Direct Testimony and Schedules
J.A. Stall

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns

Docket No. E002/CI-13-754
Exhibit___(JAS-1)

Project Scope and Design

October 18, 2013

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I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is J.A. (Art) Stall. My address is 1803 SW Foxpoint Trail, Palm City, Florida 34990.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I earned my Bachelor of Science degree in nuclear engineering from the University of Florida in 1977. I also earned a Master's degree in Business Administration from Virginia Commonwealth University in 1983.

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

A. I am currently a consultant for Northern States Power Company, a Minnesota corporation ("Xcel Energy" or "the Company"). I previously worked for Florida Power & Light ("FPL") Group, Inc. (nka NextEra) as President, FPL Group Nuclear, and in other nuclear positions for NextEra's subsidiaries.

Q. WHAT WERE YOUR PREVIOUS DUTIES IN THE NUCLEAR POWER INDUSTRY?

A. I am a career nuclear professional with approximately 35 years of nuclear operating experience. I joined Virginia Power Company in 1977, where I held various positions of increasing responsibility, including superintendent of operations, assistant station manager for safety and licensing, superintendent of technical services, and plant manager at the North Anna nuclear plant. I also held a senior nuclear reactor operator license from the U.S. Nuclear Regulatory Commission ("NRC") while working at Virginia Power Company's nuclear plants. In 1996, I joined FPL as the Site Vice President at the St. Lucie Nuclear Plant. From 2000 to 2001, I was Vice President for Nuclear

Engineering at FPL. I was named Senior Vice President, Nuclear Operations, and Chief Nuclear Officer ("CNO") at FPL in June 2001, and in 2008, I was named Executive Vice President, Nuclear Operations, and Chief Nuclear Officer. In these positions, I was responsible for the day-to-day operations of all of FPL and NextEra Energy Resources' nuclear plants.

In January 2009, I was named President, FPL Group Nuclear, reporting directly to the Chief Executive Officer. In that position, I was responsible for the overall strategic direction for the eight nuclear units owned and operated by FPL. Four of these units are in Florida (two at Turkey Point Nuclear Plant and two at St. Lucie Nuclear Plant), and four of these units are located outside of Florida – one unit at Seabrook station in Seabrook, New Hampshire; one unit at Duane Arnold Energy Center in Palo, Iowa; and two units at Point Beach Nuclear Plant in Two Rivers, Wisconsin. I also oversaw the operation of those units and supervised the development and implementation of major capital projects associated with those units.

On May 1, 2010, I retired from FPL. I continue to provide consulting services to FPL and periodically consult for other utilities. I am also a member of the National Nuclear Academy Accrediting Board of the Institute of Nuclear Power Operations ("INPO").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review Xcel Energy's life-cycle management and extended power uprate ("LCM/EPU") initiative at its Monticello Nuclear Power Plant and to compare Xcel Energy's experiences and the outcomes achieved with my own experiences and other experiences of which I am aware in the industry. I will describe challenges facing the nuclear industry in pursuing these programs, including recent industry events, the evolution of NRC regulation, and the increasing difficulty in work force management in connection with major capital projects like the LCM/EPU initiative.

II. SUMMARY OF AND BASIS FOR OPINIONS

A. Summary of Opinions

Q. HAVE YOU FORMED OPINIONS ABOUT XCEL ENERGY'S LCM/EPU INITIATIVE?

A. Yes I have. I will provide a summary of my opinions here. The basis for those opinions and related discussion about Xcel Energy's LCM/EPU initiative are contained in subsequent sections. I have attempted to structure the remainder of my testimony around the opinions stated here.

Q. PLEASE STATE YOUR SUMMARY OF OPINIONS.

A. First, it is my professional opinion that in major capital projects at a commercial nuclear plant the number one consideration is nuclear safety and ensuring the safety of plant workers, neighboring communities, utility customers, and the general public.

- My review indicates that Xcel Energy kept nuclear safety considerations as a primary driver of the scope and design of the work they undertook.

- It is a reality of the nuclear business that (i) nuclear safety considerations drive the scope of work to be undertaken; (ii) the scope of work drives the design; and (iii) design considerations drive the cost of installation to implement the chosen scope.

- In addition, the safety-first culture in the industry, based on NRC regulations, is not discretionary and requires a nuclear license-holder, such as Xcel Energy, to resolve all issues consistent with the safety-first obligations without regard to economic considerations.

Second, it is my professional opinion that the scope and design for both the life extension and uprate aspects of Xcel Energy's initiative were both reasonable and prudent.

- Safety and NRC compliance considerations required Xcel Energy to undertake an expanded scope of work and upgrade or replace more systems than expected at the early stages of the project.

- The design decisions made during the project were driven to substantially improve the performance of the plant, strengthen safety margins and maximize the plant's potential for operation through 2030. These decisions led to increased costs.

- Xcel Energy's scope choices were an important reason why the overall initiative cost more than the initial estimates. Xcel Energy chose a large scope of work so it is not surprising that the cost would be high. Some replacements were a matter of simple use of components Xcel Energy knew needed to be replaced. Other replacements were determined to be necessary as the design process progressed and we learned that the some systems were more worn than Xcel Energy had foreseen. Still other modifications were driven by key design decisions to support the uprate and ensure enhanced reliability through 2030.

- In reviewing the alternatives, I conclude that Xcel Energy made appropriate scope choices and design decisions that led to improved nuclear safety and operational performance of the plant.

Third, in my professional opinion, the scope of work ultimately implemented by Xcel Energy was appropriate to serve the twin goals of LCM upgrades to support an additional 20 years of operation and the EPU upgrades to support the uprate.

- It would have been highly inefficient if Xcel Energy focused narrowly on the uprate tasks without regard to life extension tasks because Xcel Energy would still have had to replace many systems on the basis of applicable nuclear safety, aging management, and reliability considerations.

- By including upgrades that were designed to enhance overall reliability of the plant through 2030, Xcel Energy incurred some costs sooner than it might otherwise have done without the EPU, but by combining LCM and EPU work, it achieved a more efficient result than had these modifications been pursued at separate times..

- Aging plant considerations drove many of the costs incurred by Xcel Energy. The scope of the work installed was not in excess of what would otherwise have been required over the planned life of the plant. Future work was avoided by utilizing this strategy.

Fourth, in my professional opinion, the quality of the design of the life extension aspects of Xcel Energy's initiative is evidenced by the successful implementation of all of the modifications at the end of the 2013 refueling outage. Only four relatively minor difficulties or refinements are outstanding.

- Despite the difficulties, Xcel Energy obtained a valid and valuable refurbishment of key systems and equipment important to nuclear safety in the 40-year-old Monticello plant for an overall price that is consistent with costs incurred elsewhere.

- Xcel Energy was able to increase and restore margins and enhance systems necessary to enhance reliable long-term operation.

- The successful restart to the pre-uprate power level had relatively few issues of concern relating to the initiative, and is indicative of a successful project that demonstrates industry lessons-learned were applied.

Q. ARE YOU PROVIDING OPINIONS ABOUT THE INSTALLATION OF XCEL ENERGY'S PROGRAM?

A. I was not asked to review the specifics of the implementation effort or the management of the implementation, but I am generally familiar with Xcel Energy's installation effort. I can provide some broad observations based on my industry experience that may be relevant to the Commission in assessing Xcel Energy's performance in installing the upgrades.

- I evaluated the overall costs of the Xcel Energy project and I am not surprised by them. Based on my own experience, EPU costs at FPL doubled from what was initially expected and it took more time than anticipated to complete the upgrades. It is to be expected that as the project scope increases, implementation costs and challenges increase accordingly. In an initiative of this type and magnitude it is not reasonable to expect that the operator can foresee all of the work that may need to be done.

- During EPU implementation, often additional work packages will need to be completed to addressed issues that are uncovered as design is completed and work unfolds.

- Many of the issues Xcel Energy encountered are the same as I encountered in my work. Difficulties with vendors and workforce efficiency are a normal part of major capital projects at a nuclear plant.

- The entire industry is experiencing an aging workforce and an overall lack of qualified personnel. The difficulties that Xcel Energy personnel described to me in these areas were very similar to the experiences I had.

B. Basis for Opinions

Q. WHAT IS YOUR BASIS FOR THE OPINIONS AND TESTIMONY THAT YOU ARE PROVIDING?

A. I have 35 years experience as a nuclear professional, my resume is attached as Exhibit___(JAS-1), Schedule 1. This experience provides me with the background necessary to understand the issues faced by Xcel Energy in taking the steps necessary to keep its nuclear facilities in good repair and to ensure that the plants can operate safely and reliably through the term of their extended operating licenses. During my tenure at FPL, I participated and oversaw the decision to extend the operating licenses at St. Lucie (Units 1 and 2) and at Turkey Point (Units 3 and 4). I also oversaw significant upgrade work at NextEra's Duane Arnold and Seabrook plants. This experience provides useful background for identifying issues that are likely to be encountered by another utility that is implementing upgrades..

Q. HAVE YOU BEEN INVOLVED IN LCM AND EPU PROGRAMS IN THE PAST?

A. Yes. I was primarily responsible for the EPU programs at each of FPL's four Florida nuclear units. As CNO at FPL, I developed the basis for undertaking EPU projects, was actively involved in their implementation, and participated in the State regulatory proceedings that evaluated the prudence of those EPU projects. I provided testimony to the Florida Public Service Commission for its periodic reviews of the prudence of those EPU projects. I was also actively involved in FPL's initiatives to upgrade their nuclear plants to maximize their useful life. These life-cycle management activities were an important part of my role and they needed to be coordinated with the EPU activities.

Q. WHAT WAS YOUR EXPERIENCE IN FLORIDA WITH EPU PROJECTS?

A. In the early 2000s, FPL's Florida system was experiencing a period of forecast demand growth and FPL identified a need for additional baseload capacity. FPL decided to fill some of that capacity need by uprating its four nuclear units. FPL had to move relatively quickly to implement the nuclear upgrades to accommodate the forecasted need.

FPL retained an outside vendor to prepare an estimate of the cost of the projects. The initial capital cost projections for the four EPU projects at the Florida units were estimated at approximately $1.398 billion or on average $349.5 million per unit. The final installed cost of the Florida EPUs was approximately $3.129 billion or an average of $782.25 million per unit. This was more than double the initial estimates. The primary drivers for those increased costs were: (i) expanded scope as a result of detailed design engineering, (ii) unexpected construction challenges, (iii) difficult and time-consuming implementation of modifications within the confines of the existing power plant, and (iv) nuclear regulatory issues.

Q. WHAT OTHER INDUSTRY INFORMATION DID YOU USE IN THE FORMULATION OF YOUR OPINIONS?

A. I primarily rely on my 35 years of experience in the industry with increasing responsibility over complex capital projects, such as EPU projects, LCM projects, and steam generator projects. I am familiar with the EPU concept and the experiences utilities have had. The NRC has approved 139 uprates of various types. During my tenure at NextEra, the Duane Arnold nuclear station in Iowa was purchased. That plant had undergone an EPU project prior to the purchase, and I became very familiar with the work that had been done on that station.

I am generally familiar with uprate programs that were conducted at Dresden and Quad Cities in Illinois, as both of those programs encountered issues that informed subsequent power uprates in the industry and led to a number of the design decisions underlying Xcel Energy's LCM/EPU initiative. In 2012, the

NRC granted a license amendment to uprate the Nine Mile Point station in New York. This application was pending for an extended period of time and encountered increasing licensing challenges.

Most recently, I have become aware that proposed uprate programs at three nuclear stations – La Salle, Limerick, and Cooper – were cancelled due to changing market conditions and the cost and schedule risks. Regarding Cooper Station, the Nebraska Public Power District acknowledged the difficulties other utilities were having in completing these projects on time and within original budget as important factors, particularly as the regulatory environment at the NRC has become more difficult and the market for nuclear generation has softened in the past couple of years.

Q. WHAT OTHER INFORMATION DID YOU RELY UPON?

A. Over my career, I became very familiar with the rules and regulations that apply to operating nuclear power plants, and I include my understanding of those rules and regulations in the development of my opinions. Further, I took into account the principles and practices of INPO. I will describe INPO and its function in greater detail in Section III of my testimony.

Q. WHAT INFORMATION FROM XCEL ENERGY DID YOU CONSIDER IN FORMING YOUR OPINIONS?

A. I spent three months preparing to give testimony in this proceeding.

First, Xcel Energy provided me with a packet of written materials that gave useful background on the LCM/EPU program. I reviewed the design for the initiative and assessed how the scope of the initiative evolved over time from the initial feasibility study to final implementation.

Second, I made two trips to Minnesota to interview key personnel about their experiences and the issues that they encountered. These interviews included a number of other witnesses and Xcel Energy employees who were involved with the LCM/EPU initiative: Tim O'Connor, Nate Haskell, Steve Hammer, John Bjorseth, Dave Alstad, Ed Weincam, and John Fields.

I also toured Monticello to gain additional knowledge and context regarding the in-field construction difficulties encountered. This background provided me with context for the decisions that were made. Based on the interviews, I asked for and received additional written materials about the program. Attached as Exhibit___(JAS-1), Schedule 2 is a log of the written materials I was provided during my preparation of this testimony.

III. NUCLEAR SAFETY DRIVES SCOPE AND DESIGN

Q. WHY IS NUCLEAR SAFETY A PRIMARY CONSIDERATION IN THE SCOPE AND DESIGN OF CAPITAL PROJECTS AT A NUCLEAR FACILITY?

A. The safety of nuclear power plants is based on the "defense in depth" concept, which relies on successive physical barriers (fuel, cladding, primary system pressure boundary, and containment) and other provisions to control radioactive materials and provide multiple levels of protection against damage to these barriers. Deterministic safety analysis is an important tool for conforming the adequacy and efficiency of provisions within the defense in depth concept and is used to predict the response of a nuclear power plant in predetermined operational states. This type of safety analysis applies a specific set of rules and specific acceptance criteria. Deterministic analyses are often conducted with specialized computational tools.

The advanced computational tools developed for deterministic safety analyses are used for better establishment and utilization of licensing margins or safety margins in consideration of analysis results. At the same time, the existence of such margins ensures that nuclear power plants operate safely in all modes of operation at all times.

State of the art analytical tools were developed to properly assess the existing margins and assess whether margins are adequate for the future. Further, development and application of modern codes for safety analysis enable the analysts to determine safety margins in consideration of analysis results with higher precision.

As the industry gained operating experience and analytics improved, the use of risk-informed probabilistic safety analysis has become more wide spread. This has caused the NRC and plant operators to focus on reducing the frequency of initiating events as a means of reducing the plant's overall risk profile.

The LCM/EPU initiative modifications at Monticello focused on components and systems that were shown to be significant contributors to operational risk in the industry, which can adversely affect safety. The result is an overall reduction in the plant's risk profile and increase in operating margins.

A. Margin Management

Q. WHAT DO YOU MEAN BY "MARGINS"?

A. "Margins" are essentially the amount of redundancy or "margin" that is built into a particular component or system. INPO identifies three different margins for nuclear plant design: operating margin, design margin, and analytical margin. "Operating margin" is the difference between operating limits and the range of normal operation. "Design margin" is the safety factor, beyond the design limit, that is built in to address uncertainties in design, fabrication durability, reliability, and other issues. "Analytical margin" is the factor beyond the minimum requirement of a calculation or analysis to address uncertainties in application of the analysis.

Normal aging and plant operation can eat into each of these margins. Over time the installation of new and potentially larger equipment can also degrade the level of margins. Increased thermal output by an EPU imposes further demands on the operating limit. Even systems or components not directly affected by the power increases may not function as efficiently as intended following an EPU. For all of those reasons the margin management program becomes an important tool in performing an EPU.

It is consistent with industry practice to preserve or enhance these margins where possible when undertaking EPU projects. The history of the industry suggests that future regulations will require modifications that will utilize some of this margin. Thus, it is a benefit to the plant and to the operator to enhance margins.

Q. IS MARGIN PRESERVATION/ENHANCEMENT IMPORTANT TO THE NRC?

A. Yes. The NRC's review of license amendment applications often includes inquiries and requirements pertaining to margin preservation. NRC reviewers often raise concerns about licensee decisions that appear to degrade margins. In light of the forward fit discussion elsewhere in my testimony, utilities must work proactively to address these concerns.

Q. WHAT WAS XCEL ENERGY'S POSITION ON MARGIN MANAGEMENT?

A. In developing the scope for this EPU/LCM initiative, one of Xcel Energy's fundamental considerations was to preserve or enhance preexisting margins. I understand one of Xcel Energy's goals was to enhance margins.

Based on my review of the design for the LCM/EPU initiative, it is clear that margin management was an important consideration in the rollout of Xcel Energy's initiative. The desire to protect and enhance margins influenced many of the Company's design choices. Most notably, the design of the 13.8 kV electrical distribution system restored margin that had eroded over the years as new systems were put in place that utilized the existing 4 kV system. The new 13.8 kV system provides the Company with additional margin to support operations for the remainder of the extended license uprate conditions. Other examples of improved margin and performance include replacement of the six feedwater heaters and associated piping that provides a robust system that will both support plant operations for the long term and provide sufficient capacity to operate at uprate conditions. Similarly, the new condensate demineralizer system and all of the new (and larger) pumps and motors that were installed at the plant were needed to support plant operations through 2030 as well as to provide sufficient operating margin to operate safely at the higher flows associated with the EPU.

B. INPO

Q. YOU HAVE MENTIONED INPO IN YOUR TESTIMONY TWICE. WHO IS INPO AND WHY IS IT IMPORTANT TO YOUR OPINIONS IN THIS MATTER?

A. INPO is the Institute of Nuclear Power Operations. It is an independent organization formed following the 1979 accident at Three Mile Island that advocates for the highest levels of safety and reliability by promoting excellence in the operation of nuclear electric generating plants. Xcel Energy is a member of INPO. My former employer, NextEra was a member, and I believe all U.S. nuclear reactor licensees are members. This is achieved by:

- Establishing performance objectives, criteria and guidelines for the nuclear power industry;
- Conducting regular detailed evaluations of nuclear power plants; and
- Providing assistance to help nuclear power plants continually improve their performance.

Q. WHY DO INPO'S PRINCIPLES INFORM YOUR OPINIONS?

A. I rely upon the strong culture of safety that is the foundation of the U.S. civilian nuclear program. This culture permeates the industry and INPO is a large part of fostering that culture.

When evaluating nuclear operations and projects, I think it is particularly important to account for the INPO principles regarding nuclear safety. My opinions are informed by the lessons learned from INPO's handbook *Traits of a Healthy Nuclear Safety Culture* (INPO No. 12-012).

Table 1: Nuclear Industry Safety Principles

	INPO Principle	Trait
1.	Everyone is personally responsible for nuclear safety.	Personal Accountability
2.	Leaders demonstrate commitment to safety.	Leadership Safety Values and Actions
3.	Trust permeates the organization.	Effective Safety Communication
		Respectful Work Environment
		Environment for Raising Concerns
4.	Decision-making reflects safety first.	Decision-Making
5.	Nuclear technology is recognized as special and unique.	Work Processes
6.	A questioning attitude is cultivated.	Questioning Attitude
7.	Organizational learning is embraced.	Continuous Learning
		Problem Identification and Resolution
8.	Nuclear safety undergoes constant examination.	Continuous Learning
		Problem Identification and Resolution

Q. Does following the INPO principles affect costs?

A. Yes. The focus on safety means that the utility must make design choices that implement both the letter and the spirit of this safety-conscious culture even when that means making choices that increase costs. As the Commission reviews Xcel Energy's LCM/EPU program, it is important to keep this in mind and understand that the safety culture has a major impact on costs.

C. NRC Requirements

Q. Why is it important that aging and worn equipment be replaced?

A. The fundamental principle of the NRC and nuclear utility operators is that it is of paramount importance to take the steps necessary to ensure a safe work environment and that all equipment and installations will operate safely and reliably. Nuclear safety remains of paramount concern whether a plant is brand new or 40 years old, was the subject of an uprate, or continues in its original configuration.

There are several important requirements that seek to ensure compliance with this fundamental goal. They include : (i) Corrective Action initiative; (ii) Aging Management Rule, 10 CFR Part 54.21; (iii) Maintenance Rule, 10 CFR Part 50-65; (iv) NRC Review Standard RS-001 for extended power uprates; and (v) the Back Fit rule and the Forward Fit concept as applied by NRC staff.

Q. PLEASE DESCRIBE EACH OF THESE REQUIREMENTS.

A. Each of these requirements is discussed in detail below:

- *Corrective Action Program*. Under the NRC regulations, the Corrective Action Program requires that a licensee repair any system, component, or condition that is adverse to safety. The licensee must repair or replace the component prior to completing any other work. This means that, if during implementation of a project, degraded systems are encountered that impact safety, then those systems must be corrected.

- *Aging Management Rule*. The NRC license renewal rule, 10 CFR Part 54, provides the requirements for renewal of operating licenses for nuclear power plants. 10 CFR 54.21(a)(1)(i) requires an aging management review of plant systems, structures and components that are safety-related or important to safety in order to ensure that the effects of aging will be managed so that the intended functions will be maintained for the period of extended operation. In other words, to obtain a license extension, the operator must commit to replace and repair systems to keep the plant in safe working order throughout its life. This rule mandates the utility's choice of upgrades and influences design choices because the utility must deploy upgrades that will allow the systems to operate for their intended use for the duration of the plant's extended license.

- *Maintenance Rule. 10* CFR Part 50.56 requires that a nuclear plant must be maintained rigorously to ensure that all safety-related systems and systems, structures and components that are important to safety will function according to their intended use and purpose. This creates a heightened maintenance obligation on the operator. The impact of this requirement is that if a safety-related system or a system that is important to safety needs to be repaired or replaced, the licensee is obligated to have firm plans in place to resolve the root cause of any equipment reliability issue in a timely manner. Application of this rule often drives replacement of older, obsolete equipment or even equipment for which spare parts are no longer readily available.

- *RS-001.* The NRC has published a set of review standards governing review of license amendment applications for power uprates. These review standards are intended to provide a comprehensive basis for the NRC to review thoroughly such applications. This process creates a highly technical set of requirements that must be met when seeking a license amendment to uprate the capacity of a plant. This means that licensees can be subject to requirement changes.

Taken together, all of these licensing requirements place an obligation on the operator to ensure that the facility is designed appropriately to meet the relevant design criteria and that it will meet all applicable safety requirements for the entire duration of the plant's operating license.

Q. HOW DO THE BACK FIT RULE AND FORWARD FIT CONCEPT WORK?

A. The NRC has a process by which it monitors and analyzes nuclear power plants for compliance with the design of the plant. Under 10 CFR Part 50.109, the NRC generally does not require nuclear operators to "back fit" systems (apply a change in criteria retroactively to an existing licensee) unless the NRC can demonstrate that there is a substantial increase in the overall protection of the public health and safety or the common defense and security to be derived from the back fit and that the direct and indirect costs of implementation for that facility are justified in view of this increased protection. This limitation provides licensees some comfort that they can rely upon the chosen design of their systems and that once those designs are approved, the NRC will not seek retroactive changes, except in unusual circumstances.

Q. WHAT DOES THE FORWARD FIT CONCEPT MEAN AND HOW DOES IT WORK?

A. The NRC's application of the Forward Fit concept is somewhat new and its scope has been substantially widened since I retired from NextEra. Previously, the NRC would require upgrades citing the back fit rule and would focus on the NRC's right to require upgrades that served a substantial safety function.

With regard to seeking a voluntary license amendment, however, the NRC now takes the position that it is not bound by the limits of the back fit rule. The NRC's view is that for a licensee who voluntarily seeks to change its licensing basis, the NRC may condition its approval of the proposed change upon a licensee agreement to adopt new or revised guidance whether or not the condition is predicated on a substantial safety issue (as limited by the back fit rule). Since a voluntary license change is initiated by the licensee to take advantage of a voluntary alternative offered in the NRC's regulations, the NRC's current position is that the agency is not bound by the limitations of the back fit rule.

Q. WHAT IS THE IMPACT OF THE FORWARD FIT CONCEPT ON VOLUNTARY INITIATIVES SUCH AS AN UPRATE PROJECT?

A. The NRC and nuclear plant operators are learning organizations that utilize experiences gained from one initiative and apply it to the next. This is an important and positive attribute as it facilitates a safety-conscious work environment within the nuclear licensee community and enhances nuclear safety across the entire U.S. fleet. The Forward Fit concept is an important aspect of that safety-conscious culture as it allows the NRC to apply its lessons-learned from one initiative to the next.

The forward fit concept is analogous to building codes. If a house is built in accordance with the codes and standards in place during its construction, those codes and standards will generally apply unless there is some significant safety issue or the homeowner decides to do an upgrade project. If, however, the homeowner decides to make significant changes to the house, that homeowner bears the risk of being required to bring the house up to current code.

Q. CAN YOU PROVIDE AN EXAMPLE FROM MONTICELLO WHERE STANDARDS OR CRITERIA EVOLVED AND IT IMPACTED THE SCOPE, COST OR TIMING OF THE WORK?

A. Yes. The NRC's evolving regulations drove Xcel Energy's decision to replace the steam dryer The Quad Cities nuclear station completed an EPU program that did not include replacing the steam dryer because the analysis at the time demonstrated that the existing steam dryer provided sufficient margin. However, the added steam from the uprate capacity created too high a velocity resulting in the dryer cracking.

From this experience, the NRC over time developed a new standard for analyzing steam dryers. I understand that this evolving analysis standard was applied to Monticello, causing Xcel Energy to withdraw its original license amendment request and resubmit it with a revised steam dryer analysis. Consistent with the forward fit concept, the NRC staff and Monticello staff have continued to analyze the steam dryer from a variety of different perspectives to ensure that the facility would operate safely under uprate conditions. Ultimately, in order to satisfy evolving NRC standards, it was determined that steam dryer replacement would be required.

Q. DO YOU HAVE ANY OTHER EXAMPLES OF THE FORWARD FIT CONCEPT?

A. Yes. On the issue of Containment Accident Pressure ("CAP") credit, the NRC raised a concern based upon an internal disagreement between NRC Staff and the NRC's independent Advisory Committee on Reactor Safeguards ("ACRS"). This internal agency dispute led to the NRC decision to place review of Xcel Energy's license amendment request on hold in 2009 and eventually require compliance with heightened standards in 2011. The issue was not fully resolved until early 2013 when the NRC reviewers indicated that their questions had been answered. Xcel Energy's analysis for CAP was based on its original design. However, when reviewing the EPU license amendment request, the NRC staff decided that it could not accept the original CAP analysis. When this concern was raised in 2009, there was not much industry experience available, and the NRC staff required an extensive uncertainties analysis from Xcel Energy.

The NRC put the entire EPU licensing process on hold for 18 months to work through the CAP issue. It took another 24 months to work with the boiling water reactor owners group to get the CAP issue resolved. Work at other nuclear facilities (Quad Cities and Dresden and units in Canada and Europe) provided a reasonable technical approach that the NRC eventually accepted. The CAP issue was resolved in 2013. It is a very good example of the complex and evolving analysis that utilities and regulators face to ensure that facilities maintain adequate safety margins.

Q. WHAT IS YOUR OPINION ABOUT WHETHER XCEL ENERGY APPROPRIATELY CONSIDERED SAFETY AND NRC REQUIREMENTS IN DEPLOYING THIS INITIATIVE?

A. Based on everything reviewed, safety and compliance with NRC regulations were paramount considerations for Xcel Energy in pursuing this initiative. These fundamental principles drove decision-making in all aspects of determining final design as well as all aspects of the construction initiative. In my professional opinion, the safety-first attitude was the appropriate foundation for Xcel Energy's decision-making how to deploy the LCM/EPU upgrades.

Q. PLEASE DESCRIBE HOW SAFETY IMPACTED XCEL ENERGY'S DESIGN DECISIONS.

A. Safety and NRC compliance considerations required Xcel Energy to undertake significantly more work to upgrade or replace additional systems that had aged or were not able to be utilized through 2030. Examples of the additional work that had to be addressed that arose after the initial conceptual designs, included: (i) replacement of all six feedwater heaters as opposed to undertaking minor rerating of the existing heaters, (ii) replacement of the entire condensate demineralizer system as opposed to only replacing the vessels (tanks), (iii) implementing a two-pump solution to the reactor feed pumps and motors as opposed to adding a third small supplemental pump, and (iv) addition of the 13.8 kV internal distribution system. The scope expansion from these four items caused a substantial amount of the increased cost experienced by Xcel Energy.

Q. ARE THERE BENCHMARKS IN THE INDUSTRY THAT ILLUSTRATE THE NRC'S SAFETY-FIRST APPROACH?

A. Yes. I mentioned the NRC principle to view nuclear safety issues from the frame of reference of "defense in depth." This underlying principle is always at the heart of nuclear regulation. The defense in depth concept becomes more prominent whenever there has been an adverse incident in the nuclear industry as the agency refocuses its attention on the cause of the adverse event and reexamines whether the additional measures need to be implemented in light of the event.

The Great East Japan Earthquake and the ensuing tsunami that devastated the Fukushima nuclear plant in Japan in March 2011 was the most recent such event. The Fukushima situation highlights that accidents caused by extreme natural disasters can overwhelm a plant's safety systems. While it is clear that U.S. nuclear power plants are better prepared for severe events, Fukushima plus other examples have prompted the NRC to substantially shift its focus and intensify its consideration of defense in depth concerns around natural disasters and the potential for the loss of on-site power at a nuclear plant.

Q. WHY IS THE LOSS OF ON-SITE POWER IMPORTANT?

A. Retaining on-site power to the reactor is of primary importance because power is needed to continue operating the pumps that cool the reactor. In a situation like Fukushima, all sources of on-site and off-site power were overwhelmed meaning that the plant lost the ability to cool the core. I note that in 1992, the Turkey Point Nuclear Plant (which I oversaw for several years) was hit by Hurricane Andrew, a category 5 storm. There were no significant damages to the plant and no consequences to public health and safety. Turkey Point had on-site electrical capability as well as separate diesel generators ("station blackout") that act as redundant backup systems to ensure this important safety function is always available. After Hurricane Andrew, while external power was interrupted but the internal power source remained operational throughout hurricane Thus the redundant systems worked to ensure that on-site power would be available if off-site power was lost. Monticello (and Xcel Energy's Prairie Island nuclear plant) has similar redundant capabilities.

The NRC's treatment of the CAP issue (described above) is a good example. CAP deals with the ability to maintain containment integrity even with the loss of on-site power. Ironically, the NRC resolved its internal disagreement on

CAP only a few days after Fukushima. That resolution was to require additional analysis by licensees to establish new analytical modeling of how the CAP issue would perform in a severe situation where on-site power was lost. In light of the events of Fukushima, the NRC staff indicated to Xcel Energy that it would need significant additional analysis and more review time to assure appropriate resolution of this issue. I am not surprised by this reaction as NRC staff is naturally conservative in addressing issues of nuclear safety and because conservatism is understandably heightened in the aftermath of an event like Fukushima.

D. Lessons Learned

Q. HOW SHOULD NUCLEAR UTILITIES ADDRESS CHANGING CIRCUMSTANCES AND LESSONS LEARNED FROM PRIOR PROJECTS?

A. This is a very important question as it involves one of the core values of the American nuclear industry. The NRC has stated many times that it is a learning organization, resulting in evolving standards and new requirements as it gains experience with particular issues. This dynamic is also a fundamental tenet for management at nuclear utilities.

Nuclear utilities such as Xcel Energy must be learning organizations and dedicated to self-improvement in order to ensure safe and reliable implementation and to meet the evolving requirements of the NRC. Nowhere is there a culture more dedicated to self-improvement than in the nuclear power industry.

And a hallmark of the U.S. nuclear industry is that when events occur anywhere in the world, the industry tries to learn from those events and take actions to try to prevent the possibility of similar events occurring elsewhere. Unfortunately, because the U.S. nuclear industry does not have standardized designs, applying lessons learned from other plants is often quite challenging.

Q. DOES THIS SELF-CRITICAL ENVIRONMENT SUGGEST THAT THE NUCLEAR UTILITY ACTED IMPRUDENTLY?

A. No. The focus on safety and reliability demands that a utility adapt, evolve and continually strive to get better. Far from a sign of imprudence, it is expected that utility managers review recently completed work efforts and probe how they can perform better in the future. This is also an NRC requirement and is best described as the corrective action program. The self-critical approach utilized in the industry coupled with a credible regulator is the main reason for the high levels of safety and performance in the U.S., among the best in the world.

IV. FINAL SCOPE FOR THE XCEL ENERGY PROGRAM

A. Goals and Approach for the LCM/EPU Initiative

Q. WHAT ARE THE IMPACTS THAT AGING EQUIPMENT AND OBSOLESCENCE ARE HAVING ON THE NUCLEAR INDUSTRY AS A WHOLE?

A. Equipment aging and obsolescence are having an increasing impact on nuclear plant reliability and initiatives to sustain high reliability. As the plants in the industry have aged, the need for preventative and predictive maintenance has increased. For nuclear operators who chose to seek license extensions, this became a significant issue as the need for maintenance and upgrades to support the license extension became increasingly important and costly.

In response to the problem of age-related equipment reliability, I understand that a significant aspect of the LCM/EPU initiative at Monticello was to replace systems and components that had aged and degraded in order to facilitate safe and reliable operation of the plant through the remainder of its extended license. It is to be expected that this type of life-cycle management effort would be complicated and expensive because spare parts and service expertise for equipment no longer in production or common use are becoming increasingly difficult and expensive to obtain.

Like other utilities, Xcel Energy needed to obtain custom engineering and custom fabrication of many systems. Upgrade efforts of this type are resource-intensive from a financial and human perspective and created regulatory challenges with the need for licensing new designs and technologies, not to mention the difficulty in qualifying the potential bidders to complete work to exact nuclear codes and standards.

Collectively, factors related to aging and degradation have imposed a significant burden on utilities both from financial and management perspectives. Resources focused on continuous improvement were and continue to be redirected toward addressing these factors.

Q. WHAT IS YOUR UNDERSTANDING OF XCEL ENERGY'S APPROACH TO THE LCM/EPU INITIATIVE?

A. General Electric ("GE") was the Original Equipment Manufacturer ("OEM") at Monticello and holds proprietary rights to a number of important plant systems and designs. This meant that Xcel Energy had little choice but to contract with GE to undertake the program design. I faced a comparable situation in my work in Florida where Westinghouse was the OEM and held similar proprietary rights. Using the OEM for program design is the standard industry practice.

Xcel Energy's overall approach to the project was to design a series of modifications in the plant-side systems at Monticello that would (i) ensure compliance with applicable NRC requirements for safe and reliable operation of the plant through 2030, and (ii) perform engineering and modifications to allow the plant to produce an additional 71 MW of generating capacity.

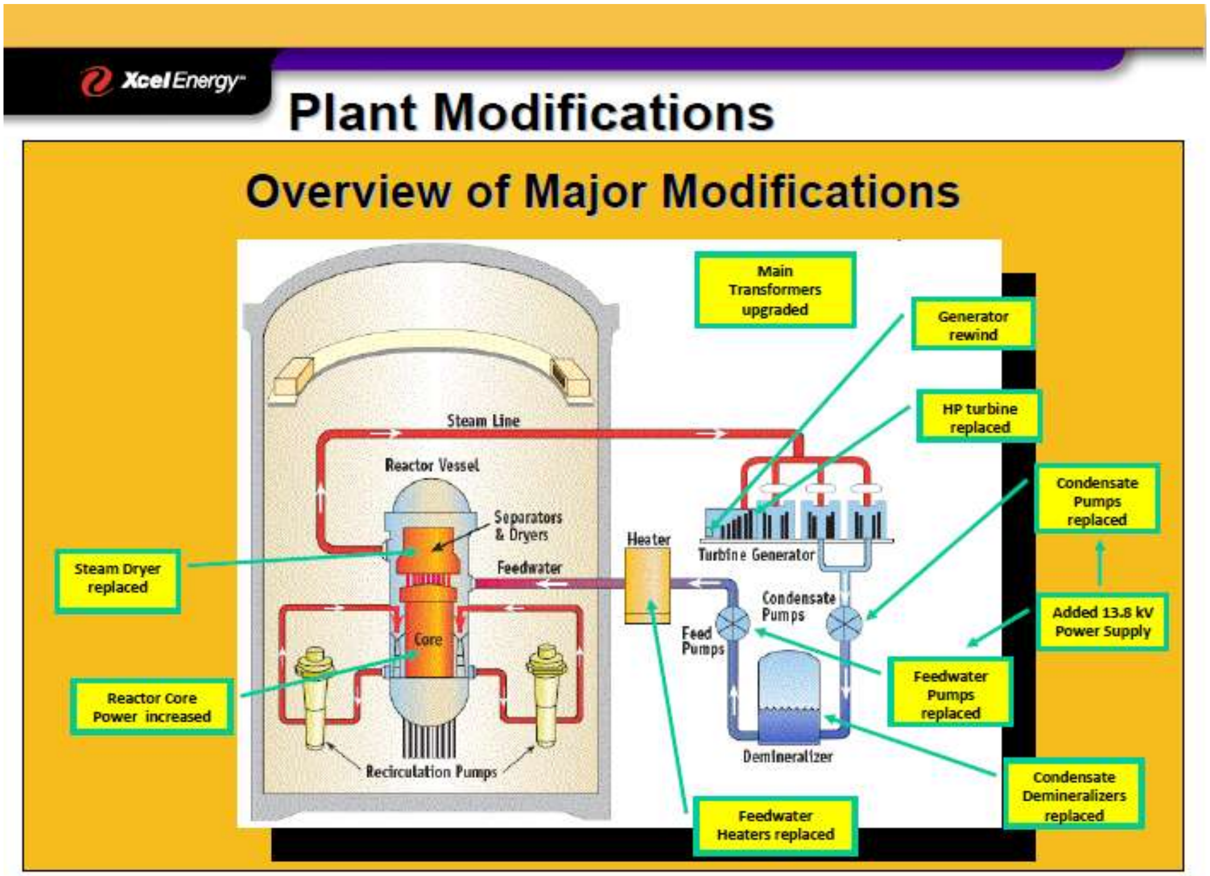
To that end, Xcel Energy started with feasibility and scoping studies that had been conducted in 2004 and 2006. I reviewed these materials in preparation of my testimony. I understand the nature and scope of the work that was contemplated at that time. Those initial analyses were not supported by detailed engineering and did not include specific analysis of the as-found conditions at Monticello.

B. Final Scope Choices

Q. DID THE LCM/EPU ALTER BOTH THE PRIMARY AND SECONDARY PLANT SYSTEMS?

A. No. The "primary" systems of a nuclear power plant are comprised of the core, the reactor, and the associated safety equipment. These primary systems provide the thermal energy used to operate the power plant. The plant-side systems (also called "secondary" systems) include the generators, transformers, pumps, motors, piping, on-site electrical, and associated equipment necessary to process and utilize steam to make electricity. I have included the following Figure 1 to distinguish the "primary" systems from the "plant-side" systems at a boiling water reactor nuclear power plant.

Figure 1. Major Plant Modifications



Q. DID XCEL ENERGY NEED TO MAKE CHANGES TO ITS ORIGINAL CONCEPTUAL DESIGN TO IMPLEMENT ALL OF THE CHANGES NECESSARY TO ACHIEVE ITS TWIN LCM/EPU PROGRAM GOALS?

A. Yes. The scope of the necessary work expanded as Xcel Energy and its advisors became familiar with the unique needs at the Monticello plant and the identification of additional plant systems that were showing age-related degradation or otherwise needed to be replaced. Ultimately, the Company designed and implemented a series of modifications that supported the long-term reliable operation of the plant. To the extent necessary, the Company sized the components to support the increased capacity. This was consistent with my experience at FPL where initial conceptual scope is modified and expanded as the analysis is refined in order to ensure that all of the work that ultimately needs to be done is identified and included.

Essentially the final scope of Xcel Energy's program resulted in the replacement and construction of the plant-side systems listed on the right side of the figure above. A substantial majority of this work would ultimately have been necessary to support the full remaining license life of the plant, including:

- Replacement of the high pressure turbine rotor,
- Replacement of the power range neutron monitor,
- Rewinding the generator,
- Replacement of the main transformers,
- Replacement of the steam dryer,
- Installation of new feedwater heaters and associated equipment,
- Replacement of the condensate demineralizer system,
- Replacement of the condensate demineralizer system;
- Installation of new reactor feed pumps and motors, and
- Installation of additional on-site electrical distribution capacity to ensure sufficient margin to serve existing and future loads at the plant.

Q. DO YOU AGREE WITH XCEL ENERGY THAT IT WAS NECESSARY TO REPLACE ALL OF THESE SYSTEMS?

A. Yes. It was a responsible and prudent decision for Xcel Energy to replace the plant-side systems as this provides Xcel Energy with a greatly improved, more reliable plant that is well positioned to operate successfully until 2030. In particular, I believe that the first five items on the list were necessary installations simply because they constitute replacement of older, and sometimes original, equipment that needed to be replaced. I do not entirely agree with Xcel Energy, however, regarding some of its reasoning why it settled on certain upgrades.

Q. WHAT IS THE NATURE OF YOUR DISAGREEMENT?

A. The NRC licensing process as well as the need to replace many safety-related and important-to-safety systems due to aging often results in replacing more systems than initially anticipated. I think that Xcel Energy's analysis leading into the LCM/EPU project inadequately took this important principle into account.

Xcel Energy has indicated that it chose to upgrade the internal electrical distribution system to 13.8 kV as a result of its design choice to install two larger reactor feed pumps and motors (instead of leaving the two existing pumps in place and adding a third smaller supplemental pump). While I agree that the "two-pump solution" to the reactor feed pumps needed a more robust electrical system than existed at Monticello, this does not adequately account for the need to upgrade the electrical system.

I think Xcel Energy's cause-and-effect rationale on this issue states a false premise. Based upon my review, it is apparent that Xcel Energy had a significant problem with inadequate margins in its on-site electric distribution system. There is little doubt that the electric system needed to be supplemented for ongoing plant reliability whether or not Xcel Energy used the two-pump solution or even decided not to install the EPU upgrades at all.

Over the past 40 years, Monticello's electric delivery capabilities had become close to maxed-out. Xcel Energy needed to implement a solution to that problem regardless and I do not agree that the project personnel should view this scope of the feed pump project as having a cause and effect relationship with the 13.8 kV upgrade.

Q. DOES DESIGNING NEW PLANT-SIDE SYSTEMS AROUND THE EXISTING PLANT EQUIPMENT PRESENT SPECIAL CHALLENGES?

A. Yes. First, the work is accomplished within the existing buildings and structures and must be designed to fit within the confines of those structures. New equipment is specifically designed to fit. This presents significant issues as workers need to implement work tasks in tight spaces and accommodate physical limitations. Often this means that workers have to do tasks sequentially (rather than in tandem) because space limitations preclude sufficient number of workers to be in a given area to complete multiple tasks. Turkey Point actually has small or smaller footprint than Monticello and it was extremely challenging to implement capital projects at that plant.

Second, working within the confines of the existing structures at a boiling water reactor raises radiation exposure concerns. Strict rules are in place to protect workers from unnecessary and excessive exposure to radiation. This requirement further complicates the work and work planning efforts since the vendors must consider more than just the time and cost.

Third, to the extent workers are required to work in proximity to radioactive contaminated areas, it is necessary for them to wear protective clothing and potentially, respirators. This substantially reduces productivity as workers may be limited in the amount of time they can remain in certain locations and are generally encumbered by this protective gear.

Fourth, many of the areas requiring work are not accessible during normal plant operations due to radiation fields. This makes walk-downs and measurements impossible during plant operations. It also means that the utility is unable to precisely assess the specific conditions that will be encountered at installation during the outage, since detailed inspection cannot occur until the plant is offline.

Q. IS IT FEASIBLE TO AVOID THESE ISSUES?

A. No, there is no way to avoid these limitations. The only remedy is to plan the work effectively and develop good contingency plans.

Q. CAN YOU PROVIDE AN ANALOGY FOR HOW THIS WORKS?

A. Yes. As discussed earlier, the challenge in a nuclear plant can be analogized to a major home repair. Homeowners generally rely upon their construction contractors to be the experts in estimating costs because homeowners are not experts in construction. Similarly, nuclear power plant operators are very experienced in running the power plant but are not experts in the tasks necessary to design or implement major construction projects.

When a contractor is working on a house remodeling project and discovers problems that were not anticipated (e.g., degraded wiring behind a wall, structural problems, rotted foundations, water damage, corroded piping, etc.), it is essential that the homeowner address those issues. It is particularly important to address problems that may involve safety. The same is true with construction at an older nuclear power plant.

Q. WHAT WAS YOUR EXPERIENCE AT FPL?

A. It was similar to what Xcel Energy experienced. With the EPU projects in Florida we experienced a significant amount of scope expansion after the projects were begun. In the case of Turkey Point, we found that the condensers needed to be replaced and we planned on that modification. This was a significant scope expansion. Beyond that, the EPUs I was included with involved some of the same modifications undertaken by Xcel Energy. We replaced the high pressure turbine, some feedwater heaters, pumps, motors, generator rewinds and other equipment. Like Monticello, we rewound the generator stator. Turkey Point also added a replacement rotor and new current transformers. With regard to pumps and motors, similar to Monticello, FPL added condensate pumps and the feedwater pump rotating assemblies were replaced. It has been my experience that the types of installations required at an older plant such as Monticello or Turkey Point tend to be similar. Age related degradation tends to be similar to the secondary systems of a nuclear plant, regardless whether it is a boiling water reactor (like Monticello and Duane Arnold) or a pressurized water reactor (such as Turkey Point or Prairie Island).

Q. XCEL ENERGY IS AN EXPERIENCED OPERATOR OF NUCLEAR POWER PLANTS. SHOULDN'T IT BE KNOWLEDGEABLE ABOUT THE CHALLENGES TO BE ENCOUNTERED IN MAJOR CONSTRUCTION PROJECTS?

A. Nuclear operators are highly skilled at operating nuclear power plants and they are trained to operate and maintain the systems that are installed in the plant.

Nuclear operators are not in the business of building or refurbishing nuclear power plants. As a result, it is not at all surprising that an operator such as Xcel Energy would not fully appreciate the challenges that might arise during major reconstruction work. The design and implementation of major construction projects is a core competency of the engineering and design consultants that utilities hire to develop projects of this type.

Q. WHAT IS YOUR PROFESSIONAL OPINION ABOUT XCEL ENERGY'S INTEGRATED APPROACH TO THE SCOPE OF DESIGN OF THE PROGRAM?

A. Xcel Energy's approach appropriately combined attributes of a prudent life-cycle management to maximize the 20-year license extension with a prudent uprate plan necessary to achieve the added capacity once the EPU license amendment is granted. I am supportive of designing a program that addresses both life extension and the increased capacity simultaneously as this is a more efficient way to implement upgrades and also reflects the practical reality that many upgrades in a 40-year-old power plant will need to be made at some point. It provides good economies of scale and synergies to implement those upgrades along with the installations necessary to support the uprate. By doing the upgrades in the same timeframe, you create an integrated design for the project with fewer future modifications required than if portions were installed over a longer timeframe.

The LCM capital project replaced obsolete instruments and controls in several critical plant control systems. In many cases, dated analog technology was replaced with digital technology. Maintenance costs increase as the equipment ages. The old equipment utilized largely obsolete technology that required special training. Additionally, many parts are not available and custom refurbishment of existing parts is necessary. New modern control equipment will minimize the potential for extended plant shutdowns, maintain plant reliability, and reduce ongoing maintenance costs.

Q. IS XCEL ENERGY'S APPROACH SIMILAR TO WHAT YOU DID IN FLORIDA?

A. Yes. In both instances the EPU projects and life-cycle management projects were designed to maximize synergies wherever practical.

VI. DESIGN OF THE SCOPE

Q. CAN YOU LIST THE TYPES OF WORK XCEL ENERGY UNDERTOOK THAT HAS BENEFITS FOR LIFE CYCLE EXTENSION AS WELL AS FOR THE UPRATE?

A. Yes. Xcel Energy's witness Tim O'Connor has created a chart listing the modifications and other activities that were undertaken as part of this initiative. This chart also provides Xcel Energy's assessment of which modifications were prompted only by the uprate and which aspects were driven by the LCM need to upgrade a system to support the extended operating license and which aspects could have been avoidable had Xcel Energy not pursued the uprate.

I did not participate in the preparation of this chart but find it a useful reference of the activities undertaken and the purposes for which Xcel Energy deployed them. There are several specific issues that I have seen in my review of the initiative design and installation and in my interviews with the Company that I think are noteworthy.

Q. HOW DO YOU CATEGORIZE THE SIGNIFICANT PROJECTS UNDERTAKEN AS PART OF XCEL ENERGY'S LCM/EPU INITIATIVE?

A. I see three essential categories of projects. They are: (1) pieces of specific equipment that needed to be repaired or replaced as a result of long use and that would need to be done to support long-term operation of the plant regardless of the EPU; (2) projects that grew in scope or were added as a result of concerns that emerged during the detailed design phase; and (3) projects that were added or expanded as a result of design decisions that support the EPU but also were essential to improve reliability and to support long-term operations.

A. Equipment Replacement Projects

Q. ARE THERE ASPECTS OF XCEL ENERGY'S SCOPE THAT WERE STRAIGHTFORWARD?

A. Yes. The Monticello plant is 40 years old and it still contained a fair amount of original equipment. A number of the required installations were as simple as taking worn or end-of-life pieces of equipment out and replacing or refurbishing them.

Q. OF THE FINAL SCOPE, WHAT WERE THE REPLACEMENTS THAT YOU VIEWED AS STRAIGHTFORWARD?

A. There were several and I will address them in turn:

- <u>Replacement of the High Pressure Turbine Rotor</u>. Considering that the plant is going to operate through 2030, it was prudent to replace the turbine rotor, whether or not the EPU was pursued. The existing turbine rotor could have accommodated operating at uprate conditions, but due to the age of the turbine rotor and the benefits of installing a larger one for the increased steam flow, Xcel Energy decided it was preferable to replace it. This scope and design choice was both appropriate and advisable for the long-term operation of the plant. While the timing of the replacement could have been deferred without the EPU, my experience with turbine rotors suggests the Monticello turbine rotor was unlikely to last for the duration of the renewed license. It made sense to combine this work with the other EPU/LCM activities.

- <u>Generator Rewind</u>. This piece of equipment was original 40-year-old equipment. It is not at all surprising to me that a generator of this vintage was in need of major repair or replacement. In fact, the existing generator was nearing the end of useful life. It failed a stress test at GE's testing facility, meaning it was at high risk of malfunction. If the generator failed during operations, it would have forced a lengthy unscheduled outage of the plant for repairs. This would increase cost and schedule risks that were avoided by rewinding the generator as part of the LCM/EPU initiative. It was a prudent choice to rewind the generator. I understand that Xcel Energy decided that rewinding the generator was a better solution for Monticello.

- <u>Replacement of the Main Transformers</u>. The main transformer was original equipment. I was surprised when I learned that Xcel Energy was able to keep a transformer viable for 40 years. I am not aware of another transformer of that vintage that lasted 40 years. I understand that the old transformer was designed so that it could have operated at uprate conditions. However, because of the age and health of this equipment, it was a prudent choice to replace it whether or not the EPU was implemented. Since the LCM/EPU initiative was underway, Xcel Energy chose to install a more robust main transformer to ensure adequate capacity for future operations. There have been lengthy forced outages in the industry due to transformer failures. So much so that INPO has issued cautions to all nuclear operators regarding monitoring for signs of transformer degradation. The decision to replace the transformer was appropriate and necessary.

- Replacement of the Steam Dryer. The steam dryer was original equipment for the plant. The decision to replace it was prudent. I understand Xcel Energy originally thought it could modify the old dryer as part of its EPU license process. Ultimately the decision to replace it was appropriate to avoid undue regulatory entanglements.

- Installation of the Power Range Neutron Monitor. This digital monitor updates the old oscillation monitor that was original equipment for the plant. This upgrade was necessary to support both the life extension and EPU purposes of the project. It was prudent to install this updated equipment.

Q. WHAT ARE YOUR OBSERVATIONS ABOUT THESE FIVE PIECES OF EQUIPMENT?

A. First, I am comfortable that, given the age and condition of these pieces of equipment, that they needed to be replaced. Xcel Energy made prudent choices by selecting these within the scope.

Second, each of these pieces of equipment were discrete installations that essentially replaced the existing equipment. So long as the design of the equipment meets required specifications, the implementation of this type of installation should be fairly straightforward. It is my understanding that, while Xcel Energy encountered some difficulties with fabrication and design (most notably with the transformer), all of these pieces of equipment were designed appropriately and are working for their intended purpose.

Q. DID YOU TRACK THE COSTS OF THESE INSTALLATION?

A. Not in any detailed way. I was advised by Xcel Energy that these pieces of equipment were not as significant as cost drivers as the other modifications that required significant construction work within the plant. This does not surprise me because the design and installation effort would be expected to be much less for installing a turbine rotor or a transformer, as opposed to rebuilding an entire system within the plant.

B. Emergent Scope Additions

Q. PLEASE DESCRIBE THE SECOND CATEGORY OF PROJECTS XCEL ENERGY CONDUCTED.

A. This second category includes modifications that were necessitated by degraded systems that Xcel Energy did not fully recognize were necessary until the design phase of the initiative was underway. The two major projects that I reviewed that fit within this category are the (i) condensate demineralizer system, and (ii) the feedwater heater system.

1. *Condensate Demineralizer System*

Q. WHAT IS THE CONDENSATE DEMINERALIZER SYSTEM?

A. The condensate demineralizer is part of the condensate and feedwater system. It assures that reactor feedwater chemistry specifications are met for purity, protecting reactor fuel and metallurgy.

Q. WHY DID XCEL ENERGY DECIDE TO REPLACE THIS SYSTEM?

A. Originally, I understand that the scope of this project was confined to replacement of the five condensate vessels, upgrading the pre-coat pumps, making some modifications to the existing analog control system, and testing.

During engineering it became clear to Xcel Energy that the scope of this project needed to be expanded because the entire condensate demineralizer system needed to be replaced. This included the replacement of the five vessels, skid-mounted pre-coat system, holding pumps, associated piping, valves, support systems, and a new control panel. This modification required the installation of a new gantry crane on the operating floor of the turbine building to support removal and installation of new vessels.

Q. WAS XCEL ENERGY'S DECISION TO REPLACE THE CONDENSATE DEMINERALIZER SYSTEM REASONABLE UNDER THE CIRCUMSTANCES?

A. Yes. Xcel Energy appropriately adapted the scope and design of this project to the circumstances.

The condensate demineralizer system was another system nearing the end of its useful life and required replacement to support long-term plant operations. The condition of this system was ultimately determined to be such that Xcel

Energy needed to deal with it in some fashion in order to comply with the requirements of the NRC Aging Management Rule and the Maintenance Rule.

Q. WHAT DO YOU MEAN THAT THIS PROJECT IMPLICATED THE NRC RULES RELATING TO APPROPRIATE MAINTENANCE OF A NUCLEAR PLANT?

A. This project is a good example of what utilities face when they install replacement equipment in older nuclear plants. The original scope presumed that the condition of the remainder of the condensate demineralizer system was in good working order. Subsequent analysis revealed that this original system needed to be replaced in its entirety.

As the project proceeded through the design phase, Xcel Energy found that the existing wiring associated with this system needed to be replaced. Replacing this wiring was not part of the originally planned work. Replacing that old wiring was the right thing to do and it was not optional under the NRC requirements.

Further, the design needed to be changed during installation because Xcel Energy discovered the existing backwash receiving tank was inadequate. It was subsequently determined that the existing tank needed to be replaced because (1) internal flow distribution was not optimal in the existing system; (2) the new system improved flow characteristics; and (3) increased sizing capacity of the new backwash tank improved functionality. This late design change added to the complexity of the project as well as the costs.

Q. WHAT WERE XCEL ENERGY'S OPTIONS REGARDING THE REPLACEMENT OF THIS SYSTEM?

A. Xcel Energy was required to ensure that the condensate demineralizer system was adequate to support uprate levels. This required the use of larger equipment. However, as the design process moved forward, it became clear that the system was in need of significant work and ultimately needed to be replaced. Later, when the degraded wiring was discovered during the installation phase, Xcel Energy had no choice but to replace it. As this particular project progressed, it became clear that significant work needed to be done to support long-term operation whether or not the uprate had been pursued.

Q. IN YOUR OPINION, WAS XCEL ENERGY'S DECISION TO EXPAND THE SCOPE OF THIS PROJECT REASONABLE?

A. Yes. Based upon my discussions with Xcel Energy personnel and my observations, it was appropriate for Xcel Energy to replace the full system. Replacing the condensate vessels (tanks) would have been an important project in its own right. However, as the design phase proceeded, it was reasonable to make the decision going from a vessel-only replacement to replacing the whole system. Further, the conditions of the original system further supported replacing it. The degraded wiring, and the need to do significant valve and piping work all pointed to the desirability to replace the entire system.

Q. PLEASE DESCRIBE WHY YOU THINK IT WAS IMPORTANT TO REPLACE THE SYSTEM?

A. It was necessary to install the larger vessels for the EPU. Those vessels allowed more surface area for the filter septa to improve performance with the higher flows. In addition, Xcel Energy advised me that the existing vessels had issues with the quality of the lining. This suggests that it was necessary to replace them regardless of the EPU.

Once it was clear the vessels needed to be replaced, it was appropriate to consider whether additional aspects of the system should be upgraded as well. Replacing the controls, for example, was a good idea to minimize the risk of sequencing errors that could ultimately have caused a reactor scram. Finally, the piping and valves associated with this system all showed signs of wear and need of replacement. In fact, there had already been an incident of a valve leaking that required maintenance. This further supported the need to replace the overall system.

Q. DID XCEL ENERGY ENCOUNTER ADDITIONAL WORK ON THE CONDENSATE DEMINERALIZER SYSTEM THAT SUGGESTED IT WAS THE RIGHT DECISION TO REPLACE IT?

A. Yes. After the scope for this project was set, Xcel Energy discovered three emergent issues that confirmed that the system needed to be replaced. These were (i) the need to redesign the T-33 blowdown tank; (ii) emergent issues with the condensate demineralizer bypass valve; and (iii) additional problems with the wiring of this 40-year-old system.

Each of these issues was discovered as Xcel Energy was preparing for the installation of the new condensate demineralizer system. It is normal for major nuclear construction to have significant issues arise during the installation preparation phase since design is an iterative process and it is typical to adjust designs and scope to address emergent conditions and to react to as-found conditions.

2. Feedwater Heaters

Q. WHAT PURPOSE DO FEEDWATER HEATERS PLAY IN A POWER PLANT?

A. Feedwater heaters in a power plant are used to pre-heat water delivered to a steam generating boiler. Preheating the feedwater improves the thermodynamic efficiency of the system. This reduces plant operating costs and also helps to avoid thermal shock to the boiler metal when the feedwater is introduced back into the steam cycle.

Q. WHAT WAS THE NATURE OF THE FEEDWATER HEATER PROJECT?

A. This modification replaces the 13A/B (Intermediate Pressure Feedwater Heaters), 14A/B (High-Intermediate Pressure Feedwater Heaters) and 15A/B feedwater heaters (High Pressure Feedwater Heaters). Xcel Energy had to procure and install the new feedwater heaters as well as remove and dispose of the existing feedwater heaters. Xcel Energy encountered significant interferences that had to be eliminated to facilitate the removal of the existing heaters and the installation of the new heaters. A significant amount of piping had to be moved or replaced. In addition, the instrumentation for the feedwater heaters was replaced. These instruments included the current level instruments that are routinely overhauled every cycle.

Q. WHY DID XCEL ENERGY DECIDE TO REPLACE THE FEEDWATER HEATERS?

A. The initial scope of this particular project was to rerate the existing feedwater heaters without replacement or substantial construction. I was a little surprised when I learned that the original scope did not encompass replacing these heaters. In a BWR, the feedwater heater system is one that experiences wear and degradation over time. In such a plant, I would expect that the higher-pressure feedwater heaters would need to be replaced at least every 20 years. I note that for Xcel Energy the 14 A/B and 15 A/B (lower pressure) were original vintage equipment in the plant. The 13 A/B heaters (higher pressure) were 30 years old. I would have expected these heaters to have needed replacement earlier.

Q. WHY WOULD YOU EXPECT THE HEATERS TO WEAR OUT SOONER?

A. The feedwater heaters are essentially large heat exchangers that heat the feedwater prior to injection in the core. These heat exchangers have to withstand high temperatures and velocities of the water traveling in and out. As a result, they are susceptible to corrosion and degradation. As Xcel Energy worked through the initial scoping for this work, they found that the heaters were showing signs of wear. Further various nozzles and pipes associated with the heaters were found to need to be replaced.

During the design phase, Xcel Energy came to the correct conclusion that these six feedwater heaters needed to be replaced due to their aging condition and signs of wear. Based on what I learned, the heaters were near the end of their useful life. The results from testing showed that tubes were becoming plugged at an increasing rate; tube leaks had become more common and it was clear that the existing heaters were degraded. .

Q. In your opinion, was Xcel Energy prudent in the way it proceeded with the feedwater heater design?

A. Yes. Xcel Energy was faced with the need to install new equipment in the existing confined space within Monticello's turbine building to support long-term operations of the plant as well as to support the uprate. Once Xcel Energy determined that the heaters needed to be replaced, it was appropriate and necessary to design the modification to replace all of them at the same time. After the decision to replace the heaters had been made, Xcel Energy had an occurrence that confirms this was the correct design choice. In mid-2010 the 15 B heater began to have significant problems with tube leaks and they had a malfunction every couple of weeks. By October of that year the problem became so severe that Xcel Energy was required to undertake a controlled shutdown of the plant to fix the plugged tubes and the tube leaks. This resulted in an outage of about one week. This makes it clear that there was a need to replace the heaters.

C. Scope Changes to Support Design

Q. Please describe the third category of projects Xcel Energy conducted.

A. This third category includes major modifications that were necessitated by design decisions that Xcel Energy made to support the optimal plant configuration for long-term operations as well as to support the uprate. The two major projects that I reviewed that fit within this category are the (i) reactor feed pumps and motors, and (ii) the 13.8 kV internal electric distribution system.

1. *Reactor Feed Pumps and Motors*

Q. DID XCEL ENERGY NEED TO INCREASE THE FLOW IN THE REACTOR FEED PUMPS AND MOTORS?

A. Yes. The reactor feed pumps were original, 40-year-old equipment. I understand that Xcel Energy was challenged in obtaining replacement parts for these old pumps. The original manufacturer of the pumps had gone out of business and there was concern over whether the replacement manufacturer would have adequate numbers of replacement parts.

Some of the existing equipment could have been reused but Xcel Energy had to do something with the main pumps and heaters to support uprate conditions. Xcel Energy investigated whether it could retain the original two pumps and supplement flow with a third pump or rather replace the existing two pumps with two larger pumps. Adding a supplemental third pump would have created complex interactions and would have required the implementation of new operating protocols.

Because of the age of the equipment, the difficulty with spare parts and the need for additional flows through the pumps, Xcel Energy decided to replace the two pumps with two larger pumps. Xcel Energy put a premium on retaining the existing operating protocols to keep things as stable as possible for its operators.

Q. DO YOU AGREE THAT THE REACTOR FEED PUMPS AND MOTORS NEEDED TO BE REPLACED?

A. Yes. In my professional opinion, replacing these pumps and heaters was the prudent thing to do for the long-term safe and reliable operation of the plant.

The motors were near the end of their useful life and needed to be replaced for life-cycle management purposes. Further, the pumps had been repeatedly repaired and the ability to continue using them was becoming uncertain. Under the NRC's aging management program and maintenance rule, the Company did not have a reasonable alternative.

Further, the feedwater regulator valves needed to be replaced to interface with the new controls that were being installed and to accommodate the increased flow requirements. All of this work served the important goal of upgrading the plant and increasing efficiency.

Q. ARE YOU FAMILIAR WITH THE DESIGN CHOICE XCEL ENERGY MADE REGARDING THE REACTOR FEED PUMPS?

A. Yes. In its initial feasibility study, Xcel Energy's contractor suggested keeping the two existing reactor feed pumps and adding a third smaller pump. This three-pump configuration was a novel approach to try to minimize the need for additional on-site electric distribution capacity. However, Xcel Energy determined that the use of the three-pump configuration was not reasonable, and selected to use two larger pumps instead.

Q. WHAT WERE XCEL ENERGY'S REASONS FOR CHOOSING THE TWO-PUMP SOLUTION?

A. First, due to space constraints, it would have been difficult to install the third pump. Also, as was the case with other projects, it would have been a challenge to address existing interferences. These problems could probably have been overcome, but would have undoubtedly cost more than Xcel Energy anticipated.

Second, the third pump was likely to require its own discrete on-site power source because the existing 4 kV distribution system had little margin and could not accommodate the increased load of the third pump and motor. I mentioned before that it is my opinion that the electrical system needed to be upgraded regardless whether the EPU projects were pursued. Choosing the third supplemental feed pump would exacerbate this concern.

Third, going from two reactor feed pumps to three pumps required significant changes in plant operations procedures. The operators at any nuclear power plant operate according to set procedures and protocols. Changing the pump configuration from two to three would have changed the interface with operators and required new procedures and associated training, introducing additional complexity to the operators.

Fourth, including a supplemental third reactor feed pump presented significant operational challenges and required complex calculations and new digital feedwater control systems to operate successfully with the remaining systems.

Q. WHAT DO YOU MEAN WHEN YOU SAY THAT THE 4 KV SYSTEM HAD LITTLE MARGIN AVAILABLE FOR FUTURE EXPANSION?

A. The 4 kV electrical system was constructed at Monticello with more capacity than was needed to power all of the systems that were installed at the plant when it was new. This extra capacity is one aspect of margin and it essentially gives the plant room to add additional loads on the existing system without needed to add capacity. Over the years, it is typical at a nuclear plant for add electrical loads over time for new equipment that is added, either because of regulatory or other plant requirements. In Xcel Energy's case, I am aware that they added at least the following additional significant loads onto the original 4 kV system: (i) increased #11 and #12 RHR Pump Motors from 600 hp to 700 hp; (ii) added Emergency Filtration Train Building Loads – TMI Required Modification; (iii) Compressed Air Building Loads – Upgrade for Compressed Air System; and (iv) New Security Building Loads – NRC Security Requirement Changes from 9/11/01. Each of these additions took up some amount of the existing capacity on the system and eroded the remaining available margins.

Q. DO YOU KNOW WHETHER XCEL ENERGY WAS, IN FACT, NEARING THE END OF ITS AVAILABLE MARGIN ON THE 4 KV SYSTEM?

A. Yes. I understand that under normal plant conditions using the 4 kV system, Xcel Energy was experiencing under-voltage conditions when they would start large motors and pumps. They successfully managed this under-voltage situation by sequencing starting large and competing loads. Xcel Energy previously installed an under-voltage relay system that acted as a timer on the voltage excursions. Using that system, so long as an under-voltage event was resolved promptly it would not create any problems. However, if the under-voltage condition persisted it would ultimately result in a trip. While Xcel Energy successfully managed this situation, it was a significant benefit to increase the margin in the electric system to avoid the need to use the under-voltage relay system.

Q. WHAT IS YOUR OPINION OF XCEL ENERGY'S CHOICE OF DESIGN FOR THE REACTOR FEED PUMPS?

A. In my professional opinion, Xcel Energy made the correct choice given the circumstances. I looked at Xcel Energy's rationale for its choice and found it to be reasonable. The two-pump solution is clearly preferable from the operators' perspective as it allows for much greater operating continuity. Having spent my early career as a nuclear operator and 35 years around nuclear operations, I cannot overstate the importance of designing systems that are user-friendly to the operators.

Q. WAS THERE SOME DISAGREEMENT ON THIS DESIGN ISSUE?

A. Yes. In my interviews with Xcel Energy personnel, there was some discussion about whether the three-pump configuration could have worked and whether the two-pump solution was necessary. This is another area where I may have a disagreement with Xcel Energy, although this one is less clear to me.

From my perspective, there was little doubt about this issue. I do not see the three-pump configuration to be particularly viable, particularly in light of the significant complications that it would have created. While I understand that this scenario may have been technically viable, as a practical matter, it was not the best solution. The three-pump configuration included at least the following problems: Space limitations; significant additional flow analysis, piping, valves, and controls; complex logic designs for multiple pump loss scenarios; new operating procedures and training; new control room switches, indicators, controllers

Q. DID THE SELECTED TWO-PUMP CONFIGURATION PRESENT CHALLENGES?

A. Yes it did. The Company identified the need for greater flow. This meant that using two pumps required making them larger to accommodate the additional flow. The larger pumps needed correspondingly larger motors. While Xcel Energy initially determined that this design also triggered the need to upgrade the electrical system, I have already stated that in my opinion, the 13.8 kV design (or some substantially equivalent electrical design) was unavoidable whether or not Xcel Energy implemented the two-pump solution with regard to the reactor feed pumps and motors. The existing 4 kV system was operating at close to capacity already and the addition of any significant load would call for that capacity being expanded. Since one of Xcel Energy's goals was to position the plant for viable operations through 2030, it was important to address the electrical system because, in my opinion, the existing 4 kV buses would not have been sufficient for the next 20 years under any reasonable circumstances.

The two-pump solution also presented challenges in the installation of the new pumps and motors in the existing space. In order to fit the pumps and motors into the preexisting space, Xcel Energy was required to redesign and install a significant amount of piping to remove obstructions and to provide the space necessary for the new equipment.

Q. WHAT IS YOUR CONCLUSION ABOUT XCEL ENERGY SELECTING THE TWO-PUMP CONFIGURATION?

A. In my opinion, the challenges presented by the two-pump solution, while not small, were less significant than the challenges presented by the three-pump configuration. I conclude that this was the best option considering all of the issues involved. Since Xcel Energy needed to upgrade the electrical system anyway, in my opinion it was appropriate to use that upgraded electric system to power the larger pumps and motors from the two-pump solution. And the constructability problems with the two-pump design were more than offset, in my opinion, by the analytical and practical challenges that would have been presented by using the third supplemental pump.

2. *Internal Electric Distribution System*

Q. WHAT DROVE XCEL ENERGY'S DECISION TO ADD THE 13.8 KV DISTRIBUTION SYSTEM?

A. Two reasons were identified by Xcel Energy. First, as described above, Xcel Energy chose the two-pump solution to address the need for greater flows with its reactor feed pumps and motors. Second, and more fundamentally, Monticello was operating with relatively small margins in terms of its on-site power capabilities, and any meaningful increase in on-site electric power demands then or in the future would have triggered upgrading the system. Xcel Energy recognized that upgrading the system was necessary for long-term safe and reliable operation of the plant.

Q. WHAT IS YOUR OPINION ABOUT THE NEED TO UPGRADE THE INTERNAL ELECTRIC SYSTEM?

A. In my professional opinion, additional on-site electrical distribution was necessary to accommodate plant operations through 2030 regardless whether Xcel Energy had pursued the EPU. The need to ensure adequate margins for the remaining life of the plant would have required an upgrade of the electrical system in any event.

I reviewed Xcel Energy's internal analysis and presentations supporting the request for authorization to include this upgrade as part of the LCM/EPU initiative. I interviewed Xcel Energy's personnel specifically on this point. I took a tour of the new 13.8 kV bus room at the plant to see how the system is laid out and to understand how space limitations factored into the deployment of this new system. Based on that review, I was able to confirm that the upgrade to a 13.8 kV electrical distribution system was an important set of work that needed to be done at some point for the long term benefit of the plant.

Q. WHAT WERE XCEL ENERGY'S OPTIONS WHEN IT DECIDED TO PURSUE THE 13.8 KV DISTRIBUTION SYSTEM?

A. Xcel Energy identified three basic options. They were:

- Replace the 4 kV system with a more robust system at the same or different voltage; or
- Add capacity to the existing 4 kV distribution system;
- Add a new primary power source for certain systems that required a more robust power supply while retaining the 4 kV system to be available to run certain equipment as necessary during certain contingency events.

Q. DO YOU AGREE WITH THESE OPTIONS?

A. No. In my opinion, Xcel Energy needed to choose either the second or third option regardless of whether it was undertaking the EPU. The first option was infeasible and should not have been considered. It certainly would not have been an appropriate outcome.

Q. WHY WAS THE COMPLETE REPLACEMENT OF THE 4 KV SYSTEM NOT A VIABLE OPTION?

A. Replacing the 4 kV system with a 'like for like' change would have presented insurmountable challenges. The internal electric distribution system is an important system that ensures the availability of on-site power to the plant-side systems if off-site power is lost. In order to serve this important safety function, the power source must be available at all times. This means it was not possible to take out the existing 4 kV system prior to construction of the new one. To the contrary, the new 4 kV system would have had to be built first so that it could be energized prior to dismantling the old system. Xcel Energy could have constructed an entirely new 4 kV bus room and installed the new system there. However, this would have resulted in essentially the same work and cost as constructing the new 13.8 kV system. Because of all of the challenges and the difficulty in predicting ultimate costs of any major change like this, it is at the very least uncertain as to which effort would have cost more. In my opinion, it is difficult to imagine that the complexity of a new 4 kV solution would have been constructible, much less cost-effective. Replacing the 4 kV system like for like would not have enhanced safety margins; instead it would have been required to add capacity to the new 4 kV system, thereby further increasing costs. The better solution was to construct the new 13.8 kV system to support both long-term plant needs as well as the larger pumps and motors being installed as part of the LCM/EPU initiative.

Q. WHAT IS YOUR OPINION ABOUT ADDING SUPPLEMENTAL 4 KV BUS WORK TO PROVIDE ADDITIONAL CAPACITY?

A. Adding a supplemental power source to the 4 kV system was not feasible. Space constraints precluded expanding or adding to the existing 4 kV bus work. On my tour of the plant it was apparent to me that simply adding another bus or two to the 4 kV system would not have been feasible. Monticello is set on a very small footprint and that tight space necessarily influences design choices. I note that the Turkey Point Nuclear Power Plant in Florida (with which I am familiar from my prior work) is also set on a very small footprint resulting in many challenges and design choices to accommodate the limited space available. There was simply no room to add more bus work to the existing 4 kV system.

Xcel Energy could have added additional 4 kV buses at a discrete location, similar to the installation of the 13.8 kV system. However, that would have been nearly the same cost and same difficulty of the 13.8 kV installation. In my opinion, if the installation was going to be at a discrete location, it was better to increase the voltage to a size that is more common.

Q. IN YOUR PROFESSIONAL OPINION, DID XCEL ENERGY MAKE THE CORRECT DESIGN CHOICE BY BUILDING A NEW 13.8 KV DISTRIBUTION SYSTEM?

A. Yes. Xcel Energy's chosen design to build a new 13.8 kV bus room while preserving the existing 4 kV buses (for their important on-site power function) solved the technical challenge of constructing in a confined space while also enhancing margins. Some of those 4 kV buses continue in operation today and provide the plant with important redundancy and added margin for future on-site power needs.

Q. HAS THE CONCERN OVER REDUNDANCY AND MARGINS OF ON-SITE POWER SOURCES INCREASED IN RECENT YEARS?

A. Yes. This is an area where the NRC and industry have learned a great deal in light of natural disaster events such as Fukushima. The loss of power supply has always been known as a critical safety issue for nuclear plants. However, scrutiny of this issue has increased dramatically in recent years as the consequences of losing on-site power became clear in Japan.

As I described earlier in my testimony, it is important that nuclear plants build additional electric capacity to ensure adequate supplies of power to the systems under all reasonable circumstances. Over the years, plant aging as well as installations of new equipment to the plant tend to use up available margin. When Xcel Energy decided to do the EPU modifications necessary to increase the plant's capacity, it was prudent to design a system that restored additional margins.

Q. IN YOUR PROFESSIONAL OPINION, WAS THE DECISION TO INSTALL THE 13.8 KV DISTRIBUTION SYSTEM APPROPRIATE WHETHER OR NOT XCEL ENERGY PROCEEDED WITH THE UPRATE ASPECTS OF THE PROJECT?

A. Yes. It is possible that the electrical work could have been deferred a few years but it is clear to me that Xcel Energy to do something with the electric system to support safe and reliable operations through 2030. It is also clear to me that the 13.8 kV system Xcel Energy chose was the best available option regardless of the uprate.

Q. ARE YOU AWARE OF ANY OTHER NUCLEAR FACILITIES THAT HAVE HAD ISSUES WITH THEIR INTERNAL ELECTRIC DISTRIBUTION SYSTEM?

A. Yes. I am aware of the experience of the Santa Maria de Garona (Garona) Spanish nuclear power plant, owned by Iberdrola. Nuclear power plants in Spain, and in most of Europe, receive 10-year periodic license extensions contingent upon their continuing safety and reliability. Garona submitted its application for a new 10-year license renewal in 2009, which license issuance was to coincide with its 40th year of operation. Garona is Monticello's twin plant, using Monticello's safety analysis for its design basis.

Garona elected after 20 years of operation to follow a process of "continuous improvement" rather than major replacements for their life-cycle management, consistent with the fact that Spain in the 1980s considered that a 40-year operating history could limit the actual operating life of a plant. Specifically, they elected to replace or upgrade electrical systems and components as they approached the end of their estimated life or became obsolete. Therefore, in every refueling outage since 1983, Garona conducted stepwise changes and upgrades to their 4 kV system to justify continued operation beyond 40 years. These resulted in 18 sequential modifications and upgrades to the 4 kV system which were costly and difficult, many of them required by the Spanish Consejo (NRC equivalent) for approval of continuing operation. Essentially, these modifications included all the major components needed for safety compliance to balance the loads, to maintain physical and electrical separation, to comply with fire-related requirements, to replace all obsolete relays and introduce new short-circuit protection, among many others. In Monticello's case, the uprate to 13.8 kV dealt effectively with loads, safety, obsolescence, and reliability in one comprehensive upgrade.

Q. BASED ON YOUR UNDERSTANDING OF THE SITUATION AT GARONA, WHAT IS YOUR PROFESSIONAL OPINION ABOUT XCEL ENERGY'S CHOICE OF ADDING THE 13.8 KV DISTRIBUTION SYSTEM RATHER THAN REPLACING OR SUPPLEMENTING THE 4 KV SYSTEM?

A. In my professional opinion, adding the 13.8 kV system was a much better and more cost-effective choice than what was done at Garona. While the one-time cost of the 13.8 kV upgrade was substantial, it was far better to upgrade the electrical system on a comprehensive basis to capture long-term benefits and increase operating margins than to make repeated sequential changes as was done in Spain. This is particularly true where there simply were limited options to make these improvements to the existing footprint.

D. Overall Design Observations

Q. DO YOU HAVE EVIDENCE THAT THE DESIGN UTILIZED AT MONTICELLO WAS APPROPRIATE AND YIELDED SATISFACTORY RESULTS?

A. Yes. Xcel Energy personnel have advised me that they have encountered very few problems with the final installations and that the modifications are working properly and as designed at the plant's current (pre-uprate) 600 MW level. Notably, the plant returned to 100 percent power levels without experiencing any transients or other adverse action and it did not cause a "SCRAM" (which is a shutdown of the reactor in response to adverse circumstances).

My experience has been that the types of major modifications that went into this initiative could readily be expected to result in relatively more difficulties than were encountered here. The relative absence of problems speaks well for the quality of design and implementation.

Q. HAS XCEL ENERGY IDENTIFIED ANY DIFFICULTIES IN THE OPERATION OF MONTICELLO SINCE THE COMPLETION OF THE PROGRAM?

A. Yes. Xcel Energy identified and described only a very small number of issues, none of which prevent the plant from operating at its full rated capacity. It is my understanding they are all resolvable with relatively minor repairs and adjustments. This suggests that the overall design was appropriate.

V. OTHER OBSERVATIONS

Q. ARE YOU FAMILIAR WITH THE INSTALLATION OF THE MODIFICATIONS NECESSARY TO IMPLEMENT LCM AND EPU UPGRADES?

A. Yes. A substantial part of my prior job was to oversee implementation of major capital projects. Through that experience, I became very familiar with the types of problems that can be encountered by a nuclear utility.

Q. PLEASE SUMMARIZE THE TYPES OF ISSUES THAT YOU ENCOUNTERED IN YOUR WORK.

A. There are several recurring categories of issues that I have encountered in deploying major capital projects. These include: (i) the need to adjust design to address previously-unknown conditions; (ii) general challenges associated with working within the footprint of an operating nuclear plant; (iii) workforce challenges; (iv) contractor performance issues; and (v) complications arising out of multi-tracking implementation.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO THE NEED TO ADJUST DESIGNS IN RESPONSE TO PREVIOUSLY-UNKNOWN CONDITIONS?

A. Designing upgrades for an operating nuclear plant is necessarily an iterative process. While significant design work can be completed prior to installation, it is generally expected that significant field design work is necessary to adjust or confirm the design to as-found conditions. Sometimes areas are not accessible while the plant is in operation thereby precluding walkdowns during the design phase. While designers can rely on the plant's as-built drawings to some extent, those drawings still need to be confirmed to reflect actual conditions. With a 40-year-old plant it is unsurprising that the as-built drawings did not completely match the actual as-found conditions. In my interviews with Xcel Energy personnel, I understood that they encountered many instances where field design changes were required as a result of drawing discrepencies.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO GENERAL CHALLENGES ASSOCIATED WITH WORKING WITHIN THE FOOTPRINT OF AN OPERATING NUCLEAR PLANT?

A. I have already mentioned in my testimony that one of the challenges of designing upgrades for an operating nuclear plant is that it is necessary to design the upgrades to fit within the preexisting space of the plant. The same considerations hold true with implementation. Once the design is finished, all interferences will need to be removed and the new equipment installed. This can present significant logistical challenges for the installer.

I am very familiar with this issue. As I mentioned, the Turkey Point Nuclear Plant has an extremely small footprint and work on that plant was very challenging. Xcel Energy advised me that the installation of the modifications was the most challenging aspect of the LCM/EPU initiative, because it was so difficult to accomplish all of the required tasks within the existing footprint.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO WORKFORCE CHALLENGES?

A. Qualified nuclear professionals require specialized training when implementing work packages at an operating nuclear plant. This coupled with evolving NRC requirements make working at a nuclear plant challenging.

The work is made more challenging considering the workforce throughout the industry is aging and beginning to retire in large numbers. A substantial percentage of the nuclear workforce is approaching retirement age, creating a need to maintain expertise and demands for staffing adjustments and training of new workers.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO CONTRACTOR PERFORMANCE ISSUES?

A. The quality of vendor performance has weakened generally over recent years and productivity has seen similar declines. Xcel Energy told me that they experienced overall productivity levels in the 2013 outage that were lower than budgeted. There is growing competition for talent in the nuclear industry, which is being driven by a shrinking skilled labor pool and high demand for skilled workers. There is also general attrition related to retirements because of the aging nuclear workforce. Another factor is the decrease in the number of U.S. nuclear engineering degree programs, from 65 in 1980 to just over 30 in 2011. There has also been talent migration from commercial nuclear operators to contracting firms, suppliers and engineering firms.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO COMPLICATIONS ARISING OUT OF MULTI-TRACKING IMPLEMENTATION?

A. While working at FPL, we obtained State regulatory approval to uprate four Florida nuclear units in an expedited manner to deploy the added capacity to meet near-term demand growth. To meet the timing requirements, FPL initiated its EPU program in parallel with design, engineering, procurement and construction efforts. Xcel Energy has advised me that they were in a similar position and that at the time they decided to embark upon the LCM/EPU initiative, they needed to multi-track the effort in order to add new capacity in time to meet growing demand.

There is no question that proceeding with multiple tasks simultaneously makes it difficult to accurately estimate the magnitude of the work that needs to be done and it was my experience in Florida that this dynamic resulted in actual costs being substantially underestimated.

Q. PLEASE ELABORATE ON THE IMPLICATIONS IF A UTILITY DOES NOT MULTI-TRACK A MAJOR INITIATIVE OF THIS TYPE.

A. If the utility chose not to pursue all activities in parallel, it would simply mean that the utility would have to perform all tasks serially. Taken to its extreme, this approach could require the utility to first obtain the NRC license, then commence detailed design, and then complete the design prior to commencing any of the implementation. While this is certainly an approach that was available, it is inconsistent with the goal of maximizing the use of the asset during its extended license period.

Q. WHAT WERE PRACTICAL CONSEQUENCES IF XCEL ENERGY DECIDED TO WAIT UNTIL IT RECEIVED ITS NRC LICENSE AMENDMENT PRIOR TO COMMENCING ANY OTHER ACTIVITIES?

A. As things ultimately unfolded, it would have meant that Xcel Energy program would have been significantly delayed. Xcel Energy filed its license amendment request in late 2008, reasonably expecting it to take about a year or a little more based on prior EPU applications. Final implementation would almost certainly have been delayed.

Of course, Xcel Energy has not yet been granted its license amendment. Assuming that the license amendment is granted in late 2013, commencing engineering, procurement and implementation only after the license was granted would have meant that implementation would not have been completed until around 2019 or 2020, with about 10 years left on the operating license.

Q. DO YOU HAVE ANY FINAL OBSERVATIONS ABOUT XCEL ENERGY'S LCM/EPU EFFORT?

A. Xcel Energy's total cost of $665 for the initiative is roughly double the initial $320 million estimate. This is entirely consistent with my experience at FPL where the cost (on a per-unit basis) was $782.25 million which was roughly double the initial estimate of $349.5 million. In addition, as I mentioned above, I understood that Xcel Energy encountered many of the same issues I encountered at FPL. The fact that Xcel Energy's cost profile was very similar to my experience and Xcel Energy encountered many of the same issues I encountered suggests to me that, on the whole, while more expensive than projected, heir initiative worked out about well, assuming they ultimately obtain the uprate license. Based on my review of the scope and design of the project, I am not surprised by the magnitude of the costs Xcel Energy incurred or the results achieved.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

John Arthur Stall (Art)

EDUCATIONAL BACKGROUND

University of Florida; Gainesville, Florida
BS, Nuclear Engineering – 1977

Virginia Commonwealth University; Richmond, Virginia
MBA – 1983

Professional Engineer (PE) License;
Virginia Inactive

BUSINESS EXPERIENCE

FPL GROUP (NextEra Energy)
Juno Beach, Florida Power &
Light May 1996 to May 2010

FPL Group is one of the nation's largest providers of electricity related services and is nationally recognized as a leader in renewable energy development activities. The company is one of the nation's largest nuclear fleet operators in the United States, with annual revenues of more than $15 billion and a presence in 27 states.

PRESIDENT NUCLEAR DIVISION
January 2009 to May 2010
Responsible for overall strategic direction of company's nuclear program. Primary focus is on actively influencing federal nuclear energy policy decisions and emerging regulatory requirements in Washington. Served as expert witness in various regulatory proceedings in numerous states in matters such as rate cases, prudency determinations and acquisitions. Reports directly to chairman and CEO of FPL Group. Have announced retirement effective, April, 2010.

SENIOR VICE PRESIDENT AND CHIEF NUCLEAR OFFICER
June 2001 to January 2009
Responsible for all aspects of FPL Group's nuclear program, 8 operating units in 4 states. Based on the doubling of FPL Group's nuclear fleet from 4 units to 8, I am skilled in due diligence, valuation and the integration of large, complex operations into an existing organization (standardization of processes). The result has been improved operating metrics and reduced production costs. Also, well versed in applying sound risk management practices to complex industrial operations.

VICE PRESIDENT, NUCLEAR ENGINEERING
March 2000 to June 2001
Responsible for all engineering related activities for the entire nuclear fleet. This included design and modification activities. Successfully implemented many major capital projects on schedule and on budget.

VICE PRESIDENT, ST. LUCIE NUCLEAR PLANT
May 1996 to March 2000
Successfully led performance turnaround at FPL's St. Lucie nuclear plant. This was an underperforming asset with operating and regulatory issues. Responsible for all site operations at this 2 unit nuclear facility.

VIRGINIA ELECTRIC AND POWER COMPANY (DOMINION)
Richmond, Virginia
June 1977 to May 1996

Dominion is one of the nation's largest producers of energy, with an energy portfolio of approximately 26,500 megawatts of generation and 7800 miles of natural gas transmission pipeline. Dominion also operates the nation's largest underground natural gas storage system with about 950 billion cubic feet of storage capacity, and serves retail customers in 11 states. Dominion is one of the largest nuclear plant operators with 7 units.

PLANT MANAGER, NORTH ANNA NUCLEAR PLANT
April 1993 to May 1996

Had complete responsibility for the day to day operation and maintenance of two, 950 megawatt nuclear units. Responsible for a team of over 700 employees, with diverse roles including operations, maintenance, engineering, financial/budgeting, security, and administrative/human resources. North Anna was consistently recognized as an industry leader in terms of regulatory and operational performance.

ASSISTANT PLANT MANAGER, OPERATIONS AND MAINTENANCE
Spring 1992 to April 1993

Responsible for all operational and maintenance activities for two, 950 megawatt nuclear units (North Anna).

ASSISTANT PLANT MANAGER, NUCLEAR SAFETY AND LICENSING, NORTH ANNA
Winter 1989 to Spring 1992

Responsible for all interactions with the United States Nuclear Regulatory commission. This included licensing actions, inspection related activities, and resolution of enforcement issues when required. As nuclear is so highly regulated, this assignment was designed to broaden skills in understanding and working effectively with government regulators.

SUPERINTENDENT PLANT OPERATIONS, NORTH ANNA
Fall 1987 to Winter 1989

Responsible for a department of 125 nuclear operators (5 operating crews) who were charged with the physical operation of two, 950 megawatt reactors. As the senior, nuclear regulatory commissioned licensed manager on site, I had final decision making responsibility for all nuclear, safety related matters on site.

SUPERINTENDENT TECHNICAL SERVICES, NORTH ANNA
1985 to Fall 1987

Responsible for all nuclear plant engineering services, instrumentation and controls maintenance technicians and the plant chemistry department.

(NORTH ANNA)
1977 to 1985

Held various positions of increasing responsibility in engineering and operating departments. Primary duties were associated with bringing plant from construction phase through pre-operational testing and subsequent commercial operations. Additionally, trained and received a senior reactor operator's license from the United States Nuclear Regulatory Commission. I spent approximately 2 years operating the reactor in the control room on rotating shifts.

MISCELLANEOUS

- Consulting periodically since retirement.
- Served as a member of the Institute of Nuclear Power Operation's (INPO) National Academy of Nuclear Training Accrediting Board since 2008.

Documents Provided to J.A. Stall in Preparation for Testimony:

Item #	Document Title/Description	Document Date
1	Timothy J. O'Connor Witness Book	11/02/2012
2	Project Status Report – License Monticello Extended Power Uprate.	01/2008
3	Project Status Report – Implement Monticello Extended Power Uprate.	06/2009
4	Attachment 9: EPU Estimate Breakdown; Monticello Mid Cycle Outage (MCO) – Project Controls – Kick Off Meeting.	07/21/2011
5	EPU Project Status Report – License Monticello Extended Power Uprate	09/2007
6	Vendor Selection for EOC of 13.8kV Modification	10/14/2009
7	MNGP – Project Management Plan/Type A – EPU-13.8kV System Additions	Rev. 02/16/2012
8	Project Scope Change Request SC-070 - Engineering for EPU	10/25/12
9	Project Scope Change Request SC-072 - 13.8kV Project	11/16/12
10	Project Scope Change Request SC-080 - 13.8kV Project	1/29/13
11	Project Scope Change Request SC-085 - 13.8kV Project	2/20/13
12	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-088 – 13.8kV Project	2/26/13
13	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-092 – 13.8kV Project	4/6/13
14	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-095 – 13.8kV Project	4/17/13
15	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-097 - 13.8 kV Project	4/30/13
16	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-098 – Contract 30970	5/1/13
17	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-099	4/25/13
18	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-100 - 13.8kV Project	5/2/13
19	Vendor Selection for EOC of 13.8kV Modification - Revised	10/14/09
20	Nuclear Project Authorization (NPA) – Implementation of 138kV Electrical Distribution System (Continuation: Sept. 2011)	12/1/11
21	13.8kV Electrical Distribution Project Status Report Update	6/13
22	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) 2013-36 - 13.8kV Project	5/12/13
23	Xcel Energy 5-Year Capital Expenditure Review and Major Project Authorizations	
24	Minute Meetings 13.8kV Project Internal Challenge Board 1R/2R Concurrent Replacement	5/8/12
25	Letter from Al Williams (MNGP EPU Project Manager) to Frank Helin (GE EPU Project Manager) re: Main Transformer Replacement	4/24/07

Item #	Document Title/Description	Document Date
26	Xcel Energy 2011 Capital Expenditure Review and Major Project Authorizations	2011
27	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – preliminary Engineering and Support for 13.8kV Modification	4/4/08
28	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – 13.8kV Modification Conditional Release	5/29/09
28	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – 13.8kV Contract Closure	11/11/09
29	Major Projects – Nuclear CNO One-Pagers – Monticello Nuclear Generating Plant Extended Power Uprate and associated Life Cycle Management Modifications	8/4/10
30	Meeting Notification with attached EPU Executive Steering Committee Meeting Agenda with notes	11/14/07
31	Project Closeout Report - 13.8k.V Project	2013
32	Rationale Behind Determination of Cost Splits Between EPU and LCM for Established Projects	
33	Pre-Outage Milestone Recovery Plan – 13.8kV Modification/Project #11257804	2/26/10
34	Project Scope Change Request SC-001 – 13.8kV	6/16/10
35	Request for Project Management Reserve/Contingency Utilization SC-002 -13.8kV Modifications	6/30/08
36	Request for Project Management Reserve/Contingency Utilization SC-003 -13.8kV Modifications	6/30/08
37	Project Scope Change Request SC-004 – MG Set Motor Replacement	6/21/10
38	Request for Project Management Reserve/Contingency Utilization SC-005 -13.8kV Modifications	6/30/08
39	Project Scope Change Request SC-008 – 2R Relocation During RFO25	8/31/10
40	Project Scope Change Request SC-011 – 2R Relocation During RFO25	9/22/10
41	Project Scope Change Request SC-013 – 2R Feeder Cable Relocation	9/27/10
42	Request for Project Management Reserve/Contingency Utilization SC-017 -13.8kV Modifications	6/30/08
43	Project Scope Change Request SC-018 – 13.8kV Modifications	11/2/10
44	Project Scope Change Request SC-028 – 13.8kV Modifications	1/28/11
45	Request for Project Management Reserve/Contingency Utilization SC-031 -13.8kV Modifications	6/30/08
46	Project Scope Change Request SC-032 – 13.8kV	3/16/11
47	Project Scope Change Request SC-038 – 13.8kV	5/11/11
48	Project Scope Change Request SC-039 – 13.8kV	5/11/11
49	Project Scope Change Request SC-042 – 13.8kV	7/12/11
50	Project Scope Change Request SC-064 – 13.8kV Project	10/17/12

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51	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Condensate Demineralizers Replacement	10/3/08
52	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Mod 4a, Condensate Demin Control Panel Replacement	10/1/08
53	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Condensate Demineralizer Bypass Valve Schedule Impact	2/3/09
54	Letter from Allen Williams to Frank Helin (cc: Joe Paritz, Mike Meier) re: PCR JXH5H-E121 – EC 11006 Condensate Demineralizer	10/12/09
55	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – CDM Mechanical and Electrical Scope Changes (EC11006)	3/3/10
56	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – EC11006, Condensate Demin, Movement of Sample Control Panel C231B	8/17/10
57	Management Oversight Committee	
58	Information Request No. 1187 - Supplement	5/20/11
59	Rationale Behind Determination of Cost Splits Between EPU and LCM for Established Projects	
60	Project Scope Change Request SC-025 – Replacement of Condensate Demineralizers	3/18/11
61	EPU Margin Impacts	4/30/08
62	EPU Project Status Report – Implement Monticello Extended Power Uprate	5/08
63	Monticello Executive Oversight Committee Briefing – Plant Performance and Optimization	7/18/07
64	EPU Steering Committee Meeting Minutes	9/22/06
65	Project Status Scorecard – EPU Projects	10/08
66	Minutes EPU Steering Committee	10/13/06
67	EPU Project Status Report – Implement Monticello Extended Power Uprate	12/07
68	Power Uprates for Monticello and Prairie Island – Feasibility Study Preliminary Results April 2006	5/6/06
69	Steering Committee, Condensate Demineralizer Upgrades	9/29/06
70	Next article in the EPU series will focus on the Condensate Demineralizer System Replacement for the Spring 2011 Outage	
71	Nuclear Project Authorization Form – Monticello Extended Power Uprate Implementation of Steam Dryer Replacement Project	2009
72	Contract Approval Rider – add to existing contract for Phase 2 – Extended Power Uprate/Life Cycle Management Project and MNGP	12/18/06
73	Monticello Nuclear Generating Plant Condensate Demineralizer Replacement Project Plan	
74	Project Status Report Template – Condensate Demineralizer & Control Panel Replacement for EPU	5/11

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75	EPU Scope Changer Request Condensate Demineralizer Panel Upgrade	11/10/06
76	NMC Today Article – Week of 5/2/08 – EPU Condensate Demineralizer Modifications	5/2/08
77	GE memo from Bruce Hagemeier to Steve Hammer (NMC) re: Transmittal of Final MNGP Extended Power Uprate Cost Scoping Assessment	5/26/06
78	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services	2/19/08
79	Letter from Allen Williams to Frank Helin (cc: K. Albrecht, C. Bomberger, J. Ball) re: PCR JXH5H-EO76 R1 "Condensate Demineralizers Replacement"	7/31/08
80	Project Scope Change Request SC-044 – EPU Implementation-Condensate Pump Replacement	8/30/11
81	Project Scope Change Request SC-062 – EC 16307 Condensate Pump HVAC Upgrade	10/19/12
82	Project Scope Change Request SC-063 – EC 16307 Condensate Pump HVAC Upgrade	7/3/12
83	Project Scope Change Request SC-077 – Condensate Pump Replacement	12/14/12
84	Project Scope Change Request SC-078 – Condensate Pump Replacement	12/14/12
85	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-091	3/20/13
86	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-101	5/10/13
87	Project Impact Notice (PIN)/Project Scope Change Request (PSCR) SC-108	5/22/13
88	Executive Oversight Committee Meeting – Monticello EPU Project	1/21/08
89	EPU Margin Impacts	4/30/08
90	Monticello Executive Oversight Committee Briefing – Plant Performance and Optimization	7/18/07
91	EPU Project Status Report – License Monticello Extended Power Uprate	8/07
92	Project Status Report – Implementation Monticello Extended Power Update	8/08
93	Project Status Scorecard – EPU Projects	9/08
94	Condensate Pump Replacement – Project Status Report	11/07
95	EPU Project Status Report – Implement Monticello Extended Power Uprate	12/07
96	Power Uprates for Monticello and Prairie Island – Feasibility Study Preliminary Results April 2006	5/6/06

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98	Nuclear Project Authorization (NPA) – Condensate Pump and Motor Replacement	12/1/11
99	Monticello Nuclear Generating Plant Condensate Pump Replacement – Type C Project Plan	6/19/09
100	Monticello Nuclear Generating Plant Condensate Pump and Motor Replacement Project Management Plan	10/11
101	Project – Condensate Pumps	8/11
102	EPU-Extended Power Uprate – Condensate Pumps (EC's 10946, 15376, 16307) PINS and Trends	
103	Monticello EPU Fleet Review/Update – Al Williams	9/12/07
104	GE memo from Bruce Hogemeier to Steve Hammer (NMC) (cc: Jon Ball, George Paptzun, Hoa Hoang, Sean Sexstone, Larry Tucker, Jim Kinsey, Cathy Petros, Robert Field (S&L)) re: Transmittal of Final MNGP Extended Power Uprate Cost Scoping Assessment	5/26/06
105	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Condensate Pump First Storage Impeller Test Spec, FW & CD system White papers	10/3/08
106	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Condensate Pump Motor Purchase	6/23/09
107	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Condensate Pump Motors PD Couples Purchase	9/25/09
108	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – EC10946-Condensate Pump Motors Area HVAC Modifications	12/14/09
109	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Condensate Pump Start Time Testing	7/11/11
110	Management Oversight Committee	9/13/06
111	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Changes to CD and RFP Motor Rotors to meet Starting Performance Requirements	9/30/11
112	Rationale Behind Determination of Cost Splits Between EPU and LCM for Established Projects	
113	Project Scope Change Request SC-016 – Condensate Pump Auxiliary Equipment Mod	10/12/10
114	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Mod 8: AOV Vendor Selection	7/17/08
115	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Mod 8 Control Valve Calculations for Dump and Drain Valve Specification	10/3/08

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117	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Feed Water Heater Drain and Dump Valve Sizing and Viton Elastomer	10/24/08
118	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Replace Existing Mod 8 Positioners with 3582 NS Positioners	2/6/09
119	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Credit for Mod 8 3582 NS Positioners	5/13/09
120	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Support Analysis for Mod 8	2/27/09
121	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – EC11309, FW Heaters Level and Pressure Transmitters Change in Division of responsibility	11/11/09
122	GE Hitachi Project Change Request – MNGP Extended Power Uprate Services – Feedwater Heater Tubeside Relief Change in Materials	5/14/10
123	EPU – Nuclear Oversight of E-13A, E-13B, E-14A, E-14B, E-15A, and E-15B Feedwater Heater Fabrication at Holtec, Inc. by Jack Phelps	5/11/11
124	Rationale Behind Determination of Cost Splits Between EPU and LCM for Established Projects	
125	Nuclear Power Authorization (NPA) – Replace 13/14/15 Feedwater Heaters	9/23/11
126	Project Scope Change Request SC055 – Feed Water Heaters	8/13/12
127	Project Scope Change Request SC056 – Feed Water Heaters	8/13/12
128	Project Scope Change Request SC057 – Feed Water Heaters	8/13/12
129	Project Scope Change Request SC059 – Feed Water Heaters	9/12/12
130	Project Scope Change Request SC071 – Feed Water Heaters	10/31/12
131	Monticello Extended Power Uprate (EPU) Xcel Energy	2/5/09
132	Project Status Report – Implement Monticello Extended Power Uprate	3/10
133	Project Status Report – Implement Monticello Extended Power Uprate	4/10
134	EPU Margin Impacts	4/30/08
135	Project Status Report – Implement Monticello Extended Power Uprate	7/09
136	Project Status Scorecard – EPU Projects	9/08
137	EPU Steering Committee Meeting Minutes	12/21/06
138	Power Uprates for Monticello and Prairie Island Feasibility Study Preliminary Results April 2006	5/6/06
139	FWH 13 A&B Replacement Project Status Report Update	8/12
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143	Feedwater Heating Projects	8/11
144	Monticello Nuclear Generating Plant – Reactor Feedwater Pump EPU Modification – Type C Project Plan	8/22/09
145	GE memo from Bruce Hagemeier to Steve Hammer (NMC) (cc: Jon Ball, George Paptzun, Hoa Hoang, Sean Sexstone, Larry Tucker, Jim Kinsey, Cathy Petros, Robert Field (S&L)) re: Transmittal of Final MNGP Extended Power Uprate Cost Scoping Assessment	5/26/06
146	Monticello Nuclear Generating Plant – Feedwater Heater Replacement Projects Project Management Plan	11/16/11
147	FWH 13 A&B Replacement Project Status Report Update	6/13
148	GE Hitachi Draft Project Change Request – MNGP Extended Power Uprate Services – Removal of Valves from scope for Mod 8 (FWH Drain Control Valves and Dump Valve Replacement)	3/18/08
149	Letter from Sean Sexstone to Judy Marcello (cc: H. Hoelscher, P. Burke, J. Hill, J. Ball, G. Paptzun, B. Hagemeier) re: Monticello EPU Cost Scoping Assessment GE Proposal No. 1208-JXFW8-EK1	2/1/06
150	GE Nuclear Energy – Nuclear Management Company - Monticello Nuclear Generating Plant – Extended Power Uprate/MELLLA+ Feasibility Study	7/04
151	GE memo from Bruce Hagemeier to Steve Hammer (NMC) (cc: Jon Ball, George Paptzun, Hoa Hoang, Sean Sexstone, Larry Tucker, Jim Kinsey, Cathy Petros, Robert Field (S&L)) re: Transmittal of Final MNGP Extended Power Uprate Cost Scoping Assessment	5/26/06
152	GE Energy Nuclear – Nuclear Management Company – Monticello Nuclear generating Plant (MNGP) – Extended Power Uprate – Cost Scoping Assessment – Oracle Project Number 40811 – Project-Specific Project Work Plan	2/06
153	Xcel Energy Contract Amendment – MNGP Extended Power Uprate Services	10/23/09
154	Letter from Frank Helin to Robert Bing re: Amendment 7 to Agreement No. 8374 (Contract Agreement No. 8374, between Nuclear Management Company, LLC and General Electric, effective September 26, 2006, as amended to date)	1/15/10
155	Contract Approval Rider for Phase 1 contract for studies and analysis associated with the Extended Power Uprate/Life Cycle Management project and MNGP	
156	Contract Approval Rider for Phase 2 - Extended Power Uprate/Life Cycle Management project and MNGP	12/18/06

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160	Contract – 2009 GE-EPU Milestones and PCR Payments	4/21/09
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162	Xcel Energy Record Information Sheet – GE-Hitachi Nuclear Energy Americas LLC	1/13/10
163	Contract – March Milestone Payment Including PCR's for EPU from GE	5/11/10
164	Contract – June Milestone Payment Including PCR's for EPU from GE	7/20/10
165	Contract – Milestone Payment per PCR E024	1/12/11
166	Contract – October Milestone Payment Including PCR's for EPU from GE	2/17/11
167	Letter/Proposal from Sean Sexstone to Robert Bing (cc: L. Bohn, S. Bernhoft, S. Hammer, J. Ball, H. Hoang, C. Hinds) re: Monticello Nuclear Generating Plant – Extended Power Uprate/Life Cycle Management Project Phase I	8/18/06
168	Contract – MNGP Extended Power Update Services	9/8/06
169	NSP/General Electric Special Conditions for Phase I of the Power Uprate of the Monticello Nuclear Generating Plant	9/26/06
170	PowerPoint – MSRC-Extended Power Uprate – Al Williams	4/8/08
171	PowerPoint – MSRC-Extended Power Uprate – Al Williams	4/8/08
172	PowerPoint – MSRC-Extended Power Uprate – Project Update	11/4/10
173	Monticello Extended Power Uprate – Project Update	10/30/08
174	PowerPoint – MSRC-Extended Power Uprate – Al Williams	4/8/08
175	PowerPoint – MSRC-Extended Power Uprate – Project Update	7/8/10
176	PowerPoint – MSRC-Extended Power Uprate – Project Update	7/8/10
177	PowerPoint – MSRC-Extended Power Uprate – Project Update	10/9/09
178	PowerPoint – MSRC-Extended Power Uprate – Project Update	10/28/08
179	PowerPoint – MSRC-Extended Power Uprate – Project Update	11/4/10
180	PowerPoint – MSRC-Extended Power Uprate – Project Update	11/4/10
181	PowerPoint – Monticello Extended Power Uprate – Project Overview	
182	Timeline and history of steam dryer and containment accident pressure analysis at MNGP	
183	Monticello Nuclear Generating Plant Project Management Plan Type A – EPU-13.8kV System Additions	2/16/12
184	Monticello Nuclear Generating Plant 1AR Cable Replacement Project Plan	6/25/09
185	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	5/10
186	Monticello Extended Power Uprate Project – Organizational Chart	4/09
187	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	4/10

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189	Project Work Plan Project No. EC-11126 Monticello Unit 1 – Xcel EPU/MS FW BOP Piping Evaluation Modification Installation	9/18/08
190	Project Work Plan Project No. EC-13195 Monticello Unit 1 – Nuclear Management Company CARVS Discharge Piping Replacement Modification Installation	10/22/08
191	Monticello Nuclear Generating Plant Condensate Demineralizer Replacement Project Plan	
192	EPU Scope Change Request Condensate Demineralizer Panel Upgrade	11/10/06
193	Monticello Nuclear Generating Plant Condensate Pump Replacement Type C Project Plan	6/19/09
194	Monticello Nuclear Generating Plant Condensate Pump and Motor Replacement Project Management Plan	10/11
195	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	12/09
196	Monticello Nuclear Generating Plant Reactor Feedwater Pump EPU Modification Type C Project Plan	8/22/09
197	MPU Management (chart)	12/6/10
198	Monticello Nuclear Generating Plant EPU Implementation EC-13638 Project Management Plan	11/11
199	Monticello NMC Organization – EPU (chart)	10/3/08
200	Monticello NMC Organization – EPU (chart)	10/31/07
201	Monticello NMC Organization – EPU (chart)	11/10/08
202	Monticello NSPN Organization – EPU (chart)	12/12/08
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204	Monticello NSPM Organization – EPU (chart)	1/31/09
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206	Monticello NMC Organization – EPU (chart)	2/29/08
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208	Monticello NMC Organization – EPU (chart)	5/14/08
209	Monticello NMC Organization – EPU (chart)	5/31/08
210	Monticello NMC Organization – EPU (chart)	6/24/08
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213	Monticello NMC Organization – EPU (chart)	2/1/08
214	Monticello Nuclear Generating Plant Exiter Replacement Plan	6/25/09
215	Monticello Extended Power Uprate Project – Organizational Chart	2/19/09
216	Major Projects – Nuclear – Monticello Extended Power Uprate	2/10
217	Monticello Nuclear Generating Plant Reactor Feedwater Pump EPU Modification Type C Project Plan	8/22/09
218	Project Work Plan Project No. EC-11264 Monticello Unit 1 – Nuclear Management Company Feedwater Flow Transmitters Upgrade Modification Installation	7/23/08

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220	Monticello Nuclear Generating Plant Generator Rewind (Stator and Field) Type C Project Plan	6/25/09
221	Project Work Plan Project No. EC-11034 Monticello Unit 1 – Nuclear Management Company EPU/Passive GEZIP Modification Installation	7/30/08
222	Project Work Plan Project No. EC-11018 Monticello Unit 1 – Xcel Energy EPU/GSU-XO1 Main Transformer Mod Installation	9/13/08
223	Monticello Nuclear Generating Plant Hydrogen Cooler EPU Modification Type C Project Plan	6/26/09
224	Project Work Plan Project No. EC-11129 Monticello Unit 1 – Xcel EPU/Isophase Bus Duct Cooling Modification Installation	9/18/08
225	Monticello Extended Power Uprate Project – Organizational Chart	1/14/09
226	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	1/10
227	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	7/09
228	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	6/09
229	Project Work Plan Project No. EC-11214 Monticello Unit 1 – Nuclear Management Company Main Steam Flow Transmitters Upgrade Modification Installation	7/23/08
230	Monticello Nuclear Generating Plant Main GSU Transformer Replacement Type C Project Plan	7/22/09
231	Monticello Extended Power Uprate Project – Organizational Chart	3/13/09
232	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	3/10
233	Monticello Extended Power Uprate Project – Organizational Chart	5/09
234	Major Projects – MNGP EPU (chart)	5/11
235	Monticello Extended Power Uprate Project Management Plan	2/22/07
236	Monticello Extended Power Uprate Project Management Plan	5/08
237	Monticello Nuclear Generating Plant Reactor Feedwater Pump EPU Modification Type C Project Plan	8/22/09
238	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	10/19/10
239	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	
240	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	8/1/10
241	Day & Zimmermann NPS – EPU Organizational Chart	10/18/10
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244	NMC Organization – EPU (chart)	
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252	Project Work Plan Project No. EC-10856 Monticello Unit 1 – Xcel Energy EPU/PRNM Mod Installation	9/13/08
253	Monticello Nuclear Generating Plant Project Management Plan Type A EPU-13kV System Additions	8/18/10
254	Monticello Nuclear Generating Plant Reactor Water Clean-Up System EPU Modification Type C Project Plan	6/26/09
255	Monticello Nuclear Generating Plant Reactor Feedwater Pump EPU Modification Type C Project Plan	6/26/09
256	Monticello Nuclear Generating Plant Reactor Feedwater Pump Replacement Project Management Plan	10/11
257	Major Projects – Nuclear – Monticello Extended Power Uprate (chart)	9/09
258	Monticello Nuclear Generating Plant Steam Dryer Replacement Project – Project Plan	
259	Project Work Plan Project No. EC-11125 Monticello Unit 1 – Xcel EPU/Torus Attached Piping (TAP) Modification Installation	9/18/08
260	Xcel Organization-EPU (chart)	6/09
261	GE Nuclear Energy – Nuclear Management Company - Monticello Nuclear Generating Plant – Extended Power Uprate/MELLA+ Feasibility Study	7/04
262	Xcel Contract Amendment – MNGP Extended Power Uprate Services	10/23/09
263	Letter from Frank Helin to Robert Bing re: Amendment 7 to Agreement No. 8374	1/15/10
264	Contract Approval Rider – Extended Power Uprate/Life Cycle Management Project and MNGP	12/31/06
265	Contract Approval Rider – Extended Power Uprate/Life Cycle Management Project and MNGP	12/20/06
266	NMC Contract – Power Uprate Monticello Phase I	9/18/06
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268	Record Information Sheet – GE-Hitachi Nuclear Energy Americas LLC	8/21/09
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271	Record Information Sheet – GE-Hitachi Nuclear Energy Americas LLC	1/13/10
272	Xcel Contract – March Milestone Payment Including PCRs for EPU from GE	5/11/10
273	Xcel Contract – June Milestones Payment Including PCRs for EPU from GE	7/20/10
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275	Xcel Contract – October Milestone Payment Including PCRs for EPU from GE	2/17/11
276	Sole Source Justification – Requisition Number: Contract 8374-Blanket	9/6/06
277	Memo from Bruce Hagemeier to Steve Hammer (NMC) (cc: Jon Ball, George Paptzun, Hoa Hoang, Sean Sexstone, Larry Tucker, Jim Kinsey, Cathy Petros, Robert Field (S&L)) re: Transmittal of Final MNGP Extended Power Uprate Cost Scoping Assessment	5/26/06
278	Monticello Steam Dryer Request for Approval	
279	Monticello Steam Dryer Request for Approval	12/8/08
280	Monticello EPU Steering Committee	9/5/08
281	NMC Steam Dryer Evaluation Results for Monticello Extended Power Uprate (EPU)	2/13/08
282	Monticello Nuclear Generating Plant Original Steam Dryer Disposal Project – Financial Counsel	6/20/11
283	Monticello Steam Dryer Licensing Issues for Extended Power Uprate	3/26/10
284	Steam Dryer Disposal	1/18/11
285	Monticello Steam Dryer Update – Charles Bomberger-Vice President-Nuclear Projects	10/08
286	Westinghouse Steam Dryer - Monticello Nuclear Generating Plant – draft b	
287	NMC Steam Dryer Evaluation Preliminary Results for Monticello Extended Power Uprate (EPU)	2/13/08
288	NMC Steam Dryer Evaluation Preliminary Results for Monticello Extended Power Uprate (EPU) with script	2/13/08
289	Monticello Steam Dryer Update – Charles Bomberger-Vice President-Nuclear Projects	10/08
290	Monticello Steam Dryer Request for Approval	
291	Westinghouse Offer for Steam Dryer Replacement During the Spring 2011 Outage	8/22/08
292	Change to the Nordic Steam Dryer for EPU	4/12/10
293	Monticello Extended Power Uprate Project Management Plan	2/22/07
294	EPU Project/Electrical Meeting - Monticello Nuclear Generating Plant Expended power Uprate Project Electrical Distribution Systems Meeting	9/18/07
295	State of Minnesota Before the Minnesota Public Utilities Commission – In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns – Direct Testimony and Schedules – James R. Alders on Behalf of Northern States Power Company, A Minnesota Corporation	10/15/13

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297	State of Minnesota Before the Minnesota Public Utilities Commission – In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns – Direct Testimony and Schedules – Scott L. Weatherby on Behalf of Northern States Power Company, A Minnesota Corporation	10/15/13
298	State of Minnesota Before the Minnesota Public Utilities Commission – In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns – Direct Testimony and Schedules – Karen Fili on Behalf of Northern States Power Company, A Minnesota Corporation	10/15/13
299	State of Minnesota Before the Minnesota Public Utilities Commission – In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns – Direct Testimony and Schedules – Steven Hammer on Behalf of Northern States Power Company, A Minnesota Corporation	10/15/13
300	State of Minnesota Before the Minnesota Public Utilities Commission – In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns – Direct Testimony and Schedules – David M. Sparby on Behalf of Northern States Power Company, A Minnesota Corporation	10/15/13
301	State of Minnesota Before the Minnesota Public Utilities Commission – In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns – Direct Testimony and Schedules – Nathan Haskell on Behalf of Northern States Power Company, A Minnesota Corporation	10/15/13
302	State of Minnesota Before the Minnesota Public Utilities Commission – In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns – Direct Testimony and Schedules – Timothy J. O'Connor on Behalf of Northern States Power Company, A Minnesota Corporation	10/15/13

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