblies placed in service during the years 2014 through 2018 for the Prairie Island Nuclear Generating Plant. Global Nuclear Fuel-Americas, LLC provided the nuclear fuel fabrication and engineering services required to manufacture the new nuclear fuel assemblies placed in service during 2015 for the Monticello Nuclear Plant. Areva NP will provide the nuclear fuel fabrication and engineering services required to manufacture the new nuclear fuel assemblies placed in service in 2017.

Cost Accounting - Nuclear fuel commodities are assigned to the new nuclear fuel assemblies at average unit cost when they arrive at the nuclear plant site based on the uranium content in the new nuclear fuel assemblies. Current year nuclear fuel commodity expenditures may remain in the nuclear fuel construction in process accounts for up to two years before assignment to a specific nuclear fuel reload (at average cost of all fuel in-process), at which time they are classified as completed construction through a capital addition to plant in service. Reload fabrication and engineering costs are specifically identifiable and assigned to each new nuclear fuel reload.

Nuclear Fuel Expenditures and Costs of Reloads Being Amortized

The following summarizes nuclear fuel capital expenditures and costs of completed fuel reloads beginning amortization for the years shown:

Xcel Energy Nuclear Fuel *$ in millions*	**Actual 2014**	**Forecast 2015**	**Budget 2016**	**Prelim 2017**	**Prelim 2018**
Capital Expenditures (excluding AFUDC) – Table NF-1	$154.3	$90.8	$118.5	$117.6	$62.3
Completed Reload Costs Beginning Amortization – Tables NF-2 (summary) & NF-3 (detail)	$130.7	$145.4	$76.1	$172.7	$71.9

The differences in reload expenditures and completed reload costs beginning amortization each year are driven by variations in the number of reactors and the specific reactors refueled in each year, and

which reloads are in process vs. completed in each year. Similarly, expenditures in a given year may vary significantly from other years based on ongoing expenditures for commodities and processing needed for upcoming reload requirements planned for each unit.

- Monticello operates on a 2-year cycle and is planning reloads every other year, in 2015 and 2017.
- Prairie Island (PI) has historically operated on 18-month to 23-month fuel cycles, but is investigating migrating to a sustained 2-year cycle for future PI reloads as well. In this sustained 2-year cycle plan, PI would have one reload for each of its units every other year, resulting in one reload completed for the site each year[1].

The components of annual capitalized expenditures charged to nuclear fuel construction in process for the years 2014 through 2018 are provided in the attached Table NF-1.

The number of fuel assemblies, average costs of fuel assemblies, and all other costs that make up the completed nuclear fuel reloads moved from construction in process accounts and beginning amortization are provided in the attached Tables NF-2 (summary) and NF-3 (detail). Note that there can be timing differences between the date the fuel assemblies are placed in service as a capital addition and the date they begin use in the reactor for fuel amortization purposes[1]. Nuclear fuel expense amortization begins when the reloaded fuel is in the reactor and being consumed from the unit being online.

[1] The 2013 Prairie Island Unit 2 refueling outage included a fuel reload in late 2013 but the unit did not go online until early January 2014. Consequently, PI had no fuel reloads begin amortization in 2013 but had two reloads begin amortization in 2014.

Northern States Power Company

$ in millions

Table NF-1: Annual Nuclear Fuel Capital Expenditures - Direct & Other Costs

Cost Component	Actual 2014	Projected 2015	Projected 2016	Projected 2017	Projected 2018	Total 2014-2018
Uranium	$ 96.7	$ 21.4	$ 53.8	$ 50.5	$ 18.3	$ 240.6
Conversion	9.1	1.5	6.9	4.6	3.8	25.9
Enrichment	37.6	39.7	43.1	37.0	30.4	187.9
Fabrication	7.2	17.7	7.8	17.3	6.4	56.5
Labor	1.3	1.9	1.3	1.6	1.4	7.6
Engineering	1.9	8.6	5.4	6.5	2.1	24.5
A&G	0.2	0.1	-	-	-	0.2
Other	0.2					0.2
Direct Total	**$ 154.3**	**$ 90.8**	**$ 118.5**	**$ 117.6**	**$ 62.3**	**$ 543.5**
AFUDC	6.3	9.8	9.1	11.5	9.8	46.5
Total	**$ 160.6**	**$ 100.6**	**$ 127.6**	**$ 129.2**	**$ 72.0**	**$ 590.0**

Northern States Power Company

$ in millions

Table NF-2: Summary - Costs of Completed Nuclear Fuel Reloads Beginning Amortization

Reload	Actual 2014	Projected 2015	Projected 2016	Projected 2017	Projected 2018	Total 2014-2018
PI2 Cycle 28*	$ 68.1					$ 68.1
PI1 Cycle 29	62.7	$ 0.4				63.0
Monticello Cycle 28**		72.1				72.1
PI2 Cycle 29		72.9				72.9
PI1 Cycle 30			$ 76.1			76.1
Monticello Cycle 29				$ 95.7		95.7
PI2 Cycle 30				77.0		77.0
PI1 Cycle 31					$ 71.9	71.9
Other				(0.1)		
Total	**$ 130.7**	**$ 145.4**	**$ 76.1**	**$ 172.6**	**$ 71.9**	**$ 596.8**

Northern States Power Company

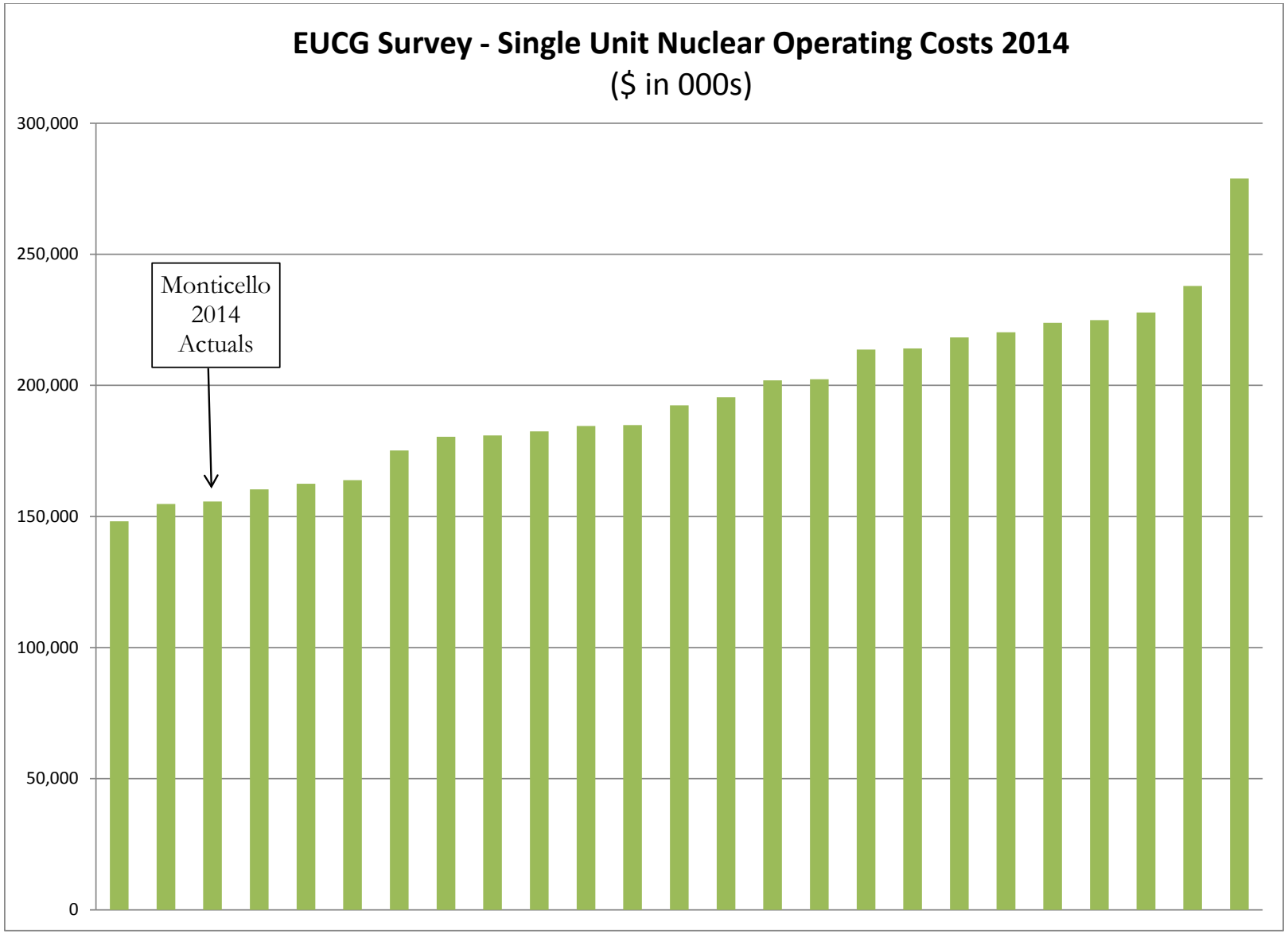
Table NF-3: Detail of Completed Nuclear Fuel Reload Costs Beginning Amortization - 2014 through 2018 ($ in millions)

Unit & cycle	Year In-Service	Batch ID	Assemblies	Average wt% U235	Average Kg U/Assembly	Uranium	Conversion	Enrichment	Fabrication	Labor	Engineering	AFUDC	A&G	Reload Total	Average $/Assembly
PI 2 Cycle 28	2014	228A	20	4.3901	391.976	$ 11.5	$ 1.1	$ 7.4	$ 2.5	$ 0.1	$ 0.1	$ 2.0	$ 0.0	$ 24.6	$ 1.23
		228B	4	4.4398	392.921	$ 2.3	$ 0.2	$ 1.5	$ 0.5	$ 0.0	$ 0.0	$ 0.4	$ 0.0	$ 5.0	$ 1.24
		228C	8	4.7610	393.190	$ 5.0	$ 0.5	$ 3.3	$ 1.0	$ 0.0	$ 0.0	$ 0.9	$ 0.0	$ 10.7	$ 1.34
		228D	4	4.8057	393.468	$ 2.5	$ 0.2	$ 1.7	$ 0.5	$ 0.0	$ 0.0	$ 0.4	$ 0.0	$ 5.4	$ 1.36
		228E	16	4.8952	395.250	$ 10.5	$ 1.0	$ 6.9	$ 2.1	$ 0.1	$ 0.1	$ 1.8	$ 0.0	$ 22.3	$ 1.39
			52	4.7847	**393.358**	$ 31.8	$ 2.9	$ 20.8	$ 6.6	$ 0.3	$ 0.2	$ 5.4	$ 0.0	**$ 68.1**	$ 1.31
PI 1 Cycle 29	2014	129A	24	4.7088	391.715	$ 12.4	$ 1.1	$ 7.7	$ 3.1	$ 0.4	$ 0.0	$ 1.9	$ 0.0	$ 26.5	$ 1.11
		129B	12	4.7532	392.081	$ 6.3	$ 0.6	$ 3.9	$ 1.5	$ 0.2	$ 0.0	$ 0.9	$ 0.0	$ 13.4	$ 1.12
		129C	4	4.8001	393.349	$ 2.1	$ 0.2	$ 1.3	$ 0.5	$ 0.1	$ 0.0	$ 0.3	$ 0.0	$ 4.5	$ 1.13
		129D	16	4.8984	394.937	$ 8.7	$ 0.8	$ 5.4	$ 2.1	$ 0.2	$ 0.0	$ 1.3	$ 0.0	$ 18.6	$ 1.16
			56	4.7793	**392.831**	$ 29.5	$ 2.7	$ 18.3	$ 7.2	$ 0.9	$ 0.1	$ 4.4	$ 0.0	**$ 63.0**	$ 1.13
Monticello Cycle 28	2015	328A	64	3.7390	173.838	11.4	1.1	9.0	4.0	0.4	0.6	0.9	0.0	$ 27.5	$ 0.43
		328B	44	3.8430	174.009	8.1	0.8	6.4	2.7	0.3	0.4	0.7	0.0	$ 19.5	$ 0.44
		328C	16	3.8660	173.586	3.0	0.3	2.3	1.0	0.1	0.2	0.2	0.0	$ 7.1	$ 0.44
		328D	40	3.8900	174.937	7.5	0.7	6.0	2.5	0.3	0.4	0.6	0.0	$ 18.0	$ 0.45
			164	3.8160	**174.127**	$ 30.0	$ 2.9	$ 23.8	$ 10.2	$ 1.2	$ 1.6	$ 2.5	$ 0.1	**$ 72.1**	$ 0.44
PI 2 Cycle 29	2015	229A	24	4.7132	392.007	$ 13.7	$ 1.3	$ 9.4	$ 3.2	$ 0.3	$ 0.8	$ 2.0	$ 0.0	$ 30.8	$ 1.28
		229B	12	4.7609	392.766	$ 6.9	$ 0.7	$ 4.8	$ 1.6	$ 0.1	$ 0.4	$ 1.0	$ 0.0	$ 15.6	$ 1.30
		229C	4	4.8085	393.525	$ 2.3	$ 0.2	$ 1.6	$ 0.5	$ 0.0	$ 0.1	$ 0.3	$ 0.0	$ 5.3	$ 1.31
		229D	16	4.9030	395.038	$ 9.1	$ 0.9	$ 7.1	$ 2.2	$ 0.2	$ 0.5	$ 1.4	$ 0.0	$ 21.3	$ 1.33
			56	4.7847	**393.144**	$ 32.0	$ 3.1	$ 22.9	$ 7.6	$ 0.7	$ 1.9	$ 4.7	$ 0.0	**$ 72.9**	$ 1.30
PI 1 Cycle 30	2016	130A	20	4.7132	392.007	$ 10.0	$ 1.1	$ 9.2	$ 2.8	$ 0.2	$ 0.8	$ 2.6	$ 0.0	$ 26.7	$ 1.33
		130B	16	4.7609	392.766	$ 8.0	$ 0.9	$ 7.5	$ 2.3	$ 0.2	$ 0.6	$ 2.1	$ 0.0	$ 21.6	$ 1.35
		130C	4	4.8558	394.279	$ 2.1	$ 0.2	$ 1.9	$ 0.6	$ 0.0	$ 0.2	$ 0.5	$ 0.0	$ 5.5	$ 1.38
		130D	16	4.9030	395.038	$ 8.3	$ 0.9	$ 7.9	$ 2.3	$ 0.2	$ 0.6	$ 2.2	$ 0.0	$ 22.3	$ 1.40
			56	4.7915	**393.252**	$ 28.4	$ 3.0	$ 26.5	$ 7.9	$ 0.7	$ 2.2	$ 7.3	$ 0.0	**$ 76.1**	$ 1.36
Monticello Cycle 29	2017	329A	88	4.0128	176.604	$ 16.8	$ 1.9	$ 14.5	$ 4.9	$ 0.7	$ 9.0	$ 3.4	$ 0.0	$ 51.3	$ 0.58
		329B	48	4.0133	176.787	$ 9.2	$ 1.0	$ 7.9	$ 2.7	$ 0.4	$ 4.9	$ 1.9	$ 0.0	$ 28.0	$ 0.58
		329C	28	4.0360	176.569	$ 5.4	$ 0.6	$ 4.6	$ 1.6	$ 0.2	$ 2.9	$ 1.1	$ 0.0	$ 16.4	$ 0.59
			164	4.0169	**176.651**	$ 31.4	$ 3.6	$ 27.1	$ 9.2	$ 1.3	$ 16.7	$ 6.4	$ 0.0	**$ 95.7**	$ 0.58
PI 2 Cycle 30	2017	230A	20	4.7132	392.007	$ 10.5	$ 1.2	$ 9.2	$ 2.9	$ 0.2	$ 1.0	$ 1.7	$ 0.0	$ 26.8	$ 1.34
		230B	16	4.7609	392.766	$ 8.9	$ 1.0	$ 7.2	$ 2.3	$ 0.2	$ 0.8	$ 1.4	$ 0.0	$ 21.8	$ 1.36
		230C	4	4.8558	394.279	$ 2.4	$ 0.3	$ 1.8	$ 0.6	$ 0.0	$ 0.2	$ 0.4	$ 0.0	$ 5.6	$ 1.41
		230D	16	4.9030	395.038	$ 9.7	$ 1.1	$ 7.1	$ 2.3	$ 0.2	$ 0.8	$ 1.5	$ 0.0	$ 22.7	$ 1.42
			56	4.7915	**393.252**	$ 31.5	$ 3.6	$ 25.3	$ 8.1	$ 0.7	$ 2.8	$ 5.0	$ 0.0	**$ 77.0**	$ 1.37
PI 1 Cycle31	2018	131A	8	4.6365	394.456	$ 4.6	$ 0.5	$ 3.3	$ 1.2	$ 0.3	$ 1.4	$ 1.4	$ 0.0	$ 12.6	$ 1.58
		131B	8	4.8831	394.456	$ 4.9	$ 0.5	$ 3.5	$ 1.2	$ 0.3	$ 1.4	$ 1.5	$ 0.0	$ 13.2	$ 1.66
		131C	28	4.9166	395.129	$ 15.5	$ 1.8	$ 13.8	$ 4.1	$ 1.0	$ 4.9	$ 5.0	$ 0.0	$ 46.0	$ 1.64
			44	4.8597	**394.884**	$ 25.0	$ 2.8	$ 20.6	$ 6.4	$ 1.6	$ 7.6	$ 7.8	$ 0.0	**$ 71.9**	$ 1.63

Nuclear Operations Business Area O&M Costs - Non-Outage

($ in millions)

	Dollar Amounts						***Annual % Change***				***Average Annual % Changes***		
$ in Millions	2012 Actuals	2013 Actual	2014 Test Year Budget Requested	2014 Actual	2015 Forecast	2016 Test Year Budget	% Change 2013 Actual vs. 2012 Actual	% Change 2014 Actual vs. 2013 Actual	% Change 2015 Forecast vs. 2014 Actual	% Change 2016 Budget vs. 2015 Forecast	Average Annual Change: 2012 to 2014	Average Annual Change: 2014 to 2016	Average Annual Change: 2012 to 2016
Site Costs (Non-Outage)													
A. Internal Labor	130.3	139.5	155.5	151.7	158.7	154.4	7.1%	8.8%	4.6%	-2.7%	8.2%	0.9%	4.6%
B. External Labor (Contractors & Consultants)	30.0	40.2	26.8	35.8	26.0	26.4	33.8%	-11.0%	-27.4%	1.6%	9.6%	-13.1%	-3.0%
Subtotal Workforce Costs	160.3	179.7	182.3	187.5	184.7	180.8	12.1%	4.3%	-1.5%	-2.1%	8.5%	-1.8%	3.2%
C. Materials & Chemicals	16.2	16.2	14.9	16.3	14.8	15.1	0.3%	0.4%	-9.1%	2.0%	0.4%	-3.6%	-1.6%
D. Employee Expenses	3.9	5.7	4.9	5.7	2.8	4.6	44.8%	0.8%	-51.8%	65.7%	23.0%	-10.1%	4.1%
E. Other	4.8	4.9	5.6	6.6	5.7	8.2	1.6%	36.9%	-13.7%	42.6%	19.6%	11.6%	17.8%
Non-Outage Site Costs Total	185.2	206.4	207.6	216.1	208.0	208.7	11.5%	4.7%	-3.7%	0.3%	8.4%	-1.7%	3.2%
Non-Site Costs Total													
F. Nuclear-related fees	31.9	31.5	35.2	36.9	37.5	39.2	-1.3%	17.1%	1.5%	4.7%	7.8%	3.2%	5.7%
G. Security	26.7	27.8	29.0	29.6	31.8	33.4	4.1%	6.5%	7.3%	5.1%	5.4%	6.4%	6.3%
Non-Site Costs Total	58.6	59.3	64.2	66.5	69.2	72.6	1.1%	12.2%	4.1%	4.9%	6.7%	4.6%	6.0%
Total Non-Outage O&M	243.8	265.7	271.8	282.7	277.3	281.3	9.0%	6.4%	-1.9%	1.5%	8.0%	-0.2%	3.8%


EUCG Survey - Single Unit Nuclear Operating Costs 2014
($ in 000s)
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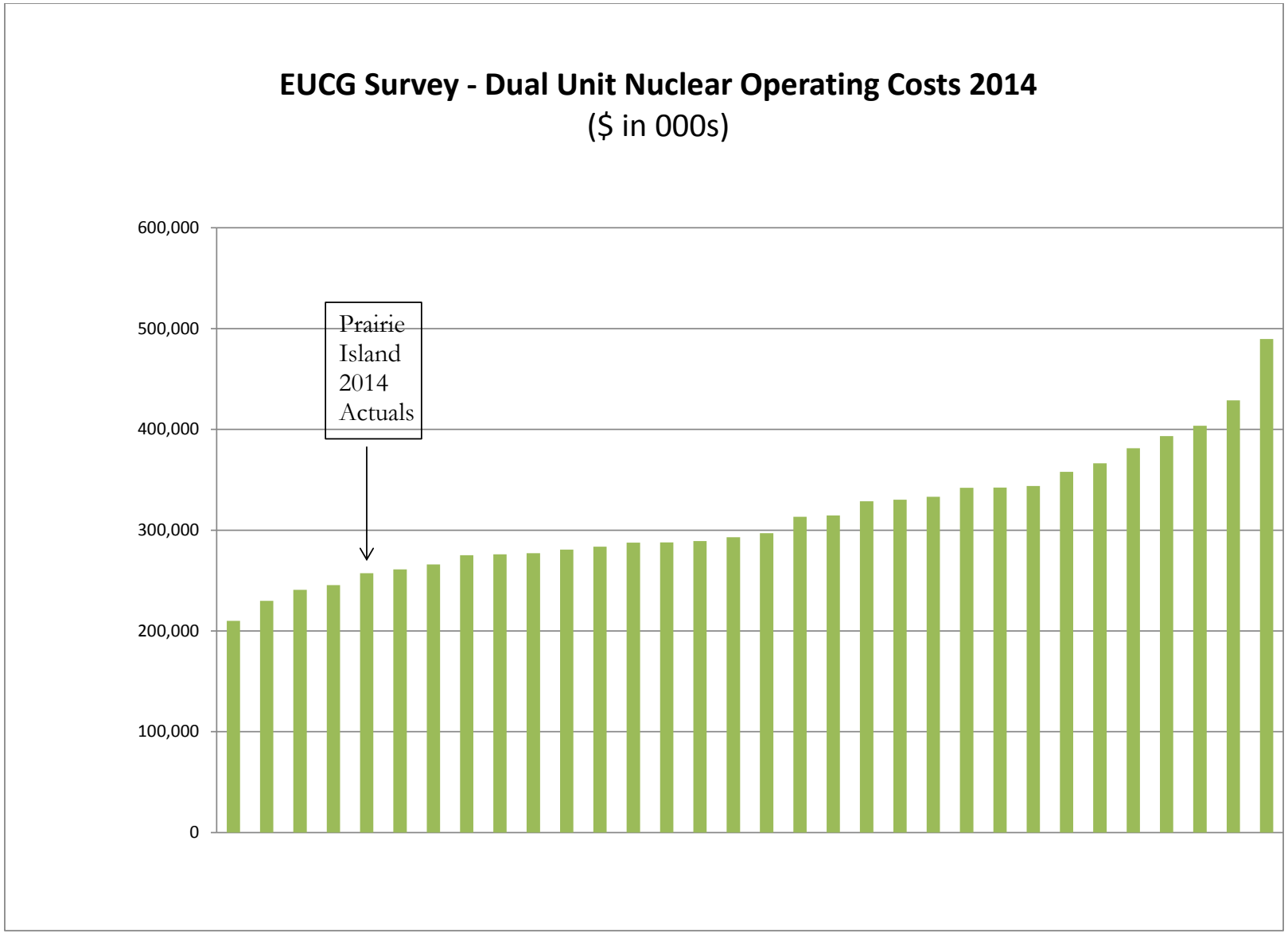
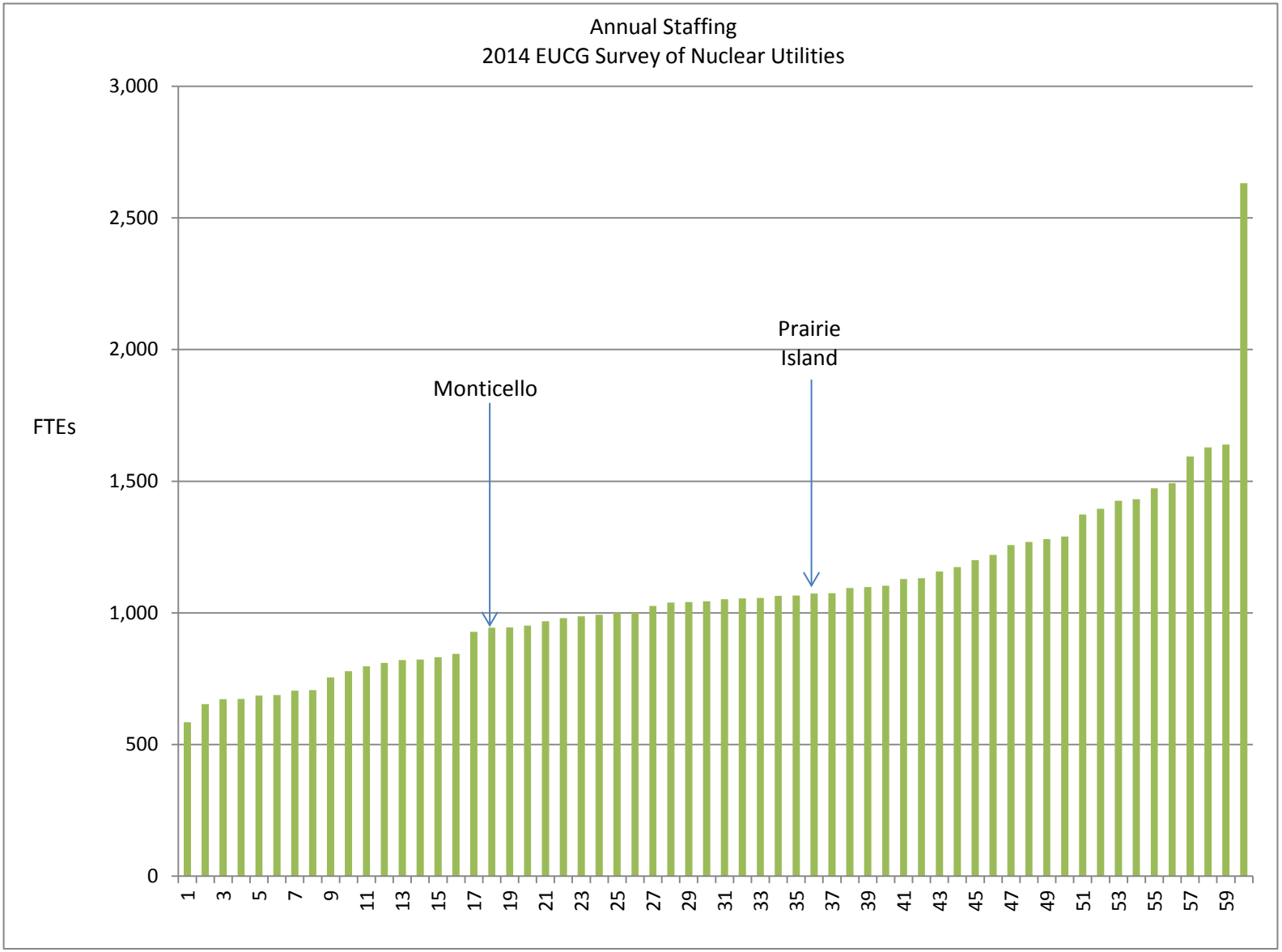
250,000
200,000
150,000
100,000
50,000
0
Monticello
2014
Actuals


EUCG Survey - Dual Unit Nuclear Operating Costs 2014
($ in 000s)
600,000
500,000
400,000
300,000
200,000
100,000
0
Prairie Island 2014 Actuals


Annual Staffing
2014 EUCG Survey of Nuclear Utilities
FTEs
3,000
2,500
2,000
1,500
1,000
500
0
Monticello
Prairie Island
1
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Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

Last Updated: November 28, 2007

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

Statement of Purpose

This accounting policy addresses the operations and maintenance (O&M) expenditures that are associated with the routine refueling of a nuclear unit and are categorized as planned major maintenance activities. Please refer to the attached list of definitions for any terminology used in this policy. Xcel Energy's utility subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC) and by various state commissions. All of the utility subsidiaries' accounting records must conform to the FERC Uniform System of Accounts. Additionally, Xcel Energy is subject to regulation by the Securities and Exchange Commission (SEC).

The overall goal of this document is to achieve a consistent policy that defines common procedures to ensure correct and consistent accounting that complies with FERC guidelines and SEC regulations for the proper handling of planned major maintenance activities associated with routine nuclear refueling across all applicable entities. It is common practice across the industry to allow expenditures to be charged to a deferred work order associated with a routine nuclear refueling in order to amortize the costs over the next fuel cycle. Due to the magnitude of this issue, it is necessary that the proper accounting be defined to assure accurate books and records of the Company. Currently, Northern States Power Company, a Minnesota corporation (NSPM) is the only Xcel Energy operating company with nuclear facilities, but the policy would apply to any subsidiary with such facilities.

Applicability

This Uniform Policy is effective on the date stated below and on that date, this policy became effective for all utility subsidiary companies. This Uniform Policy is applicable to all Xcel Energy utility subsidiaries that deal with nuclear facilities.

Summary

Because Xcel Energy is regulated by various government entities, the Corporate Controller is responsible for accounting policies for Xcel Energy within the framework of the SEC, FASB, FERC, and state regulatory requirements. These policies will include establishing and maintaining effective internal controls as it relates to the books and records of Xcel Energy and the preparation of all consolidated external reports as required by the SEC, FERC, and the state regulators.

Within this framework, Regulatory Accounting will establish appropriate accounting policies in order to meet the FERC and GAAP/SEC accounting requirements. At the end of each month, in order to recognize the regulatory assets correctly on the Company's balance sheet and to provide for the proper amortization to the income statement, only those refueling O&M expenditures that satisfy the criteria defined herein should be recognized to the appropriate deferred work orders.

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

This policy defines the expectations surrounding treatment of routine refueling O&M expenditures as planned major maintenance activities that should be charged to deferred work orders to assure proper internal controls are in place and a proper audit trail exists. Where allowed by a regulatory jurisdiction, the deferral and subsequent amortization of these expenditures meet the guidance issued under FASB Staff Position No. AUG AIR-1 (FSP AUG AIR-1), *Accounting for Planned Major Maintenance Activities*. It is Regulatory Accounting's responsibility to maintain this policy and to ensure, in conjunction with the business unit personnel, consistent application of the procedures contained in the policy. Regulatory Accounting will monitor FERC regulations and other accounting rules that impact this policy and make changes as necessary to maintain accounting compliance. Thus, business areas are responsible to understand and to adhere to the policy. Regulatory Accounting will assist business areas to appropriately apply the policy.

Definitions

Capital – The purchase or construction of a retirement unit that will be recorded on the balance sheet as an asset after meeting the GAAP criteria for being an asset

FASB – Financial Accounting Standards Board

FERC – Federal Energy Regulatory Commission

FSP – FASB Staff Position

GAAP – Generally Accepted Accounting Principles

O&M Expenditure – Expenditure incurred in the normal operations of the assets or restores the fixed asset to operating status and assists in assuring that the fixed assets achieve useful life expectations

SEC – Securities and Exchange Commission

Work Order – An account numbering system used to group costs (often referred to as a subledger in the JD Edwards general ledger system)

Content

Characterization

This policy is based on the FSP AUG AIR-1 that modifies certain positions of AICPA Industry Audit Guide, Audits of Airlines, which defines three allowable treatments for planned major maintenance activities: direct expense, built-in overhaul, or deferral. Xcel Energy uses two methods: direct expensing and deferral with an amortization, often referred to as a "deferral-and-amortization method". The deferral-and-amortization method is used only when authorized by a specific regulatory jurisdiction. Thus, if no approval exists for a specific jurisdiction, the jurisdiction must use the direct expense method. As the costs for planned major maintenance activities provide value to the constructed asset over the next cycle to which the refueling relates (typically the next 18 to 24

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

months), the deferral-and-amortization method has the benefit of better matching costs to the period in which it relates. These costs include, but are not limited to; contract labor, company labor and benefits, materials and supplies, transportation, machine equipment, tool usage, permits, equipment rental, taxes, and various incurred for planned major maintenance activities such as cleaning, servicing, replacement, or repair, as well as costs of replacement components, minor parts, and interactive agents (such as certain fluids or elements).

In general, those nuclear refueling outage costs that are properly includable to a regulatory asset under the deferral-and-amortization method should be charged to the appropriate reload-specific set of deferred work orders. A series of deferred work orders will be established for each reload to align with the applicable FERC Account to which the O&M cost would have been charged if it had been expensed, such that the amortization is expensed to those same O&M FERC Accounts. Any work done during a refueling outage that meets the requirements for capitalization is not includable in the deferred work orders. In addition, costs for standard maintenance or normal operations, which occur during a refueling outage and which are **not** listed in the definition of includable expenses shown below, are to be expensed to the appropriate O&M accounts. This policy defines the expenses allowed to the deferred work orders established for refueling outage costs and helps one understand the limits in the use of these deferred work orders.

Definition

Nuclear reactors are typically shut down once every 18 to 24 months to refuel approximately one third of the reactor core. There are many costs associated with a refueling outage. These include the following O&M costs:

- Replacement of approximately one third of the nuclear fuel assemblies in the reactor core;
- Numerous inspections on equipment to ensure safety and compliance with requirements;
- Test and maintenance jobs that can be performed only when the reactor is shut down; and
- Repairs and refurbishment of major nuclear and non-nuclear components of the plant (e.g., control rods, main coolant pumps, steam generators, turbine valves and blading, main electric generator).

This is a general list of items. However, other costs arise during a refueling outage that may be appropriate for deferral and amortization. Such costs may only be deferred following a review of the new charges for compliance with this policy and, upon compliance, approval by the outage manager and the site accounting manager (with retention of the appropriate documentation). If work begins on these activities prior to receiving approval, the expenditures will be treated as an O&M expense. However, certain costs occurring before and after the actual period when the unit is off-line are allowable to deferred work orders. Descriptions of allowed pre-outage costs and post-outage costs are included below.

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In addition to the work performed in a "base" refueling outage, more extensive work is required during refueling outages, usually staggered over a 10-year period, to comply with periodic Nuclear Regulatory Commission (NRC) and insurance requirements. In addition, it is anticipated that more extensive refueling outages occasionally will be needed as larger projects are completed. These more extensive outages will require longer periods and higher costs than typical refueling outages, but are one-time expenses not anticipated to be repeated over the license renewal period. Because each unit has different operating characteristics and parameters, each has its own fuel cycle, ranging from 18 to up to 24 months. Thus, the number of refueling outages scheduled in any given year will vary, with two outages occurring in most years, one in others, and the potential for even three refueling outages occurring in some years. Extensive planning goes into the preparation and execution of these outage schedules.

The deferral-and-amortization method of accounting will include only costs directly associated with a planned refueling outage. All other work, albeit done at the time of the outage, will be directly charged to the appropriate O&M or capital accounts as has been traditionally done. Planned outage costs for the next refueling can begin soon after the unit returns to service as contracts are being set and material is being ordered. However, most of the costs associated with planned outage work occur within the actual outage period. An activity or work order is considered planned outage work if one of the following conditions applies:

- The plant impact of the work scope requires an outage to complete;
- The work scope is required by Technical Specifications, license-based provisions, or other regulatory requirements to be performed during the outage timeframe;
- The work scope duration required exceeds greater than 75% limited condition operations ("LCO") duration;
- The work scope requires a preventative maintenance test ("PMT") or a test that can only be performed during an outage, and the work that is required ensures unit reliability for the next cycle.

Pre-outage Costs

As with any large project, capital or maintenance, there is considerable planning that occurs in order for the outage to be as efficient as possible. These planning costs are allowed as part of the deferred work order even if the costs occur in a prior year. The earliest that outage costs can occur is shortly after the unit comes on-line from the last outage. Costs cannot be deferred that occur any earlier than the beginning of the operating cycle immediately before the outage being planned.

Allowable costs during the pre-outage period include the following:

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- Outage milestone planning to develop a systematic approach for preparing for an outage;
- Surveillance and special testing of equipment;
- Any work issues identified for performance prior to a planned outage.

As with all the costs, proper documentation must exist to support the appropriateness of the charge to the FERC specific deferred work order. Any charge that does not meet the above requirements should be charged directly, in the current period, to the appropriate O&M account.

Post-outage Costs

Typically, costs continue to come in throughout the month following the return to service. This is expected, however any costs that are known and measurable in the month when the unit returns to service should be recorded as an unvouchered liability in that month. The month when the bill is received will then contain a reversal of the unvouchered liability and recognition of the actual expense. This true up from estimate to actual is often referred to as a "pick up".

Allowable costs during the post-outage period include the following:

- Resolution of disputed outage contractor issues;
- Delay charges;
- Costs associated with the removal of equipment to support outage activities.

As with all the costs, proper documentation must exist to support the appropriateness of the charge to the FERC specific deferred work order. Any charge that does not meet the above requirements should be charged directly, in the current period, to the appropriate O&M account.

Non-outage Costs

Non-outage activities may be added to the outage schedule based on work benefits that can be gained by delaying the work until the outage. Although this work is performed at the same time as the refueling outage, it is not included in the deferral and amortization. This includes the following, but is not limited to these examples:

- Personnel exposure to radiation that can be measurably reduced by performing the work when the unit is shutdown rather than at power assuming the work can be deferred to a planned outage;
- Regular maintenance work on the same component that is scheduled for work during the outage and the work can be safely delayed until the outage;

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- Work based on economic considerations and surveillance or preventative maintenance tasks that are scheduled during the outage period and cannot be rescheduled outside of the outage period.

Unplanned Outage Costs

Unplanned outages include the work that cannot be delayed until the next planned outage and requires the unit to be shutdown in order for the work to be completed. Also included in unplanned outages is any work done when the unit is brought off line for safety reasons. Costs related to these unplanned outages, as well as all non-outage activity costs, are not eligible for the deferral-and-amortization method of accounting, and will continue to use the direct expense accounting method.

Accounting

Deferred Work Order

Each outage for each unit is assigned a separate set of FERC specific deferred work orders. Before the first refueling outage charge is anticipated, the business area will request a series of deferred work orders be issued. The set of deferred work orders will include one work order for each nuclear production FERC O&M account anticipated to be charged (the same FERC accounts used to record the refueling outage costs to expense). As costs are incurred during the outage, the FERC specific deferred work order will accumulate costs previously charged to the specific FERC O&M account. The use of work orders facilitates the accumulation of charges, but it also facilitates review for audit purposes.

Other Regulatory Assets

The accumulation of refueling outage costs for those jurisdictions allowing the deferral-and-amortization method will be cleared from the deferred work order to FERC Account 182.3, *Other Regulatory Assets*. The subsequent amortization of each balance reduces the regulatory asset to zero over the period the plant is operating until the next reload outage. The regulatory asset account will be maintained separate for each reload at each unit and also by each applicable nuclear production FERC O&M account. It is anticipated that this information will be segregated via a work order tag in the regulatory asset account.

Various Jurisdictions

For any rate jurisdiction that has not approved the use of the deferral-and-amortization method for nuclear refueling outage costs, that jurisdiction will continue to use the direct expensing method for its portion of the nuclear refueling outage costs. Therefore, unless all rate jurisdictions authorize use of the deferral-and-amortization method, the accounting will be maintained by rate jurisdiction.

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Assuming there are some rate jurisdictions that will allow the use of the deferral-and-amortization method and others that will not, the following steps generally will occur:

1. The nuclear plant personnel identify the refueling expenses that are appropriate to be deferred. Plant personnel do not allocate jurisdictional costs and thus gather total company charges only under this policy.
2. The plant personnel assign the identified costs in step 1 to a deferred work order, with each work order being specific to a FERC account and a particular reload.
3. The charges in the deferred work order are allocated to the various rate jurisdictions each month (based on the appropriate jurisdictional allocation factor in use at the time for each nuclear production FERC O&M account).
4. For those jurisdictions using the deferral-and-amortization method, the jurisdictional work order will set up the regulatory asset for amortization.
5. For those jurisdictions using the direct expense method, the costs in the jurisdictional work order are expensed in the month incurred.
6. The regulatory asset is maintained by each reload and by each applicable FERC O&M account such that the amortization is charged to the appropriate FERC O&M account each month

Amortization

The monthly amortization is calculated for each nuclear production FERC account for each reload for each unit separately. The amortization is a straight-line calculation derived by dividing the amount accumulated for the refueling outage by the number of months in the amortization period. The following method is used to calculate the amortization period.

Amortization Period

The amortization begins with the month the unit comes on-line, and continues through the month before it comes back on-line with the next refueled core. The intent behind using this period is to be assured that the previous deferral finishes the month prior to the next one beginning, leaving no months without an amortization or having amortizations from the previous and current reload overlapping. For example, the unit comes off line in February 2008 to refuel and comes back on-line March 2008. The plant operates through the rest of 2008, all of 2009, and comes off-line in February 2010 for the next refueling. This refueling is complete in March 2010. The amortization period is the number of months from March 2008 to February 2010, or 24 months in this example.

The number of months in the amortization is set based on the expected future refueling date for the next outage. The date, although a forecast, is a fairly certain date that will usually only fluctuate by one or two months on either side of the forecast date. When it is known that the next reload date has moved, the amortization period is adjusted. The amortization is adjusted for the remaining months by dividing the current balance by the remaining months in the amortization period. Continuing the

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

above example, if the refueling date is revised from February 2010 to April 2010 in January 2010, then the remaining amortization period is lengthened by two months. In January 2010, the remaining amortization was 2 months and is lengthened to 4 months based on the revised date for refueling.

FERC O&M Accounts

Based on accumulating the charges to a FERC specific deferred work order, the amortization is calculated for the month for each applicable O&M account. Each refueling operation may have a different spread of the costs incurred across the various nuclear O&M accounts; therefore, there may be many amortizations being calculated for each reload to effectively charge the correct FERC O&M account. The amortization is charged to the same nuclear production O&M expense account as would be used for direct expensing. The amortization period is the same across all FERC O&M account amortizations.

Applicable FERC O&M Accounts to Nuclear Refueling Outages

FERC Account	Account Title
Operations	
517	Operation Supervision and Engineering
519	Coolants and Water
520	Steam Expenses
523	Electric Expenses
524	Miscellaneous Nuclear Power Expenses
Maintenance	
528	Maintenance Supervision and Engineering
529	Maintenance of Structures
530	Maintenance of Reactor Plant Equipment
531	Maintenance of Electric Plant
532	Maintenance of Miscellaneous Nuclear Plant

Pick-ups

The term "pick-ups" is used to refer to the trailing costs that occur subsequent to the completion of the work. Business unit personnel are expected to book all known or estimable costs in the final month of the outage work. By recognizing an estimate of work completed to date, the amortization can begin with a very close approximation of total costs in the deferred work orders. The costs incurred in the "post-outage" phase are recognized in the deferred work orders with a debit offset by a credit to account payable or unvouchered liabilities. When the final costs are determined, the entire estimate is reversed with the actual payment being recognized to the appropriate deferred work order.

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There is a time limit on this process. Costs not finalized within three months after the unit begins operating are settled to expense.

Direct Expensing

Assuming a jurisdiction may not adopt this change of accounting for its customers, their portion of the O&M costs will be expensed when incurred. The jurisdictional split is determined at the time the set of FERC specific deferred work orders is requested for the outage. Every charge booked to the deferred work order will be allocated between jurisdictions that allowed the deferral-and-amortization method of accounting and those jurisdictions using the direct expense method. For example, if 75% of the jurisdictions allow deferred accounting and 25% do not, for every dollar incurred, 25 cents is expensed immediately and 75 cents is deferred and amortized. See steps defined under the "*Various Jurisdictions"* section above.

Tax Treatment

The treatment described to this point deals with the financial treatment of these costs for book purposes. The treatment of these costs for tax purposes is not impacted by whether the costs are deferred and amortized or expensed as incurred. The amount spent in a given year on refueling costs is what is deducted for income tax purposes. Therefore, choosing to defer some of the O&M costs for the books creates a timing difference between the book and tax recognition for these refueling costs. To recognize this difference, a deferred tax liability is created, setting up when the costs are expensed for taxes and flowing back when the amortization is complete.

Policy Application

Making the decision of where a particular cost should be charged may not always be clear and concise and interpretations will have to be made. Nuclear refueling costs meeting the above criteria for deferral can be charged to a deferred work order while all routine maintenance and standard operating costs should be charged to the appropriate O&M expense accounts. Any uncertainty about this policy should be directed to Regulatory Accounting for resolution.

Regulatory

Interchange Agreement

Costs incurred in the nuclear production O&M FERC accounts are shared between the two Northern State Power companies through the FERC jurisdictional "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)" (Interchange Agreement). Costs are shared based on assignment to specific FERC accounts using a ratio of either the 36 month coincident peak demand or current year energy requirements. Through the Interchange Agreement, NSPM bills a proportionate share of the nuclear production O&M expense to NSPW. The use of the

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

deferral-and-amortization method of accounting for nuclear production O&M costs will change the pattern of expensing, however, the content of what is being expensed as well as the FERC accounts used to record those same expenses has not changed. Therefore, there is no impact to the Interchange Agreement resulting from this use of the deferral-and-amortization method.

Internal Controls

Regulatory Accounting has initiated the following tasks to assure that a valid work order for the regulatory assets resulting from this process exists from month to month:

- Working with the nuclear plant personnel to assure that proper documentation of cost assignment is being maintained;
- Periodically reviewing deferred work orders to assure that only proper costs are being included;
- Establishing the appropriate jurisdictional allocations for each deferred work order;
- Communicating this policy and its implications for the budgeting process for departmental operating expenses to all business unit personnel responsible for departmental budgets;
- Providing forecast information for the future amortizations applicable to this method based on the business area's budget of deferred costs.

Accountabilities

Business Unit Personnel

Business unit personnel are responsible for the following:

- Requesting set of deferred work orders prior to the first refueling outage charge;
- Making sure all costs are being appropriately tracked based on the rules stated above;
- Assuring unvouchered liabilities are booked timely;
- Providing all supporting documentation for the costs contained in any deferred work order;
- Keeping Regulatory Accounting aware of any changes to the refueling schedule in time to affect the monthly amortization.

Regulatory Accounting

Regulatory Accounting is responsible for the following:

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- Performing the compliance accounting associated with this deferral;
- Providing the appropriate jurisdictional allocators for the various accumulating work orders;
- Calculating and documenting the monthly amortization;
- Providing all relevant deferral related information for the amortization for the forecast and for rate case preparations;
- Periodically reviewing work orders for the appropriateness of charges and working with the business unit personnel to resolve any issues.

References

FASB Staff Position No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*, September 2006

Supercedure

This is the first issuance of this policy.

Appendices

There are no appendices to this policy

Prairie Island Unit 1 - Fall 2014 Actual Outage Costs

BU (Dept)#	BU (Dept) Description	Cost Description	Total Cost
Contractors			
		[TRADE SECRET BEGINS	**[TRADE SECRET BEGINS**
257400	PI Site Management	[redacted]	[redacted]
257403	PI Quality Control	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257410	PI Maint - Mechanical	[redacted]	[redacted]
257411	PI Maint - Electrical	[redacted]	[redacted]
257411	PI Maint - Electrical	[redacted]	[redacted]
257411	PI Maint - Electrical	[redacted]	[redacted]
257411	PI Maint - Electrical	[redacted]	[redacted]
257411	PI Maint - Electrical	[redacted]	[redacted]
257411	PI Maint - Electrical	[redacted]	[redacted]
257414	PI Maint-Craft Aug	[redacted]	[redacted]
257414	PI Maint-Craft Aug	[redacted]	[redacted]
257414	PI Maint-Craft Aug	[redacted]	[redacted]
257415	PI Maint - Facilities	[redacted]	[redacted]
257416	PI Planning	[redacted]	[redacted]
257419	PI Rad Prot-Operations	[redacted]	[redacted]
257419	PI Rad Prot-Operations	[redacted]	[redacted]
257419	PI Rad Prot-Operations	[redacted]	[redacted]
257420	PI Rad Prot - Radwaste	[redacted]	[redacted]
257423	PI Operations Support	[redacted]	[redacted]
257424	PI Work Control Center	[redacted]	[redacted]
257425	PI Safety & Health	[redacted]	[redacted]
257427	PI Outage	[redacted]	[redacted]
257427	PI Outage	[redacted]	[redacted]
257427	PI Outage	[redacted]	[redacted]
257427	PI Outage	[redacted]	[redacted]
257429	PI Project Mgmt Office	[redacted]	[redacted]
257429	PI Project Mgmt Office	[redacted]	[redacted]
257430	PI Project Management	[redacted]	[redacted]
257430	PI Project Management	[redacted]	[redacted]
257436	PI Training - Support	[redacted]	[redacted]
257436	PI Training - Support	[redacted]	[redacted]

Prairie Island Unit 1 - Fall 2014 Actual Outage Costs

BU (Dept)#	BU (Dept) Description	Cost Description	Total Cost	
Contractors				
257443	PI Engineering Systems			
257443	PI Engineering Systems			
257443	PI Engineering Systems			
257451	PI Eng Prog - Equip Rel P			
257451	PI Eng Prog - Equip Rel P			
257452	PI Eng Prog - Insp&Mtrls			
257453	PI Engineering Design			
257464	PI Accounting/Finance			
257464	PI Accounting/Finance			
257465	PI Security			
257465	PI Security			
257465	PI Security			
257465	PI Security			
Various	Various			
		TRADE SECRET ENDS]	**TRADE SECRET ENDS]**	
		Total Contractor		**$ 26,052,065**
Fees				
257437	PI Licensing	NRC ISI Inspection	$ 40,037	
		Total Fees		**$ 40,037**
Leases				
Various	Various	Treasure Island Center for Training	$ 49,464	
		Total Leases		**$ 49,464**
Materials				
Various	Various	Materials	$ 3,379,270	
		Total Materials		**$ 3,379,270**
Labor				
Various	Various	Employee Labor	$ 13,921,536	
		Outage Labor from Other Sites	$ 431,449	
		Total Labor		**$ 14,352,985**
Employee/Operating Expenses				
Various	Various	Employee Expenses	$ 84,727	
		Outage Employee Expenses from Other Sites	$ 180,258	
		Total Empl/Oper		**$ 264,985**
		GRAND TOTAL		**$ 44,138,805**

Prairie Island Nuclear Generating Plant
Outage Labor Costs - Unit 1 Refueling Outage 29 (1R29) - Fall 2014 Actual

Business Unit No. & Description	Object Acct No. & Description		Labor $
257401 PI Employee Concerns Prog	711190 Overtime	$	2,209
257402 PI Quality Assurance/NOS	711190 Overtime		26,278
257403 PI Quality Control	711150 Premium Time		17,849
257403 PI Quality Control	711190 Overtime		50,101
257404 PI Perform Improvement	711190 Overtime		6,374
257405 PI Plant Management	711190 Overtime		4,404
257406 PI Chemistry	711190 Overtime		25,347
257407 PI Chemistry-Tech Sup	711150 Premium Time		55,914
257407 PI Chemistry-Tech Sup	711190 Overtime		105,440
257408 PI Chemistry -Operations	711150 Premium Time		152,719
257408 PI Chemistry -Operations	711190 Overtime		259,887
257410 PI Maint - Mechanical	711141 Productive Loaded Labor		-
257410 PI Maint - Mechanical	711150 Premium Time		250,931
257410 PI Maint - Mechanical	711190 Overtime		695,006
257411 PI Maint - Electrical	711141 Productive Loaded Labor		-
257411 PI Maint - Electrical	711150 Premium Time		135,581
257411 PI Maint - Electrical	711190 Overtime		413,652
257412 PI Maint - I&C	711141 Productive Loaded Labor		(1,742)
257412 PI Maint - I&C	711150 Premium Time		120,993
257412 PI Maint - I&C	711190 Overtime		347,119
257413 PI Maint - Support	711190 Overtime		73,801
257414 PI Maint-Craft Aug	711141 Productive Loaded Labor		1,762,230
257414 PI Maint-Craft Aug	711150 Premium Time		21,019
257414 PI Maint-Craft Aug	711190 Overtime		1,853,397
257414 PI Maint-Craft Aug	711275 Other Comp- Welfare Fund		2,001,957
257415 PI Maint - Facilities	711141 Productive Loaded Labor		237,657
257415 PI Maint - Facilities	711150 Premium Time		25,254
257415 PI Maint - Facilities	711190 Overtime		298,972
257416 PI Planning	711141 Productive Loaded Labor		3,408
257416 PI Planning	711150 Premium Time		2,909
257416 PI Planning	711190 Overtime		323,732
257417 PI Rad Protection	711190 Overtime		50,740
257418 PI Rad Prot - Support	711150 Premium Time		46,194
257418 PI Rad Prot - Support	711190 Overtime		104,970
257419 PI Rad Prot-Operations	711150 Premium Time		251,984
257419 PI Rad Prot-Operations	711190 Overtime		480,071
257422 PI Shift Operations	711150 Premium Time		677,057
257422 PI Shift Operations	711190 Overtime		1,183,713
257423 PI Operations Support	711190 Overtime		35,883
257424 PI Work Control Center	711190 Overtime		94,989
257425 PI Safety & Health	711190 Overtime		11,115
257427 PI Outage	711190 Overtime		81,520
257428 PI Scheduling	711190 Overtime		39,051
257430 PI Project Management	711190 Overtime		18,141
257432 PI Training - Operations	711190 Overtime		31,403
257433 PI Training - Technical	711190 Overtime		24,260
257434 PI Training - Maint	711190 Overtime		54,831
257435 PI Training - Simulator	711190 Overtime		2,700
257436 PI Training - Support	711190 Overtime		45,011
257437 PI Licensing	711190 Overtime		5,509
257440 FT PI Eng FIN	711190 Overtime		112,405
257442 FT PI Eng Reactor Systems	711190 Overtime		79,192
257443 PI Engineering Systems	711190 Overtime		19,408
257444 FT PI Eng Nuc Safety Systems	711190 Overtime		92,898
257445 PI Eng Systems - Elec/I&C	711190 Overtime		129,026
257446 PI Eng Systems - BOP	711190 Overtime		60,576
257447 FT PI Eng Support	711190 Overtime		110,283
257449 PI Engineering Programs	711190 Overtime		13,577
257450 PI Eng Prog-LT Term Prog	711190 Overtime		85,237
257451 PI Eng Prog - Equip Rel P	711190 Overtime		95,907
257452 PI Eng Prog - Insp&Mtrls	711190 Overtime		119,063
257454 FT PI Eng Mech Civil Design	711190 Overtime		183,509
257455 PI Eng Design-Electrical	711190 Overtime		67,505
257456 PI Eng Des -Config Contr	711190 Overtime		53,820
257457 PI Eng Design - Support	711190 Overtime		6,214
257459 PI Doc Control/Procedures	711150 Premium Time		7,084
257459 PI Doc Control/Procedures	711190 Overtime		64,286
257461 PI Administration Svcs	711150 Premium Time		14,869
257461 PI Administration Svcs	711190 Overtime		40,461
257462 PI Business Planning	711190 Overtime		6,854
257463 PI Emergency Planning	711190 Overtime		3,394
257465 PI Security	711150 Premium Time		2,319
257465 PI Security	711190 Overtime		30,092
	Subtotal Total 2014 Labor $'s	**$**	**13,909,519**
	2013 Labor for Outage 1R29		12,017
	Total 2013 & 2014 Labor $'s	**$**	**13,921,536**
	Labor for Travelers		431,449
	Total 1R29 Labor	**$**	**14,352,985**

Monticello Planned Refueling Outage (RFO 27) - Spring 2015

Actual Costs Through August, 2015

		Years 2014-2015
Contract Services		
[TRADE SECRET BEGINS		[TRADE SECRET BEGINS
TRADE SECRET ENDS]		TRADE SECRET ENDS]
Total Contract Services	**$**	**29,907,824**
Employee Expenses		
Mileage, Per Diem		104,104
Total Employee Expenses	**$**	**104,104**
Labor		
Total 2014 Labor- RF027		122,696
2015 Labor- RFO27		5,371,182
2015 Labor Overtime- RFO27		7,503,181
Travellers- RF027		493,230
Other		359
Total Labor	**$**	**13,490,646**
Materials		
Base Outage Materials		5,102,209
Total Materials	**$**	**5,102,209**
Utility/Other Expenses		
Equipment Rental		466,168
Total Utility/Other Expenses	**$**	**466,168**
Grand Total - Actual Through August 2015	**$**	**49,070,950**
Outage Costs Amortized into 2016-2017 per Rate Case - June 2015 Forecast	$	48,400,000

Monticello Planned Refueling Outage - Spring 2015
Actual 2015 Labor Costs Through August 31, 2015

Business Unit (Dept) #	Business Unit (Dept) Description	Premium/ Incremental Labor	Overtime Labor
257200	MT Site Management	$ -	$ 2,069
257202	MT Quality Assurance/NOS	$ -	$ 24,421
257203	MT Quality Control	$ 15,266	$ 54,890
257204	MT Perform Improvement	$ -	$ 12,315
257205	MT Plant Management	$ 1,486	$ 27,409
257206	MT Chemistry	$ 107,295	$ 250,067
257210	MT Maint - Mechanical	$ 244,447	$ 418,496
257211	MT Maint - Electrical	$ 168,375	$ 284,201
257212	MT Maint - I&C	$ 197,485	$ 326,777
257213	MT Maint - Support	$ (8)	$ 269,828
257214	MT Maint-Craft Aug	$ 3,854,078	$ 2,499,907
257215	MT Maint - Facilities	$ 55,969	$ 127,148
257217	MT Rad Protection	$ 234,703	$ 581,010
257222	MT Shift Operations	$ 445,589	$ 1,094,579
257227	MT Outage	$ -	$ 52,763
257228	MT Scheduling	$ -	$ 86,748
257230	MT Project Management	$ (0)	$ 12,011
257232	MT Training - Operations	$ 800	$ 119,695
257233	MT Training - Technical	$ -	$ 31,582
257234	MT Training - Maint	$ -	$ 77,874
257235	MT Training - Simulator	$ -	$ 8,084
257236	MT Training - Support	$ 2,955	$ 30,768
257237	MT Licensing	$ 798	$ 11,161
257244	MT Engineering Systems	$ (60)	$ 406,325
257251	MT Engineering Programs	$ (4)	$ 254,505
257253	MT Engineering Design	$ (5)	$ 237,517
257258	MT Records Management	$ 3,587	$ 18,925
257259	MT Doc Control/Procedures	$ (3)	$ 41,948
257261	MT Administration Svcs	$ 34,235	$ 113,657
257263	MT Emergency Planning	$ (3)	$ 3,486
257265	MT Security	$ 4,197	$ 23,016
Grand Total - 2015 Labor		$ 5,371,182	$ 7,503,181

Prairie Island Unit 2 - Fall 2015 Outage Budget

Cost Description	Total Cost
CONTRACTORS	
[TRADE SECRET BEGINS	**[TRADE SECRET BEGINS**

Prairie Island Unit 2 - Fall 2015 Outage Budget

Cost Description	Total Cost	
CONTRACTORS		
[TRADE SECRET BEGINS	**[TRADE SECRET BEGINS**	
		$ 24,057,992
TRADE SECRET ENDS]	**TRADE SECRET ENDS]**	
Total Contractor		**$ 26,057,992**
FEES		
NRC ISI Inspection	$ 31,080	
Total Fees		**$ 31,080**
LEASES/RENTS		
Filtration Equipment for TB Sump-Western Oilfields	$ 15,300	
Oxygen Services Welding Equipment	$ 6,630	
Outage Scaffold Rental	$ 61,200	
Outage trailer rental for Westinghouse	$ 10,000	
Treasure Island Center for Training	$ 21,562	
Total Leases		**$ 114,692**
MATERIALS		
Base Outage Materials	$ 143,727	
Supply Chain Ld @10.6%	$ 5,177	
Add support to FW Recirc Drain Line	$ 90,000	
Base Outage Systems Materials	$ 1,337,451	
Containment FCU Replace ZX Valve Trim	$ 150,000	
Repl Level Transm Rhtr Drain Tank	$ 150,000	
Supply Chain Ld @10.6%	$ 290,700	
Base Outage Systems Materials	$ 321,554	
Safety-Related (SR) Inverters on DC System	$ 150,000	
Supply Chain Ld @10.6%	$ 50,197	
Base Outage Systems Materials	$ 137,809	
Supply Chain Ld @10.6%	$ 14,820	
Frham/Orex Outage Safety Equipment	$ 520,200	
Supply Chain Ld @10.6%	$ 7,676	
Unitech scrub purchase and trailer lease	$ 63,991	
Personal Protective Equipment	$ 25,263	
Safety Equipment	$ 16,053	
Supply Chain Ld @10.6%	$ 1,487	
Outage Handbooks	$ 5,359	
Supply Chain Ld @10.6%	$ 193	
Total Materials		**$ 3,481,657**
LABOR		
Employee Labor	$ 13,146,015	
Total Labor		**$ 13,146,015**
EMPLOYEE EXPENSES & OTHER		
Employee Expenses	$ 72,280	
Operating Expenses	$ 53,003	
Total Empl/Oper		**$ 125,284**
OUTAGE SUPPORT - from other Plants		**$ 140,000**
CONTINGENCY - mainly related to uncertainty from inspection discovery and possible emergent issues		**$ 2,518,966**
GRAND TOTAL		**$ 45,615,686**

Prairie Island Unit 2 - 2015 Outage Labor Budget Detail: Premium and Overtime Dollars

Business Unit (Dept)	Cost Object	Total
		[TRADE SECRET BEGINS
257401: PI Employee Concerns Prog	711190: Overtime	
257402: PI Quality Assurance/NOS	711190: Overtime	
257403: PI Quality Control	711150: Premium Time	
257403: PI Quality Control	711190: Overtime	
257404: PI Perform Improvement	711190: Overtime	
257405: PI Plant Management	711190: Overtime	
257406: PI Chemistry	711190: Overtime	
257407: PI Chemistry-Tech Sup	711150: Premium Time	
257407: PI Chemistry-Tech Sup	711190: Overtime	
257408: PI Chemistry -Operations	711150: Premium Time	
257408: PI Chemistry -Operations	711190: Overtime	
257410: PI Maint - Mechanical	711150: Premium Time	
257410: PI Maint - Mechanical	711190: Overtime	
257410: PI Maint - Mechanical	711190: Overtime	
257411: PI Maint - Electrical	711150: Premium Time	
257411: PI Maint - Electrical	711190: Overtime	
257411: PI Maint - Electrical	711190: Overtime	
257412: PI Maint - I&C	711150: Premium Time	
257412: PI Maint - I&C	711190: Overtime	
257412: PI Maint - I&C	711190: Overtime	
257413: PI Maint - Support	711190: Overtime	
257414: PI Maint-Craft Aug	711142: Productive Labor	
257414: PI Maint-Craft Aug	711146: Prod Lab-Attrit (frmly taxes)	
257414: PI Maint-Craft Aug	711190: Overtime	
257414: PI Maint-Craft Aug	711275: Other Comp- Welfare Fund	
257415: PI Maint - Facilities	711142: Productive Labor	
257415: PI Maint - Facilities	711146: Prod Lab-Attrit (frmly taxes)	
257415: PI Maint - Facilities	711150: Premium Time	
257415: PI Maint - Facilities	711190: Overtime	
257415: PI Maint - Facilities	711190: Overtime	
257416: PI Planning	711190: Overtime	
257417: PI Rad Protection	711190: Overtime	
257418: PI Rad Prot - Support	711150: Premium Time	
257418: PI Rad Prot - Support	711190: Overtime	
257419: PI Rad Prot-Operations	711150: Premium Time	
257419: PI Rad Prot-Operations	711190: Overtime	
257422: PI Shift Operations	711150: Premium Time	
257422: PI Shift Operations	711190: Overtime	
257422: PI Shift Operations	711190: Overtime	
257423: PI Operations Support	711190: Overtime	
257424: PI Work Control Center	711190: Overtime	
257425: PI Safety & Health	711190: Overtime	
257427: PI Outage	711190: Overtime	
257428: PI Scheduling	711190: Overtime	
257429: PI Project Mgmt Office	711150: Premium Time	
257429: PI Project Mgmt Office	711190: Overtime	
257432: PI Training - Operations	711190: Overtime	

Prairie Island Unit 2 - 2015 Outage Labor Budget Detail: Premium and Overtime Dollars

Business Unit (Dept)	Cost Object	Total
		[TRADE SECRET BEGINS
257433: PI Training - Technical	711190: Overtime	
257434: PI Training - Maint	711190: Overtime	
257435: PI Training - Simulator	711190: Overtime	
257436: PI Training - Support	711190: Overtime	
257437: PI Licensing	711190: Overtime	
257440: FT PI Eng FIN	711190: Overtime	
257442: FT PI Eng Reactor Systems	711150: Premium Time	
257442: FT PI Eng Reactor Systems	711190: Overtime	
257443: PI Engineering Systems	711190: Overtime	
257444: FT PI Eng Nuc Safety Systems	711190: Overtime	
257445: PI Eng Systems - Elec/I&C	711190: Overtime	
257446: PI Eng Systems - BOP	711190: Overtime	
257447: FT PI Eng Support	711190: Overtime	
257450: PI Eng Prog-LT Term Prog	711190: Overtime	
257451: PI Eng Prog - Equip Rel P	711190: Overtime	
257452: PI Eng Prog - Insp&Mtrls	711190: Overtime	
257454: FT PI Eng Mech Civil Design	711190: Overtime	
257455: PI Eng Design-Electrical	711150: Premium Time	
257455: PI Eng Design-Electrical	711190: Overtime	
257456: PI Eng Des -Config Contr	711190: Overtime	
257459: PI Doc Control/Procedures	711150: Premium Time	
257459: PI Doc Control/Procedures	711190: Overtime	
257461: PI Administration Svcs	711150: Premium Time	
257461: PI Administration Svcs	711190: Overtime	
257462: PI Business Planning	711190: Overtime	
257465: PI Security	711150: Premium Time	
257465: PI Security	711190: Overtime	
257416: PI Planning	711190: Overtime	
		TRADE SECRET ENDS]

Prairie Island Unit 1 - Fall 2016 Outage Budget

BusUnit(Dept)	BusinessUnit (Dept)Desc	Cost Description	2016 Total
Contractors			
		[TRADE SECRET BEGINS	**[TRADE SECRET BEGINS**
257403	PI Quality Control		
257403	PI Quality Control		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
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257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257410	PI Maint - Mechanical		
257411	PI Maint - Electrical		
257411	PI Maint - Electrical		
257411	PI Maint - Electrical		
257411	PI Maint - Electrical		
257411	PI Maint - Electrical		
257411	PI Maint - Electrical		
257411	PI Maint - Electrical		
257411	PI Maint - Electrical		
257411	PI Maint - Electrical		
257412	PI Maint - I&C		
257412	PI Maint - I&C		
257412	PI Maint - I&C		
257414	PI Maint-Craft Aug		
257414	PI Maint-Craft Aug		
257414	PI Maint-Craft Aug		
257414	PI Maint-Craft Aug		
257415	PI Maint - Facilities		
257415	PI Maint - Facilities		
257419	PI Rad Prot-Operations		
257419	PI Rad Prot-Operations		
257419	PI Rad Prot-Operations		
257419	PI Rad Prot-Operations		
257419	PI Rad Prot-Operations		
257419	PI Rad Prot-Operations		
257419	PI Rad Prot-Operations		
257420	PI Rad Prot - Radwaste		
257420	PI Rad Prot - Radwaste		
257424	PI Work Control Center		
257424	PI Work Control Center		
257427	PI Outage		
257427	PI Outage		
257430	PI Project Management		
257430	PI Project Management		
257430	PI Project Management		
257430	PI Project Management		
257430	PI Project Management		
257436	PI Training - Support		
257436	PI Training - Support		
257437	PI Licensing		

Prairie Island Unit 1 - Fall 2016 Outage Budget

BusUnit(Dept)	BusinessUnit (Dept)Desc	Cost Description	2016 Total	
Contractors				
		[TRADE SECRET BEGINS	[TRADE SECRET BEGINS	
257451	PI Eng Prog - Equip Rel P			
257451	PI Eng Prog - Equip Rel P			
257451	PI Eng Prog - Equip Rel P			
257452	PI Eng Prog - Insp&Mtrls			
257452	PI Eng Prog - Insp&Mtrls			
257464	PI Accounting/Finance			
257464	PI Accounting/Finance			
257465	PI Security			
257465	PI Security			
257465	PI Security			
257465	PI Security			
257465	PI Security			
				$ 20,648,613
Various	Various			
Various	Various			
		TRADE SECRET ENDS]	TRADE SECRET ENDS]	
		Total Contractors		$ 23,648,613
Employee Expense				
257400	PI Site Management	Outage Recognition/Meal Tickets	$ 11,660	
257410	PI Maint - Mechanical	Outage Union Employee Exp - Safety Shoe Reimburse	$ 2,040	
257411	PI Maint - Electrical	Outage Union Employee Exp - Safety Shoe Reimburse	$ 2,040	
257412	PI Maint - I&C	Outage Union Employee Exp - Safety Shoe Reimburse	$ 2,040	
257414	PI Maint-Craft Aug	Craft Aug Mileage Expense	$ 8,470	
257414	PI Maint-Craft Aug	Craft Aug Per Diem Expense	$ 25,833	
257415	PI Maint - Facilities	Facilities Per Diem Expense	$ 17,336	
257461	PI Administration Svcs	Admin Per Diem Expense	$ 840	
		Total Employee Expense		$ 70,259
Fees				
257437	PI Licensing	NRC ISI inspections	$ 40,232	
		Total Fees		$ 40,232
Leases				
257410	PI Maint - Mechanical	Filtration Equipment for TB Sump-Western Oilfields	$ 3,606	
257410	PI Maint - Mechanical	Oxygen services welding equipment	$ 6,763	
257410	PI Maint - Mechanical	Satellite Shelters-Westinghouse crew	$ 11,000	
257414	PI Maint-Craft Aug	Outage Scaffold rental	$ 62,424	
257427	PI Outage	Ziegler-Generators and Compressors	$ 49,806	
257436	PI Training - Support	Treasure Island for Training Facility	$ 30,500	
		Total Leases		$ 164,099
Materials				
257406	PI Chemistry	Base Outage Materials	$ 148,114	
257406	PI Chemistry	Supply Chain Ld @15%	$ 22,217	
257410	PI Maint - Mechanical	Base Outage Systems Materials	$ 1,761,008	
257410	PI Maint - Mechanical	Warehouse Load Materials Outage - @ 15%	$ 264,151	
257411	PI Maint - Electrical	Base Outage Systems Materials	$ 321,554	
257411	PI Maint - Electrical	Warehouse Load Materials Outage - @ 15%	$ 48,233	
257412	PI Maint - I&C	Base Outage Systems Materials	$ 137,809	
257412	PI Maint - I&C	Warehouse Load Materials Outage - @ 15%	$ 20,671	
257419	PI Rad Prot-Operations	Frham/Orex Outage Safety Equipment	$ 451,205	
257419	PI Rad Prot-Operations	RP Outage supplies from Warehouse	$ 50,000	
257419	PI Rad Prot-Operations	Warehouse Load Materials Outage - @ 15%	$ 14,000	
257425	PI Safety & Health	Personal Protective Equipment	$ 25,768	
257425	PI Safety & Health	Safety Equipment	$ 16,374	
257425	PI Safety & Health	Warehouse Load Materials Outage - @ 15%	$ 6,321	
257427	PI Outage	Outage Handbooks	$ 5,466	
257427	PI Outage	Warehouse Load Materials Outage - @ 15%	$ 820	
		Total Materials		$ 3,293,713
Other Operating Expenses				
257425	PI Safety & Health	Safety dpmt Outage OT	$ 19,668	
257460	PI Information Technology	IT dpmt Outage OT	$ 24,720	
		Total Other Operating Expenses		$ 44,388
Employee Labor				
Various	Various	Overtime	$ 11,278,083	
		Total Labor		$ 11,278,083
Other - Support from Other Plants				
Various	Various	Outage Support from other Plants		$ 140,000
		Total Other		
Contingency				
Various	Various	**Contingency - Emergent Issues (and uncertainly from discovery from generator inspection)**		$ 4,320,253
		GRAND TOTAL		$ 42,999,639

Prairie Island Unit 1 - 2016 Outage Labor Budget Detail: Premium and Overtime Dollars

Labor Center	Business Unit (Dept)	Cost Object (Type)	Total Cost
			[TRADE SECRET BEGINS
0330W: NGS Construction	257414: PI Maint-Craft Aug	711142: Productive Labor	
0330W: NGS Construction	257414: PI Maint-Craft Aug	711146: Prod Lab-Attrit (frmly taxes)	
0330W: NGS Construction	257414: PI Maint-Craft Aug	711150: Premium Time	
0330W: NGS Construction	257414: PI Maint-Craft Aug	711190: Overtime	
0330W: NGS Construction	257414: PI Maint-Craft Aug	711275: Other Comp- Welfare Fund	
0480A: Operations	257422: PI Shift Operations	711150: Premium Time	
0480A: Operations	257422: PI Shift Operations	711190: Overtime	
0480D: PI Plant Management	257412: PI Maint - I&C	711150: Premium Time	
0480D: PI Plant Management	257412: PI Maint - I&C	711190: Overtime	
0480E: Engineering	257411: PI Maint - Electrical	711150: Premium Time	
0480E: Engineering	257411: PI Maint - Electrical	711190: Overtime	
0480M: Maintenance	257410: PI Maint - Mechanical	711150: Premium Time	
0480M: Maintenance	257410: PI Maint - Mechanical	711190: Overtime	
0480R: PI Maint Fac-Union	257415: PI Maint - Facilities	711142: Productive Labor	
0480R: PI Maint Fac-Union	257415: PI Maint - Facilities	711146: Prod Lab-Attrit (frmly taxes)	
0480R: PI Maint Fac-Union	257415: PI Maint - Facilities	711150: Premium Time	
0480R: PI Maint Fac-Union	257415: PI Maint - Facilities	711190: Overtime	
45601: FT PI Administration Services	257461: PI Administration Svcs	711150: Premium Time	
45601: FT PI Administration Services	257461: PI Administration Svcs	711190: Overtime	
45603: FT PI Chemistry	257406: PI Chemistry	711190: Overtime	
45604: FT PI Emergency Planning	257463: PI Emergency Planning	711190: Overtime	
45608: FT PI Eng Prog-Equip Rlbility	257451: PI Eng Prog - Equip Rel P	711190: Overtime	
45609: FT PI Eng Prog-Insp&Materials	257452: PI Eng Prog - Insp&Mtrls	711190: Overtime	
45610: FT PI Engineering Systems	257443: PI Engineering Systems	711190: Overtime	
45611: FT PI Engineering Systems-BOP	257446: PI Eng Systems - BOP	711190: Overtime	
45612: FT PI Eng Systems-Elec/I&C	257445: PI Eng Systems - Elec/I&C	711190: Overtime	
45613: FT PI Eng Support	257447: FT PI Eng Support	711190: Overtime	
45614: FT PI Eng Dsgn-Conf Cntrl	257456: PI Eng Des -Config Contr	711190: Overtime	
45616: FT PI Eng Nuc Safety Systems	257444: FT PI Eng Nuc Safety Systems	711190: Overtime	
45619: FT PI Licensing	257437: PI Licensing	711190: Overtime	
45621: FT PI Maint-Electrical	257411: PI Maint - Electrical	711190: Overtime	
45622: FT PI Maint-Instr&Cntrl	257412: PI Maint - I&C	711190: Overtime	
45623: FT PI Maint-Mechanical	257410: PI Maint - Mechanical	711190: Overtime	
45624: FT PI Maint-Support	257413: PI Maint - Support	711190: Overtime	
45625: FT PI Maint-Facilities	257415: PI Maint - Facilities	711190: Overtime	
45626: FT PI Operations Support	257423: PI Operations Support	711190: Overtime	
45627: FT PI Outage	257427: PI Outage	711190: Overtime	
45628: FT PI Performance Improvement	257404: PI Perform Improvement	711190: Overtime	
45629: FT PI Planning	257416: PI Planning	711190: Overtime	
45630: FT PI Plant Management	257405: PI Plant Management	711190: Overtime	
45631: FT PI Procedures/Doc Control	257459: PI Doc Control/Procedures	711150: Premium Time	
45631: FT PI Procedures/Doc Control	257459: PI Doc Control/Procedures	711190: Overtime	
45633: FT PI Rad Protection-Opns	257419: PI Rad Prot-Operations	711150: Premium Time	
45633: FT PI Rad Protection-Opns	257419: PI Rad Prot-Operations	711190: Overtime	
45634: FT PI Radiation Protection	257417: PI Rad Protection	711190: Overtime	
45635: FT PI Radiation Protectn Spprt	257418: PI Rad Prot - Support	711150: Premium Time	
45635: FT PI Radiation Protectn Spprt	257418: PI Rad Prot - Support	711190: Overtime	
45636: FT PI Scheduling	257428: PI Scheduling	711190: Overtime	
45637: FT PI Security	257465: PI Security	711150: Premium Time	
45637: FT PI Security	257465: PI Security	711190: Overtime	
45638: FT PI Shift Operations	257422: PI Shift Operations	711190: Overtime	
45641: FT PI Work Control	257424: PI Work Control Center	711190: Overtime	
45642: FT PI Quality Assurance/NOS	257402: PI Quality Assurance/NOS	711190: Overtime	
45643: FT PI Safety & Health	257425: PI Safety & Health	711190: Overtime	
45644: FT PI Quality Control	257403: PI Quality Control	711150: Premium Time	
45644: FT PI Quality Control	257403: PI Quality Control	711190: Overtime	
45645: FT PI Employee Concerns Prog	257401: PI Employee Concerns Prog	711190: Overtime	
45647: FT PI Eng Design-Support	257457: PI Eng Design - Support	711190: Overtime	
45649: FT PI Training-Operations	257432: PI Training - Operations	711190: Overtime	
45650: FT PI Training-Technical	257433: PI Training - Technical	711190: Overtime	
45651: FT PI Training-Maint	257434: PI Training - Maint	711190: Overtime	
45652: FT PI Training-Simulator	257435: PI Training - Simulator	711190: Overtime	
45653: FT PI Training-Support	257436: PI Training - Support	711190: Overtime	
45654: FT PI Chemistry-Support Staff	257407: PI Chemistry-Tech Sup	711150: Premium Time	
45654: FT PI Chemistry-Support Staff	257407: PI Chemistry-Tech Sup	711190: Overtime	
45655: FT PI Chemistry-Operations	257408: PI Chemistry -Operations	711150: Premium Time	
45655: FT PI Chemistry-Operations	257408: PI Chemistry -Operations	711190: Overtime	
45656: FT PI Eng FIN	257440: FT PI Eng FIN	711190: Overtime	
45657: FT PI Eng Reactor Systems	257442: FT PI Eng Reactor Systems	711150: Premium Time	
45657: FT PI Eng Reactor Systems	257442: FT PI Eng Reactor Systems	711190: Overtime	
45658: PI Project Mgmt Office	257429: PI Project Mgmt Office	711150: Premium Time	
45658: PI Project Mgmt Office	257429: PI Project Mgmt Office	711190: Overtime	
Grand Total			
			TRADE SECRET ENDS]

2015 Nuclear Business Unit Scorecard for AIP

Strategic Call To Action	*Key Performance Indicator*	*2014 YE Actual*	*Threshold*	*Target*	*Maximum*	*Weight*
Safety	OSHA Recordable Incident Rate (Xcel Employees Only)	0.25	0.26	0.19	0.13	10%
Operational Excellence	NRC ROP	1.7	2.0	1.3	1.0	15%
	INPO Index	79.5	82.9	86.4	88.1	15%
	INPO Plant Performance Index	77	77	80	83	15%
	Outage Duration	PI Unit 1 44 days	38 days	34 days	30 days	15%
Cost Competitiveness	PTT Index	New	50%	100%	150%	15%
	Capital Budget and Schedule Adherence	104 Pts	50 Pts	100 Pts	150 Pts	10%
	Operational Excellence Savings	New	$9.73ML	$11.45ML	$13.17ML	5%
						100.0%

PTT Index	*Weight*
On Budget - Variance to Plan Per Phase	25%
On Time - Milestone Achievement	25%
Solution Simplification - Change/Customization requests	25%
Business Transformation - Management Commitment	25%

Definitions

OSHA Recordable Incident Rate (Xcel Employees Only)	The OSHA Injury Rate will be the total number of validated OSHA recordable injuries that occur at Monticello, Prairie Island and Marquette Plaza (headquarters) for Xcel employees working for the Nuclear Department related to a common exposure of 100 full-time workers. (Calculation = Number of OSHA Recordable Cases x (100 x 2000) / Annual Hours Worked). The factor is based on 2 injuries for Xcel Employees for Maximum, 3 injuries for Target, and 4 injuries for Threshold. Our actual injuries: 2013 - 6 and 2014 - 4
NRC ROP	The NRC utilizes the Action Matrix as a graded approach to address plant performance issues. The Action Matrix consists of five regulatory response columns. Plants in Column 1 (Licensee Response) receive the minimum "baseline" set of inspections because their violations are minor. Plants in Column 2 (Regulatory Response) have a single finding of low or moderate safety significance and receive a supplemental inspection. If the performance decline persists, reactors can move into the Degraded Cornerstone Column, the Multiple/Repetitive Degraded Cornerstone Column, and finally the Unacceptable Performance Column. The NRC's level of oversight and complexity of inspections escalates as plants transition through the columns. In addition to the Action Matrix, the NRC also assigns a cause to all violations identified by the NRC. These causes are known as "cross-cutting aspects" because they are plant behaviors that often cut across all plant departments. When a plant experiences an increased number of violations with a common cause they will assign a Substantive Cross Cutting Issue in that area which indicates a potential plant safety culture issue.
INPO Index	A performance indicator formulated by the Institute of Nuclear Power Operators (INPO) that tracks overall plant performance in the industry. The index is calculated using a weighted combination of plant performance indicators and has a value between 0 and 100. The higher the index the higher the performance. The plant performance measures included in the index are unit capability factor, INPO forced loss rate, forced loss events, unplanned weighted manual and automatic shut downs, safety system performance, loss shutdown cooling/decay heat removal events, fuel reliability defect, collective radiation exposure, chemistry effectiveness, and total industrial safety accident rate. The majority of these measures are used over the period between refuel outages, so for PI the measure would an 18 month rolling and for Monticello, a 24 month rolling.
INPO Plant Performance Index	PPI is an INPO tool intended to identify trends and monitor station performance between evaluations. PPI is a mathematical model of a stations performance that uses approximately 120 currently reported Plant Information Center (PIC) indicator data points. The data populates four sub-models in the areas of equipment, operational focus, events, and organizational effectiveness. These four sub-models are input into a master model, which calculates PPI, from which INPO generates performance trend graphs. The PPI is determined quarterly. Due to the 50 day delay in publication of the PPI data the year end goal is based on 3rd quarter 2015 results.
Outage Duration	Outage duration is defined as the generator output breaker open for start of the refueling outage until the output breaker is closed for power ascension for the subsequent unit operating cycle.
PTT Index	This measure aligns to the other Xcel Energy business units and measures the nuclear support of the project. The idex includes 4 parts, On budget, On schedule, Customization Requests, and our ability to accept the changes.
Capital Budget and Schedule Adherence	The Project Performance Index is a measure of in-servicing mandatory, strategic and equipment reliability projects to improve plant operations. The indicator will measure the success of in-servicing projects identified (or substituted) at each station on-schedule and on-budget. The emphasis of this KPI will be on the top priority projects for Monticello and Prairie Island that are relate to the 2014 MN Rate Case. Completing the committed projects in 2015 is key. The Target of 100 points is a stretch due to the complexity of projects for Fukishima during both the Monticello and Prairie Island refueling outage, and the step up generator project at PI also during the outage.
Operational Excellence Savings	Stated in Millions of dollars, this measure captures supply chain savings, contract administration savings, Fleet PTT savings, Material savings, and PTT early release savings. Nuclear is estimating $11.45ML in supply chain savings and $0.02 in Fleet PTT savings. This is aligned with all other Xcel Energy Business Units.

NRC Oversight and Performance Ratings

NRC Reactor Oversight Process (ROP) and Action Matrix

The NRC has instituted a Reactor Oversight Process (ROP) to evaluate the safety and security performance of the nuclear power reactors in the U.S.[1] The NRC's ROP uses seven "cornerstones" to describe the essential features of its strategic performance areas: reactor safety, radiation protection, and security[2]. Performance in these cornerstones is assessed on a quarterly basis using nearly 20 discrete performance indicators reported by the reactor owners, supplemented by findings from NRC inspections. The link between the assessment component of the ROP and mandated NRC responses is called the Action Matrix.

The Action Matrix features five columns of performance, as rated by the NRC:

- **Column I** - When the performance indicators and inspection findings all fall in expected ranges, a reactor is placed in Column I, or "Licensee Response," reflecting the fact that the licensee takes responsibility for addressing these minor problems and the NRC continues with its normal inspections.
- **Column II** - If performance in a cornerstone drops a little below expectations, the reactor moves into Column II "Regulatory Response," reflecting the fact that the NRC now responds by increasing inspections.
- **Column III** - If performance drops further in a cornerstone or declining performance is detected in another cornerstone, a reactor moves into Column III, "Degraded Cornerstone," where the ROP mandates additional NRC inspections.
- **Column IV** - If declining performance deepens and/or broadens, a reactor moves into Column IV, "Multiple/Degraded Cornerstone," where the NRC takes further action.
- **Column V** - If performance problems reach epidemic proportions, a reactor enters Column V, "Unacceptable Performance," and is shut down by the NRC.

[1] The NRC has summarized its *Reactor Oversight Process* in a diagram included as Attachment A.

[2] The NRC's cornerstones are listed on Attachment B, the NRC's *Regulatory Framework*.

NRC Ratings for Inspection Findings and Performance Reviews

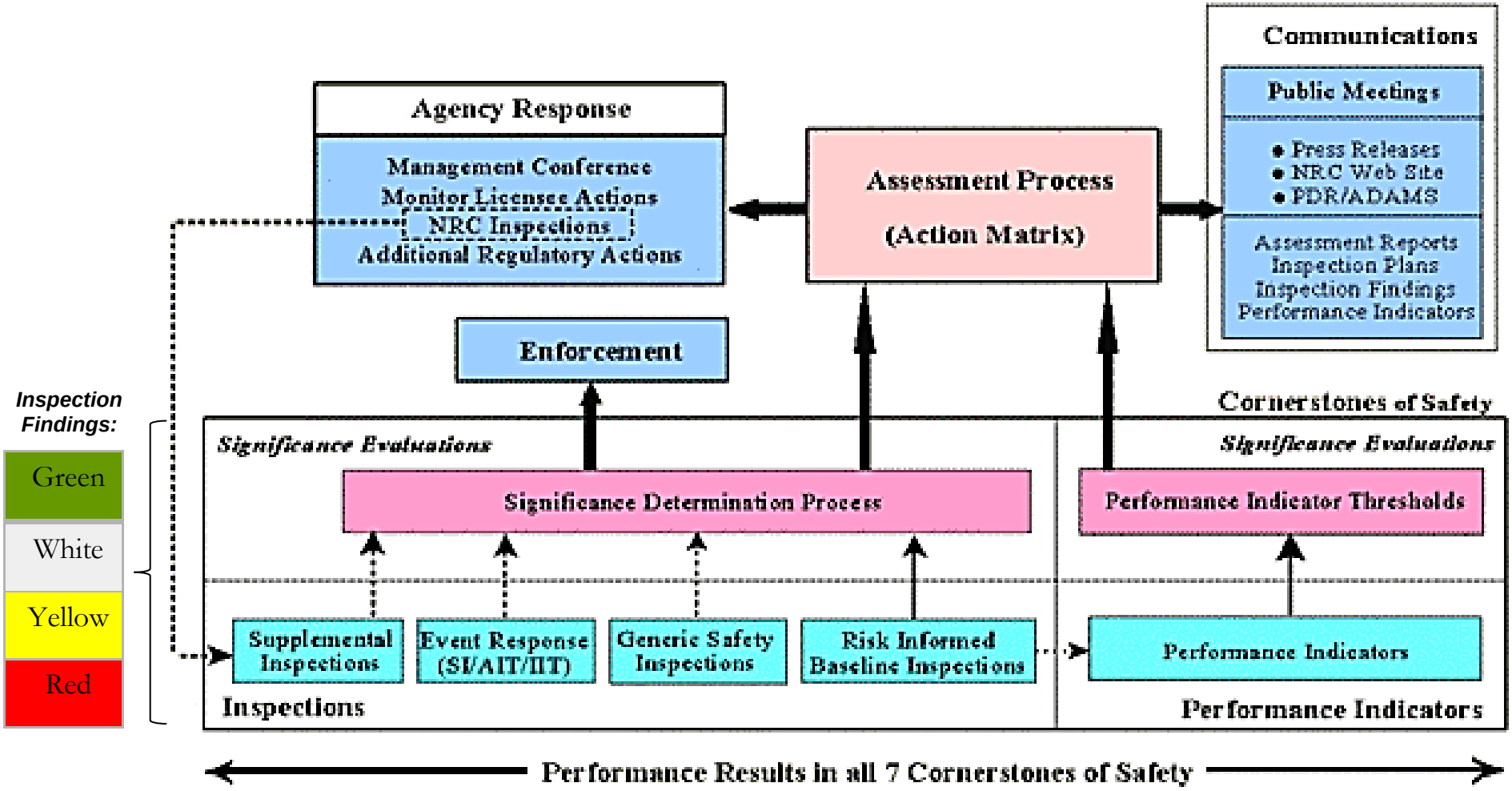
The NRC uses a color-coding scheme to rank the level of concern for issues it identifies for nuclear operators, either through inspections or through review of quarterly performance reporting. These rankings range as follows:

- **Green** - lowest level of concern
- **White** – second lowest level of concern
- **Yellow** – second highest level of concern
- **Red** - highest level of concern

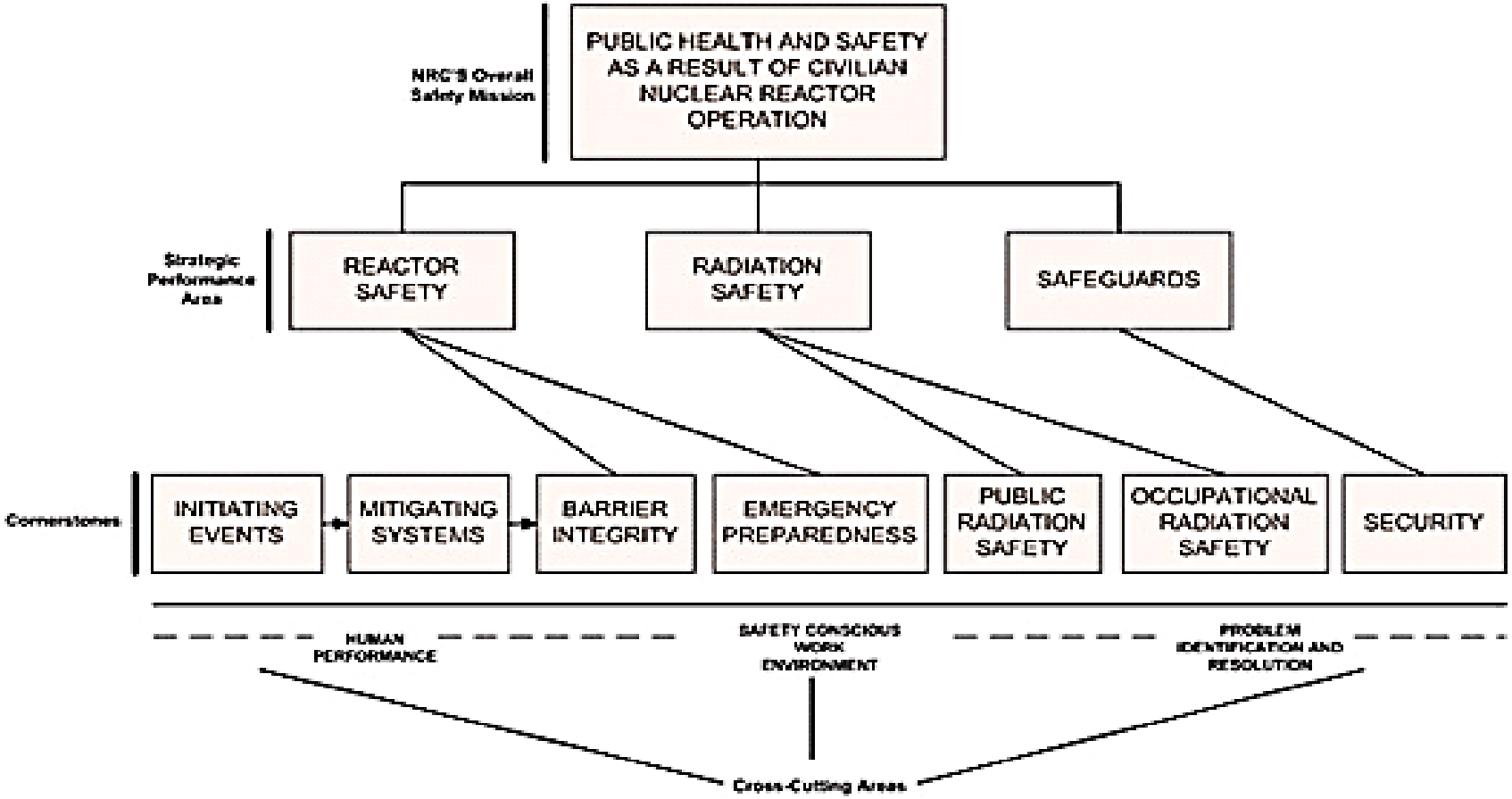
The number and severity of issues identified for a plant unit at a point in time determine its Column rating under the ROP Action Matrix. For example, if only green (lowest level) issues are outstanding, the unit remains at Column I. If a single white finding/issue is outstanding, the unit is moved to Column II and requires more NRC oversight and inspections until the issue is considered resolved, or "closed". If multiple white findings, or a single yellow finding, is outstanding, the unit is moved to Column III, with more oversight and inspections, and so on.

The column status of a nuclear unit remains in place for each calendar quarter, and is only moved upward (i.e. from II to I) at the beginning of the next quarter after an outstanding issue is closed by the NRC. Column status can moved downward (e.g. from I to II) immediately when an issue is officially determined by the NRC to be outstanding. The NRC has an appeals and review process for operators to challenge a proposed inspection or performance review finding, including conferences, public hearings and other procedures. The NRC does not announce the official change in column status for a unit until after this process concludes.

NRC's
REACTOR OVERSIGHT PROCESS



NRC's
REGULATORY FRAMEWORK



Continuing Accountability and Performance Results for 2012-2013 KPIs (that appeared to be eliminated from the following year's AIP Scorecard)

Initial KPI & Year included in Nuclear Scorecard	Is there a KPI in 2013 that includes this item?	Is there a KPI in 2014 that includes this item?	Is there a KPI in 2015 that includes this item?	Has Satisfactory Performance Been Achieved Yet? (If so, Year)	Handling of KPI in Subsequent Year's Nuclear Scorecard	Performance Improvement Status/Results since initial year in Nuclear Scorecard (through 2015)
A. Operational industry performance gaps that improve safe and reliable generation						
2012 Equipment Reliability Index	YES	YES as part of 3/2/1 tiles	YES See column at far right	NO for PI, YES for Monti (2015)	These initiatives were measured in 2013 and 2014 KPIs in 3/2/1 tiles for Machine Performance, Safety Systems, and Independent Assessments.	Measured in 2015 KPIs via the INPO index and INPO Plant Performance Index. Not meeting target objectives at mid-year 2015 due to equipment issues at Prairie Island early in year. Year-end 2015 results are not expected to reach target, and may not meet minimum levels. Consequently, Equipment Reliability will continue as a focus area in 2016 scorecard.
2012 Safety System Performance	YES	YES as part of 3/2/1 tiles	YES See column at far right	NO for PI, YES for Monti (2015)		
2013 3/2/1 Performance Tiles	N/A – this is 2013 item	YES as part of 3/2/1 tiles	YES See column at far right	YES for most areas, NO for some areas		
2013 Closing industry performance gaps (INPO AFIs) % closed or on track	N/A – this is 2013 item	YES as part of 3/2/1 tiles	YES See column at far right	NO – both stations are still seeking higher INPO ratings/indices		
B. Nuclear Regulatory Commission – rebuild confidence and building regulatory margin						
2012 NRC Findings & Violations – Self Identified	YES	YES as part of ROP	YES See column at far right	YES (2015)	The 2012 measure is a subset of the NRC Reactor Oversight (ROP) process, which was a 2013 KPI. This initiative was also measured in 2014 3/2/1 Regulatory Margin tile.	Measured in 2015 via NRC ROP KPI. Although we are meeting/ exceeding our performance objectives and sustaining, these measures will continue in the 2016 scorecard as we try to build more regulatory margin.
2013 NRC Performance (ROP)	N/A – this is 2013 item	YES as part of 3/2/1 tiles	YES See column at far right	YES (2015)		

Continuing Accountability and Performance Results for 2012-2013 KPIs (that appeared to be eliminated from the following year's AIP Scorecard)

Initial KPI & Year included in Nuclear Scorecard	Is there a KPI in 2013 that includes this item?	Is there a KPI in 2014 that includes this item?	Is there a KPI in 2015 that includes this item?	Has Satisfactory Performance Been Achieved Yet? (If so, Year)	Handling of KPI in Subsequent Year's Nuclear Scorecard	Performance Improvement Status/Results since initial year in Nuclear Scorecard (through 2015)
C. Improved planning and execution of capital projects and planned outages - both schedule and cost						
2012 Project & Outage Performance	YES	YES See 2 next items below	YES See column at far right	YES for projects (2014), NO for outage	These KPIs focus on the predictability of executing projects on time/budget and the ability to return the units to service with high reliability for customers. Capital initiative was measured in 2014 by Capital Project In-Service Dates and Decision Making KPI. Outage not a KPI in 2014 (but was in 2015)	Projects - We are meeting performance objectives with our capital projects. We continued measuring in 2015 via Capital Budget and Schedule adherence KPI. Outage - Measured in 2015 via Outage Duration KPI, but we are not yet meeting performance objectives for outage duration. Consequently, Outage will continue as a focus area in 2016.
2013 Outage Preparation & Execution	N/A – this is 2013 item	NO – replaced with 3/2/1 goals for 2014 only	YES See column at far right	NO		
2013 Capital Performance Index	N/A – this is 2013 item	YES See column at right	YES See column at far right	YES (2014)		
D. Keeping our costs competitive and with low rate of growth						
2013 Nuclear Supply Chain Savings	N/A – this is 2013 item	YES Fuel contract savings part of Cost per Mwh initiative	YES See column at far right	YES (all years)	This initiative was measured in 2014 as part of KPIs for Cost per MWh initiatives and Sustainability Pipelines 3/2/1 tile.	Meeting and sustaining performance objectives in all years. Measured in 2015 via Operational Excellence KPI.
E. Protecting employees and the public from radiation exposure						
2013 Collective Radiation Exposure	N/A – this is 2013 item	NO – goal was met	NO – goal was met	YES (2013-14)	Still monitored but not as a separate KPI.	Meeting and sustaining performance objectives in all yrs

INPO – "ABOUT US" From Their Website as of 9/22/2015

Our Mission

Our mission at the Institute of Nuclear Power Operations (INPO) is to promote the highest levels of safety and reliability – to promote excellence – in the operation of commercial nuclear power plants.

We work to achieve our mission by:

- Establishing performance objectives, criteria and guidelines for the nuclear power industry
- Conducting regular detailed evaluations of nuclear power plants
- Providing assistance to help nuclear power plants continually improve their performance

What We Do

INPO employees work to help the nuclear power industry achieve the highest levels of safety and reliability – excellence – through:

- Plant evaluations
- Training and accreditation
- Events analysis and information exchange
- Assistance

These are the four cornerstones of INPO.

Plant Evaluations

INPO evaluation teams travel to nuclear electric generating facilities to observe operations, analyze processes, shadow personnel, and ask a lot of questions.

With an intense focus on safety and reliability, our evaluation teams assess the:

- Knowledge and performance of plant personnel
- Condition of systems and equipment
- Quality of programs and procedures
- Effectiveness of plant management

Additionally, INPO conducts corporate evaluations that are also focused on safety and reliability.

Training and Accreditation

Our National Academy for Nuclear Training provides training and support for nuclear power professionals.

Nuclear professionals from across the United States – and throughout the world – attend training at the INPO facility in Atlanta and take the various online courses offered by INPO.

In addition, we evaluate individual plant and utility training programs to identify strengths and weaknesses and recommend improvements. Selected operator and technical training programs are accredited through the independent National Nuclear Accrediting Board.

INPO – "ABOUT US" From Their Website as of 9/22/2015

Events Analysis and Information Exchange

INPO assists in reviewing any significant events at nuclear electric generating plants.

Through INPO information exchange and publications, we communicate lessons learned and best practices throughout the nuclear power industry.

Assistance

At the request of individual nuclear electric generating facilities, INPO provides assistance with specific technical or management issues in areas related to plant operation and support.

Our Values

Our values at INPO are the foundation of all that we do professionally and personally.

- Excellence – make it better
- Perseverance - there is no finish line
- Leadership – make things happen
- Relationships – knock down walls and build bridges
- Integrity – we are what we say and do

Our History

Established by the nuclear power industry in December 1979, the Institute of Nuclear Power Operations is a not-for-profit organization headquartered in Atlanta.

The Kemeny Commission – set up by President Jimmy Carter to investigate the March 1979 accident at the Three Mile Island (TMI) nuclear power plant – had recommended that:

- The (nuclear power) industry should establish a program that specifies appropriate safety standards including those for management, quality assurance, and operating procedures and practices, and that conducts independent evaluations.
- There must be a systematic gathering, review, and analysis of operating experience at all nuclear power plants coupled with an industry-wide international communications network to facilitate the speedy flow of this information to affected parties.

In addressing those recommendations, the nuclear power industry:

- Established INPO – the Institute of Nuclear Power Operations
- Charged INPO with a mission that we continue to pursue today:
  - ***To promote the highest levels of safety and reliability – to promote excellence – in the operation of commercial nuclear power plants.***

INPO – "ABOUT US" From Their Website as of 9/22/2015

Our Future

Today the U.S. nuclear industry and INPO can be proud of their decades-long partnership. The industry's record of progress—in virtually every aspect of safety and reliability— demonstrates how much has been achieved since the TMI accident. Performance indicators reflect significant industry progress in many areas.

But while this hard-earned success is well deserved, the special nature of nuclear technology reminds us that our industry is always judged against the highest of standards. We cannot stand still or think we have accomplished enough, especially at a time when our industry is undergoing rapid change.

This is an exciting time to be a part of the nuclear industry, and a part of INPO. The industry is poised to begin building new plants. Another change is the increasingly global nature of the nuclear business. Additionally, our newest nuclear professionals—younger and more diverse—bring with them great enthusiasm and a fresh perspective that can benefit INPO and the industry.

INPO is preparing its workforce of the future. Founded in 2008, INPO's chapter of North American Young Generation in Nuclear provides opportunities for young nuclear professionals at INPO and throughout the industry to participate in knowledge transfer, networking and professional development events.

INPO - From Wikipedia, the free encyclopedia Sept. 22, 2015

Institute of Nuclear Power Operations

The **Institute of Nuclear Power Operations** (INPO), headquartered in Atlanta, GA, is an organization established in 1979 by the U.S. nuclear power industry in response to recommendations by the Kemeny Commission Report, following the investigation of the Three Mile Island accident. INPO sets industry-wide performance objectives, criteria, and guidelines for nuclear power plant operations that are intended to promote operational excellence and improve the sharing of operational experience between nuclear power plants. INPO is funded entirely by the U.S. nuclear industry.

INPO conducts plant evaluations at nuclear stations and identifies both strengths and areas for improvement that are intended to be shared with other nuclear stations as a method to share best practices and common weaknesses. The results of INPO plant evaluations are not shared with the public and any related information shared within the nuclear industry does not typically include the name of the plant. INPO assigns a score between one and four to each nuclear site following the evaluation, where an "INPO 1" is the most favorable score, and an "INPO 4" is an indicator of a nuclear station with significant operational problems.

The INPO Advisory Council consists of leading experts from the nuclear industry, as well as others whose expertise is relevant to the safe operation of nuclear power plants. Advisory Council members have included Dr. Edgar H. Schein, a retired MIT professor who is widely credited with inventing the term "corporate culture;" and Dr. Rodger Dean Duncan, a thought leader in organizational development and human performance.

Nuclear Ops Discovery - 2016 Electric Rate Case
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Docket No. E002/GR-15-826
Exhibit___(TJO-1), Appendix A

Case No.	Party	IR No.	Description	Addressed in 2016 TY Case
12-961	DOC	139-I	Capital Projects Reference: Budgeted capitalized nuclear fuel expenditures.	TJO-Direct on pages 109, 119 and 130. Also see Chart 2 & Schedule 5.
12-961	DOC	140-I	Provide the actual nuclear fuel capital expenditures for the last test year (2014) and most recent actual (2015) costs.	TJO-Direct, Schedule 5, Table NF-1. Also see Chart 2 and TJO Schedule 5 for 2016-2018 budgeted amounts.
12-961	DOC	152-A	Operating and Maintenance (O&M) expense for nuclear Non-Outage Costs. The Direct Testimony of Timothy J. O'Connor at Table 6 provides nuclear non-outage O&M costs for 2012-14 actual costs, 2015 forecast, and 2016 test year budget costs and average percentage of change from most recent actual (2014) to test year (2016) and average change per year for the period 2014-2016. Please provide the same information and same format as columns 1 and 2 of Table 5 for 3 most recently completed years (2012, 2013 and 2014) 2010 actual, 2011 test year, 2012 actual costs (if actual costs are not yet available please provide actual through 3rd quarter plus budget for 4th quarter with a break out of the actual and budgeted costs).	Non-outage O&M summary 2012-2014 (actuals), 2015 (forecast) and 2016 (test year budget) are provided in TJO-Direct Schedule 6, including average change per year for periods 2012-2014 and 2014-2016. Budget for last rate case test year 2014 is also provided on Schedule 6.
13-868	DOC	1137	Nuclear Capital Spending Trend - Please provide all nuclear capital expenditure budget amounts for 2016 through 2018 and all actual nuclear capital expenditures for 2012 to 2014, and all test year approved amounts for nuclear capital expenditures for 2012, 2013 and 2014, plus 2015 forecast for nuclear capital expenditures. B. Clarify if the amounts that represent the nuclear capital expenditures on a Total Company NSPM or Minnesota electric jurisdictional basis. Also indicate if the amounts include AFUDC.	Section III Tables 2 & 3
13-868	DOC	1153	O&M Expenses for Non-Outage -- Please include the following: 2012-2013 actuals, 2014 test year budget requested, 2014 acutal, 2015 test year forecast and 2016 test year budget.	Section IV Schedule 6
13-868	DOC	1155	Nuclear Headcount/Labor -- Provide the nuclear headcount and labor $ associated with the headcount for 2012 to 2014 actuals, 2015 forecast and 2016 budget. B. Please explain reasons for headcount and labor increases for the period 2012 to 2016.	Section IV Table 7 & Schedule 6
13-868	DOC	1163	uclear Fees & Dues - A. Please include 2013-2014 actuals, 2014 test year budget, 2015 forecast and 2016 test year budget B. Please provide percentage differences between each year and the respective prior year.	Section IV Tables 8, 9 & 10

Nuclear Ops Discovery - 2016 Electric Rate Case
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Case No.	Party	IR No.	Description	Addressed in 2016 TY Case
13-868	DOC	1164	Security Increase -- Please provide the actual security costs for 2014, forecasted costs for 2015, and 2016 test year.	Sections II, III & IV, Tables 7 & 11 and Schedule 6
13-868	DOC	1165	Outage Costs -- A. Compare the average cost per day for each outage by plant/unit over time, and explain significant differences in outage length and cost per day between years for each plant /unit, for the years 2014-2016. B. The outage costs on Table 12 are on a Total Company NSP basis; C. The updated Monticello/Spring and PI Unit 2/Fall 2015 outages; the PI Unit 1/Fall 2014 outage for actual total outage costs and duration, and 2016 amortization for PI Unit 1; and D. O&M Outage Forecasts for 2017-2018	Section V Tables 12, 13, 14 & 15 Schedules 8, 9 and 10
13-868	MCC	217	Xcel Energy's nuclear performance goal scorecard for 2015 -- Show a breakdown into various key performance areas. Please show where project cost control is included, the person with overall cost control responsibility, and the consequences of a project running over the approved budget.	Section VI Schedules 11, 12 and 13
13-868	MCC	230	Explain the major capital projects added to Nuclear's rate base and related investments for 2016-2018.	Section III Table 5