Direct Testimony and Schedules
Peter A. Gardner

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-21-630
Exhibit___(PAG-1)

Nuclear Operations

October 25, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have 37 years of experience in the nuclear industry, including a diverse background in operations, maintenance, and engineering at both boiling and pressurized water reactors. Before joining Xcel Energy in 2013, I held the positions of Plant Manager, Operations Director and several other management roles at Exelon Corporation. I also performed an on-loan rotation from Exelon to Institute of Nuclear Power Operations (INPO) and acted as an Organizational Team Leader, visiting several domestic plants.

I graduated from Saint Joseph's University with a MBA in Finance; and also from Widener University with a BS in Engineering; and from Penn State University with a degree in Nuclear Engineering. I received a Senior Reactor Operator License from Limerick Generating Station. My resume is attached as Exhibit___(PAG-1), Schedule 1.

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

A. My testimony supports the capital and operating and maintenance (O&M) spending requested for Xcel Energy's Nuclear Operations Business Area (Nuclear Operations or Nuclear) in this rate case.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY AND AN OVERVIEW OF NUCLEAR OPERATION'S PLANS FOR THE NEXT THREE YEARS.

A. This case, and our pending 2019-2034 Upper Midwest Resource Plan, present important questions for the Minnesota Public Utilities Commission with respect to the future of Xcel Energy's nuclear generation and its role in a carbon-free energy future. For over 50 years, our Monticello Nuclear Generating Plant (Monticello) and Prairie Island Nuclear Generating Plant Units 1 and 2 (Prairie Island) have provided 1,700 MW of reliable, safe, and carbon-free energy to our customers.

Together, these plants comprise more than half of our existing carbon-free generation and approximately 30 percent of our total generation for the NSP system; and serves over 1.5 million homes. The nuclear fleet produced over 14.6 million megawatt hours (MWh) of electricity in 2020, which is the highest generation record since the nuclear fleet began operating. This performance resulted in a nuclear fleet-wide capacity factor of over 96.1 percent.

Our reliance on these plants avoids the emission of 12 million metric tons of carbon dioxide each year. The continued role of nuclear on our system is, therefore, critical to ensuring that we continue to make progress in reducing our carbon emissions toward our corporate goal of achieving an 80 percent reduction in carbon emissions by 2030, as well as our long-term goal of 100 percent carbon-free energy by 2050. Minnesota also has significant carbon reduction goals,[1] and our nuclear plants help advance those goals as well.

Meanwhile, our nuclear fleet adds important resource diversity to our generation portfolio and provides a hedge against not only gas price volatility but also the uncertainty of technological development, future renewable pricing, and the future of solar capacity values. It is also a critical piece of our reliability requirement, as it is not a fuel limited resource, is not subject to pipeline limitations during the winter season and has a strong operating history during cold (and hot) weather events. Lastly, it is important to note the state, community, and employment benefits associated with our nuclear fleet. The fleet currently employs approximately 1,400 full time staff in and around the Monticello and Red Wing communities. This includes full-time and contract staff who support nuclear operations. According to a 2017 Nuclear Energy Institute (NEI) study, the fleet supports an estimated 6,100 additional jobs across Minnesota and generates $1 billion in economic activity each year. This study is attached as part of Exhibit___(PAG-1), Schedule 2.

While we view nuclear power as a central piece of our generation fleet, we recognize that maintaining a fleet of nuclear power plants also presents unique requirements, such as specialized safety needs and a very high level of regulatory oversight. Safety is the Company's first priority for nuclear generation and is an ever-present consideration in any investment we make. We also understand, though, that the future of our nuclear fleet depends on our ability to deliver performance at a reasonable cost, and we have undertaken substantial efforts to

[1] Minn. Stat. § 216H.02, subd. 1.

adopt an innovative approach to plant operations while reducing O&M costs 17 percent from 2016 levels. As discussed in our last rate case, the Company has worked closely with INPO and the Nuclear Regulatory Commission (NRC) to improve equipment and human performance. The Company has also worked with its industry partners, most notably in connection with NEI's "Delivering the Nuclear Promise" initiative (DNP). These efforts have ultimately brought our plants into top quartile performance. In fact, by every measure, our nuclear fleet has never operated on a more consistent, efficient, and safe basis.

To maintain this level of performance, we must continue to address the reliability of our equipment. The NRC's aging management programs require monitoring and planning for upgrades to refurbish equipment to "like new" condition or replace it. We discuss some of these investments later in my testimony.

My Direct Testimony outlines both the benefits of nuclear energy generally and the specific performance of our nuclear fleet since the Company's 2016 rate case, Docket No. E002-GR-15-826 (the "2016 Rate Case"). After discussing these issues, and the purpose and mission of Nuclear Operations, I discuss industry trends that are likely to affect our plans over the next three years, our current capital investment plan for the coming years; why the level of capital we propose to invest in our nuclear plants is reasonable, and the kinds of projects that we plan to undertake. I illustrate in detail that we are making the right kind of investments in our nuclear facilities; balancing the need for safety and our obligation to manage to regulatory requirements with customers' interests in cost-effective, carbon-free energy.

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

Overall, the Company views nuclear generation as a cornerstone not only of our overall fleet, but also of our industry-leading carbon reduction goals. We have undertaken significant efforts to drive industry-leading performance while reducing the costs of our nuclear operations—all while keeping safety as our first priority. As discussed in my testimony, our anticipated capital and O&M levels are reasonable. As shown in the Electric Utility Cost Group (EUCG) data in Exhibit___(PAG-1), Schedule 5, both of the Company's nuclear sites are among the lowest O&M cost nuclear facilities in the nation. The information provided in this testimony strongly supports rate recovery in this case at the levels requested.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony is organized as follows:

- *Section II* – Nuclear Operations Overview and Fleet Performance
- *Section III* – Capital Investments
- *Section IV* – Non-Outage O&M Budgets
- *Section V* – Planned Outage O&M Budgets
- *Section VI* – Conclusion

II. NUCLEAR OPERATIONS OVERVIEW AND FLEET PERFORMANCE

A. Overview and Value Proposition

Q. PLEASE DESCRIBE XCEL ENERGY'S CORE NUCLEAR OPERATIONS.

A. Xcel Energy owns and operates three nuclear units; one unit at Monticello, Minnesota; and two units at Prairie Island in Welch, Minnesota.

Monticello is a single-unit boiling water reactor rated for gross output at 671 MW and was originally licensed by the NRC in 1970. The NRC approved a renewed license for the facility in 2006, allowing the plant to operate through 2030. As discussed in our pending 2019-2034 Upper Midwest Resource Plan, the Company intends to seek a Certificate of Need (CON) from the Commission to expand the Independent Spent Fuel Storage Installation ("ISFSI") to allow the plant to operate an additional 10 years, to 2040, as well as a Subsequent License Renewal ("SLR") from the NRC that will authorize operation until 2050, as NRC SLRs are issued for a twenty-year period.

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

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

A. Our top priority is operating at the industry's highest standards for safety and reliability. However, we also recognize that we must operate our plants at a competitive cost, and we have been on a journey of continuous improvement to drive strong performance and reduce cost—all while maintaining a focus on safety and reliability. Our mission in Nuclear is to foster a learning environment that promotes safe operations, continually raises operational performance to standards of excellence, promotes accountability for strong financial stewardship, and demonstrates leadership within the nuclear industry and the communities we serve.

Q. WHAT IS THE VALUE PROPOSITION FOR NUCLEAR FROM A CUSTOMER PERSPECTIVE?

A. Nuclear offers more than 1,700 megawatts of cost-effective, carbon-free, generating capacity, enough to power 1.5 million homes in our service territory. In 2020, Nuclear provided about 30 percent of the generation used by the NSP system in the upper Midwest—*all with no greenhouse gas emissions*. See Exhibit___(PAG-1), Schedule 2, which includes the latest NEI Fact Sheet on Minnesota and Nuclear Energy. The value proposition for Nuclear has several components.

Reliable Carbon-Free Energy

Nuclear power is a key component of the Company's vision to be 100 percent carbon-free by 2050 and currently provides 30 percent of the electricity used by Xcel Energy's Upper Midwest customers. The Company simply cannot achieve the aggressive levels of carbon reduction desired by both Xcel Energy and the State of Minnesota at an affordable price without nuclear generation on our system at this time.

Specifically, our nuclear plants are critical to our current plan, as set forth in our Integrated Resource Planning (IRP) docket,[2] to retire our Sherco Units 2 and 1 in 2023 and 2026 respectively, as we become less reliant on coal generation.

Our nuclear fleet provides around-the-clock grid stability, voltage support, and overall reliability – some of the positive grid-supporting attributes that are currently provided by our coal units. Our nuclear plants have up to 24 months of fuel when refueled, and thus are not subject to fuel supply disruptions. They also are not subject to pipeline limitations during the winter season, and they have a very strong operating history during cold and hot weather events. In fact, we achieved a nuclear fleet-wide capacity factor of over 96.1 percent in 2020. Monticello is at the core of the NSP bulk power system. The grid has grown around this core near Becker and depends on ongoing power injection at this point. Continued reliable carbon free power injection at this site helps ensure a stable resource transition given the evolution of resources around it.

No other generation source is as reliable as Nuclear. Nuclear plants are designed to run at consistently high output levels, unlike most other generation resources. Nuclear generation provides the constant output that is an important and necessary complement to the large amounts of intermittent, renewable generation on our system.

[2] E002/RP-19-368 2020-2034 Upper Midwest Integrated Resource Plan

Clean Energy

Nuclear is a critical component of the Company's carbon reduction goals. Nuclear energy produces 50 percent of NSP-Minnesota's emission-free electricity and is unique in that it can do so virtually around the clock[3]. As a result, it is estimated that in 2020, Minnesota's nuclear facilities prevented the emission of 9.5 thousand short tons of nitrogen oxides, 13 thousand short tons of sulfur dioxide, and 12.9 million metric tons of carbon dioxide. NEI's summary of emissions avoided in Minnesota in 2019 is included in the Minnesota Fact Sheet provided in Schedule 2. The role of nuclear generation is further heightened as more and more coal generation comes offline.

Cost-effective Resource

Now, more than ever, our nuclear fleet is delivering this carbon-free energy at a competitive cost. We achieved these successful operating results while continuing to maintain safety and affordability through operational excellence. In 2020, our fleet achieved its third year in a row of production costs below \$30/MWh, which represents over a 30 percent decline from 2013. We have reduced our annual O&M costs relative to 2016 by over \$50 million, which represents a seventeen percent improvement compared to 2016 results, and marks the sixth straight year of declining O&M in our nuclear operations from 2014. We have achieved these operational savings while continuing to prioritize safety. Both the Monticello and Prairie Island plants have maintained high levels of safety performance, achieving top marks on the industry's rigorous safety evaluations. In fact, our nuclear fleet was recognized as one of the highest performing fleets in the country according to our nuclear industry peer group,

[3] See Schedule 2, NEI Report

and, based on that strong operational performance, Xcel Energy was recently chosen by NuScale Small Modular Reactor (SMR) Technologies to enter a memorandum of understanding (MOU) to explore the feasibility of Xcel Energy serving as a plant operator at NuScale Plants.

The impact of these cost reductions can be seen in the economic modeling for our 2019 Integrated Resource Plan. The Company's Alternate Preferred Plan, filed in June 2021, continues to show benefits of a ten-year extension of our Monticello unit to 2040, and operating our Prairie Island units at least through their current license lives. In short, these resources are essential to the achievement of our carbon reduction goals and are part of a cost-effective plan to achieve those goals.

Resource Diversity

Our nuclear fleet adds important diversity to our generation portfolio and provides a hedge against not only gas price volatility but also the uncertainty of technological development, future renewable pricing, and the future of solar capacity values. The importance of a diverse portfolio of resources to an affordable and reliable clean energy transition cannot be overstated. In addition to resource diversity, operational and resource diversity attributes provide important benefits. We need a mix of large and small plants with their different operational attributes in order to maximize production and reduce risk.

Jobs and Economic Development

Xcel Energy currently employs approximately 1,400 people working in, or directly supporting, our Nuclear business area, but the economic impact of our fleet goes well beyond that. In its report "*The Impact of Xcel Energy's Nuclear Fleet* *on the Minnesota Economy*," provided as part of Schedule 2, NEI estimates that in 2016, "Xcel Energy's nuclear facilities were estimated to contribute $595 million to Minnesota's gross state product (GSP). . ." In addition, the report finds that "…for every dollar of output from Xcel Energy's nuclear operations, the state economy produces $1.98."

The Company's nuclear fleet also generates substantial tax revenue for the state, contributing about $42 million in state and local taxes annually.

Q. YOU MENTIONED AN MOU THE COMPANY ENTERED INTO WITH NUSCALE. ARE ANY COSTS RELATED TO THAT POTENTIAL DEAL INCLUDED IN THIS CASE?

A. No. There is no planned work related to that potential deal during the MYRP period, and accordingly no related costs are included in the case.

B. Nuclear Fleet Performance

Q. BEFORE DISCUSSING RESULTS, PLEASE REVIEW NUCLEAR OPERATIONS' STRATEGIC FOCUS AREAS, AS COMMUNICATED IN THE LAST RATE CASE.

A. In the 2016 Rate Case, we discussed the following three strategic focus areas that would shape Nuclear Operations' work during the term of the MYRP:

- *Safe operations* - with the goal of meeting the NRC's expectation for public safety by complying with our operating license, ensuring plant security and adequately planning for emergencies, safely conducting dry fuel storage, and anticipating what safety issues might be coming. Our goal was to achieve Column 1 status, without "greater than green" findings[4] or cross-cutting issues raised by the NRC and without significant operating events.

[4] See Exhibit___(PAG-1), Schedule 9, which includes a summary of the NRC's Reactor Oversight Process and the color coding used to designate findings from inspections and performance reporting.

- *Reliability* - targeted at delivering high-capacity factors, meeting system generation output expectations and optimizing refueling outages.
- *Cost optimization and higher performance standards* - through optimizing fuel cycles, building connections with the Utility Services Alliance, and using strategic sourcing focusing on performance accountability, and implement organizational best practices.

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

A. We delivered. In focusing on these strategies, we have undertaken substantial efforts to change the way we approach plant operations and deliver benefits to our customers. Working with third-party consultants with expertise in both nuclear operations and general cost containment and efficiency strategies, and with the INPO and NEI, we have achieved industry-leading results; not only in the performance of our nuclear plants, but also in managing the costs we are investing to achieve that performance. Indeed, as this testimony is filed, we have all units in Exemplary Status at INPO, all units in NRC Column 1 Status with all green performance indicators, and all units with no identified NRC Safety Culture issues. While maintaining this elite position with INPO and the NRC is not guaranteed, the Company continues to strive to maintain the practices that have helped us achieve this exceptional level of performance. The end result is that, at this moment, our nuclear plants have never operated on a more consistent, efficient, and safe basis.

Since the 2016 Rate Case, we have achieved the following results:

- *Safe operations* – Both Monticello and Prairie Island are currently NRC Column 1 plants with all green performance indicators. Both the

Monticello and Prairie Island plants have maintained high levels of safety performance, achieving top marks on the industry's rigorous safety evaluations. In fact, our nuclear fleet was recognized as one of the highest performing fleets in the country.

- *Reliability* – The investments we have made in our plants over the past several years have paid off. Since January 2018 (through August 2021), Monticello has operated at an average capability factor of 94.2 percent, including 99.3 percent in 2018 and 98.6 percent in 2020, both non-refueling years. In that same timeframe, Prairie Island achieved a combined average capacity factor of more than 95 percent, including a 99.9 percent on Unit 2 in 2018; 99.4 percent on Unit 1 in 2019; and 99.3 percent on Unit 2 in 2020, all non-refueling years.

All three nuclear units have remained online continuously since their last refueling outages. As of mid-September, Monticello has been online more than 120 days, Prairie Island Unit 1 has been online for more than 340 days, and Prairie Island Unit 2 has been online for more than 690 days. The fleet is currently industry leading according to INPO's "Days to First Shutdown" indicator (based on end of August 2021 data), which shows Xcel's fleet averaging over 650 days from startup after a refueling outage until first shutdown.

Additionally, the plants operated at high-capacity factors during winter months including the Polar Vortex of 2019. Similarly, the summer months of 2021 saw the nuclear fleet operating at full power during peak summer loads. In short, our nuclear fleet has never performed better.

- *Cost optimization and higher performance standards* – Most importantly, we have achieved these successful operational results while continuing to maintain safety and affordability, through operational excellence. As I discussed earlier, our fleet continues to achieve operational savings while continuing to prioritize safety. We are in the process of implementing technology projects that will enable efficiencies related to the NRC-required Corrective Action Program (CAP), the maintenance decision-making based on better data, and the automation of work management.

C. Industry Developments, Trends and Challenges

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

A. We consider two recent industry developments to be especially impactful for purposes of this rate case: the NRC's increasing efforts to advance risk-informed licensing and regulation, and the success of industry group collaborations. I will discuss each of these in more detail.

NRC's Risk-Informed Regulation & Licensing – Since 2017, the NRC has been working to advance risk-informed regulation and licensing. Risk-informed regulation is defined by the NRC as "[a]n approach to regulation taken by the NRC, which incorporates an assessment of safety significance or relative risk. This approach ensures that the regulatory burden imposed by an individual regulation or process is appropriate to its importance in protecting the health and safety of the public and the environment." This approach uses insights from probabilistic risk assessments (PRAs), along with other engineering insights, to arrive at regulatory strategies.

The NRC is also engaging in increased numbers of risk-informed license application reviews (LARs). The goal is to achieve shorter review times. In 2016, the NRC approved 40 risk-informed LARs, and in 2017, it approved 45 risk-informed LARs. From a practical perspective, this allows plants to meet the same high standards of safety and compliance while also allowing some flexibility as to the means by which that level of safety and compliance is achieved. The risk-informed approach leads to cost savings and increased safety by allowing nuclear operators to direct investment to where it will have the greatest positive impact on performance and safety, based on consideration of that plant's characteristics. The agency has renewed its focus on advancing these efforts and risk-informed regulation will likely have substantial impact during the period covered by this rate case.

Industry Collaboration – Beginning in 2015, NEI, its member companies, and third-party experts began the DNP initiative. In its early stages, this initiative concentrated on three areas: (1) maintaining a focus on safety and reliability; (2) improving the efficiency of operating nuclear plants; and (3) ensuring monetary recognition of nuclear energy's value. Beginning in 2018, the focus of this initiative shifted to an effort to develop, review, and approve efficiency-boosting ideas on an industry-wide basis. This stage of the initiative involved recommending opportunities with the most significant savings opportunities to industry leadership, aligning the industry on the way to move forward on those ideas, and approving efficiency bulletins outlining those ideas. The goal of DNP was to allow plant owners and personnel to focus on critical efficiency enhancements with the least amount of administrative burden, allowing plants to operate more efficiently while retaining safety and reliability. While DNP at the industry level is complete, the Company has continued the principles set forth in DNP through implementation of our own Nuclear Transformation initiatives.

Q. PLEASE DESCRIBE THE COMPANY'S RISK-INFORMED PROJECTS AND LICENSING EFFORTS.

A. Risk-informed processes allow for better focus on design and operational issues commensurate with their importance to public health and safety. The Company's risk-informed projects are intended to reduce Nuclear's operating costs through reduction in maintenance costs and purchasing costs, along with introducing more flexible operating requirements. In 2020, the Company completed the Surveillance Frequency Control Program (SFCP) at both plants. We will complete, for both plants, two additional risk-informed projects, the Risk-Informed Engineering Program (RIEP) and the Risk-Informed Completion Times (RICT) program, in 2021. The SFCP allows the licensee the ability to extend the intervals for appropriate surveillances, directly reducing the costs of the maintenance. The RIEP program allows for purchasing alternative parts for low-risk components and also allows for less frequent testing and maintenance of these components. The RICT allows for deferential treatment of select maintenance activities that might otherwise result in expensive plant shutdown activities. The Company has designated risk-informed decision-making as a core competency.

In July of 2019, the Company's LAR for Prairie Island, which sought to revise the National Fire Protection Association (NFPA) 805 Project License Conditions to a process based on risk versus a deterministic approach, was approved by the NRC. The License Amendment incorporated new PRA modeling into the Prairie Island Fire Model. Incorporating the new methodologies allowed for the fire model risk to be revised and resulted in the removal of five modifications that were part of the original NFPA 805 project scope to be removed. Removal of these modifications reduced the amount of capital spend for the NFPA 805 project by approximately $8 million. The investment cost for the model revisions and license submittal, by contrast, was under $0.4 million. All NFPA 805 modifications across Prairie Island have been completed.

Q. PLEASE EXPLAIN HOW THE COMPANY HAS IMPLEMENTED EFFICIENCY MEASURES DEVELOPED BY THE INDUSTRY.

A. The Company consistently reviews and, where practical, implements industry efficiency innovations. Our most significant recent adoption of an industry efficiency innovation is our implementation of the "Transform the Maintaining the Plant Organization" efficiency opportunity as described in NEI Efficiency Bulletin 17-23. The efficiency bulletin moves technical resources from engineering to the "Maintain" organization enabling a unified decision-making strategy for equipment reliability. This model promotes working within the design of existing plants to achieve operational and safety goals rather than making modifications to plants. This leads to greater operational efficiencies while lowering O&M and capital spend. The Company leads the industry on that initiative, and we are being benchmarked by other utilities on our work in this area. Our implementation of this model is one of the factors that led us to achieving INPO 1 (exemplary) status.

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

A. The industry has been faced with a number of trends that present both opportunities and challenges for the Company. One of the most significant trends we have seen in the utility industry generally is an increased focus on carbon reduction and the transition away from coal generation. Xcel Energy has been an industry leader on carbon reduction, and our goal of achieving 100 percent, carbon-free energy by 2050 has been adopted not only by other utilities across the nation, but also by the State of Minnesota. Nuclear's around-the-clock carbon-free energy is a critical component of this shared goal.

Industry challenges also exist. While the Company's nuclear fleet is performing at a historically high level, the Company remains concerned about issues related to permanent fuel storage and labor resource challenges for certain nuclear positions given the combination of an aging industry workforce nationwide, competitive demand for experienced nuclear personnel, and the uncertainty of long-term public policy commitments to nuclear energy in the U.S.

Q. THE COMPANY HAS RECEIVED FUNDING FROM THE DEPARTMENT OF ENERGY (DOE) TO EXPLORE HYDROGEN PRODUCTION. CAN YOU DESCRIBE THIS PROJECT?

A. Earlier, I discussed our efforts to increase the flexibility of our plants to allow the integration of additional renewables into our system. The incorporation of hydrogen production fits into that strategy because it would allow us to operate the plant at full output while also lowering power output. The Company partnered with two additional utilities and Idaho National Laboratory (INL) to explore the potential economics of producing hydrogen from an existing nuclear power plant. Our first hydrogen related effort included INL receiving funding from the DOE to perform certain studies and the Company contributed in-kind labor. The goal of this project was to study the potential marketplace for hydrogen, and the technical and economic feasibility of doing so at our nuclear facilities. We explored two types of hydrogen production—low temperature electrolysis, which uses electricity to change water into hydrogen and oxygen; and high temperature electrolysis, which adds steam from the nuclear plant to help improve the efficiency of the process compared to low temperature electrolysis.

On October 8, 2020, it was announced that Xcel Energy was selected for an additional grant from DOE. The project funded by the additional grant will demonstrate that Xcel Energy can install an electrolysis system that will use both steam and electricity generated from nuclear energy to generate hydrogen. This is called high temperature steam electrolysis (HTSE). HTSE improves the efficiency (compared to low temperature electrolysis) by about 33 percent, thus reducing future hydrogen production costs. This demonstration project is expected to take approximately two years and will be supported by INL and a consortium of utilities.

Q. IS THERE AN ESTIMATE OF THE COST AND TIMING ASSOCIATED WITH THE PROJECT?

A. The primary expense is the procurement of the High Temperature Steam Electrolysis (HTSE) equipment using U.S. manufacturing capabilities. This equipment has never been installed at a nuclear plant and has not been deployed at this scale in any industrial facility in the United States. The remainder of the costs are typical design and construction costs to implement the project. The O&M project is currently anticipated to begin in 2022 and be completed in 2024, pending final DOE approval to begin the project in 2022.

The total grant award from the DOE for the hydrogen project is $13.8 million. Our consortium partners Arizona Public Service and INL will each receive funds from the grant to do related nuclear-to-hydrogen integration projects. The grant is an 80/20 cost share agreement where DOE will reimburse Xcel Energy 80 percent of our expenses up to an incurred amount of $11 million for the project. If Xcel expends the entire $11 million, DOE will reimburse it approximately $8.5 million. There is no DOE reimbursement for Xcel expenditures beyond $11 million.

Q. WHAT ARE THE KEY BENEFITS XCEL ENERGY EXPECTS TO GAIN FROM COMPLETING THE HYDROGEN PROJECTS?

A. Xcel Energy's vision of producing 100 percent carbon-free electricity by 2050 recognizes that exploration into new technologies is needed to achieve that goal. Hydrogen generated from carbon-free power is a leading candidate to help us reach our 2050 vision by using excess carbon-free power to generate hydrogen. Our industry leading hydrogen projects allow the Company to advance its understanding of both technical and economic aspects of integrating hydrogen technology at its nuclear power plants.

Integrating hydrogen generation with a nuclear plant has the potential added value of allowing additional renewable generation to be built by using the nuclear plant to make hydrogen while renewable generation is high and the amount of power the grid requires from the nuclear plant is therefore lower. The hydrogen made at the nuclear plant could then be stored to make electricity during those times when renewable generation is less available. Hydrogen is also used in many other industries.

Collectively, our research and development projects have the potential to drive down the costs of hydrogen generation while taking steps towards reaching our carbon reduction goals.

Q. WHAT ARE THE POTENTIAL USES FOR HYDROGEN PRODUCED AT ONE OF THE PLANTS?

A. Prairie Island and Monticello both use hydrogen as part of their normal operations, so "in-house" production at one of the plants would eliminate our need to purchase hydrogen from a third party. Additionally, the Company's natural gas combustion turbines could someday be converted to using hydrogen as a fuel source, enabling those plants to reduce their carbon output. Other key potential uses include as an alternative to fossil fuels in the transportation industry, heating, agriculture, refining, and steel manufacturing.

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

A. We need to continue to work with the DOE to resolve long-term fuel storage and disposal issues at a reasonable cost.[5] We also need to ensure we maintain a stable, qualified workforce given the industry's staffing challenges. Additionally, as part of moving towards a carbon-free generation fleet by 2050, we are working on increasing our operational flexibility so that we can ramp down our plants during periods of high transmission congestion and low prices, such as times when abundant renewable resources are available on our system. We have demonstrated our units' ability to participate in the MISO Day Ahead market by flexing a number of times in 2020. This helps with the Company's efforts to integrate its continuing renewable additions. Currently, we have moved beyond the pilot stage, with all three units in the market.

Finally, during the period of this rate case, we will begin the work on relicensing our Monticello plant. Although the Monticello license will not expire until 2030, relicensing is a lengthy process. The NRC is currently considering subsequent relicensing of nine units at three plants and has approved subsequent relicensing of two units at Turkey Point, two units at Surry, and two units at Peach Bottom as part of a pilot program intended to pave the way for efficient processing of relicensing applications in the 2020s. The Company will comply with the five-year "safe harbor" requirement by submitting its application in advance of 2025.

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[5] The costs of dry cask storage are the subject of a settlement with the DOE, which resulted from DOE's breach of the Standard Contract established in 1998 for the disposal of spent nuclear fuel. Under that settlement agreement, DOE is obligated to reimburse the Company for costs incurred due to DOE's failure to begin removing spent nuclear fuel from commercial power plant site nationwide beginning in January 1998. Pursuant to various Commission Orders, these DOE reimbursement dollars are typically refunded to customers by means of a base rate refund, though the Company has occasionally been ordered to apply the DOE reimbursement dollars to the Nuclear Decommissioning Trust (NDT).

D. Key Nuclear Strategies for the Long Term

Q. HOW DOES NUCLEAR PROPOSE TO ADDRESS THE KEY ISSUES AND TRENDS DISCUSSED ABOVE?

A. We have already begun this work and are seeing the results. As I discussed earlier, the Company's investments in its nuclear plants over the past six years have factored into our industry-leading performance. As a result of this performance, the Company's nuclear operation is becoming a benchmark for other nuclear utilities. This success allows us to focus on issues such as providing leadership in identifying a permanent fuel storage solution, working on pipeline issues related to workforce, and improving the Company's ability to integrate additional renewable resources into its system by increasing operational flexibility.

Q. PLEASE DISCUSS THE COMPANY'S EFFORTS WITH REGARD TO STORAGE OF SPENT FUEL.

A. With the Yucca Mountain proposal on hold, and no apparent alternative permanent storage facility, we continue to rely on interim dry cask storage for the near term. And while continued investment in dry cask storage remains a necessity; at the same time, the Company is working with other industry leaders on developing alternative interim and permanent solutions to address the storage of spent nuclear fuel. For example, in May of 2019, my predecessor in this role, Timothy O'Connor, who is now EVP, Chief Operations Officer at the Company, testified before the United States Senate Committee on Environment and Public Works on this topic; addressing the ongoing need for a permanent repository for nuclear fuel and in support of developing interim consolidated storage sites. We will continue to participate in discussions on this issue and actively support both the development of a permanent repository and consolidated interim storage sites.

The most likely prospects for offsite storage of spent fuel for our nuclear plants are consolidated interim storage facilities (CISFs). There are currently two private CISFs seeking NRC licensure, the Holtec HI-STORE CISF (Holtec), proposed to be located in southeastern New Mexico, and the Interim Storage Partners (ISP) Storage Facility proposed to be located in Andrews County, Texas.[6] The NRC recently issued a license to ISP. With respect to Holtec, environmental and safety reviews are ongoing at the NRC, and the NRC expects to issue this license by early 2022. That said, there are a number of additional requirements that will need to be met before either of these facilities are able to accept spent fuel. After receiving the NRC license, each facility will need to work with their respective states on permitting issues and will develop a business model for operations prior to construction. In addition, the Department of Energy will begin its own process to find a consent-based interim storage location over the next few months, and it is unclear how this will impact the two private facilities currently in licensing. The Company continues to monitor the progress of the licensing of these two potential CISFs.

Q. PLEASE DISCUSS THE COMPANY'S EFFORTS WITH RESPECT TO WORKFORCE PLANNING.

A. We have created a robust internal succession plan and achieved significant depth in our staffing. We also have a retention plan to ensure continuity of our

[6] In addition, the Private Fuel Storage, LLC (PFS) facility proposed for the West Central Utah reservation of the Skull Valley Band of Goshute Indians remains licensed by the NRC. That said, no additional work has been conducted with respect to the PFS facility for many years, and substantial obstacles will likely prevent the revival of this project at this point.

bench strength. Maintaining a qualified and engaged workforce, however, remains an ongoing priority, and one that all high-performing nuclear organizations view as critical to maintenance of the industry's high standards of performance and safety. As a result, the Company must continue to create staffing pipelines that sustain the supply of qualified licensed-required positions such as operators, radiation protection technicians, and instrumentation and control technicians. Since the extended time for training to meet regulatory qualification expectations for these roles can be up to two years, these pipelines have to be in active hiring mode continuously each year. While capital and operational improvements have allowed for some reduction in headcount, a continuing pipeline is needed to replace experienced employees that depart either due to retirement or attrition.

Q. HOW DOES THIS RATE CASE RELATE TO THE STRATEGIC INITIATIVES AND TRENDS OUTLINED ABOVE?

A. In order to sustain our high level of performance and continue our leadership in the areas of risk-informed programming, the Company must continue to make capital investments as well as incur O&M expenses to support the ongoing operation, safety, and reliability of the Company's nuclear power plants. We are now at a point where the majority of significant modifications needed to operate both plants until the end of their current licenses have been made, and the Company's focus is now on maintaining the plants and implementing risk-informed programs.

Our culture is rooted in the idea of continuous improvement, and Nuclear will continue to focus on efficient ways to deliver high levels of performance and safety while also lowering costs to customers.

III. CAPITAL INVESTMENTS

A. Overview and Trends

Q. FOR THIS CASE, DO THE NUCLEAR CAPITAL INVESTMENTS FOR THE 2022 TO 2024 TIME PERIOD CONTINUE TO BE PRESENTED IN THE CAPITAL BUDGET GROUPINGS THAT YOU DISCUSSED IN THE 2016 RATE CASE?

A. Yes. For long-range planning purposes, Nuclear continues to group projects around a common theme to assist in the analysis of budget plans, assignment of project management resources, and benchmarking across the industry. The Company now uses the term "Major Category" to describe these groups, and I will use that terminology in the remainder of this Testimony. These major categories enable the application of common practices among similar projects. The groupings (excluding fuel loads) can be described as follows:

- *Dry Cask Storage* is work associated with on-site dry spent fuel storage and loading campaigns, as well as projects related to the Independent Spent Fuel Storage Installation (ISFSI) and related NRC-mandated aging management programs given the lack of a permanent federal repository for spent fuel.
- *Mandated Compliance* includes regulatory, security, and license commitment activities required by federal or state regulators (normally the NRC), including industry commitments made to the NRC, as well as projects that require NRC approval.
- *Reliability* activities improve equipment reliability or reduce maintenance activities and include life cycle management programs and projects.

- *Improvements* include activities that improve system and equipment performance and operation (for example: digital upgrades) and can reduce O&M costs.
- *Facilities & Other* includes facility work such as building improvements, roof replacements, road repairs, and general plant additions such as small tools and equipment.

Q. AND FOR THE YEARS 2018-2020, CAN YOU PROVIDE A SUMMARY OF HOW YOUR INVESTMENTS FELL INTO THOSE MAJOR CATEGORIES?

A. Yes. Table 1 below provides a summary of Nuclear's capital additions by major category (in millions) for the years 2018-2020.

Table 1
Nuclear Capital Additions 2018-2020
Including AFUDC (in millions of $)

NSPM Electric Utility Nuclear	**2018**	**2019**	**2020**
Dry Cask Storage	$ 68.4	$ 1.2	$ 11.2
Mandated Compliance	78.1	3.7	8.4
Reliability	138.0	78.9	22.1
Improvements	6.9	11.8	22.4
Facilities & Other	0.8	1.2	3.7
Subtotal – Projects	**$ 292.2**	**$ 96.8**	**$ 67.8**
Nuclear Fuel	82.1	157.5	79.2
Total Nuclear Additions	**$ 374.3**	**$ 254.3**	**$ 147.1**

Q. CAN YOU FURTHER DISCUSS THESE CATEGORIES AND WHAT MAY DRIVE INVESTMENTS IN THEM IN ANY GIVEN YEAR?

A. Each of the nuclear major categories now in use has a strategic driver that can change the need for investment year by year.

- The Dry Cask Storage category is necessary to safely store old/used fuel on-site and will continue to be a need until a federal repository is established.
- Mandated Compliance is driven by the requirements of the NRC or other regulators as a condition of maintaining our license to operate the plants.
- Reliability is driven by the fact that the Company's nuclear plants are over 45 years old and require ongoing capital investment to maintain reliable operation through equipment upgrades and replacement to address aging and obsolescence issues.
- Improvement is largely opportunity driven. When there are fewer Mandated Compliance or pressing Reliability projects in the budget, projects designed to improve output or operational performance and efficiency, which can provide a payback for the investment through higher output or lower operating cost.
- Facilities and Other projects are ongoing activities to maintain plant building and properties and provide small tools and equipment to support normal plant operation.
- Fuel is necessary to operate the reactors and provide the steam to generate power.

We have reduced our capital forecast relative to earlier forecasts such as the 2015 resource plan. While our focus has shifted from plant modification to maintenance projects, there is still substantial capital investment required in the future for our nuclear plants. We believe that continued investment is warranted given the value of safe, carbon-free, reliable, generation that these plants deliver, providing the power for over 1.5 million homes. More importantly, capital investments cannot be viewed in isolation, as the level of capital investments may impact O&M expenditures and vice versa. Only a full review of both capital investments and O&M expenses can provide an accurate view of the overall cost of any business or business area, including Nuclear Operations. Our long-term capital investment plan balances regulatory requirements, equipment risk, funding capabilities, and customer benefit and cost.

Q. WHAT ACTIVITY HAS OCCURRED WITH RESPECT TO THESE MAJOR CATEGORIES IN 2020 AND SO FAR IN 2021?

A. Nuclear added projects in 2020 in the amount of $11.2 million in Dry Cask Storage, $8.4 million in Mandated Compliance, $22.1 million in the Reliability Grouping, $22.4 million in Improvements, and $3.7 million in Facilities & Other. Also, Nuclear added $79.2 million of fuel in connection with a $78.7 million refueling at Prairie Island Unit 1 along with $0.5 million of trailing charges for the Prairie Island Unit 2 from 2019.

As of July 2021, Nuclear forecasted to add projects in 2021 in the amount of $13.0 million in Dry Cask Storage, $4.9 million in Mandated Compliance, $70.8 million in the Reliability Groupings, $20.8 million in Improvements, and $5.8 million in Facilities & Other. Nuclear is also forecasted to add approximately $147.3 million of fuel in connection with refuelings at Prairie Island Unit 2 and Monticello.

Q. LOOKING AHEAD, WHAT ARE YOUR CAPITAL FORECASTS FOR 2022-2024 BY MAJOR CATEGORY?

A. Table 2 below provides a summary of Nuclear's budgeted capital additions for the years 2022-2024.

Table 2
Nuclear Capital Additions 2022-2024
Including AFUDC (in millions of $)

NSPM Electric Utility Nuclear	2022 Budget	2023 Budget	2024 Budget
Dry Cask Storage	$ 24.8	$ 16.3	$ -
Mandated Compliance	1.0	1.0	1.0
Reliability	61.2	128.4	54.2
Improvements	9.0	12.0	5.6
Facilities & Other	0.8	1.6	0.4
Subtotal – Projects	**$ 96.8**	**$ 159.3**	**$ 61.2**
Nuclear Fuel	77.6	158.2	70.8
Total Nuclear Additions	**$ 174.3**	**$ 317.5**	**$ 132.0**

Q. WHAT KEY PROJECTS WILL YOU BE INVESTING IN OVER THE TIME PERIOD 2022-2024?

A. We will be investing in a number of projects that I discuss below. Fuel is always a key capital investment in any year, and for the 2022 to 2024 multi-year rate plan time period accounts for almost 50 percent of the total capital additions for Nuclear.

Beyond fuel and dry cask storage, we intend to invest in a cooling tower rebuild at Prairie Island and cooling tower upgrades at Monticello, analog process control replacements at Prairie Island, nuclear technology infrastructure at Prairie Island, baffle-former bolt replacements at Prairie Island, security computer server upgrades at Prairie Island, 12 Reactor Coolant Pump (RCP) motor replacement at Prairie Island, Nuclear Instrument System (NIS) channel bypass installation at Prairie Island, 121/122 control room chiller upgrades at Prairie Island, condenser steam bellow replacements at Prairie Island, intake travelling screen replacements at Prairie Island, cooling tower transformer replacements at Prairie Island, operating cycle implementation at Prairie Island, and turbine stop valve replacements at Monticello.

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

A. Overall, we anticipate future investments in projects in each of the capital budget categories. Table 3 below summarizes nuclear capital expenditures by major category (excluding AFUDC) for the test years 2022-2024 in comparison to actuals for 2018-2020 and the forecast for 2021.

Table 3
Nuclear Capital Expenditures 2018-2020 (Actual) 2021-2024 (Forecasted)
Excluding AFUDC (in millions of $)

NSPM Electric Utility Nuclear	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Fcst**	**2022 Budget**	**2023 Budget**	**2024 Budget**
Dry Cask Storage	$ 26.4	$ 8.3	$ 16.6	$ 18.4	$ 16.3	$ 12.4	$ 16.0
Mandated Compliance	21.4	2.8	6.6	7.8	7.3	8.3	7.4
Reliability	109.6	46.0	32.5	68.0	93.3	102.8	65.3
Improvements	10.7	16.0	20.9	23.3	16.7	15.2	8.1
Facilities & Other	0.8	2.8	4.5	3.3	3.6	1.9	0.6
Subtotal – Projects	**$ 168.9**	**$ 75.9**	**$ 81.1**	**$ 120.8**	**$ 137.2**	**$ 140.6**	**$ 97.4**
Nuclear Fuel	62.7	128.3	52.2	104.7	86.8	104.4	83.0
Total Nuclear Expenditures	**$ 231.6**	**$ 204.2**	**$ 133.3**	**$ 225.5**	**$ 224.0**	**$ 244.9**	**$ 180.4**

These expenditures accumulate as projects progress, AFUDC is added, and the total costs are placed in service as capital additions, as discussed in the next section of my testimony. As illustrated in Table 3 above, Nuclear's capital expenditures, excluding fuel, exhibit an increase beginning in 2021 through 2023. We expect this level of expenditures will decrease beginning in 2024.

Q. PLEASE EXPLAIN THE COMPANY'S NUCLEAR CAPITAL ADDITIONS.

A. Table 4 below summarizes nuclear capital additions by major category for the years 2022-2024 in comparison to actuals for 2018-2020 and the forecast for 2021. The additions in Table 4 include accrued AFUDC.

Table 4
Nuclear Capital Additions 2018-2020 (Actual) 2021-2024 (Forecasted)
Including AFUDC (in millions of $)

NSPM Electric Utility Nuclear	2018 Actual	2019 Actual	2020 Actual	2021 Fcst	2022 Budget	2023 Budget	2024 Budget
Dry Cask Storage	$ 68.4	$ 1.2	$ 11.2	$ 13.0	$ 24.8	$ 16.3	$ -
Mandated Compliance	78.1	3.7	8.4	4.9	1.0	1.0	1.0
Reliability	138.0	78.9	22.1	70.8	61.2	128.4	54.2
Improvements	6.9	11.8	22.4	20.8	9.0	12.0	5.6
Facilities & Other	0.8	1.2	3.7	5.8	0.8	1.6	0.4
Subtotal – Projects	**$ 292.2**	**$ 96.8**	**$ 67.8**	**$ 115.3**	**$ 96.8**	**$ 159.3**	**$ 61.2**
Nuclear Fuel	82.1	157.5	79.2	147.3	77.6	158.2	70.8
Total Nuclear Additions	**$ 374.3**	**$ 254.3**	**$ 147.1**	**$ 262.6**	**$ 174.3**	**$ 317.5**	**$ 132.0**

While capital additions are directly affected by our capital expenditures, the capital additions trend may not mirror precisely the capital expenditure trend. The capital expenditure trend reflects the progress of the project's spend through the months, whereas the capital addition trend reflects the total cost at the conclusion of the construction or implementation process when the asset is placed in service. The difference between capital expenditures and capital additions reflects the varying lengths of time required to complete different projects.

Q. ARE THERE ANY TRENDS YOU WOULD LIKE TO HIGHLIGHT THAT ARE DEMONSTRATED BY TABLE 4?

A. Yes. Nuclear capital additions show a significant decline after 2018. The decrease from 2018 to 2019 is primarily driven by the completion of $68 million of Dry Cask storage projects at both sites, and three Mandated Compliance projects: the Byron Open Phase projects[7] at both sites of $16 million, and the completion of the NFPA 805 Fire Model and Modification work at Prairie Island for $44 million. The Reliability category is substantially greater in 2023 than both recent years and 2024. This is primarily due to approximately $27 million in connection with replacement of baffle-former bolts at Prairie Island, and approximately $16 million for the Prairie Island Intake Traveling Screen Replacement project.

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

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

Management does its best to predict the progression in which projects are completed, which ones will be completed in each year, and how much in additions will flow into rate base for the test year. However, given new regulatory requirements, emergent equipment issues, changing business priorities, and constraints on corporate funding availability, it is difficult to plan

[7]These projects were implemented following an event at the Byron Station where offsite power was lost, revealing a vulnerability in the original plant protective relaying scheme design in that it was unable to detect the open phase connection resulting from a switchyard component failure. This work was completed as part of an NEI Initiative.

precisely in advance which individual projects will be completed in each future year. In addition, complications in engineering and design, challenges in vendor bidding or performance, and constraints for resource scheduling can cause the timing and cost of individual project additions to change in any year from that assumed in the budget. That said, the 2022 to 2024 capital budgets are our current best estimate of the capital work needed in the coming years. Even if the individual projects making up the budgets may change slightly, these budgets remain reasonably representative of the capital investment needed for Nuclear Operations in 2022 to 2024.

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

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

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW CHANGING CIRCUMSTANCES IMPACT CAPITAL INVESTMENT DECISIONS?

A. Yes. In 2018, Prairie Island was scheduled to complete a project to replace several valves on the Cooling Water Header which had degraded and could not be relied upon to provide an adequate isolation boundary. Through additional analysis, we were able to determine a more cost-effective maintenance strategy to address the valve degradation that did not necessitate valve replacement. Because we did not need to expend capital funds on valve replacement, we were able to reallocate those funds to complete the Environmental Equipment Qualification (EEQ) Computer Model project, which resolved several NRC Non-Cited Violations related to the Equipment Qualification Program. This project also reduced future O&M expense and capital equipment replacements by providing refined analysis methods that extended the environmentally qualified life of several key pieces of plant equipment.

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

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

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

A. Yes. We are committed to meeting our performance goals while staying within our overall capital budget.

Q. WHAT DO YOU CONCLUDE ABOUT NUCLEAR'S 2022-2024 CAPITAL INVESTMENT FORECASTS?

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

B. Capital Budget and Investment Planning Process

1. Reasonableness of Overall Capital Budget

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

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

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

In addition, to gain an accurate picture of the overall costs of any business, capital investments must be viewed together with O&M expenses, since timely and prudent capital investment can lead to lower O&M expenses going forward. For example, the Security Physical Upgrades Phases I & II projects at Monticello directly reduced the number of Security Officers required onsite, which reduced the plant's O&M costs. The Security Physical Upgrades Phase I, completed in 2017, had an annual cost savings of $1.1 million. The Security Physical Upgrades Phase II, completed in 2018, has an annual cost savings of $2.5 million. The Security Protective Strategy project at Prairie Island completed in 2020 had an annual cost savings of approximately $3.7 million.

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

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

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

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

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

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

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

- Plant Health Committee (PHC) and Long-Range Planning (LRP) processes at each plant site
- Fleet Project Review Group (PRG) with members from each plant site and the fleet
- Executive PRG, which includes the Chief Nuclear Officer and Nuclear Vice Presidents (for projects in excess of $3 million)

Projects in excess of $5 million level are addressed by broader Xcel Energy functions, as discussed in the testimony of Ms. Ostrom. Ultimately, these processes appropriately balance the needs of our nuclear plants with the need for cost-effective electric generation for our customers, arriving at a reasonable budget for Nuclear in each year. I explain this governance and oversight process in more detail below.

2. *Nuclear Capital Planning Process & Governance*

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

A. NRC license requirements are entered into the CAP and evaluated regularly by the Engineering and Regulatory Affairs functions. CAP is an NRC-mandated license compliance program. The evaluations include not only plant license requirements, but also the NRC's new rules and regulations, Regulatory Issue Summaries, Task Interface Agreements, and other communications. The CAP program is quite extensive and complicated. About one-half of our engineering resources are dedicated to the CAP program, reviewing safety licensing documentation so the plant can operate in compliance with NRC requirements.

If deviations from NRC requirements are identified, and capital funding is required to resolve the deviation, then a project request is initiated using Nuclear's project review and approval process procedures. The request is also added to the long-range plan using Nuclear's LRP process within our Project Review and Approval Process procedures, as I discuss later.

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

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

The PHC is the cornerstone for addressing equipment reliability issues. The PHC is an industry best practice developed from INPO's excellence standards. The PHC's primary focus is to understand the site's existing equipment reliability issues, prioritize these issues and ensure that the site resources are aligned to support resolution consistent with their priority. The process ties together material condition evaluations, work identification and approval, and the business planning process. One output of the PHC is providing inputs to the LRP, which outlines current and future project expenditures as I describe later.

PHC inputs are forwarded to the LRP committee for prioritization and ranking. The LRP results are sent to PRG for approval. The PHC/LRP recommends projects to PRG, which then ensures that capital projects are properly ranked and thus re-evaluates priorities of previously authorized capital projects, as required.

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

A. Capital projects are prioritized in accordance with the Station Common Priority Scheme, which provides guidance for ranking projects based on various criteria for risk and urgency. The prioritization guidance is integrated into the planning, implementation, and budgeting processes for capital projects. For the current year, the prioritization guidance works to manage capital spend to the approved budgets, to evaluate the impact of emergent issues, and to communicate these impacts to the affected process owner. For future years, the process activities work to formulate project budgets and to identify potential adjustments to optimize whenever possible. The PHC validates or assigns the prioritization ranking for capital projects in accordance with the Station Common Priority Scheme. As I noted earlier, the PRG reviews the risk and urgency rankings of all recommended projects for the nuclear fleet, and continually re-evaluates priorities of previously authorized projects, as required, to allocate (and re-allocate) available capital funding for the nuclear fleet.

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

A. The LRP establishes a multi-year baseline project plan for each plant based on the plant's strategy and prioritization of work through the end of current license. A project must be identified on the LRP to be included in the annual capital budget. During creation of the annual budget, the PRG uses the LRP to determine which capital projects will be proposed for a given year. The PRG ensures proposed projects are subjected to effective business evaluations and management review at key decision points prior to committing significant resources and ensures projects meet corporate financial objectives. At the time of the annual budget creation, the fleet Executive Project Review Group (EPRG) reviews and approves the LRP for the fleet for the five-year budget period, which is then submitted for corporate review and approval by Xcel Energy through the Finance Council before the consolidated budget is approved by the Board.

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

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

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

From a process standpoint, most project requests that are approved by the PHC are assigned a Project Manager. The Project Manager develops or revises the initial project estimate based on the principles described in *Project Management Institute Manual* procedures. Cost estimating is based on industry standards[8] included in Project Management procedures. These standards provide for varying levels of estimates as a project proceeds. The PRG reviews the initial cost estimate and approves or rejects the project for funding authorization. The LRP includes the annual project cash flows.

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

[8] AACE International, formerly the Association for the Advancement of Cost Engineering, prepares professional practice guides (PPG) for engineers such as PPG#7, *Cost Engineering in the Utility Industries*. *See* ACEE INTERNATIONAL, www.aacei.org (last visited Oct. 21, 2015); the Project Management Institute (PMI) provides guidance on project management procedures. *See* PROJECT MANAGEMENT INSTITUTE, www.pmi.org (last visited Oct. 25, 2019).

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

Project planning also uses, when appropriate, benchmarking and performance contracts with vendors to more effectively predict and control project costs. Benchmarking can range from a phone call to a site contact or a site visit. Benchmarking can also be internal or external to Xcel. Our benchmarking of project costs within the nuclear industry is typically limited to higher-level order-of-magnitude figures due to the sensitivity and confidentiality of detailed financial information. However, this higher-level benchmarking has provided valuable insights for budgeting Monticello's subsequent license renewal. Originally, the project's estimate was based on extrapolating Monticello's initial license-renewal project from nearly 15 years ago. However, during the development of the Monticello subsequent license-renewal budget, we benchmarked the project against subsequent license renewals recently completed by other utilities. The resulting information was used to reduce the project's initial estimate and provide a higher level of confidence in the accuracy of the budget.

Industry benchmarking was also used to reduce cost with respect to our Fukushima work, as we were able to align equipment needs and program costs for similar work with other companies. We utilized benchmarking on the RCP replacement at Prairie Island in 2016. Internal benchmarking, which involves utilizing information gained from similar projects at other Xcel plants, is used on projects where possible. For example, we have engaged in detailed internal cost benchmarking for projects like our Cooling Tower projects at both Monticello and Prairie Island.

Contract negotiation has also helped improve cost predictability. Negotiation of long-term construction and maintenance agreements have allowed us to access better rates, implement cost incentives and penalties for contracted work, and more effectively leverage resources to avoid in-processing costs. We work with our vendors on larger projects like the Electric Generator Replacement at Prairie Island to build in performance milestones and liquidated damages to hold vendors accountable for the quality, cost, and timeliness of their work. After the capital expenditure budgets by project are prepared and expected in-service dates are established, all the projects are accumulated by month and year, and the aggregate capital budgets are reviewed by the Nuclear management team in the governance process discussed previously. The combination of project-specific reviews and approvals, and overall alignment with strategic decision making, provides accountability for a reasonable level of capital investment for Nuclear.

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

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

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

Q. DO YOU BELIEVE THAT NUCLEAR'S PROCESS RESULTS IN CAPITAL BUDGETS FOR 2022-2024 THAT REPRESENT A REASONABLE LEVEL OF COSTS FOR CUSTOMERS TO INCUR?

A. Yes. This process results in a reasonable budget that is representative of the capital investment needed to meet Nuclear's prioritized requirements and plant needs for the test year. In each year, Nuclear capital additions are reasonable and necessary to maintain the stability, safety, reliability, and compliance of our nuclear plants in service of our customers. The capital budgets for this period are reasonable given the life cycle status of our plants based on industry comparisons with costs of similar projects and considering inputs of independent validations of the need for these projects.

3. Capital Budget Updates & Oversight of Emergent Work

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

A. Not entirely. As I discussed previously, the capital budgeting process identifies a list of potential projects that must be prioritized based on risk and urgency.

This list is continually updated and, given the fact that the budget is prepared six to eighteen months prior to the budget period, priorities can certainly change in that timeframe. For example, many projects have long lead times for engineering, design, scoping, resource appropriation and scheduling, and consequently the timing of the final work can shift between the budget preparation and project completion.

In addition, new priorities can arise from emerging regulatory requirements as a result of the Fukushima accident or equipment degrading faster than expected. These changing priorities require Nuclear to continually reassess the relative ranking of risk and urgency for all projects and new priorities can rank ahead of previously identified ones. When total corporate funding is limited, that can mean that some projects are delayed to make room for the new priority projects that are identified after the budget was prepared.

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

A. Project Review and Approval Process procedures establish the process to systematically plan for capital expenditures for long-term operation of the Xcel Energy Nuclear plants. It supports making operation, resource allocation, and risk management decisions to maximize fleet value to stakeholders while maintaining and improving safety and reliability for the public and plant staff. The LRP process works in conjunction with the PRG and the Station Common Plant Priority Scheme procedures. Periodically, it may be necessary to reallocate and reforecast capital expenditures as unforeseen problems encountered are difficult to fix, and often require final implementations that differ from initial conceptual plans. When new projects arise, the site LRP committees will initially recommend the reallocation of plant prioritization and will propose the capital forecast with the new funding information. The PRG reviews and either approves or rejects the site LRP committee recommendations and proposals. Before the funds are authorized to reallocate capital spend, however, the Vice President, Engineering and Technical Services, must concur with the PRG recommendations and approve the revised capital forecast. The site executive leadership is accountable to the Nuclear executive leadership team via EPRG; and the Nuclear executive leadership team is accountable to the Company's Financial Council. These accountabilities effectively reallocate resources as part of managing our business.

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

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

From a process standpoint, when changes are identified that will impact project budget, scope, schedule, or quality, the resolution and approval are documented on Project Impact Notice/Project Scope Change Request form in accordance with Project Management Manual procedures. If the change is significant, PRG procedures require that a change to the project funding authorization be prepared and submitted to PRG for approval.

If at any time during a project's execution the total cost is projected to exceed an authorization threshold, additional corporate review and approval is required. The responsible Project Manager shall ensure the project is re-presented to PRG, EPRG, Xcel Energy Corporate Investment Review

Committee, or Finance Council for approval as governed by corporate policies/procedures based on the total project authorization.

Project Impact Notice/Project Scope Changes can release contingency dollars for additional funds needed within the authorization of the project. Contingency funds are released with proper authorization by the Director of Nuclear Fleet projects for the first 50 percent and the Vice President of Nuclear Engineering and Technical Services for the second 50 percent for use in scope changes in projects.

Q. Are you familiar with the November 1, 2018 Final Report of Global Energy & Water Consulting LLC (GEWC) to the Department of commerce regarding Prairie Island (the "2018 GEWC Report")?

A. Yes. That report was commissioned by the Department as a result of our 2015 Integrated Resource Plan (IRP) (Docket No. E002/RP-15-21) and our 2016 Rate Case filing. Filings in those two dockets in 2015 indicated a need to increase capital expenditures at Prairie Island beyond what we had previously forecasted. The Commission determined that, as a result of those filings, a thorough analysis of all projected Prairie Island costs was needed. GEWC was retained to provide that analysis.

Q. Are you familiar with the recommendations contained in that report?

A. Yes. The recommendations were generally aimed at improving communications, documentation and transparency around capital project estimates and future certificates of need.

Q. WHAT IS THE COMPANY'S CURRENT VIEW WITH RESPECT TO THE RECOMMENDATIONS CONTAINED IN THAT REPORT?

A. Over the course of several rate cases filed with the Commission since 2010, we have detailed our progress in working toward a standard of excellence that today places us at the top of the industry, as I've previously discussed. That said, I agree that the Company and our regulators can benefit from additional proactive communication. However, the Company believes that there needs to be a balance between these goals and the ability of the Company to maintain a reasonable amount of flexibility. At this point in time, we do not believe that implementing the recommendations as written would substantially improve the concerns that led to the preparation of the 2018 GEWC Report.

As I noted earlier, one of the catalysts for the preparation of the 2018 Final GEWC Report was a disparity between the cost estimate provided in connection with a CON proceeding and the amount of costs for those projects sought to be recovered in the 2016 Rate Case. It's important to recognize that since that time, the Company's capital budgeting process has been improved, including those processes related to making adjustments to those budgets and project priorities, which I discussed earlier in my testimony.

Q. DID THE COMPANY ADDRESS POTENTIAL LIFE EXTENSIONS FOR THE NUCLEAR FLEET IN THE 2019 IRP, AS GEWC SUGGESTED?

A. Yes. Our 2020-2034 IRP filing presented a Preferred Plan that includes a license extension at Monticello and the continued operation of Prairie Island through its current operating licenses. In June of this year, the Company filed an Alternate Plan, which also includes the proposed license extension at Monticello and continued operation of Prairie Island. As part of our economic analysis in the IRP, we modeled scenarios that included early retirements, license extensions, and continued operations through current licenses for all three of our nuclear units and compared those outcomes to a variety of other modeling scenarios. Finally, we discussed the NRC relicensing process and assessment criteria, along with our proposal to submit a CON with the Commission for additional dry cask storage at Monticello, which has now been filed with the Commission. The Company is taking a proactive approach to planning for the expiration of our current NRC licenses, and we believe the path laid out in the resource plan is reasonable and provides for a measured and transparent approach to considering the future of our nuclear fleet.

Q. HAS GEWC PROVIDED ANY ADDITIONAL REPORTS TO THE DEPARTMENT OF COMMERCE RELEVANT TO NUCLEAR'S PLANNING FOR CAPITAL PROJECTS SINCE THE 2018 GEWC REPORT?

A. Yes. GEWC provided a report to the Department of Commerce in December 2020 (the 2020 GEWC Report). That report was filed in the IRP docket. The 2020 GEWC Report concluded that "[t]he Monticello forecast budget for capital spending is well within reason considering the age and the need to prepare the unit for relicensing (See Chart 2, Page 12 of this report). The forecast capital spending for the next 20 years is well below capital spending during the last 10+ years. The outlier that is still not very well documented is the capital necessary to accomplish the Subsequent License Application/Review (SLA/SLR) and it will not be until Xcel completes is license review and application to the NRC.

With respect to Prairie Island, the 2020 GEWC Report found "Prairie Island capital budget forecast (See Chart 1, Page 10) indicates an increasing budget for the next four to five years, primarily to address new dry cask storage, mandated compliance issues and reliability. However, beginning in 2026 the capital budget forecast starts a decline that reflects the units nearing license expirations." The report also concluded that the capital forecast used in the IRP filing, which has not changed substantially since that forecast was filed, were within reason.

4. *Major Capital Projects*

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

A. It is my understanding that the MYRP statute in Minnesota requires a utility to "provide a general description of the utility's major planned investments over the plan period." To comply with this requirement, we have identified the major nuclear capital projects we believe fall under this category of investments and describe those projects below.

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

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

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

A. We anticipate placing 15 major capital projects in service during the period 2022 through 2024. These projects, depicted in Table 5 below, include:

Table 5
Major Capital Project Additions
(in millions of $)

Capital Grouping	Project	Capital Addition Years		
		2022	2023	2024
Dry Cask Storage	PI Dry Casks #48-64	$ 23.7	$ 16.3	
Reliability	PI Baffle-Former Bolt Replacement		$ 27.4	$ 18.9
	PI Intake Traveling Screen Replacement		$ 16.0	
	PI Cooling Tower Transformer Replacements	$ 6.8	$ 7.7	
	MT Cooling Tower Upgrade	$ 12.5		
	PI Cooling Tower Rebuilds		$ 10.5	
	PI U1 & U2 Condenser Steam Bellow Repl	$ 4.5	$ 4.5	
	PI Analog Process Controls Replacement	$ 2.1	$ 1.3	$ 2.4
	PI Control Room Chillers			$ 4.4
	MT Turbine Stop Valve Replacement		$ 4.2	
	PI Security Servers Replacement			$ 3.5
	PI 12 RCP Motor Replacement CESP	$ 3.4		
	PI Nuclear Instrumentation Channel Bypass	$ 3.3		
Improvements	PI Nuclear Technology Infrastructure	$ 4.5	$ 0.1	
	PI Operating Cycle		$ 8.3	
Total Major Capital Project Additions		**$ 60.9**	**$ 96.1**	**$ 29.2**

Some of these projects span multiple years, with portions of the project placed in-service as they are put into use each year. The major capital projects we expect to complete during the plan period, as well as the additional key projects we anticipate completing in 2022-2024, are discussed in more detail under each plan year, below.

C. 2022 Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NUCLEAR CAPITAL ADDITIONS BUDGET FOR 2022.

A. The total NSPM Nuclear 2022 capital additions are budgeted to be $96.8 million for projects and $77.6 million for fuel. Table 6 below sets forth the anticipated capital additions for 2022 by major category:

Table 6
Total Nuclear Capital Additions 2022
Including AFUDC (in millions of $)

NSPM Electric Utility Nuclear	2022 Budget
Dry Cask Storage	$ 24.8
Mandated Compliance	1.0
Reliability	61.2
Improvements	9.0
Facilities & Other	0.8
Subtotal – Projects	**$ 96.8**
Nuclear Fuel	77.6
Total Nuclear Additions	**$ 174.3**

Q. WHAT ARE THE PRIMARY DRIVERS OF THE 2022 CAPITAL ADDITIONS PLACED INTO SERVICE BY THE NUCLEAR OPERATIONS BUSINESS AREA?

A. Project additions include $23.7 million for the newest Prairie Island cask loading campaign, $12.5 million for a cooling tower upgrade at Monticello, and $6.8 million for Prairie Island cooling tower transformer replacements. Fuel additions are an ongoing capital requirement over the refueling cycles of each plant, and in 2022 we will have one at Prairie Island.

1. Dry Cask Storage

Q. WHAT ARE DRY CASK STORAGE PROJECTS?

A. Dry Cask Storage projects are associated with on-site dry spent fuel storage and loading campaigns. Because the Federal Government has not yet identified a permanent, long-term spent fuel storage facility, the Company must store spent fuel on-site in the interim. The timing of spent fuel storage is also designed to enable a full core offload for each unit at any time. Because of the longer on-site storage now required, we will need to implement several aging management programs for the storage casks, including continued/extended licenses from the NRC.

Q. PROVIDE AN EXAMPLE OF A DRY CASK STORAGE PROJECT NUCLEAR OPERATIONS ANTICIPATES PLACING IN SERVICE IN 2021.

A. The 2022 budget for capital additions for Dry Cask Storage is $24.8 million. This is primarily a single project, the Prairie Island Casks #48-64 Project with the planned addition for delivery, management, oversight, loading, and placement of Casks #48 through 50.

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Q. WHAT IS THE 2022 TEST YEAR BUDGET FOR THIS CAPITAL PROJECT ADDITION?

A. The Nuclear Operations business area has established a budget of $23.7 million for this Dry Cask Storage project addition during the 2022 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

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

With respect to this specific project, the budget for additions represents the estimated capital expenditures (excluding any removal costs) plus AFUDC incurred for the Prairie Island ISFSI Expansion.

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

A. As Table 4 from earlier in my testimony shows, Dry Cask Storage project additions ranged from approximately $1 million to $68 million per year in 2018 to 2020, with $13.0 million in forecasted additions for 2021. Substantial dry cask work was completed in 2018 for $68.4 million. Additions for 2019 were $1.2 million. Additions for 2020 were $11.2 million. Forecasted additions for 2021 are 13.0 million. The budget for Dry Cask Storage additions in 2022 is about $24.8 million.

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

A. Dry Cask Storage project additions are different each year based on the specific needs for fuel storage at each site as refueling outages are completed, the spent fuel storage pools are filled, and ISFSI licensing approvals and activities proceed. As noted, the 2022 additions relate primarily to cask loading at Prairie Island.

Q. DO YOU EXPECT SOME LEVEL OF VARIATIONS TO CONTINUE?

A. Yes. Because the level of work required to complete, dry storage installations will continue to vary each year. The dry storage containers authorized by the Commission will continue to be loaded periodically in order to support nuclear plant operations at Monticello and Prairie Island. The licenses for the dry storage installations will also have to be periodically amended in order to continue to comply with NRC regulations. The Prairie Island ISFSI license was renewed in 2015 and imposed Aging Management Programs (AMP) for dry cask storage at Prairie Island and the license was amended in 2020 to store up to 64 casks as previously authorized by the PUC. The Monticello license has also been renewed and will require implementation of AMP sometime prior to 2028. Periodic dry cask storage licensing activities will continue at Prairie Island for activities such as the addition of new fuel types being used at Prairie Island to the TN40HT license. In addition, as noted earlier in my testimony, the

Company has submitted an application to the Commission for a CON to authorize the expansion of the Monticello ISFSI through 2040 and will be submitting an application for SLR to the NRC in 2023.

In addition to NRC requirements, if no permanent or interim storage solution is available by the time the plants reach decommissioning, another CON will be required from the Commission to add the additional storage capacity necessary to support decommissioning. In the most recent Triennial Decommissioning Accrual docket, the Commission approved the current annual accrual, finding this accrual was appropriate to support safe spent fuel management for 60 years after plant shutdown. We will continue to take all required actions to ensure the continued safe operation of these fuel storage facilities are compliant with NRC licenses and Commission requirements. The activities needed to meet these requirements will cause varying amounts of dry cask additions over the years.

a) Major 2022 Dry Cask Storage Project: Prairie Island Casks #48-64 Project

Q. PLEASE DESCRIBE THE PROJECT.

A. The Prairie Island Casks #48-64 Project includes the procurement, fabrication, loading, and transfer of TN-40HT Dry Fuel Storage Casks 48-64 to the Prairie Island ISFSI. This project also includes submission of a number of license amendments to the NRC and a Request for Change filing with the Commission to allow for use of alternate dry fuel storage technologies at Prairie Island. Depending on the results of the Request for Change filing, the project will re-evaluate the dry fuel storage technology to be used for loadings beginning in 2027. The timing of this project is dependent on the completion of the Prairie

Island ISFSI expansion project. The ISFSI Expansion project is scheduled to be completed during the fall of 2021, and the first cask loading campaign under this project will be in Spring 2022.

Q. WHAT EFFECT WOULD APPROVAL OF THE REQUEST FOR CHANGE FILING HAVE ON THIS PROJECT?

A. The Company has already ordered five (5) TN40HT casks to accommodate the scheduled loading in 2022, 2023 and 2025, so there would be no effect on the project through 2025.

If the Commission approves the Request for Change, the Company would issue a Request for Proposal to the various cask vendors in 2023. Assuming a new technology is selected, cask fabrication activities would begin in 2025. The project budget would be adjusted once a contract is signed to reflect the lower cost of the new technology. If a new technology is selected, all of the fuel would be loaded in a single campaign in 2027. Savings would be realized from the time the new casks are ordered through loading, approximately 2025-2027.

If the Request in Change is not approved, there would be additional fuel loading in nine (9) additional TN40HTs in 2027, 2029 and 2032, and there would be no budget change.

Q. DESCRIBE THE CASK LOADING PROCESS.

A. During a nuclear plant refueling, spent (used) fuel is removed from the reactor core and placed in the spent fuel pool for temporary storage. The spent fuel pool has limited capacity, and fuel must eventually be removed from the pool to make room for the next refueling. Each plant keeps enough room in the spent fuel pool to accommodate a full reactor core offload. Fuel to be removed from the pool is loaded into metal casks which are lowered in a special loading area in the pool. Once the selected fuel assemblies are loaded into the cask, the lid is installed under water, and the cask is removed from the pool. The water is drained from the cask and vacuum dried to remove all remaining moisture. Inert gases are then injected into the sealed casks to prevent degradation of the spent fuel during interim storage. The casks are loaded and sealed in the Auxiliary building, and then transferred to the ISFSI storage pad located outside the plant.

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

A. The Prairie Island Casks #48-64 Project supports the continued operation of Prairie Island Units 1 and 2 through the end of their current licenses, in 2033 and 2034, respectively. These units continue to provide critical efficient and reliable carbon-free resources for our customers.

2. *Mandated Compliance*

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

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

Q. PLEASE PROVIDE EXAMPLES OF KEY MANDATED COMPLIANCE PROJECTS SCHEDULED TO GO IN SERVICE DURING THE 2022 TEST YEAR.

A. There are no key mandated compliance projects forecasted to in-service in 2022.

Q. WHAT IS THE 2022 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $1.0 million for Mandated Compliance project additions during the 2022 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

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

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Mandated Compliance projects that are expected to be completed and placed in service during 2022. We first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project are revised, the cost estimate can be updated over the period the project is in progress. The capital additions budget for 2022 represents the total of expenditures expected to be incurred (excluding removal costs), plus AFUDC accrued over the project duration, that are expected to be completed and placed in-service during the year 2022.

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

A. As Table 4 from earlier in my testimony shows, Mandated Compliance project additions ranged from approximately $1 million to $80 million per year in 2018 through 2020, with $4.9 million in forecasted additions for 2021. The 2022 budget for Mandated Compliance additions of $1.0 million is lower than prior years and is currently expected to remain flat in 2023 and 2024.

Q. WHAT IS DRIVING THESE TRENDS?

A. The major drivers for this downward trend are completion of the NFPA 805 Fire Model and Modification work at Prairie Island. In the 2017-2019 timeframe, the largest Mandated Compliance Projects placed into service included: Byron Open Phase Detection Modifications at both stations; the Fukushima Hardened Vent Modifications at Monticello; and NFPA 805 Fire Model and Modifications at Prairie Island (AFW Train Separation for both Units, Incipient Fire Detection Modification, Cooling Tower 11 and Cooling Tower 12 Bus Source Modifications). The downward trend in Mandated Compliance is expected to continue in the 2022-2024 timeframe due to the lack of significant regulatory changes that would drive plant modifications.

3. Reliability

Q. WHAT ARE RELIABILITY PROJECTS?

A. Reliability projects enhance equipment and generation reliability by reducing safety system unavailability and forced losses in production output, reducing the need for maintenance activities, and implementing life cycle aging equipment management/ replacement programs. They are driven by the fact that the Company's nuclear plants are all over 45 years old and require ongoing capital investment to maintain reliable operation through equipment upgrades and replacement. In effect, these projects are intended to, consistent with our NRC license obligation, make the plants "like new" under the renewed/extended operating licenses to 2030 for Monticello and 2033-2034 for Prairie Island, as well as the planned license extension at Monticello.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY RELIABILITY PROJECT SCHEDULED TO GO IN SERVICE DURING THE 2022 TEST YEAR.

A. The large Reliability projects with 2022 additions are Monticello Cooling Tower Upgrade Phase III project, the Prairie Island Cooling Tower Transformer Replacement, the Prairie Island Unit 1 Condenser Steam Bellow Replacement, the Prairie Island Analog Process Control replacement, the Prairie Island 12 RCP Motor Replacement CESP, and the Prairie Island NI Channel Bypass panel. I discuss the 2022 project additions in more detail later in my testimony.

Q. WHAT IS THE 2022 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $61.2 million for Reliability project additions during the 2022 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

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

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Reliability projects that are expected to be completed and placed in-service during 2022. Our budget allotment to Reliability projects comes first from our strategy to meet operating performance goals set consistent with excellence standards from the NRC and INPO, as I discussed earlier.

For specific projects, we first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project are revised, the cost estimate can be updated over the period the project is in progress. The capital additions budget for 2022 represents the estimated total of expenditures incurred (excluding removal costs), plus AFUDC accrued over the project duration, that are expected to be completed and placed in-service during the year 2022.

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

A. As Table 4 from earlier in my testimony shows, Reliability project additions have fluctuated from year to year based on the specific projects undertaken in each year. The 2022 budget for Reliability additions of $61.2 million is lower than the $138 million in 2018, the $78.9 million in 2019, and the $70.8 million forecasted for 2021. As will be discussed later in my testimony, the budgeted Reliability additions are higher in 2023 and lower in 2024. Reliability Projects make up our largest project grouping.

The nuclear industry is trending towards committing more capital investment to equipment reliability through replacement and refurbishment, as this work is needed to achieve (or maintain) performance excellence and cost efficiencies. High production output of 90 percent of capacity or more, such as that achieved by our fleet, is consistent with top quartile operations. Our commitment to achieve and maintain output at those levels ensures the delivery of 1,700 megawatts of clean carbon-free energy to our customers and leverages our cost per MWh over a larger base of production output.

4. Monticello Cooling Tower Upgrade, Phase III

Q. PLEASE DESCRIBE THE PROJECT.

A. Cooling Tower 12 is being disassembled and rebuilt using all new materials and equipment/components. The current concrete basin and input riser pipes are being reused. Like the cooling tower rebuild at Prairie Island, this project is needed to maintain compliance with our National Pollutant Discharge Elimination System (NPDES) permit. Also, the towers are structurally degraded after nearly 50 years of operation and currently being temporarily supported by scaffolding.

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

A. The benefits of this project are to reduce long- and short-term O&M costs of maintaining the towers as well as increasing the reliability of the plant. The existing towers were not designed to the current EPU conditions, and this rebuild will allow the plant to avoid down-powers by increasing cooling margin to the plant discharge canal and restore structural integrity to the towers. The materials are also being changed to fiberglass, which has an expected life of 20+ years; as opposed to wood, which has an expected life of 7+ years.

Q. DID NUCLEAR CONSIDER OPTIONS BESIDES REPLACEMENT?

A. Yes. Structural refurbishment of degraded components using like-for-like materials (i.e., wooden components) was considered, but the refurbishment option had a life expectancy of approximately 7 years. This would necessitate a second refurbishment in order to reach the end of the current operating license. Pursuing a full rebuild allows for the use of fiberglass components which have a life expectancy of approximately 25 years and allows for the addition of cooling capacity. Additionally, a full rebuild can be conducted at substantially less cost than two structural refurbishments.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2022 capital addition for the project is approximately $12.5 million, including AFUDC. The project is forecasted to in-service in 2022.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The project budget was developed using vendor quotes via a competitive bid process facilitated by the supply chain processes.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The Cooling Tower 12 rebuild is currently in the design phase with construction expected to begin in fall of 2021.

Q. PLEASE DESCRIBE THE PROJECT.

A. This Project will replace the Cooling Tower 11 Transformer and Cooling Tower 12 Transformer at Prairie Island, based on Electric Power Research Institute (EPRI) guidance and the estimated service-life of the current transformers. Replacement transformer upgrades include a dissolved gas in oil monitor.

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

A. Replacement of transformers that have been degraded by age reduces the likelihood of failure of these transformers. Failure of the transformers impacts cooling tower capability and reliability of power to safety buses.

Q. DID NUCLEAR CONSIDER OPTIONS BESIDES REPLACEMENT?

A. No. Transformers have an expected life and they must be replaced before the risk of failure is reached.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2022 capital addition for the project is approximately $6.8 million and the 2023 capital addition is approximately $7.7 million, including AFUDC. The project is forecasted to have a final in-service in 2023.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The budget estimate was based on actual costs for recent comparable auxiliary transformer replacement projects at Prairie Island, with adjustments for scope differences, cost escalation, and contingency. For example, the Cooling Tower 11 and 12 transformers are smaller, and replacement is less complex than one of the comparable projects. Thus, the base estimate for each cooling tower transformer was reduced from that of the earlier project. As described above, the budget was then adjusted for installation of transformers, engineering, inflation, and contingency.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. NRC approval is not required for this project as the change can be evaluated under 10 CFR 50.59.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Conceptual design and transformer specification development began in 2020. Transformer specification is being finalized, and the project and will be going out for RFP in the fourth quarter of 2021. Following transformer contract award, remaining engineering design activities will be completed. Construction work will begin in 2022 with one transformer being replaced in fall of 2022 and the other being replaced in spring of 2023.

5. Prairie Island Unit 1 Condenser Steam Bellow Replacement Project

Q. PLEASE DESCRIBE THE PROJECT.

A. This project will remove and replace 15 steam bellows condensers and expansion joints.

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

A. The bellows help to minimize the effects of thermal expansion and pipe stress from the extraction steam line to the feedwater heaters inside the condenser. The loss of the bellows results in loss of thermal efficiency. Replacement is needed because this equipment is at end-of-life.

Q. DID NUCLEAR CONSIDER OPTIONS BESIDES REPLACEMENT?

A. Yes. Minor refurbishment of the steam bellows was considered but not pursued because a refurbishment is similar in complexity to a full replacement. Additionally, the steam bellows and expansion joints are past the industry average for life expectancy.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2022 capital addition for the project is approximately $4.5 million, including AFUDC. The project is forecasted to in-service in 2022.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. Estimates were received from BHI and the vendor performing the vulcanization of the expansion joint.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project is currently budgeted through LRP and is working towards getting appropriate funding.

6. Prairie Island Analog Process Controls Replacement Project Phase

Q. PLEASE DESCRIBE THE PROJECT

A. This project will continue with replacement of Foxboro Analog Process Control Modules. This project will install new Curtiss-Wright Scientech NUS Control Modules in select locations per the priorities set by the Site Operations and Instrumentation & Controls Departments. The control systems in scope are the following: Chemical Volume Control System, Over Pressure Protection

System, Heater Drain/Feed Water Heater, Main Steam & Reactor Coolant, Boron Recycle and Safety Injection control systems. The systems allow the operators to control the nuclear plant. Approximately 140 plant process control modules will be replaced under this project. The project will span across five years (2020-2024) and four refueling outages, which are required for safe and efficient installations.

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

A. Replacement of these control modules will eliminate ongoing equipment issues with those control system modules replaced. This Project replaces 50-year-old Foxboro modules with like-for-like NUS modules to eliminate failures. In recent years, there has been an increasing rate of Foxboro process control module failures. A failure of these control modules causes Plant Operation Challenges and disruptions. These modules are a constant challenge for the Control Room Operator and the Instrumentation and Controls technicians.

Q. DID NUCLEAR CONSIDER OPTIONS BESIDES REPLACEMENT?

A. Yes. We evaluated the potential for refurbishing existing equipment but determined that it was not feasible given the age and obsolescence of the equipment. We also evaluated an alternate strategy of upgrading to a distributed control system for wholesale replacement of the control systems addressed by this project. This was determined to be cost prohibitive. The selected option of replacing the obsolete control modules with a design equivalent module was determined to be the most cost-effective approach to address the reliability issues associated with the existing Foxboro controllers.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2022 capital addition for the project is approximately $2.1 million, including AFUDC. The 2023 and 2024 capital additions including AFUDC are approximately $1.3 million and $2.4 million, respectively. The project is forecasted to have a final in-service in 2024. The project costs include employee labor, outside contractors, materials and equipment, and some employee travel expenses associated with the project.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The detailed project estimate was developed based on vendor proposals for contracted services and materials and previous experience with the first phase of replacements and underwent detailed management review and challenges to confirm accuracy.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. This change was evaluated under the 10 CFR 50.59 process and does not require prior NRC approval.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Currently, the project is entering the engineering design phase. The project will be installed over four refueling outages starting in 2021.

7. Prairie Island 12 RCP Motor Replacement

Q. PLEASE DESCRIBE THE PROJECT.

A. This project will replace the 12 RCP Motor during 1R33 refueling outage. The 12 RCP motor has a 14-year preventative maintenance (PM) due in 2022. The 12 RCP motor will be replaced with the capital rotating spare RCP motor. The motor is located inside containment and requires opening/closing of the equipment hatch for replacement.

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

A. The key project benefit is continued reliable plant operation. The operating RCP motors are on a preventative maintenance plan to mitigate risk of failure resulting from age related degradation. The RCP motors are required for plant operation and an operating RCP motor failure would result in a plant trip or an extended shutdown.

Q. DID NUCLEAR CONSIDER OPTIONS BESIDES REPLACEMENT?

A. No. This is a reoccurring preventative maintenance strategy for the RCP motors.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2022 capital addition for the project is approximately $3.4 million, including AFUDC. The 2023 capital addition including AFUDC is approximately $18 thousand. The project is forecasted to in-service in 2022.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The budget was developed using actual costs from a past equivalent project.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project was authorized funding in July 2021 to begin planning.

8. Prairie Island NI Channel Bypass Panel

Q. PLEASE DESCRIBE THE PROJECT.

A. The scope of this modification includes the installation of 8 Westinghouse NIS Power Range BTI Panels to enable testing of the NIS Power Range channels in a bypass condition instead of in the "tripped" condition. The Westinghouse NIS Power Range BTI Panels will be installed for all four NIS Power Range channels on Unit 1 and Unit 2. Additionally, two test "dummy" panels will be installed in channels 1 and 2 of the training simulator.

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

A. The benefit of proceeding with this project is to reduce the potential for an inadvertent reactor trip.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2022 capital addition for the project is approximately $3.3 million, including AFUDC. The project is forecasted to in-service in 2022.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The budget for the project was developed using estimates from S&L and Westinghouse.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. NRC approval is not required for installation of the bypass panels. NRC approval is needed via a LAR in order to operate the bypass panels as intended to satisfy required surveillance procedures.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. All work is on schedule. Engineering change has been approved. Factory Acceptance Testing was completed in August 2021, the panels arrived in September. Work orders are in review now. I&C will perform the installation in 2R32 and 1R33 outages.

9. Improvements

Q. WHAT ARE IMPROVEMENT PROJECTS?

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

Q. HOW MUCH IS BUDGETED FOR CAPITAL ADDITIONS RELATED TO IMPROVEMENT PROJECTS IN THE 2022 TEST YEAR?

A. $9.0 million of capital additions are budgeted for Improvement projects.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

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

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Improvement projects that are expected to be completed and placed in-service during 2022. We first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project are revised, the cost estimate can be updated over the period the project is in progress. The capital additions budget for 2022 represents the estimated total of expenditures incurred (excluding any removal costs), plus AFUDC accrued over the project duration, that are expected to be completed and placed in service during the year 2022.

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

A. As Table 4 from earlier in my testimony shows, Improvement project additions can fluctuate from year to year based on the specific projects undertaken in each year.

The nature of Improvement projects is that, while they are valuable projects that result in improved efficiency, they are lower priority than projects in the Mandated Compliance and Reliability categories. As a result, they are completed as opportunities to improve arise and have funding capability given other priorities. In 2018 and 2019, we undertook larger improvement projects with higher relative priority. In 2018 we completed the Turbine Supervisor Instrumentation upgrade at Prairie Island. In 2018 and 2019 both sites continued projects to update surveillance testing frequencies and engineering programs to a risk informed approach based on Probabilistic Risk Assessments (PRA). Prairie Island also implemented a project to tie the RHR system on Unit 2 to the purification system in 2019 and Unit 1 in 2020, which shortens outages by reducing the time required to clean up activity in the Reactor Coolant System.

In 2020, the Security Protective Strategy update was completed at Prairie Island. This project added protective features that increased the effectiveness of the Physical Security Plan (PSP) and reduced station O&M cost annually by reducing security posts. The Maintaining the Plant and the Fleet Excellence Plans both focus on maintaining and improving existing equipment rather than modification of the plants, which leads to an increase in Improvement projects.

Q. PLEASE DISCUSS THE KEY IMPROVEMENT PROJECTS BUDGETED TO GO IN SERVICE DURING THE 2022 TEST YEAR.

A. The only significant Improvement project addition budgeted in 2022 is the Nuclear Technology Infrastructure project at the Prairie Island Plant, budgeted at $4.5 million for 2022 additions. This project is installing the technological infrastructure for future site enhancements to improve worker and plant efficiencies. This project will provide benefits by enabling the use of electronic work packages, voice over internet protocol (VoIP) communications, remote equipment performance monitoring and potential other future applications.

10. Prairie Island Nuclear Technology Infrastructure Project

Q. PLEASE DESCRIBE THE PROJECT.

A. The Prairie Island Nuclear Technology Infrastructure Project will install a permanent wireless communications network throughout the Prairie Island Site – including both units and eight outbuildings. This wireless system will enable the use of electronic work packages, voice over internet protocol (VoIP) communications, remote equipment performance monitoring and potential other future applications.

Q. WHAT ARE THE BENEFITS OF PROCEEDING WITH THIS PROJECT?

A. As discussed earlier, this project is installing the technological infrastructure for future site enhancements to improve worker and plant efficiencies.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2022 capital addition for the project is approximately $4.5 million, including AFUDC. The 2023 capital addition including AFUDC is approximately $75,000. The project is forecasted to in-service in 2022. This cost includes both units' turbine buildings, the auxiliary building, the diesel buildings, both units' containment buildings and eight other site buildings.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The project budget was created by performing a study phase that assessed the scope of the project. Once the scope was validated, vendor estimates for the required equipment, installation, and engineering were obtained.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No. Because there is no change to our license basis, NRC approval is not required.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Currently, the project has completed the engineering and installation for both units' turbine building scope of work. The turbine scope has approximately 50 wireless access points. Engineering is also complete for the auxiliary building scope. Engineering for both the reactor building and containment buildings, along with the outbuildings, remains on schedule. Implementation for the auxiliary building, containment buildings, and outbuildings is on track to begin in October 2020 with a late 2022 in-service date.

11. Facilities and Other

Q. WHAT ARE FACILITIES AND OTHER PROJECTS?

A. The Facilities and Other grouping include facility work such as building improvements, roof replacements, road repairs, and general plant additions such as small tools and equipment. This grouping includes ongoing activities to maintain plant buildings and properties and provide small tools and equipment to support normal plant operation.

Q. WHAT IS THE 2022 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $0.8 million for Facilities and Other project additions during the 2022 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

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

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Facilities and Other projects that are expected to be completed and placed in-service during 2022. We first establish scope, estimate cost, and build an activity schedule for each project; many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project revised, the cost estimate can be updated over the period the project is in progress. The capital additions budget for 2022 represents the estimated total of expenditures incurred (excluding removal costs), plus AFUDC accrued over the project duration, that are expected to be completed and placed in service during the year 2022.

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

A. As Table 4 from earlier in my testimony shows, Facilities and Other project additions have fluctuated from year to year based on the specific projects undertaken in each year. The 2022 budget for Facilities and Other additions of $0.8 million is the same as the 2018 additions of $0.8 million, and lower than the 2019 additions of $1.2 million, the 2020 additions of $3.7 million, and the 2021 forecasted additions of $5.8 million. In general, Facilities and Other additions tend to be the smallest capital project grouping, except when significant projects are a priority.

Q. ARE ANY MAJOR FACILITIES AND OTHER PROJECTS BUDGETED TO HAVE CAPITAL ADDITIONS IN 2022?

A. No. The total 2022 capital additions for Facilities and Other projects are $0.8 million, so there are no individual major projects for the 2022 test year.

12. Fuel

Q. WHAT ARE FUEL PROJECTS?

A. Fuel capital additions relate to the nuclear fuel loaded into the reactor to provide the heat energy that turns the turbine and powers the plants' generators. In fossil plants, fuel such as coal is delivered to the plant, stored on-site as inventory, and then loaded in the plant to burn. For nuclear plants, we contract with outside vendors to purchase uranium (called yellowcake), convert the uranium to a gaseous state, enrich and fabricate the uranium gas into fuel pellets and assemblies usable in the reactor, and install the fuel assemblies during refueling outages. In-house fuel engineers optimize the configuration of the fuel assemblies and the configuration of the fuel assembly placement in the reactor core. They also work with the fuel fabrication vendors to analyze new types of fuel products to evaluate increased fuel performance and cost savings.

Because this process takes almost two years from beginning to end, and because the fuel lasts for multiple years until it is fully used up, nuclear fuel expenditures are considered capital work. The various fuel expenditures are accumulated in CWIP, AFUDC is accrued, and the fuel is considered placed in-service after it arrives on-site, is inspected, and accepted. At Monticello, fuel is consumed over approximately three refueling cycles, with approximately one-third of the fuel assemblies removed and replaced in each refueling outage. At Prairie Island Unit 1 and Unit 2, approximately 46 percent of the fuel assemblies are removed and replaced during each refueling outage. Fuel is amortized over the period it resides in the reactor. Each unit's fuel is loaded as an addition every other year, so with three units we would alternate years with two fuel projects when Monticello and Prairie Island both have a refueling; with years with one project when only Prairie Island has a refueling.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FUEL PROJECT SCHEDULED TO GO IN-SERVICE DURING THE 2022 TEST YEAR.

A. The test year 2022 has one fuel project with capital additions, the reload for Prairie Island Unit 1.

Q. WHAT IS THE 2022 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $77.6 million for the Prairie Island Unit 1 fuel project addition.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

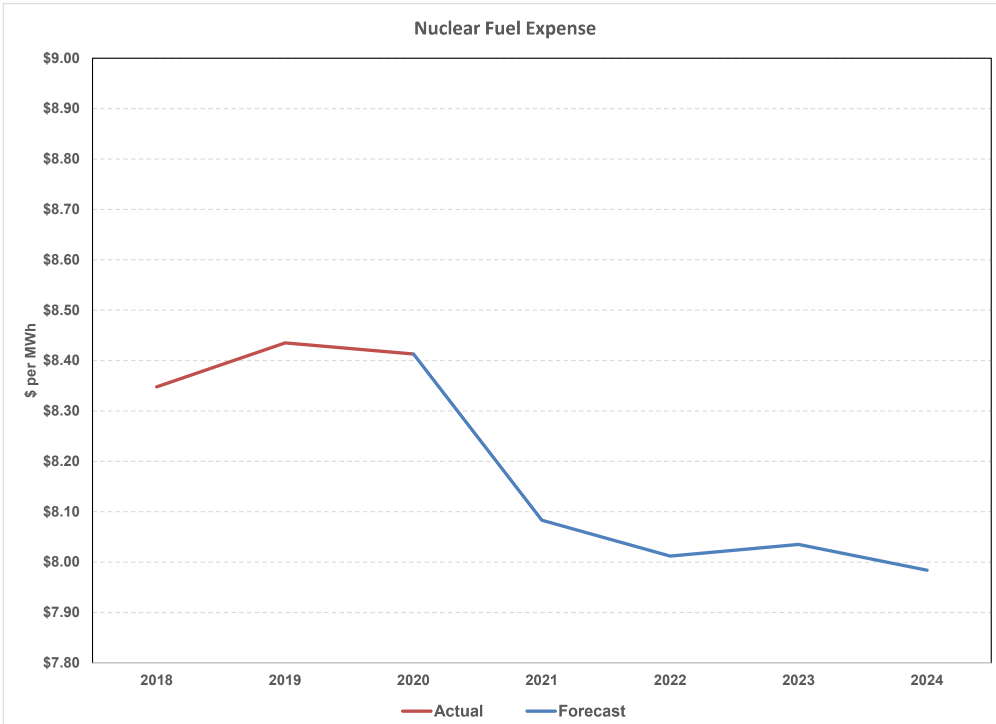
A. The budgeting for nuclear fuel additions is different than the process described earlier in my testimony for other capital projects. The costs incurred for uranium purchase, conversion, and enrichment are tracked using segregated units of measure and applied to refueling loads using an average cost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

See additional details in Exhibit___(PAG-1), Schedule 3, regarding the nature of capital fuel expenditures, the process used to estimate and track nuclear fuel costs, the number of assemblies in each fuel reload, and the specific types of fuel costs included in budgets for capital fuel expenditures and additions over various periods including the test year 2022.

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

A. As Table 4 from earlier in my testimony shows, fuel project additions fluctuate from year to year largely based on whether they include a refueling for a single unit or for two units. Comparing single refueling years, the 2022 budget for fuel additions of $77.6 million is lower than both the 2021 additions of $147.3 million and the 2019 additions of $157.5 million. Each fuel load varies as to the number of assemblies installed in the reactor. In 2018, costs increased as a result of the Gadolinia and Integral Fuel Burnable Absorber (GAD/IFBA) project for Prairie Island Unit 1 Reload for Cycle 31. The GAD/IFBA project consisted of a combination of burnable absorbers, Gadolinia and Integral Fuel Burnable Absorber, in the fuel design. This project allowed movement to 24-month cycles and will eliminate two refueling outages over the life of the plant. Figure 1 below summarizes our amortized cost of capital fuel additions, expressed as fuel expense per MWh, over the periods 2018-2020 (actual), 2021 (forecast), and 2022-2024 (budget).

Figure 1



We continue to monitor industry initiatives and search for opportunities to reduce the cost of nuclear fuel. There are a number of ongoing industry initiatives that we are following and, as appropriate, participating in, that may help to reduce the cost of nuclear fuel.

We are also actively pursuing the use of the next generation of fuel assemblies at our Monticello plant. These new fuel assemblies provide for greater efficiency in the use of the uranium.

Finally, a number of our long-term nuclear fuel supply contracts are ending within the next five years. We are evaluating the current market conditions and the long-term market forecasts provided by several industry consultants to enhance our strategy for contracting for future nuclear fuel commodity supply.

See additional details in Schedule 3, regarding the nature and specific types of fuel costs included in capitalized fuel expenditures, additions and amortized costs over various periods including 2022.

Q. ARE NRC APPROVALS NEEDED FOR FUEL PROJECTS?

A. Yes. As noted above, the fuel fabrication supplier for our Monticello plant has introduced a new fuel design that is more efficient than our current fuel design, and we are pursuing using this new fuel design at our Monticello plant to reduce fuel costs. The use of this new fuel design will require NRC approval prior to use. The work to obtain approval will occur from 2020 – 2023, with the first use of the fuel planned for the 2023 refueling.

D. 2023 Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NUCLEAR CAPITAL ADDITIONS BUDGET FOR 2023.

A. The total NSPM Nuclear 2023 capital additions are budgeted to be $159.3 million for projects and $158.2 million for fuel.

Q. WHAT ARE THE PRIMARY DRIVERS OF THE 2023 CAPITAL ADDITIONS PLACED INTO SERVICE BY THE NUCLEAR OPERATIONS BUSINESS AREA?

A. Project additions include $16.3 million for the cask loading campaign at Prairie Island, $27.4 million for baffle former bolt replacements at Prairie Island Unit 2, $16.0 million for intake travelling screen replacements at Prairie Island, and $10.5 million for a cooling tower rebuild at Prairie Island. Fuel additions are an ongoing capital requirement over the refueling cycles of each plant, and in 2023 we will have two refuelings; one at Monticello and one at Prairie Island Unit 2.

1. Dry Cask Storage

Q. WHAT IS THE SIGNIFICANT DRY CASK STORAGE PROJECT FOR THE 2023 PLAN YEAR?

A. The significant dry cask storage project Nuclear anticipates placing in service in 2023 relates to the loading and placement of casks 51 and 52 at the Prairie Island plant. This is part of the multi-year project that is forecasted to continue through 2032. I described this project earlier in my testimony.

Q. WHAT IS THE 2023 TEST YEAR BUDGET FOR CAPITAL ADDITIONS FOR THIS PROJECT?

A. The Nuclear Operations business area has established a budget of $ 16.3 million for this Dry Cask Storage project addition during the 2023 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Dry Cask Storage projects.

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

A. The project supports the continuing operation of Prairie Island Units 1 and 2 through the end of the current licenses, 2033 and 2034, respectively.

2. *Mandated Compliance*

Q. WHAT IS THE 2023 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $1.0 million for Mandated Compliance project additions during the 2023 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Mandated Compliance projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY MANDATED COMPLIANCE PROJECT PLANNED TO GO IN-SERVICE DURING THE 2023 PLAN YEAR.

A. The total amount of Mandated Compliance project additions in 2023 is $1.0 million, thus I do not discuss any individual Mandated Compliance projects.

3. *Reliability*

Q. WHAT IS THE 2023 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $128.4 million for Reliability project additions during the 2023 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Reliability projects.

Q. PLEASE DESCRIBE THE KEY RELIABILITY PROJECTS PLANNED TO GO IN-SERVICE DURING THE 2023 PLAN YEAR.

A. The largest Reliability project capital additions include replacement of the baffle former bolts at Prairie Island Unit 2, a cooling tower rebuild at Prairie Island, replacement of intake traveling screens at Prairie Island, the replacement of a cooling tower transformer at Prairie Island, replacement of the condenser steam bellow at Prairie Island Unit 2, and replacement of turbine stop valves at Monticello. Also, on-going additions from the Prairie Island Infrastructure Project, the Prairie Island Analog Process Controls Upgrade and the Prairie Island RCP Motor Replacement CESP project discussed earlier in "2022 Capital Additions" will occur in 2023.

a. Prairie Island Unit 2 Baffle-Former Bolt Replacement

Q. PLEASE DESCRIBE THE PROJECT.

A. This project will replace a portion of the baffle-former bolts, which are the bolts which hold the horizontal supports for the core together, at Prairie Island Unit 2.

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

A. NRC regulations (or license) require inspection of the baffle-former bolts in Prairie Island Unit 1 and 2. The results of the inspection may lead to replacement of the bolts. Based on the age of the bolts, as well as analysis of worst case predicted conditions, the decision was made to move forward with replacement of the baffle-former bolts in both Prairie Island units, with Unit 2 slated for 2023 and Unit 1 slated for 2024. This will avoid the need for any additional inspection or replacement through the end of the current licenses in both units. This will also allow for predictability in outage scope and duration and eliminates significant contingencies and the potential for delay associated with inspection followed by potential replacement.

Q. DESCRIBE THE PROJECT COST.

A. The 2023 capital addition for the project is approximately $27.4 million, including AFUDC. The project is forecasted to in-service in 2023.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. This budgeted cost is based on estimates from other facilities in the industry that have experience with replacements of these bolts. The estimates included a generalized breakdown in engineering, construction, project loads, and contingency.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Planning is underway to include this work in the Fall 2023 Prairie Island Unit 2 outage.

b. Prairie Island 121-128 Intake Traveling Screen Replacement

Q. PLEASE DESCRIBE THE PROJECT.

A. This Project will replace all eight Intake Traveling Screens, which have reached the end of their design life and are experiencing structural degradation of the track support and guide assemblies as well as the concrete foundation for the lower track support.

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

A. Like the cooling tower rebuild discussed later in my testimony, this project is needed to comply with our NPDES permit. The existing screens will be replaced by new screens with an improved design that will take the screens to the end of plant life, improve overall reliability and performance, and also reduce annual maintenance costs.

Q. DID NUCLEAR CONSIDER OPTIONS BESIDES REPLACEMENT?

A. Yes. Continuation of the current maintenance strategy was considered. However, this option was not pursued due to the level of structural degradation of the screen assemblies, equipment obsolescence, and operational issues currently experienced with the existing equipment.

Q. DESCRIBE THE PROJECT COST.

A. In 2023 this project will include $16 million of capital additions. Project costs included materials and labor.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. Benchmarking was performed at another Xcel site during the construction phase of replacing similar screens. Project scoping considered the option for equivalent screens and an alternate option for an updated design screen. The most cost-effective option is being selected based on project costs and ongoing O&M costs.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The engineering specifications for the replacement screens are currently under development. An RFP for the replacement screens was issued in the fourth quarter of 2020. Following contract award, the remaining design activities will proceed in 2021 with installation starting in 2022 and completing in the spring of 2023.

c. Prairie Island 122 Cooling Tower Rebuild.

Q. PLEASE DESCRIBE THE PROJECT.

A. There are four cooling towers at the Prairie Island site; this is a multi-year program with Cooling Tower 121 completed in 2021 and Cooling Tower 122 planned for 2023. The other two cooling towers were completed in previous years. The project addresses long-term material degradations and restores the condition of the Prairie Island cooling towers to support continued plant operations. The objectives of this project are to: (1) ensure cooling water compliance with state environmental regulations under NPDES permits issued by the Minnesota Pollution Control Agency; and (2) facilitate adequate cooling water availability to continue operation of the plants at 100 percent of output capacity.

The project includes: (1) replacement of the horizontal structural members, fill supports, and fill; (2) replacement of the flow distribution headers, valves, and supports; (3) replacement of the hot-water deck and associated supports; (4) partial replacement of the fan deck and supports; (4) replacement of eight fan-motor drive units; (5) replacement of the Outside Louvers; (6) replacement of drift eliminators; (7) replacement of Cooling Tower Lighting; and (8) installation of upper plenum walkway extensions.

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

A. This project is essential to ensure compliance with our NPDES permit requirements, which is necessary for the Company to maintain compliance with state and federal environmental laws. This project will also improve cooling equipment reliability for plant operations, eliminate the risks of de-rating the unit in the event of cooling issues from equipment failures, and reduce maintenance repairs that would continue to be necessary without this project. In short, this project keeps us environmentally responsible and puts our cooling equipment in good working condition for the long run.

Q. DID NUCLEAR CONSIDER OPTIONS BESIDES REPLACEMENT?

A. Yes. In fact, in the 2016 Rate Case, the Company discussed its then-current plan to replace the Cooling Towers at Prairie Island. However, based on the results of inspections and the results of our Cooling Tower 124 project, we determined that the most cost-effective manner of achieving the goals outlined above was through a rebuild rather than full replacement or other options such as a partial refurbishment.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2023 capital addition for the project is approximately $10.5 million, including AFUDC. The project is forecasted to in-service in 2023.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The 2023 capital addition for this project of approximately $10.5 million reflects the employee labor, outside contractors, materials and equipment, and other costs such as tool/equipment rentals necessary to complete this work. The project's work scoping document was created and reviewed by Nuclear management. The approved scoping document was used to develop detailed requests for quotes and proposals from multiple vendors for tower header replacement (services and materials). Internal labor cost estimates were developed using inputs from each of the responsible work groups supporting the project and historical operating experience. The in-service dates were developed to support and align with the allowable out-of-service windows for our Cooling Towers based on applicable NPDES permit requirements.

We have done internal benchmarking of similar cooling tower work performed on the Company's Sherco and King coal plants, in addition to incorporating lessons learned and actual costs from the 124 and 123 Cooling Tower refurbishments at Prairie Island. We also had the vendor for the Prairie Island materials procurement and construction project provide an order of magnitude cost estimate for the complete structural overhaul of our cooling towers. Data from those sources was used to prepare the detailed estimates for this project's total costs, including site/contract engineering, field oversight, management and administrative overheads, and contingencies.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project is authorized to start in 2022 with project completion in spring 2023.

d. Replacement of the Cooling Tower 11 Transformer and Cooling Tower 12 Transformer at Prairie Island

Q. PLEASE DESCRIBE THE PROJECT.

A. This $7.7 million project addition is the second half of the Cooling Tower 11 and Cooling Tower 12 Transformer Replacement Project at Prairie Island, based on EPRI guidance and the estimated service-life of transformers. The project is discussed in detail in the 2022 Reliability Capital Additions section.

e) Prairie Island Unit 2 Condenser Steam Bellow Replacement

Q. PLEASE DESCRIBE THE PROJECT.

A. This $4.5 million Project addition is the same as the Unit 1 project described in the 2022 Reliability Capital Additions but for Unit 2.

f) Monticello Turbine Stop Valve Replacements

Q. PLEASE DESCRIBE THE PROJECT.

A. This project would replace the four turbine stop valves (SVs) internals, four combined stop and intercept valves (CIVs) internals, and the four turbine control valves (CVs) internals with new, pre-inspected valve internals to comply with nuclear insurer requirements during Monticello's 2023 outage.

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

A. Turbine stop valves and control valves are required by Nuclear Electric Insurance Limited, the insurance company that insures all nuclear plants, to be inspected to maintain insurability. The inspection includes disassembly, removal, cleaning, inspection of valve internals, evaluation of parts for reuse, replacement of parts as identified, and reassembly. The replacement of valve internals will facilitate inspections prior to outage, thereby shortening outage duration by approximately four to six days. In addition, this project would reduce radiological dose risk because personnel would be working on non-contaminated materials instead of the highly contaminated materials currently installed in the valves.

Q. DID NUCLEAR CONSIDER OPTIONS BESIDES REPLACEMENT?

A. Yes. Removal, disassembly, inspection, and cleaning was considered in lieu of replacement, using pre-inspected rebuilt internal valve assemblies. However, replacement of internal valve assemblies was pursued instead because it minimizes worker radiation dose, reduces the likelihood of damage during disassembly, and minimizes challenges of cleaning and handling contaminated parts.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2023 capital addition for the project is approximately $4.2 million, including AFUDC. The project is forecasted to in-service in 2023. The project cost includes the cost of new materials, disposal costs for old materials, and cost of labor for inspection of the new internals, engineering analysis of new components, valve disassembly and reassembly.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. Past turbine and valve work was considered along with the General Electric long-term contract information for turbine related work was used to determine the project estimate.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project is currently in the study phase to determine the prudency and feasibility of the project scope and to evaluate alternatives to ensure the best value is realized for the customer.

4. Improvements

Q. WHAT IS THE 2023 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $12.0 million for Improvement project additions during the 2023 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Improvement projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY IMPROVEMENT PROJECT PLANNED TO GO IN-SERVICE DURING THE 2023 PLAN YEAR.

A. The only key 2023 capital addition is the Prairie Island Operating Cycle Project for $8.3 million.

5. Prairie Island Operating Cycle

Q. PLEASE DESCRIBE THE PROJECT.

A. The Prairie Island Operating Cycle is a capital project designed to allow longer operating cycles for units 1 and 2. The current operating cycle is 18 months with a grace of 6 months for Prairie Island and is, therefore, limited to 24 months maximum. The implementation of this project will result in extending the possible operating cycle length to 24 months with a 6-month grace period.

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

A. Implementing this project successfully will result in flexibility in operating cycle length. The flexibility in operation will allow the site outage schedule to meet the needs of the power generation group and allow more efficient fuel burnup.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2023 capital addition for the project is approximately $8.3 million, including AFUDC. The project is forecasted to in-service in 2023.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The project forecast was developed by completing a study to determine the most efficient option to achieve operational cycle flexibility. The most efficient option was chosen. The industry means for implementation was reviewed for project and project estimates were developed for those activities.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. The project cannot be implemented unless the NRC approves the LAR to implement Generic Letter 91-04. The LAR NRC approval would allow modification of surveillance intervals to be compatible with a 24-month fuel cycle, which, when combined with a 6-month grace period, would extend to 30 months.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project funding was authorized in 2020. The project is active and resources have been identified. The LAR was submitted in August 2021 and expected to be approved by August 2022, prior to the PI Unit 1 Fall outage.

6. Facilities and Other

Q. WHAT IS THE 2023 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS CATEGORY?

A. The Nuclear Operations business area has established a budget of $1.6 million for Facilities and Other project additions during the 2023 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Facilities and Other projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FACILITIES AND OTHER PROJECT PLANNED TO GO IN-SERVICE DURING THE 2023 PLAN YEAR.

A. The total amount of Facilities and Other project additions in 2023 is only $1.6 million for both sites, and thus no individual projects are considered key for that year.

7. Fuel

Q. WHAT IS THE 2023 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $158.2 million for Fuel project additions during the 2023 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Fuel projects. See additional details in Schedule 3, regarding the nature of capital fuel expenditures, the process used to estimate and track fuel costs, the number of assemblies in each fuel reload, and the specific types of fuel costs included in budgets for capital fuel expenditures and additions over various periods, including 2023.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FUEL PROJECT PLANNED TO GO IN-SERVICE DURING THE 2023 PLAN YEAR.

A. During 2023 we plan to complete two fuel projects, a refueling at Prairie Island Unit 2 and at Monticello during their scheduled outages that year. All of the budgeted fuel additions for 2023 relate to these projects.

E. 2024 Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NUCLEAR CAPITAL ADDITIONS BUDGET FOR 2024.

A. The total NSPM Nuclear 2024 capital additions are budgeted to be approximately $61.2 million for projects and $70.8 million for fuel.

Q. WHAT ARE THE PRIMARY DRIVERS OF THE 2024 CAPITAL ADDITIONS PLACED INTO SERVICE BY THE NUCLEAR OPERATIONS BUSINESS AREA?

A. Project additions include $54.2 million for equipment reliability. The principal reliability additions relate to Prairie Island Unit 1 Baffle Former Bolt Replacement, Prairie Island Control Room Chillers, and Prairie Island Security Computer Servers. Fuel additions are an ongoing capital requirement over the refueling cycles of each plant, and in 2024 we have one fuel reloading at Prairie

Island Unit 1.

1. Dry Cask Storage

Q. ARE THERE ANY SIGNIFICANT DRY CASK STORAGE PROJECTS FOR THE 2024 PLAN YEAR?

A. There are no budgeted capital additions for Dry Cask Storage work in 2024.

2. Mandated Compliance

Q. WHAT IS THE 2024 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $1.0 million for Mandated Compliance project additions during the 2024 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Mandated Compliance projects.

Q. CAN YOU PROVIDE AN EXAMPLE OF A KEY MANDATED COMPLIANCE PROJECT PLANNED TO GO IN SERVICE DURING THE 2024 PLAN YEAR.

A. The total amount of Mandated Compliance project additions in 2024 is only $1.0 million, thus I do not discuss any individual Mandated Compliance projects.

3. Reliability

Q. WHAT IS THE 2024 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $54.2 million for Reliability project additions during the 2024 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Reliability projects.

Q. PLEASE DESCRIBE THE KEY RELIABILITY PROJECTS PLANNED TO GO IN-SERVICE DURING THE 2024 PLAN YEAR.

A. The three largest Reliability project capital additions are: Prairie Island Unit 1 Baffle-Former Bolt Replacement, Prairie Island 121/122 Control Room Chillers, and Prairie Island Security Computer Servers. Also, on-going additions from the Prairie Island Analog Process Controls replacement discussed earlier in "2022 Capital Additions" will occur.

a. Prairie Island Unit 1 Baffle-Former Bolt Replacements

Q. PLEASE DESCRIBE THE PROJECT.

A. This project will replace a portion of the baffle-former bolts, which are the bolts which hold the horizontal supports for the core together, at Prairie Island Unit 1. This project is the same as the Unit 2 project discussed in "2023 Reliability Capital Additions," but will be conducted at Unit 1.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2024 capital addition for the project is approximately $18.9 million, including AFUDC. The project is forecasted to in-service in 2024.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The project budget is based on estimates from other facilities in the industry that have experience with replacements of these bolts. The estimates included a generalized breakdown in engineering, construction, project loads, and contingency.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Planning is underway to include this work in the Fall 2023 Prairie Island Unit 2 outage.

b) Prairie Island 121/122 Control Room Chillers

Q. PLEASE DESCRIBE THE PROJECT.

A. This project will replace the control system for each of the 121 and 122 Control Room Chillers. Each Control Room Chiller provides cooling for a loop of the Safeguards Chilled Water System. This system provides cooling for the main control room, relay room, and several other safety related equipment rooms.

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

A. This project addresses aging management challenges with the existing chillers which will improve the reliability of this equipment by replacing the obsolete control system. The controls replacement will align the system with industry standards and ensure reliable operations of the system which is needed for both normal and emergency plant operations.

Q. DID NUCLEAR CONSIDER OPTIONS BESIDES REPLACEMENT?

A. Yes. A full chiller replacement as well as the continuation of the existing maintenance strategy were considered as alternatives. Based on the reliability challenges and obsolescence of the control system, a maintenance strategy for the controls portion of the chiller was determined to not be effective to ensure reliability for the remaining plant life. Based on the current performance of the chiller units themselves, a complete replacement of the 121/122 control room chillers was not determined to be needed as the maintenance strategy has been effective for managing the mechanical portions of the chiller units.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2024 capital addition for the project is $4.4 million, including AFUDC. The project is forecasted to be in-service in 2024.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The project budget was developed based on analogous estimates using similar controls related replacements performed at Monticello and Prairie Island.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. NRC approval is not expected to be required for this project. Digital controls upgrades for safety related components frequently require NRC approval prior to implementing. However, as part of detailed project scoping, potential control system designs are being evaluated through the 10CFR 50.59 evaluation criteria to ensure the design can be implemented without requiring NRC approval through a LAR.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Pre-project planning and detailed scoping are being performed to evaluate potential control system designs to integrate with the existing control room chillers. As part of that process, proposals are being solicited to develop detailed bottom-up estimates for the project. Engineering is expected to start in mid-2022 with the replacements scheduled to be performed in 2023 and 2024.

c) *Prairie Island Security Computer Servers*

Q. PLEASE DESCRIBE THE PROJECT.

A. This project will upgrade the IT hardware and associated software on the PINGP Security Computer System, this includes servers, workstations, network switches, cyber appliances, etc.

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

A. The existing system's hardware and software is at or near obsolescence. In order to continue to maintain the system at a high level of availability/reliability and to remain in compliance with regulatory Cyber Security and Physical Security requirements, the hardware and software need to be upgraded to the latest vendor supported technology.

Q. PLEASE DESCRIBE THE PROJECT COST.

A. The 2024 capital addition for the project is approximately $3.5 million, including AFUDC. The project is forecasted to in-service in 2024.

Q. HOW WAS THE PROJECT BUDGET DEVELOPED?

A. The project budget was developed using the actual cost from similar previous projects as well as the current Monticello upgrade project.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Business case has been developed and submitted through Business Systems and is on the project plan for IT for 2023/2024 but is not yet funded.

4. Improvements

Q. WHAT IS THE 2024 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $5.6 million for Improvement project additions during the 2024 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Improvement projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY IMPROVEMENT PROJECT PLANNED TO GO IN-SERVICE DURING THE 2024 PLAN YEAR.

A. There are no significant Improvements projects slated for the 2024 Plan Year.

5. Facilities and Other

Q. WHAT IS THE 2024 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $0.4 million for Facilities and Other project additions during the 2024 plan year, using the same capital project budgeting process I discussed earlier in my testimony for 2022 Facilities and Other projects. Since the total amount of Facilities and Other project additions in 2024 is only $0.4 million for both sites, I have not discussed individual projects in my testimony.

6. Fuel

Q. WHAT IS THE 2024 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business area has established a budget of $70.8 million for fuel project additions during the 2024 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2022 Fuel projects. See additional details in Schedule 3, regarding the nature of capital fuel expenditures, the process used to estimate and track fuel costs, the number of assemblies in each fuel reload, and the specific types of fuel costs included in budgets for capital fuel expenditures and additions over various periods including 2024.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FUEL PROJECT PLANNED TO GO IN-SERVICE DURING THE 2024 PLAN YEAR.

A. During 2024 we plan to complete one fuel project, a refueling at Prairie Island Unit 1. All of the budgeted fuel additions for 2024 relate to this project.

IV. NON-OUTAGE O&M BUDGET

A. Overview and Trends

Q. HOW IS YOUR TESTIMONY ORGANIZED IN THIS SECTION?

A. I first provide a discussion of the overall request for our non-outage O&M expenses and briefly describe the initiatives that we are taking in an attempt to reduce our cost growth (with a goal of keeping costs flat to +/- 1% on an average annual basis) while at the same time improve safety, reliability, and performance. I then discuss the major cost categories included in the test year with a discussion of the drivers behind any changes. The O&M expenses related to our planned maintenance/refueling outages are discussed in Section V of my testimony.

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

A. We split non-outage O&M items into two general cost categories associated with operating our nuclear plants: workforce costs and non-workforce costs. Non-outage Workforce costs include employee labor, non-employee contractors and consultants, and security contractors. Non-workforce costs consist of material costs, employee expenses, nuclear-related fees, and other expenses.

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

A. As an Xcel Energy business area, Nuclear Operations follows the budget process established by the corporate Financial Performance and Planning group, as discussed in the testimony of Company witness Ms. Ostrom. The starting point for that area developing the O&M spending guidelines is the most recent five-year financial forecast. Specifically, the starting point for the 2022-2024 Budgets was the most recent (2021-2026) forecast. The Financial Council reviews this information, considering Xcel Energy's business plans and a number of other factors. After considering this information, the Financial Council establishes overall growth target guidelines for the new five-year O&M budgets, which each business area is expected to meet.

Once overall O&M spending guidelines are determined and communicated, the Nuclear Operations budgets are built from the "bottom up" by individual components, such as employee labor, contract labor, consulting costs, and materials expense by budget managers. In the example of labor, current salary and headcount data is fed from our payroll system to our budgeting system. Planned headcount additions and subtractions over the five-year period are added to the budget system based on current workforce plans; projected merit increases are applied by the corporate budgeting group, based on the assumptions provided in the corporate budget instructions, and approved by Human Resources.

The budgets are built in detail, and not based simply on prior year costs, to which an inflation factor could be applied. However, the corporate budget instructions provide cost escalation factors to apply, if needed, for those costs to which inflation-based growth is appropriate to apply. The Nuclear Operations business area reviews the budgets submitted by department managers at each of the three sites with the responsible Vice President. As part of our effort to meet corporate targets, adjustments are usually made after the site reviews before being submitted for review with the Chief Nuclear Officer.

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

A. Yes. Since the budgets are prepared about eight months in advance of the budget year, emergent items arise that require a reprioritization of authorized spend levels. Examples of these emergent O&M items are forced outages and extensions to planned outages. In the Nuclear Operations area, a budget manager completes a form to request approval to spend money on an unbudgeted item. The manager can propose to use budgeted dollars from a different line item in his/her own budget or ask for help in identifying savings from another department to cover the emergent cost. For a more costly unforeseen event such as a forced outage, there may be a need to find budget savings on a broader scale, such as in other departments, or across the entire Nuclear Operations business area.

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

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

A. Like all business areas, Nuclear is accountable for managing to its O&M budget for the year. The budget managers in each department are required to evaluate their ability to meet their budget as part of the monthly forecast process, with the help of the Nuclear Finance staff. This allows the business area to compare the approved budget with updated forecasts of spend, including actuals to date and estimates through end of year, that reflect changes in business operations that could not have been anticipated at the time the budget was first approved. Each Vice President holds monthly financial meetings where budget managers describe the results for the current month compared to the forecast, any changes to expected year-end results, and risks (of higher costs) or opportunities (for lower costs) that have not yet been reflected in the forecast. In addition, I hold a monthly meeting with my direct reports to review the status of financial performance of the entire Nuclear business area, and to assess what actions may be needed to manage to the overall O&M budget.

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

A. The Company's ongoing financial governance process allows a business area to adjust, on a continuing basis, its business plans and financial forecasts. For example, a business area (such as Nuclear) may face cost increases or new items not anticipated at the time the budget was created, or may need to reduce, delay, or accelerate spending in response to emerging new priorities, or unforeseen or changed circumstances. The monthly forecasting process allows those changes to be properly reflected in our business plans and forecasts. However, each business area is responsible for managing to its original O&M budget as approved, so when unforeseen costs occur, the business area makes every attempt to absorb them within its budget by reprioritizing other work. If it is unable to do so, the business area can request to increase their O&M forecast. Variances and updated forecasts are reviewed monthly with the Xcel Energy Financial Council.

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

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

Q. WHAT IS THE COMPANY'S NON-OUTAGE O&M BUDGET FOR THE 2022 TEST YEAR?

A. As shown in Table 7 below, our 2022 test year non-outage O&M expenses are budgeted at $224.3 million, similar to our actual 2020 costs.

Table 7

Nuclear Operations Non-Outage O&M Costs

($ in millions)

$ in millions	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Act/ Fcst**	**2022 Test Year Budget**	**2023 Test Year Budget**	**2024 Test Year Budget**
Workforce Costs							
A. Internal Labor	$ 125.3	$ 123.3	$ 122.5	$ 121.2	$ 118.7	$ 119.8	$ 121.6
B. External Labor (Contractors & Consultants)	27.4	24.3	19.4	19.2	22.0	20.0	20.5
C. Security	31.1	31.1	30.7	28.1	28.7	30.2	31.2
Subtotal Workforce Costs	$ 183.8	$ 178.7	$ 172.6	$ 168.5	$ 169.4	$ 170.0	$ 173.3
Non-Workforce Costs							
D. Materials & Chemicals	15.3	15.6	11.4	10.3	10.6	11.0	10.8
E. Employee Expenses	3.0	3.6	1.8	1.8	1.9	1.9	1.9
F. Nuclear-related fees	33.9	34.7	34.9	35.4	36.4	36.8	37.1
G. Other	7.6	6.5	5.9	6.0	6.0	6.1	6.1
Subtotal Non-Workforce Costs	$ 59.8	$ 60.4	$ 54.0	$ 53.5	$ 54.9	$ 55.8	$ 55.9
Total Non-Outage O&M	**$ 243.6**	**$ 239.1**	**$ 226.6**	**$ 222.0**	**$ 224.3**	**$ 225.8**	**$ 229.2**

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

A. From 2018 through the 2024 budget, our non-outage O&M expenses are decreasing by an average of 1.0 percent annually. The calculated percentage changes by year, and average annual percentage changes over various two- and four-year periods, for non-outage O&M expenses is attached as Exhibit___(PAG-1), Schedule 4.

The Company made significant strides in reducing Nuclear non-outage O&M costs since 2016. Our total in 2016 was $258.7 million. These expenses decreased by an average annual rate of 3.2 percent per year from 2016 to 2020. During this period, several continuous improvement (CI) initiatives were deployed: 1) Delivering the Nuclear Promise (DNP) Efficiency Bulletin implementation through 2017 (primarily focused on centralization of support organizations and outage process improvements, 2) beginning in 2018, dividing the Maintain and Operate groups using another DNP EB, EB 17-23 "Transform the Maintaining the Plant Organization," which created maintenance efficiencies by minimizing handoffs, 3) working with the U.S. Department of Energy (DOE) in 2019 to further refine and implement efficiencies related to service organization and creating a vision of "compliance through technology" principles, and 4) completing the EB-17-23 transformation, and reorganizing into the four main functions (Operate/Maintain/Support/Strategy) in 2020. In addition to these CI initiatives, the pandemic was a significant contributor to reduced O&M levels in 2020 and 2021. From 2021 through 2024, total non-outage O&M costs are forecast to increase a modest 1.1 percent on average, a rate below normal inflation and forecasted merit increases, with respect to both workforce and non-workforce spend.

Q. WHY ARE NON-OUTAGE COSTS FORECAST TO INCREASE OVER THE TERM OF 2021 – 2024 AT 1.1 PERCENT?

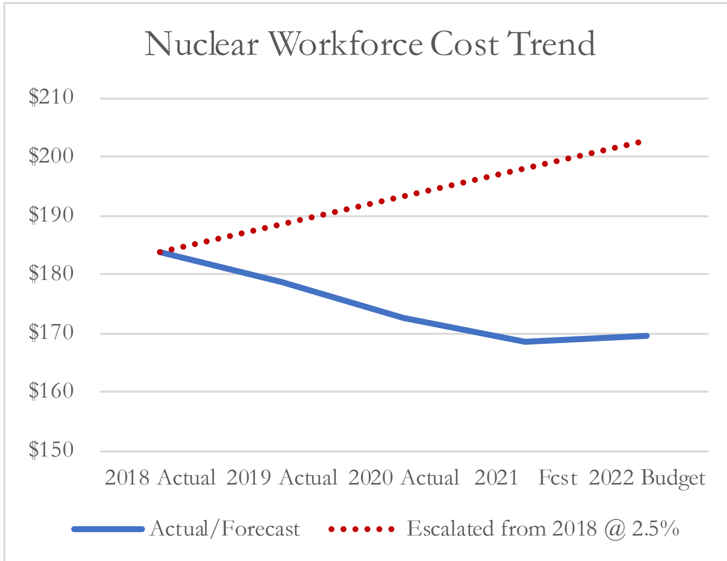
A. Because workforce costs account for roughly 75 percent of the O&M costs for this period, these costs have a strong influence on the overall trend. Forecasts from 2021-24 for non-outage workforce costs include 2.5 to 3 percent per year increases, which are offset by decreasing headcount assumptions resulting from management decisions to slow hiring and limit personnel at our facilities during the pandemic to ensure worker safety. Cost management efforts to eliminate manual handoffs in information and in work processes have also succeeded in reducing budgeted O&M costs.

In addition to the strides we've made in managing employee labor costs, we've significantly reduced security contractor costs as well. In 2017-2018 we made innovative security staffing changes, in 2018-2019 we saw staffing reductions from capital strategy improvements at Monticello, and we saw similar savings from our Prairie Island capital security project implemented in the final quarter of 2020, with full annual savings in 2021.

Q. PLEASE PROVIDE A COMPARISON BETWEEN NUCLEAR WORKFORCE COSTS OVER RECENT YEARS AND WHAT WOULD BE EXPECTED GIVEN RELATIVELY STANDARD ESCALATION RATES.

A. In Figure 2 below, Nuclear workforce costs from 2018 to 2022 are compared to a more normal trendline beginning with 2018 actual workforce costs escalated at 2.5 percent per year through 2022.

Figure 2



Q. HAS THE COMPANY BEEN SUCCESSFUL IN REDUCING NUCLEAR O&M SPEND OVER A LONGER PERIOD?

A. Yes. A review of Total (non-outage and outage) O&M costs over the past ten years further demonstrates the Company's success in O&M reduction. We had O&M costs of $290 million in 2011. If we had escalated the $290 million in 2011 at a conservative rate of 2 percent per year, we would predict $361 million in O&M costs in 2022. This would total to cumulative O&M spend of about $3.18 billion over the ten years from 2011-2020. Instead, we spent only $3.09 billion over that ten-year period, saving about $90 million. The Company's proposed total O&M spend for Nuclear in 2022 is $265 million, which is $25 million lower than 2011.

Further, our overall total non-outage O&M costs in 2022 are budgeted to be less than actual 2018, 2019, and 2020 levels, and only slightly above 2021 levels. These costs in 2023 and 2024 are forecast to remain at levels below 2019 actuals.

Q. DO YOU ANTICIPATE THAT NUCLEAR WILL BE ABLE TO CONTINUE TO ACHIEVE INCREMENTAL O&M REDUCTIONS?

A. The significant reduction from 2019 to 2020 was largely a result of the pandemic. This effect will continue in 2021 due to ongoing pandemic conditions and the Company's desire to keep our employees as safe as possible by minimizing travel and the number of personnel at our facilities. Management decisions to slow hiring during these uncertain times also resulted in natural reductions to workforce costs and employee expenses. The Company also deferred certain projects that were slated to move forward in 2020-2021.

Beginning in 2022, we expect our non-outage O&M costs to begin to normalize. That said, the nuclear group plans to create savings sufficient to absorb inflation in 2022.

Q. PLEASE PROVIDE ADDITIONAL DISCUSSION OF THE OPERATIONAL CHANGES THE COMPANY HAS MADE TO REDUCE O&M.

A. As I mentioned earlier in my testimony, the two main drivers of cost reductions to date involved centralizing support functions at the fleet level. This provides the opportunity to compare processes and select best practices, utilize resources across peaks at both sites, and reduce supervision. The non-outage support functions include: Security, Performance Improvement, Emergency Preparedness, Nuclear Oversight, Regulatory Services, Engineering, and Projects.

We have centralized responsibility for outage duration and cost improvements. Our efforts with respect to outages have included negotiation of longer-term contracts at reduced prices with major outage vendors, along with other groups within Xcel Energy, for greater purchasing power. These contracts cover refueling, generator and turbine services, and outage supervision and craft. We have also benchmarked our outage duration and cost against the industry and have implemented some of the specific techniques at the Company that we observed while visiting other sites. Our submission of risk-based LARs will lower costs by reducing the frequency of inspections required during outages.

We have undertaken to limit overtime expenses in areas such as operations relief and outages, limit the number of supplemental workers used, reducing maintenance contractor costs by reconfiguring the use of in-house resources, and absorbing attrition by implementing technology.

Specifically, we are installing the Prairie Island Nuclear Technology Infrastructure project (discussed earlier in my testimony) in 2021-2022 to enable other technology tools to be deployed throughout our plants, such as the CAP Intelligence, GE Asset Performance Monitoring, and Electronic Work Packages projects discussed in the IT testimony.

Q. HOW DOES THE TREND IN NUCLEAR-RELATED FEES IMPACT THE COMPANY'S ABILITY TO CONTINUE TO REDUCE NUCLEAR O&M?

A. The ongoing increases in certain nuclear-related fees presents a significant obstacle to additional O&M reductions. Total O&M from 2018 to 2021 is declining, while government-based payments, which include certain O&M costs like NRC fees and state emergency preparedness fees, are generally rising and/or mandated by government. As discussed below, the Company has little or no control over these government-imposed costs.

B. Non-Outage O&M Budget Categories – 2022 Test Year

1. Employee Labor

Q. PLEASE DISCUSS THE NON-OUTAGE EMPLOYEE LABOR INCLUDED IN THE NUCLEAR BUSINESS AREA'S 2022 TEST YEAR.

A. Non-outage employee labor expenses included in the test year are approximately $118.7 million and include all regular pay for Nuclear employees, including base pay, premium pay, and overtime consistent with applicable bargaining agreements. They do not include annual incentive pay.

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

A. As shown in Table 7 above, internal labor costs decreased 1.6 percent from $125.3 million in 2018 to $123.3 million in 2019 and decreased another 0.6 percent to $122.5 million in 2020. In 2021, we're forecasting further decreases from $122.5 million to $121.2 million, a 1.1 percent decrease. This follows the current trend of lower labor costs due to our cost management efforts. In 2022, our labor costs are decreasing by 2.1 percent to $118.7 million.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. Labor decreased over the period 2018-2020 mainly due to a reduction of headcount achieved through cost management initiatives, with the majority of reductions coming from the consolidation of support functions at the fleet level, rather than at the plant level. In addition, I discussed previously how the pandemic influenced our decisions to minimize headcount replacements in 2020-2021. Continued reductions in internal labor costs in 2022 are due to 3 key capital technology projects that will enable efficiencies related to the NRC-required CAP, the maintenance decision-making based on better data, and the automation of work management.

Q. PLEASE EXPLAIN THE DIFFERENCE IN EMPLOYEE LABOR FROM 2020 ACTUAL COSTS TO THE 2022 TEST YEAR BUDGET IDENTIFIED ABOVE IN TABLE 7.

A. The labor budget in 2022 is decreasing by $3.8 million from 2020 levels, an annual average decrease of 1.1 percent per year. The majority of labor cost decreases from 2020 to 2022 are due to a decrease in the average funded headcount over 2021-2022 from average 2020 levels by 33 FTEs. In addition, we are utilizing more internal labor on strategic capital improvements to keep overall costs down.

Q. PLEASE DESCRIBE THE CHALLENGES THE NUCLEAR ORGANIZATION FACES WITH RESPECT TO MAINTAINING ITS EMPLOYEE WORKFORCE.

A. Maintaining a skilled and engaged workforce is one of the Company's top priorities as it impacts cost, performance, and safety. It remains a significant challenge to recruit and retain technically experienced nuclear employees. The compensation levels necessary to recruit and retain experienced nuclear employees is ever increasing based on the limited number of nuclear plants in the United States and the highly competitive practices employed by other nuclear companies in pursuit of the same experienced personnel.

The supply of possible nuclear employees is becoming more limited as well. With the industry being more than 50 years old, many experienced nuclear personnel are well along in their careers and will be in a position to retire in the next five to ten years.

Further, the lack of clear long-term public policy support for nuclear energy in the United States is limiting the entry of new employees into the industry. We are doing our part to attract new, younger employees to nuclear through our internship, "pipeline," and rotational programs, particularly in the operations and engineering areas.

Finally, given the nuclear industry's openness in sharing issues and their resolution, plants with new performance issues are able to identify and recruit personnel who have worked at other plants who have successfully resolved issues. Our plants are performing at historic levels, which makes our employees desirable candidates to other utilities that are seeking to improve their performance, as our employees have demonstrated ability to operate successful plants. These other companies are offering signing bonuses and retention incentives to attract and retain experienced employees from other nuclear companies. We need to ensure that we are providing adequate pay, training, and opportunities to attract and retain the caliber of workers that we need to continue to operate at our current high level. Talent development, including fostering a culture of continuous improvement, is a constant focus for the Nuclear organization, and an essential element to achieve our performance objectives for our stakeholders.

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

A. No. To limit the number of contested issues, we are not seeking recovery of Nuclear retention program costs in this case.

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

A. Yes. However, because we've achieved many of the goals the program was designed to attain, use of the program will be limited. This program has been successful; over the last few years, we have built a succession plan that will ensure that Nuclear continues to have employees with the necessary skills to safely and efficiently operate our plants going forward. As a result, we have scaled back the scope of our retention plan and deploy it only in specific circumstances on a case-by-case basis.

We have successfully reduced turnover, and as discussed previously, overall performance at both plants has continued to improve, resulting in record high performance in safety, reliability, and capacity. We have now incorporated other retention provisions in our employee agreements to help attract and retain qualified personnel and have taken other steps to attract and retain the right skilled workforce at our plants; including the planned development of new, multi-skilled union positions. The benefits of maintaining our employee base are clear both on an operational basis and a cost basis as we avoid the costs related to recruiting and training replacement employees or hiring additional contractors to fill the gaps.

2. Non-Employee Contractors and Consultants

Q. PLEASE EXPLAIN THIS BUDGET CATEGORY.

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

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

A. As Table 7 above shows, contractor/consultant costs decreased from $27.4 million in 2018 to $24.3 million in 2019, decreased significantly to $19.4 million in 2020, and are forecasted to decrease again to $19.2 million in 2021. For 2022, costs are budgeted to increase from 2020-21 levels, with a budget of $22.0 million.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. Budget increases for 2022 are primarily due to required engineering program/analysis updates and the DOE hydrogen project for engineering and construction, discussed previously. We group Internal Labor and External Labor together intentionally as Workforce Costs because when significant attrition occurs, we may need to hire external labor to get work accomplished. Conversely, when attrition slows, we may not need to use external help as much as we've done in the past.

3. Security Costs

Q. WHAT ARE SECURITY COSTS?

A. Security costs reflect the contract labor workforce we procure to meet the security post requirements of the NRC along with the Xcel Energy labor costs necessary to provide governance and oversight of the contract security force. Posts are manned 24 hours per day / 7 days a week. This has resulted in Security being the largest single functional workforce in the Nuclear organization. The number of security officers manning each post is based on coverage requirements set by the NRC. The specific logistics of each plant must be mapped to the NRC's requirements, and coverage levels must be maintained at all times. If any unusual security issues are noted, additional "compensatory" posts may be required on a temporary basis until a permanent security remedy can be designed and implemented, subject to NRC approval. The Security workforce item excludes the internal security management team that oversees the contract workforce. (The internal team costs are included in the Internal Labor line item.) The workforce costs are paid to an outside security firm based on the number of officers required per post and the contracted labor and benefit rates agreed to with the Company.

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

The NRC requires self-assessment of security effectiveness and also performs inspections. Issues found from either self-assessments or inspections must be remedied initially through compensatory measures and followed up with a longer-term permanent remedy. Our goal is to comply with requirements but seek cost-effective means to do so, which can involve capital modifications to reduce compensatory measures where feasible.

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

A. As Table 7 above shows, Security Contractor costs decreased from 2018 to 2020 by an average of 0.6 percent. In 2021, we're forecasting an 8.5 percent decrease. The decline in 2020 was due primarily to the savings from the Prairie Island capital security strategy project implemented in the last quarter of the year, offset by the cost of Prairie Island's NRC Force on Force exercise which causes incremental costs every 3 years for each site. In 2021, there was a full year of savings related to the security project that drove the larger decrease.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. As mentioned previously, a number of cost management initiatives have been undertaken related to security contractor costs: in 2016-2018 we implemented innovative staffing changes; in 2017-2018 we realized O&M benefits at Monticello related to our capital security strategy project and we saw similar benefits from our Prairie Island capital security project beginning in the fourth quarter of 2020. Table 8 below shows the major components that are driving the decreases in security costs from actual 2020 to test year 2022.

Table 8

Security Decrease Breakdown:

2020 Actuals to 2022 Test Year *(in millions of $)*

2020 Actual Security Contractor Costs	**$30.7**
[PROTECTED DATA BEGINS…	
	…PROTECTED DATA ENDS]
2022 Test Year Security Contractor Costs	**$28.8**

The trend toward consistent increases in security costs (except for years with an NRC Force on Force exercise) over time is expected to return in the future as the impact of the cost management initiatives will no longer be available to offset the annual merit increases of the officers. We expect a continuing national concern over the enhanced security of nuclear plants, not only to provide protection for external events post-Fukushima, but also for hostile threats to plant and public safety. Of course, with a mindset toward continuous improvement, we will stay abreast of industry and technological advances in this area for any opportunities to reduce costs and be more effective.

4. *Materials Costs*

Q. PLEASE EXPLAIN THIS BUDGET CATEGORY.

A. Materials costs include tools, equipment and other resources to maintain and operate our nuclear generating facilities. They include items such as chemicals used in the nuclear generation process, radiological supplies, overhaul supplies not meeting capitalization thresholds, computer supplies, intake screen parts, boiler fuel oil, and ammunition used by on-site security personnel. The materials costs included in O&M are generally those consumed in the operating process or small in amount and are in addition to materials capitalized in construction projects.

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

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

A. As Table 7 above shows, materials costs decreased from 2018 to 2020 from $15.3 million to $11.4 million. We are forecasting even lower costs of about $10.3 million in 2021, with increases in 2022 to $10.6 million, which remains lower than 2020 levels.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

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

The $1 million decrease from 2020 to 2021 is largely due to decreased maintenance and project work planned in 2021. The continuing pandemic strategy is to defer work as much as possible without compromising safe operations. We are expecting to return to pre-COVID maintenance volumes in 2022, with a focus on work that had been deferred.

5. Employee Expenses

Q. PLEASE DISCUSS WHAT EMPLOYEE EXPENSES ARE INCLUDED IN THE NUCLEAR OPERATION BUSINESS AREA'S 2022 TEST YEAR O&M BUDGET.

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

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

A. As Table 7 above shows, employee expenses increased from 2018-2019 from $3.0 million in 2018 to $3.6 million in 2019. In 2020, we experienced a significant decrease to $1.8 million, with employee expenses predicted to remain relatively flat into 2022.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

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

Due to the COVID-19 pandemic, nearly all travel activity stopped in March 2020, and travel continues to remain restricted late into 2021. We anticipate staff travel between sites for this support to continue to stay flat in 2021 and beyond, due to the technology tools deployed such as Microsoft Teams, cell phones with Wi-Fi access to show real-time plant conditions to remote experts, etc.

6. Other Expenses

Q. PLEASE DISCUSS WHAT OTHER EXPENSES ARE INCLUDED IN THE NUCLEAR OPERATION BUSINESS AREA'S 2022 TEST YEAR O&M BUDGET.

A. "Other" O&M expenses are composed mainly of information technology and support costs (such as software licensing and hardware maintenance), utility costs (i.e. electricity and gas used by the sites), rents (for equipment and facilities), facility and site maintenance costs, fleet vehicle transportation costs, permits, office supplies, and printing costs.

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

A. As Table 7 above shows, other O&M Expense costs decreased from $7.6 million in 2018 to $6.5 million in 2019. Costs dropped again in 2020 to $5.9 million, with forecasted costs in 2021 to increase slightly to $6.0 million and to remain flat in 2022. Approximately $1.1 million of costs classified as "other" in 2018 represented some unusual items at Monticello, such as $600,000 renovation of 40- and 50-year old bathrooms/showers (24) in two buildings serving approximately 530 workers; $120,000 for carpeting in the training center, and $360,000 for site paving repairs. Absent those unusual items and one-time reductions in 2020, costs in the "other" category have remained, and will continue to remain, relatively constant.

7. *Nuclear-Related Fees*

Q. WHAT ARE INCLUDED IN NUCLEAR-RELATED FEES?

A. Nuclear fees include industry specific fees and dues. Fees are assessed by the industry's Federal regulatory oversight agency (NRC), by the industry's operational oversight organization (INPO), by governmental emergency preparedness and management agencies such as Federal Emergency Management Agency (FEMA), and various state agencies consistent with agreements with the Prairie Island Indian Community (PIIC). Dues are assessed by various industry organizations and groups. Table 9 depicted below lists out the various components of Nuclear Fees and the changes by year.

Table 9

Nuclear Fees

($ in millions)

$ in millions	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Act/ Fcst**	**2022 Test Year Budget**	**2023 Test Year Budget**	**2024 Test Year Budget**
NRC	$ 18.0	$ 18.7	$ 18.4	$ 19.3	$ 19.6	$ 19.8	$ 20.0
FEMA / State EP	6.6	6.1	6.5	6.6	7.0	7.1	7.2
INPO	3.0	3.1	3.1	3.1	3.1	3.2	3.2
EPRI	2.4	2.4	2.2	2.2	2.2	2.3	2.3
PI Indian Community	1.9	2.5	2.5	2.5	2.5	2.5	2.5
NEI & Other Industry Groups	2.0	1.9	2.2	1.7	2.0	1.9	1.9
Total Nuclear Fees/Dues	$ 33.9	$ 34.7	$ 34.9	$ 35.4	$ 36.4	$ 36.8	$ 37.1

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

A. As Tables 7 and 9 above show, Nuclear Fees increased from approximately $33.9 million in 2018 to $34.7 million in 2019 and to $34.9 million in 2020. Nuclear Fees are forecasted to increase to $35.4 million in 2021 and budgeted to increase again to $36.4 million in 2022. Overall, fees and dues in the test year 2022 are increasing an average of 2.1 percent per year from actual 2020 levels.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. Both NRC fees and FEMA/state emergency preparedness (EP) fees have fluctuated in various years and account for most of the increase overall in 2018 to 2020; the 2022 increase is driven by higher fees for NRC and FEMA/EP. Fluctuations in other categories create slight changes in the overall fees. PIIC fees are constant at an average of $2.5 million per year.

Q. PLEASE EXPLAIN THE DIFFERENCE IN NUCLEAR-RELATED FEES FROM 2020 ACTUAL COSTS TO THE 2022 TEST YEAR BUDGET IDENTIFIED ABOVE IN TABLES 7 AND 9.

A. Two areas are driving increases in fees and dues from 2020 to 2022: NRC fees and FEMA/EP fees. None of the other fees are increasing, and NEI and other industry groups' dues are decreasing during that period. I will explain the drivers for the larger changes in the next set of questions in my testimony.

Q. PLEASE EXPLAIN THE VARIATIONS IN NRC FEES OVER THE YEARS, IN PARTICULAR THE INCREASE IN 2022 FROM ACTUAL 2020 LEVELS.

A. NRC fees consist of two components, NRC Reactor fees, which are fixed fees assessed on a per-reactor basis, and NRC Inspection fees, which vary based on work the NRC does for each operator. NRC Reactor fees are based on total NRC budgeted resources less the costs billed for inspections (which are recovered through NRC Inspection fees) and allocated equally amongst total operating reactors under the NRC's purview. Table 10 below summarizes the changes in these two components from 2020 to 2022.

Table 10

Nuclear Fees – NRC

($ in millions)

$ in millions	2018 Actual	2019 Actual	2020 Actual	2021 Act/Fcst	2022 Test Year Budget	2023 Test Year Budget	2024 Test Year Budget
NRC Reactor Fees	$ 13.6	$ 14.7	$ 14.4	$ 15.4	$ 15.3	$ 15.5	$ 15.6
NRC Inspection Fees	4.4	4.0	4.0	3.9	4.3	4.3	4.4
Total NRC Fees	$ 18.0	$ 18.7	$ 18.4	$ 19.3	$ 19.6	$ 19.8	$ 20.0

Q. PLEASE EXPLAIN THE VARIATIONS IN NRC REACTOR FEES.

A. The variations in NRC Reactor fees are dependent on total NRC budgeted resources and the offsetting costs billed for inspections. In 2019, NRC's budgeted resources stayed relatively consistent with 2018 levels despite the reduction in total operating reactors and inspections due to the shutdown of the Oyster Creek reactor at the end of 2018. As a result, the per-reactor fees increased 8.1 percent (one fewer reactor over which to spread the NRC costs). In 2020, NRC decreased its budgeted resources consistent with the shutdown of Pilgrim, Three Mile Island Unit 1, and Indian Point Unit 2 reactors and, as a result, the per-reactor fees decreased 2.0 percent. In 2021, the reactor fees increased by about $1 million or 6.9 percent due to an increase in NRC's budgeted resources and a reduction in the number of reactors due to the shutdown of Duane Arnold and Indian Point-3.

The 2022 test year budget for NRC Reactor fees assumes that the NRC continues to maintain its budgeted resources at 2021 levels. As such, per-reactor fees will increase for years when the number of reactors decreases. The NRC's fiscal year ends September 30. We assume that reactor fee levels will increase one percent each year for the fourth quarter of 2021, and again in the fourth quarter of 2022 due to inflation.

We base our assumed level of one percent annual increases in reactor fees on the best information available, considering NRC communications, history and experience. However, the NRC's assessed reactor fees are intended to cover all of their agency costs other than those funded by inspection fees, and when NRC budgets include unique drivers (such as one-time programs like Fukushima, or expected staffing increases), past history is not necessarily predictive of future fee changes.

Q. PLEASE EXPLAIN THE TREND IN NRC INSPECTION FEES FROM 2020 TO THE TEST YEAR.

A. The 2022 test year fees for NRC inspections are budgeted to increase 4 percent from the average levels billed during 2018 to 2020. NRC inspections in 2018 were notably higher, driven by the larger amount of cyclical biennial and triennial inspections at both plants. Our current level of inspection billings in 2021 is slightly lower than 2020 actuals and we project a higher level of inspections (including routine cyclical biennial and triennial inspections and non-routine ad-hoc inspections) to continue into 2022.

Q. DOES THE COMPANY SEE ANY OPPORTUNITY TO DECREASE NRC FEES?

A. Potentially. While the NRC fees are largely beyond the Company's control, the Company will work with industry and oversight agencies, such as NRC and INPO, to leverage advances in technology to streamline certain processes. If such measures gain acceptance in the future, they could possibly lower the cost of NRC and INPO oversight.

Q. PLEASE EXPLAIN THE VARIATIONS IN FEMA/EP FEES; IN PARTICULAR, THE INCREASE EXPECTED FROM 2020 ACTUALS TO 2022.

A. There are four main elements of emergency planning fees: one at the national level, FEMA; and three at the state and local levels: Minnesota Department of Public Safety (Homeland Security and Emergency Management); Wisconsin Radiological Emergency Planning Program; and Pierce County in Wisconsin (Office of Emergency Management). We base our assumed level of annual increase/decrease in these costs on the best information available, which typically includes communications directly from the applicable agency, historical rates of increase, and any knowledge of unique drivers such as one-time programs or expected staffing increases. The 2022 increase can be summarized as shown in Table 11 below.

Table 11
Nuclear Fees - FEMA/Emergency Preparedness (EP)
($ in millions)

$ in millions	2018 Actual	2019 Actual	2020 Actual	2021 Act/ Fcst	2022 Test Year Budget	2023 Test Year Budget	2024 Test Year Budget
FEMA	$ 1.1	$ 1.1	$ 1.2	$ 1.3	$ 1.3	$ 1.3	$ 1.3
Minnesota EP	4.5	4.4	4.5	4.5	4.8	4.9	5.0
Wisconsin EP	0.9	0.5	0.7	0.7	0.8	0.8	0.8
Pierce County WI EP	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Nuclear Fees/Dues	$ 6.6	$ 6.1	$ 6.5	$ 6.6	$ 7.0	$ 7.1	$ 7.2

The primary driver of the increase seen in 2022 from 2020 is the $0.3 million increase in Minnesota EP fees. The increase in Minnesota EP fees is driven by additional regulatory rules and training requirements for emergency planning and preparedness. The NRC requires communities supporting nuclear plants to perform regular drills to practice preparedness for hostile actions (such as an attack on the plant) and responses to external events (such as flooding or tornado threats).

The current budget set by the Minnesota Department of Public Safety (Homeland Security and Emergency Management) is $5.5 million for the state budget period of July 1, 2021 through June 30, 2022. This is slightly higher than the state budget of $5.4 million for the period of July 1, 2020 through June 30, 2021. The final state bill for the period of July 1, 2019 through June 30, 2020 was $4.4. Recent history has indicated that the budget level set by the state is higher than final actual billings. We budgeted $4.8 million for 2022, which is approximately $0.7 million below the state budget.

Q. PLEASE DESCRIBE THE PIIC FEES.

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

> The commission shall approve a rate schedule providing for the automatic adjustment of charges to recover the costs or expenses of a settlement between the public utility that owns the Prairie Island nuclear generation facility and the Mdewakanton Dakota Tribal Council at Prairie Island, resolving outstanding disputes regarding the provisions of Laws 1994, chapter 641, article 1, section 4. The settlement must provide for annual payments, not to exceed $2,500,000 annually, by the public utility to the Prairie Island Indian Community …

Under this statutory provision, the Company paid the PIIC various levels of fees, depending on their nature as recurring or non-recurring, under the settlement agreement.

The average payment since 2017 has been $2.5 million and is expected to remain at that level going forward. As noted in Table 9 above, only $1.9 million was recorded in 2018. This was a correction from an accounting error in 2017, when $3.1 million was recorded, and does not reflect a change in fees.

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

A. As discussed above, the total O&M costs at Prairie Island and Monticello continue to compare favorably to other facilities across the United States. The EUCG charts set forth at Schedule 5 provides comparison charts for total operating costs in 2020 for single unit sites like Monticello and dual unit sites like Prairie Island. Total operating costs include all of our O&M, including non-outage and outage. This data is provided by the EUCG based on surveys of industry companies, including the Company. These comparisons show the cost of our plants to be lower than most plants on a total dollar basis for operating costs.

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

Q. WHAT IS THE LEVEL OF O&M EXPENSE NUCLEAR SEEKS TO RECOVER FOR THE 2023 AND 2024 PLAN YEARS?

A. As shown in our 2023 and 2024 supporting information, provided in Volume 5 of our Initial Filing, Nuclear is forecasting changes in its non-outage O&M expenses for Plan Year 2023 in the following areas:

- A slight increase in workforce cost of $0.6 million (0.4 percent) due largely to labor merit increases and contractual security increases, offset by headcount decreases due to efficiencies.
- A slight increase in non-workforce costs of $0.9 million (1.6 percent) due to higher materials spend associated with the installation period of the DOE hydrogen project I discussed earlier in my testimony, and to normal increases in nuclear-related fees.

Nuclear is also forecasting changes in its non-outage O&M for Plan Year 2024 in the following areas:

- An additional increase in workforce costs of $3.3 million (1.9 percent) due largely to labor merit increases and contractual security increases, offset by headcount decreases due to efficiencies.

- A slight increase in non-workforce costs of $0.1 million (0.2 percent) for increases in nuclear-related fees.

These forecasted increases for 2023-2024 are significantly below expected increases associated with annual increases in merit pay and nuclear fees. Costs in these years are still well below 2019 actuals which represent our commitment to keep costs relatively flat.

V. PLANNED OUTAGE O&M BUDGET

A. Overview and Trends

Q. HAS THE COMPANY MADE ANY CHANGES TO HOW IT HANDLES OUTAGES SINCE ITS LAST RATE CASE?

A. Yes. As noted above, as part of the cost management and best practices initiatives, Nuclear has centralized outages on a fleet-wide basis under a single leader. When planning outages, the Company targets a desired duration and cost for each outage. In addition, the Company has entered into a number of long-term contracts with its outage contractors in order to negotiate better prices for outage services. Also, during the 2018 outage at Prairie Island Unit 1, we implemented a new fuel design that will allow that unit to operate for 24 months between refueling instead of 22 months. The same fuel design was implemented at Prairie Island Unit 2 during the fall 2019 outage.

Q. HAS THE COMPANY SEEN ANY RESULTS FROM THESE CHANGES?

A. Yes. Since centralizing the outage function in 2016, both the duration and total outage O&M costs of outages have been reduced. This can be seen below in Table 12 below.

Table 12
Planned Outage Cost and Duration
($ in millions)

Unit / *Period*	**PI Unit 1 Fall 2018**	**MT Spring 2019**	**PI Unit 2 Fall 2019**	**PI Unit 1 Fall 2020**	**MT Spring 2021**	**PI Unit 2 Fall 2021**	**PI Unit 1 Fall 2022**
Outage Duration (Days)	35	30	24	25	33	**[PROTECTED DATA BEGINS…**	
Total Outage O&M Cost	$33.2	$32.8	$29.3	$22.5	$26.2		

...PROTECTED DATA ENDS]

A comparison between two outages involving generator replacement at Prairie Island shows the impact of this initiative. The 2018 outage at Prairie Island Unit 1 included, among other things, replacement of the plant's original main electric generator. This outage lasted 35 days at a cost of $33.2 million, with the duration primarily driven by the electric generator replacement. By contrast, a 2015 outage that included the main electric generator replacement at Prairie Island Unit 2 and was done prior to the outage initiative, took 50 days.

In addition, the extension of the refueling cycle (i.e., time between refueling) at Prairie Island Units 1 and 2 is anticipated to save between $60-$70 million over the next 15 years by eliminating two planned outages over the life of the two units. The projected $60-$70 million is based on predicted average outage cost of $30-$35 million per outage.

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

A. Table 13 below shows the trend for Outage O&M (i.e., Outage Costs net of Deferral & Amortization) for our nuclear plants from 2018-2022.

Table 13
Net Nuclear Planned Outage O&M Costs
($ in millions)

	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Test Year Budget	Annual Avg % Change: 2020 to 2022
Planned Outage O&M Costs - Nuclear Operations Spend	$ 34.5	$ 60.7	$ 23.9	$ 57.9	$ 28.6	
Deferral of Current Year Outage O&M Costs	(34.3)	(60.8)	(24.0)	(58.0)	(28.6)	
Outage O&M Amortization	53.1	50.7	46.1	40.0	40.7	
Net Nuclear Outage O&M	**$ 53.3**	**$ 50.6**	**$ 46.0**	**$ 39.9**	**$ 40.7**	**-5.8%**

Overall outage spend varies by year based on whether one or two outages is performed. Prairie Island generally alternates outages for its Units 1 and 2 each fall, resulting in one outage per year at that site, and in odd years (2017, 2019, and 2021) Monticello has its outage in the spring in addition to Prairie Island's. In addition, spend can be periodically skewed upward when required longer frequency (6-20 years) inspections, emergent regulatory requirements or unusual emergent maintenance occurs.

With an approximately 24-month amortization process for the spend between outages, that trend has resulted in a decrease in amortized outage costs from $63 million in 2017 to $53.1 million in 2018, $50.7 million in 2019, and 46.1 in 2020. The forecast for 2021 is $40 million and 2022 is $40.7 million. As discussed in the next section of my testimony, the scope, and therefore the cost, of each outage is driven by the level of planned maintenance, inspections, emergent work, and construction projects performed during the outages each year.

It should be noted that outage spend in Table 13 above is on an annual cash flow basis for all work done on any outage being planned or performed that year. The outage spend includes pre-outage planning work that is deferred, sometimes into the next calendar year, and is then amortized along with the cost of work performed during the outage.

Q HOW DOES THE COMPANY SET THE PLANNED OUTAGE O&M BUDGET FOR THE NUCLEAR OPERATIONS BUSINESS AREA?

A. Planned outages refer to regularly scheduled refueling outages during which we also perform off-line maintenance to the plant. The first step in developing the budget for planned outage costs is to identify the scope and schedule of refueling outages. The schedule for a planned outage in a given cycle is determined by the unit's fuel reloading needs, which, as discussed earlier in my testimony, has a target of every other year at each unit. Monticello has historically been on a 24-month fuel cycle and Prairie Island has been on a 22- to 24-month cycle. Recently, we have performed refuelings at Monticello in the spring of odd years. At Prairie Island, we have performed refuelings in the fall of even years for Unit 1 and the fall of odd years for Unit 2. This schedule is based on continuous operation of the plant and can change depending on unplanned outages and their impact on the fuel operating cycles. The scope of a refueling outage includes recurring activities (the activities completed during every refueling outage), periodic activities (activities that occur on a defined schedule but not necessarily every refueling outage), corrective maintenance and other one-time or special activities (such as capital projects).

The specific scope of each refueling outage is driven by both NRC license requirements (such as the plant's Technical Specifications) and industry-defined programs. Industry expert groups such as INPO, NEI and equipment owner groups provide best practices in critical equipment preventative maintenance and safety systems protection, which are key inputs to outage scope. These groups are part of the industry trends and strategies I referred to earlier in my testimony. We are also required to meet all industrial codes like American Society for Mechanical Engineers (ASME)[9] and environmental requirements. Another set of inputs comes from plant operating and safety risk needs and reliability preventive measures for cycle-to-cycle operations. All of these activities are estimated individually and then aggregated to create the initial long-range outage budget.

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

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

inflation. After initial planning, we solicit vendor bids for work scopes with performance criteria.

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

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

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

A. A long-range plan exists, which lays out the major activities for each outage for at least six years. The detailed planning process starts two years in advance of the refueling outage and before the prior refueling outage is completed. As an example, when Prairie Island started its Unit 1 outage in the fall of 2020, the work planning for the Spring 2021 Monticello outage was nearly completed and the scoping for the Prairie Island Unit 2 outage in the fall of 2021 was complete to ensure readiness for the 2021 outages. After each outage, a formal critique is performed to ensure work performed in the previous refueling outage helps us to improve in future outages. This has been a key part of our improvements.

We continue to look for ways to improve outage performance to reduce our planned outage duration and cost. For the fall 2020 outage at Prairie Island, we implemented some of these improvement initiatives, including sequencing of testing and innovative improvements in schedule updates to improve predictability.

Q. HOW WILL THE PANDEMIC (COVID-19) OR FUTURE PANDEMICS IMPACT THE OUTAGES?

A. The Company did not have a spring 2020 nuclear outage but was very engaged with the industry on learnings from other facilities impacted by the COVID virus. Based on these learnings and our focus on keeping our people and the local communities safe, several actions were taken. First, work which was slated to be done by contractors outside of the local area was reviewed to determine if it is necessary for regulatory compliance, safety, or reliability and was removed where possible. Additional staffing, facilities, testing, and training were also added to assist with cleaning of high traffic areas, social distancing and otherwise reducing the risk of spread of the virus. COVID measures added costs to the fall 2020 outage, and the Spring 2021 outage. It is expected that COVID related costs will be added to the Fall 2021 outage and future outages, depending on society's ability to address this pandemic. We remain committed to the health of our employees and the local community.

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

A. An overriding consideration in planning every outage is concern for plant shutdown safety and managing the unique outage configuration scenarios. The primary requirement is to ensure continuous nuclear fuel cooling when the nuclear reactor is shut down for an outage. The schedules undergo a detailed review to ensure this critical function and the equipment that support it are maintained throughout the outage.

The planning process for outage work activities follows industry best practices and includes numerous planning milestones that are consistent for each outage. This consistency across outages has led to a measure of predictability that has assisted us in lowering our overall outage costs. These include pre-outage work-order planning milestones, identification of major maintenance and projects, a review of scope based on the previous outage, and extensive engineering and project planning milestones. Several of the milestones will result in updated inputs into the final outage budget forecast development. Although efforts are made to maintain budget, scope changes do occur, and emergent issues due to plant needs or regulatory requirements arise that require deviations from budget to ensure safety, compliance, and reliability are not compromised.

A base schedule, which incorporates learning from past outages, is available for each outage. New work is reviewed to determine the safest and most efficient time for it to be completed within the existing schedule. Work activities that can safely be done on-line are performed outside of outage timeframes to minimize the outage duration and cost. The risk of an unintended consequence when performing work while a unit is on-line is reviewed. We also consider that doing the work while the unit is shut down can improve the available access to plant equipment and afford the opportunity to reduce radiation doses to the workers while accomplishing the work. All of these factors are considered in developing an outage's work plan.

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

A. Starting with our 2015 scheduled outage, the Company incorporated a contingency for anticipated emergent work, based on experience with historical outages and has created a process specifically to resolve emergent items. With these changes, we are expected to remain on schedule and on budget for all outages, even when we encounter emergent work. When we encounter unplanned work, we evaluate the schedule and budget to determine how we can manage to the budget given current work requirements. However, the sites do not compromise on safety or reliability. If emergent equipment issues arise that could directly or indirectly pose a safety risk at the plant, the work will be performed, and unplanned costs will be incurred.

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

A. Yes. For example, the NRC requires compliance with the ASME Code to inspect a certain population of plant components. If an indication is found during these initial inspections, the ASME Code requires us to increase the population of components to be inspected. Similarly, we have periodic inspections for specific equipment components required by the NRC and mechanical engineering code at five- or ten-year intervals. Should issues be identified during these periodic inspections, work will need to be performed to address the identified equipment concerns.

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

When equipment failures are identified through inspections, we are bound by the NRC corrective action process, whereby all failures must have an extent of condition determination, with expanded inspection scopes occurring when conditions dictate.

For example, in the Prairie Island Unit 2 Fall 2019 outage, we were required to test the Main Steam Safety Valves per the ASME Code. One of the valves did not pass this test, so a scope expansion was required by the Code. This required us to remove an additional two valves, send them to South Carolina for testing, then return them to the site to reinstall. They passed and were reinstalled without impacting critical path. If one of these additional valves had failed, however, we would have needed to again expand scope to an additional five valves, which would have taken over critical path. This same scenario applies to other types of inspections that we are required to conduct during outages.

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

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

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

The Company tracks outage costs consistent with the Commission's requirements for outage cost deferral/amortization. Exhibit___(PAG-1), Schedule 6, which is the Company's Planned Outage Policy, incorporates these requirements.

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

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

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

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

After initial planning, potential scope and work changes are considered and the impact on outage duration, schedule, and cost evaluated. Regular challenge boards meet at the site and fleet level to identify opportunities to improve job performance, optimize the work schedule, and redeploy resources with the goal of doing the right level of work with minimal outage cost.

We recognize that we need to balance the refueling and maintenance requirements of the plant with our ability to fund those activities given all Nuclear priorities and the limited O&M resources for the Company as a whole. The final outage budget considers both needs and available resources.

Q. PLEASE EXPLAIN HOW THE NUCLEAR OPERATIONS BUSINESS AREA MONITORS OUTAGE O&M EXPENDITURES DURING THE OUTAGE TIMEFRAME.

A. Once the outage commences, the scope and schedule of outage refueling and maintenance activities are monitored by Site, Finance, and Outage Management personnel to ensure the nature, timing, and sequence of activities are properly understood and appropriately planned. From a cost perspective, we use a daily outage tracking process to monitor the current and future resources and assess if changes are needed for each day's activities. If changes are needed, the resources are either redeployed to other outage jobs, or given days off until work becomes available. This tracking and monitoring enables us to avoid costs of unnecessary contract staff remaining on site when their work is rescheduled, and to avoid outage overtime and premium pay for internal labor when possible.

We oversee the work of contractors in the field, and continually review resource mobilization and demobilization curves for work planned. We use our Nuclear Oversight Services (NOS) group and individual work groups to oversee quality assurance for work performed. We have roving human performance teams to assure safety and compliance. This collective effort is designed to lead to efficiency, productivity, and optimal costs.

Q. HOW DOES THE COMPANY MANAGE INCREASES IN ACTUAL COSTS EXPERIENCED FROM THE PLANNED OUTAGE O&M BUDGETS?

A. Planned outage costs are part of the O&M budget that Nuclear is expected to manage to, as is every other Company business area. When we experience increases in planned outage costs from budget, we need to evaluate what opportunities we have to offset the higher outage costs in order to have overall O&M track with the budget expected for the year. The inclusion of contingency amounts within our outage budget have helped in this regard, as have our cost management efforts to lower the duration and cost of our planned outages.

Q. HOW DOES THE COMPANY'S MANAGEMENT OF ACTIVITIES FOR PLANNED OUTAGES COMPARE TO INDUSTRY PRACTICE?

A. Our scheduled outage planning process follows the industry process through use of standard milestones used to measure progress for planning. These milestones are discussed in our outage procedures and are measured in a "t minus" approach where we plan and oversee progress toward critical milestone points. Under this approach, off-line maintenance work and capital projects during a planned outage have milestones for scope freeze and design modifications to be completed. Our procedure for outage preparations, Refueling Outage Management, is based on industry best practices shared through INPO as well as the EPRI.[10] Oversight of external contractors used

[10] Electrical Power Research Institute's (EPRI) document 1022952, *Effective Refueling Outages* (www.epri.com).

during all projects is achieved through the guidance provided in our contractor oversight procedure, which is based on industry guidance taken from INPO.

Q. HOW DOES THE COMPANY'S MANAGEMENT OF COSTS FOR PLANNED OUTAGES COMPARE TO THE INDUSTRY?

A. Like us, all nuclear utilities have regular refueling outages during which they perform off-line maintenance work and construction projects. We regularly have an opportunity to benchmark other nuclear companies' experience with outage costs – formally and informally – through our industry groups, quality reviews, and interaction with peers. There are two common cost drivers for the outages; duration and total scope.

Duration – Some companies perform outages with the primary goal of short duration even if cost is driven up. These outages can be completed in the sub 20-day range but at a significantly higher cost. This is done for the purpose of maximizing net generation of the facility, even at significant costs.

In 2016, we implemented a long-range plan to reduce overall outage durations and costs by centralizing the outage organization and putting a single owner on outage performance. This has resulted in an overall reduction in both costs and duration. By doing so, we have put ourselves in the position of being able to implement our strategy of setting an optimum balance between cost and generation loss. We perform our outages in the spring and fall of the year when our overall grid demand is low, and renewables can support a large portion of the electric demand. This allows us to plan our outages for the 25-30-day range and reduce costs due to savings in overtime and less supplemental labor. By having a mix of generation resources in the overall NSP system, we are able to plan for a little longer outage to reduce the overall cost.

Since 2015 (the year prior to commencing the outage initiative), we have reduced our costs from $47 million to under $30 million and durations from 50 days to 24 days. In 2019, the industry mean was $37.5 million and 33.5 days. It should be noted that both duration and cost at sites across the industry were impacted by the COVID 19 pandemic for the spring 2020 through Spring 2021 outages. The industry expects an impact on the fall 2021 outages as well, including the Prairie Island Unit 2 outage, due to added cleaning, facility, and testing costs, as well as potential lower productivity due to social distancing, necessary facial coverings, and quarantining.

It should also be noted that all companies experience longer outages when they have emergent issues to address.

Total Scope: - Ultimately, the total scope of work in the outage determines the overall cost. As such, we have completed initiatives to right size the outage through regulatory change requests, review of equipment performance and innovative monitoring, which allows us to predict failure based upon performance instead of time. This, in conjunction with our long-range plan, which identifies when long frequency items will occur, allows us to minimize the impact of the longer items by coordinating them with other work in these outages.

Looking forward, we have set a target of 30 days and $32 million for a base outage with additional costs for specific one-time and low frequency work.

We believe this will keep us in the top half of industry performance.

We have been able to accomplish this in recent outages and will continue to work the duration downward through efficiency and effective labor/resource management. The changes we have made in our outage process, as well as the long-term contracts we've entered into with our key outage vendors, are helping to drive both duration and overall cost down.

Q. Please describe the Company's ongoing compliance requirement associated with its refueling outage expenditures.

A. Yes. Pursuant to the Erratum Notice issued in Docket No. E-002/GR-15-826, the Company has been required to make a compliance filing showing the level of its nuclear refueling outage expenditures by FERC account and by nuclear plant, as well as the Company's profit level resulting from the carrying charge, on an annual basis. The Company has made these compliance filings on May 1, 2018, April 30, 2019, April 29, 2020, and April 29, 2021.

Q. Does the Company have a proposal with respect to these filings?

A. Yes. Given that these filings have not generated responses over the last four years, the Company proposes discontinuing those filings after its filing due by May 1, 2022.

B. Planned Outage O&M Budget Components

Q. WHAT REFUELING OUTAGES IS THE NUCLEAR BUSINESS AREA INCLUDING FOR COST RECOVERY IN THE 2021 TEST YEAR?

A. The Commission has authorized the use of a deferral and amortization process to spread the costs of our scheduled refueling/maintenance outages over the period between outages. Under this approach, four planned refueling outages have costs that are amortized into the 2022 test year. They are: fall 2020 outage at Prairie Island Unit 1; spring 2021 outage at Monticello; fall 2021 outage at Prairie Island Unit 2, and fall 2022 outage at Prairie Island Unit 1. Table 14 below summarizes the impact of amortization of these outages' costs in 2021.

Table 14

Planned Outage O&M Costs Included in 2021 Amortization Expense

($ in millions)

Unit / *Period*	**PI Unit 1** / **Fall 2020**	**MT Spring 2021**	**PI Unit 2** / **Fall 2021**	**PI Unit 1** / **Fall 2022**	**Total 2022 O&M**
			[PROTECTED DATA BEGINS		
Outage Duration (Days)	25	33			[redacted]
Total Outage O&M Cost	$22.5	$26.2			
			…PROTECTED DATA ENDS]		
Portion included in 2021 Amortization Expense	$9.0	$13.1	$16.2	$2.4	$40.7

The Company tracks these costs consistent with the Commission's requirements for outage cost deferral/amortization. Schedule 6 is the Company's policy incorporating these requirements, and Mr. Halama explains the amortization of these planned outage costs in his Direct Testimony.

I will now discuss each of those outages affecting the 2022 test year further. Two of the outages were completed prior to summer 2021 and include actual costs through June 2021. The other two will take place in the fall of 2021 and 2022 at Prairie Island and are based on estimated costs. (The fall 2021 outage at Prairie Island is scheduled for October 2021. The costs for this outage included in this initial filing are based on our July 2021 budget and therefore are estimated.) Attached as Exhibit___(PAG-1), Schedule 7 is a detailed breakdown of the actual planned outage costs incurred for the fall of 2020 and spring 2021 outages. Exhibit___(PAG-1), Schedule 8 provides an estimate of the two planned outage costs for fall 2021 and 2022.

1. Prairie Island Fall 2020 Outage

Q. PLEASE DESCRIBE THE SCOPE OF THE FALL 2020 OUTAGE AT PRAIRIE ISLAND UNIT 1 IN COMPARISON TO PRIOR/OTHER OUTAGES.

A. The scope of the fall 2020 outage at Prairie Island Unit 1 included fuel reloading, a list of off-line maintenance projects and inspections, and certain capital projects. Specifically, we implemented an upgrade to the Ovation controls (governing feedwater), NFPA 805 work, implementation of the Purification Modification (all three similar to the 2019 Prairie Island Unit 2 outage) and repair or upgrade additional equipment. In addition, we had gains from Technical Specifications Task Force (TSTF)- 425 on this unit as well. TSTF 425 reduced the work to be done during outages by reducing the frequency of required surveillances. Main steam turbine work was deferred from this outage in order to minimize the number of out-of-the-area workers brought to the site to minimize potential COVID 19 impacts on the surrounding community and the site workers. Additional COVID costs were incurred for pre-access testing, a cleaning / disinfecting team, and lost productivity. The outage was completed within the scope and budget.

2. Monticello Spring 2021 Outage

Q. PLEASE DISCUSS THE SPRING 2021 MONTICELLO OUTAGE'S EXPECTED DURATION AND TOTAL ESTIMATED COST.

A. The scope of the spring 2021 outage at Monticello included fuel reloading, a list of off-line maintenance projects and inspections, and some long frequency work. Specifically, we completed a portion of the 10-year ISI Vessel Weld UT exams, a Major Preventative Maintenance procedure on one of our Recirc MG sets, and a 15-year Integrated Leak Rate test on our Containment vessel. As discussed earlier, these added both duration and cost to our outage base durations. The planned duration was 30 days which includes 2 days of contingency and the estimated cost was $32 million. Actual duration was 33 days due to some emergent equipment repair needs. Even with the increased duration, staffing was effectively managed to keep cost at $26.2 million. Note that similar to the fall 2020 outage, we were impacted on both cost and duration due to COVID complications on worker efficiency, worker availability, and COVID cleaning protocols.

3. Prairie Island Unit 2 – Fall 2021 Outage

Q. PLEASE DISCUSS THE FALL 2021 PRAIRIE ISLAND UNIT 2 OUTAGE'S EXPECTED DURATION AND TOTAL ESTIMATED COST.

A. The scope of the fall 2021 outage at Prairie Island Unit 2 includes fuel reloading and a list of off-line maintenance projects and inspections, and several capital projects that were safer to schedule while the unit was off-line. The major extra work for this outage is the six-year inspection of our Steam Generators. This inspection requires eddy current testing of the main heat transfer equipment between the reactor and the turbine. The estimated cost for the outage is **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** with a duration of **[PROTECTED DATA BEGINS… ... PROTECTED DATA ENDS].**

4. Prairie Island Unit 1 – Fall 2022 Outage

Q. PLEASE DISCUSS THE FALL 2022 PRAIRIE ISLAND UNIT 1 OUTAGE'S EXPECTED DURATION AND TOTAL ESTIMATED COST.

A. The scope of the fall 2022 outage at Prairie Island Unit 1 includes fuel reloading and a list of off-line maintenance projects and inspections, and several capital projects that were safer to schedule while the unit was off-line. These capital projects will include the 12 RCP Motor replacement, Condenser Steam Bellows Replacement, the Analog Process Controls Replacement, and the Nuclear Instrumentation Channel Bypass. The estimated cost for the outage is **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** with a duration of **[PROTECTED DATA BEGINS… … PROTECTED DATA ENDS].**

Q. HOW WERE THE ESTIMATED O&M COSTS FOR THE 2021 AND 2022 OUTAGES DETERMINED?

A. As I noted earlier in my testimony, the workplan for each outage starts prior to the conclusion of the previous outage for the unit and captures input from a number of sources (inspections required, equipment age and maintenance needs, risk and reliability analysis, etc.). Using this information, a plan is developed to scope out the work needed and the desired sequence of activities for efficient execution of an outage schedule. Resources needed are estimated in man hours, the use of internal versus external staffing is evaluated, and materials and equipment costs are projected. Improvement ideas are formed and implemented by our staff and the forecast is modified as these are implemented.

Q. WHY IS THIS A REASONABLE ESTIMATE OF THE OUTAGE O&M FOR THE 2021 AND 2022 OUTAGES?

A. The refueling outage budget process is dynamic, and planning remains fluid until the day the outage starts because it needs to adapt to emergent issues that may arise during the outage. The forecast for the fall 2021 outage was based on the best estimate of cost for scheduled activities and includes a contingency for emergent issues anticipated as of July 2021. This estimate is consistent with our recent experience with comparable outages, as I noted earlier in my testimony.

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

Q. WHAT IS THE LEVEL OF OUTAGE O&M EXPENSE NUCLEAR SEEKS TO RECOVER FOR THE 2022 TEST YEAR AND THE 2023 AND 2024 PLAN YEARS?

A. Over our last several rate cases, the Commission has approved a method of deferring and amortizing Nuclear Outage O&M expenses between outages. Under this approach, the refueling costs are deferred and amortized during the period between refueling outages. After several years of reduction, the amount of the Nuclear Outage O&M amortization is expected to increase due to slightly higher base costs, required long-term inspections, and changes in amortization periods. The Company proposes to use its forecasted amortization amounts for purposes of establishing 2022 through 2024 Outage O&M expense. The budgeted annual Outage O&M expenses on an amortized basis are summarized below in Table 15.

Table 15

Nuclear Planned Outage O&M Forecasts – 2021-2023

(in millions of $)

Nuclear Operations Planned Outage O&M Amortization Expense (in millions of $)	**2022**	**2023**	**2024**
Outage O&M - Amortized	$ 40.7	$ 45.2	$ 46.8

Q. ARE THERE SPECIFIC DRIVERS THAT YOU HAVE IDENTIFIED FOR NUCLEAR THAT WILL IMPACT THE EXPENSE LEVELS FOR 2023 AND 2024 OUTAGE O&M BUDGETS?

A. Yes. As shown in our 2023 and 2024 supporting information, provided in Volume 5 of our Initial Filing, Nuclear is forecasting changes in its outage O&M expenses for Plan Years 2023 and 2024 in the following areas:

- Our 2023 amortized outage O&M budget is increasing from 2022 levels primarily due to higher outage costs assumed for the Prairie Island Unit 1 2022 outage for **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** and the Monticello 2023 outage for **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**. Although these outage cost estimates are normal for an outage, they happen to be higher than the ones performed in 2021 during COVID 19 conditions.
- Our 2024 amortized outage O&M budget is increasing from 2023 levels primarily due to the outages at Prairie Island in 2023-24 being longer in duration due to the first-time evolution replacing the Baffle- Former Bolts at each unit (Prairie Island Unit 2 in 2023 and Unit 1 in 2024).

Q. ARE THERE ANY SIGNIFICANT LONG-RANGE PLAN ITEMS COMING UP IN 2023 – 2025?

A. Yes. As I discussed previously, the baffle-former bolts will be replaced in the fall 2023 on Prairie Island Unit 2. The same replacement will take place in the fall of 2024 for Prairie Island Unit 1. The current estimate for the capital replacement in 2023 is approximately $19 million and in 2024 is approximately $27 million.

Additionally, at Prairie Island, we have standard longer-term inspections / replacements coming due on other components directly related to the reactor vessel including a Lower Internals inspection, reactor head volumetric exams, Unit 1 Steam Generator Eddy Current exams, and reactor coolant pump motor change outs. These are part of our normal long-term inspections and change outs performed at all PWR style reactors.

Q. OVERALL, IS THE COMPANY'S O&M COSTS FOR PLANNED OUTAGES, BOTH THOSE INCURRED AND THOSE FORECASTED FROM 2021-2024, REASONABLE?

A. Yes. Over the past few years, the Company has been able to predict and budget for some level of emergent work in its planned outages. Overall, outage duration and cost is trending down as a result of process changes we have adopted; the Company continues to implement measures that will increase outage efficiency and extend the time between outages.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Nuclear capital investments and O&M budget presented in this rate case. Xcel Energy's Nuclear fleet provides more than 1,700 megawatts of safe, reliable, carbon-free generation that serves over 1.5 million homes and is critical to the Company's and the State's goals of supporting a clean energy future. Our capital investments focus on plant reliability and improvements, and the fuel, storage, and compliance requirements necessary to continue to operate these plants into the future. Our O&M expense budgets reflect the operating costs needed to effectively run, maintain, and refuel our fleet of nuclear plants. We have managed our O&M activities to keep the rate of future cost growth low and to operate our plants as efficiently as possible.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Peter A. Gardner

PROFESSIONAL EXPERIENCE:

Chief Nuclear Officer & Senior Vice President, Xcel Energy 2020 - Present

- Nuclear Strategic Direction
- Business Plans and Finance
- Operations for Corporate, Monticello and Prairie Island Nuclear Generating Plants
- Decommissioning and Nuclear Fuel Storage

Vice President Nuclear Fleet Ops- Governance & Oversight & Performance Improvement, Xcel Energy 2017- Present

- Governance & Oversight , CFAMS and Site Focus Teams
- Performance Improvement / OR / Performance Analytics
- Training, Regulatory, Emergency Preparedness, Security

Site Vice President (SVP) Monticello Nuclear Generating Plant, Xcel Energy 2014 – 2017

- Setting Strategic Direction for the station
- Direct Reports: DSO, Engineering Director, Training Director
- Corporate Oversight Role

Director Site Operations (DSO) Monticello Nuclear Generating Plant, Xcel Energy 2013 – 2014

- Oversight of Single Unit BWR
- Oversight of Operations, Budgets $110 M O&M and $60M Capital, short and long term planning
- Direct Reports: Plant Manager, Recovery Manager, Business Support Director
- 2014 Responsible for successful INPO PE, OPS Accreditation, NRC PI&R, and NRC 95002 Inspection.

INPO Organizational Effectiveness Team Leader 2012 – 2013

- Qualified as Team Leader
- Performed Multiple Station Plant Evaluations as well as other inspections (SOER10-02 etc)

Plant Manager (PM) Limerick Generating Station 2009 – 2012
Exelon Corporation, Pottstown, PA

- Oversight of Dual Unit BWR with direct oversight of Operations, Maintenance, Work Management, Rad Protection, Safety and Chemistry Departments (Staff of 850)
- Oversight of day to day operations, budgets $175M O&M and $65M Capital, short and long term planning

Operations Director 2006 – 2009
Exelon Corporation, Pottstown, PA

- Oversight and day-to-day Operations of both Limerick Units with a staff of 150.
- Shift Operations, Clearance and Tagging, Ops Support & Services, and Reactor Engineering, Online and Outage Support.

Reactor Engineering Branch Manager 2005 – 2006
Exelon Corporation, Pottstown, PA

- Managing Reactor Engineering Branch for two nuclear units.
- Reactor Engineering programs, procedures and core management.
- Reactivity Management sponsor for the station.

Operations: Shift Manager, Shift Supervisor (SRO), Operations Services Manager 1998 – 2005
Exelon Corporation, Pottstown, PA

- Managing Operations Services Branch (Combination of Licensed SRO's and RO's).
- Oversight and responsibility for preparing work week packages and refueling outage plans.
- Site Clearance and tagging program owner
- Direct supervision and control of operations personnel in support of running Limerick Unit 1 & Unit 2.
- Led crew of 3 Shift Supervisors, 4 Reactor Operators and 9 Equipment Operators through various workweeks and refueling outages.
- Direct supervision and control of operations personnel in support of running Limerick Unit 1 & Unit 2
- Licensed operator training 1997-1998

Engineering 1988 – 1997
Exelon Corporation, Pottstown, PA

- Various roles in Design, Reactor, ECCS, Balance of Plant and Test Engineering
- Startup Test Director for Power Rerate Program for Limerick Units 1 and 2
- Station Special Nuclear Material Coordinator and Shift Reactor Engineer responsibilities.
- System Engineering for multiple systems (Recirc, SLC, RWCU,Core Spray, RCIC and Instrument Air etc.)
- System Engineer responsibilities for Service Water, Feedwater Heaters and Drains, Moisture Separators, Extraction Steam and the Condenser

Peter A. Gardner

EDUCATION/TRAINING:

- MBA Finance, St. Joseph's University, Philadelphia, PA
- B.S.E. General Engineering, Widener University, Chester, PA
- A.S. Nuclear Engineering, Pennsylvania State University, University College, PA

Misc. External Responsibilities:

- Chair NEI Used Fuel Committee
- INPO VP Advisory Committee
- Chair RIWG Committee NEI (2018 -present)
- Board of Directors Minnesota Council on Economic education (2018-present)
- USA (United Services Alliance) BOD
- Monticello Industrial Economic Development Committee Board Member 2015-2017

Areas of Expertise

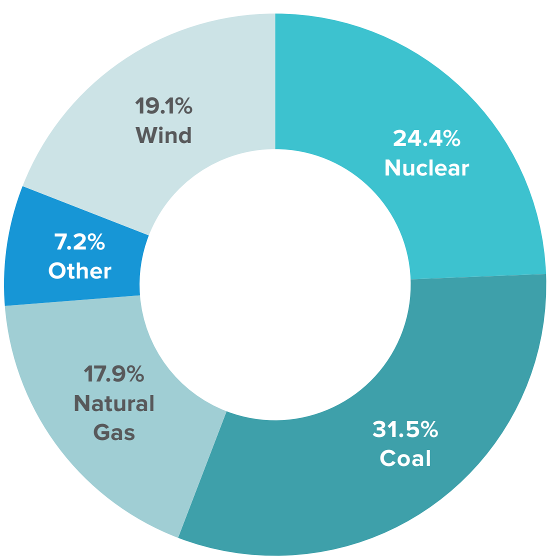
Leadership	Strategic Planning and Vision
Organizational Effectiveness	Continuous Improvement
Business Acumen	Succession Planning and Selection

MINNESOTA NUCLEAR ENERGY FACT SHEET

Carbon-Free Energy

- Minnesota's nuclear power reactors produce 51 percent of the state's carbon-free electricity, complementing wind and solar to achieve a carbon-free future.
- Minnesota's nuclear energy facilities employ more than 1,550 workers.
- Nuclear is the only carbon-free energy source that is available 24/7.
- Nuclear plants in Minnesota generate 14.1 million megawatt-hours of electricity a year, enough to power 1.5 million households.
- Minnesota requires 26.5-31.5 percent of electricity sales to come from renewables. Nuclear energy is a zero-emission option that can help reduce carbon at a large scale.

Sources of Electricity in Minnesota



Other includes petroleum, biomass and geothermal along with hydro, wind and solar if they account for less than 3% of electricity generated.

Source: ABB Velocity Suite / U.S. Energy Information Administration

Nuclear Energy Facility	Company	Location	Capacity (MW)	Capacity Factor (%)[1]
1 Monticello	Xcel Energy	Monticello	617	97.1
2 Prairie Island 1	Xcel Energy	Red Wing	521	98.8
3 Prairie Island 2	Xcel Energy	Red Wing	519	97.8
		State Totals	**1,657**	**98**

Source: U.S. Energy Information Administration

[1] Capacity factor three-year average is electricity produced compared to the maximum that could be produced and is calculated based on generation in 2017, 2018 and 2019.

Supporting Jobs and the Economy

- Nuclear energy facilities in Minnesota employ more than 1,550 workers.
- American innovators are developing new nuclear technologies that have the potential to create additional jobs and bring in export dollars.
- Nuclear power saves consumers an average of 6 percent on their electricity bills and contributes approximately $60 billion to the country's GDP annually.

continued —


Monticello


Monticello


Prairie Island

The Largest Emission-Free Source

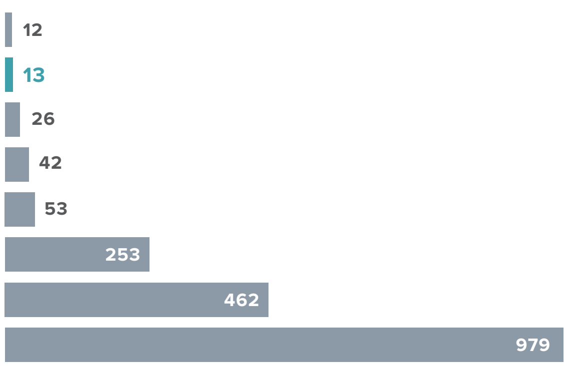
- The use of nuclear energy in 2019 prevented the emission of 476 million metric tons of carbon dioxide. This equals the amount released in a year by 102.8 million passenger cars.
- Nuclear energy is the only carbon-free electricity source that can produce large amounts of electricity around-the-clock.
- Numerous studies demonstrate that nuclear energy's life cycle greenhouse gas emissions are comparable to renewable energy, such as wind and hydropower, and far less than coal or natural gas-fueled power plants.
- The nation's nuclear energy facilities also prevented the emission of 217,357 short tons of sulfur dioxide and 244,970 short tons of nitrogen oxide in 2019.

Emissions Prevented in Minnesota	Quantity Prevented in 2019
Sulfur dioxide (SO2)	12,631 short tons
Nitrogen oxide (NOX)	9,220 short tons
Carbon dioxide (CO2)	12.55 million metric tons

Source: U.S. Environmental Protection Agency and U.S. Energy Information Administration

Comparison of Life Cycle Emissions

Tons of Carbon Dioxide Equivalent per Gigawatt-Hour



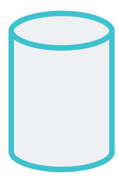
IPCC, 2014: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.

High Industry Security Standards

- Each plant employs a highly-trained security force, strict access controls and multiple backup safety systems to ensure safety and security for plants and nearby communities.
- The independent U.S. Nuclear Regulatory Commission holds nuclear power plants to the highest security standards of any industry, and the industry exceeds these standards.

Managing Used Nuclear Fuel

- Nuclear energy facilities store used fuel safely and securely on site. The U.S. nuclear industry is working with the federal government on a solution for permanently storing fuel rods at a consolidated location.
- There are 1,486 metric tons of used nuclear fuel in storage at nuclear plant sites in Minnesota.
- As of 2016, Minnesota has contributed approximately $457 million to the federal Nuclear Waste Fund.
- All the used nuclear fuel produced by the nuclear energy industry over 60 years—if stacked end to end—would cover an area the size of a football field to a depth of less than 10 yards.
- The actual volume of nuclear fuel is small. Fuel rods that go into a nuclear reactor are made up of uranium fuel pellets. One pellet, the size of your fingertip, creates as much energy as one ton of coal, 149 gallons of oil or 17,000 cubic feet of natural gas. This means used nuclear fuel takes up little space when it is eventually stored.



1 URANIUM FUEL PELLET
THE SIZE OF YOUR FINGERTIP

After the cooling period, nuclear energy facilities store used fuel safely on-site in steel and concrete vaults.

Source: Gutherman Technical Services

NEI NUCLEAR ENERGY INSTITUTE

The Impact of Xcel Energy's Nuclear Fleet on the Minnesota Economy

An Analysis by the Nuclear Energy Institute

April 2017

NUCLEAR ENERGY INSTITUTE

www.nei.org

Contents

Nuclear Energy Institute
1201 F St., NW, Suite 1100,
Washington, DC 20004-1218
202.739.8000

Executive Summary

Xcel Energy Inc. (Xcel Energy) owns and operates two nuclear energy facilities, including three reactors, in Minnesota and has its headquarters in Minneapolis, Minnesota. The two nuclear energy facilities are:

- Monticello Nuclear Generating Plant in Monticello, Minnesota
- Prairie Island Nuclear Generating Plant in Red Wing, Minnesota

Almost 6,100 jobs in Minnesota result from Xcel Energy's nuclear operations.

The two nuclear facilities have been an integral part of the region's clean energy portfolio and economic fabric since the 1970s. They have generated reliable emission-free electricity, thousands of jobs, and billions of dollars of economic activity while Xcel Energy has been deeply involved in its local communities, proving the plants' value as economic contributors to Minnesota and the Upper Midwest.

To quantify the employment and economic impact of these facilities, the Nuclear Energy Institute (NEI) conducted an independent analysis. Based on data provided by Xcel Energy on employment, operating expenditures, revenues and tax payments, NEI conducted the analysis using a nationally recognized model to estimate the facilities' economic impacts on the Minnesota economy. Regional Economic Models, Inc. (REMI) developed the Policy Insight Plus (PI+) economic impact modeling system, the methodology employed in this analysis. (See section 5 of this report for more information on the REMI methodology.)

Key Findings

Xcel Energy's nuclear operations support:

Xcel Energy's nuclear operations are estimated to generate $1 billion of total economic output annually in Minnesota.

Economic stimulus. Xcel Energy's nuclear operations are estimated to generate $1 billion of total economic output annually, which contributes $600 million to Minnesota's gross state product each year. This study finds that for every dollar of output from Xcel Energy's nuclear operations, the state economy produces $1.98.

Tax impacts. NEI estimates that Xcel Energy's nuclear facilities in Minnesota contribute about $33 million in state and local taxes annually. In 2015, Xcel Energy reported over $34.5 million in state and local taxes paid. Xcel Energy is the largest property tax payer in Minnesota. NEI estimates that Xcel Energy's nuclear facilities contribute over $113 million in federal taxes each year.

Thousands of high-skilled jobs. Approximately 1,700 jobs exist at Xcel Energy's nuclear energy facilities, which includes 140 nuclear support positions at its headquarters in Minneapolis. This direct employment creates about 4,200 additional jobs in other industries in Minnesota. A total of nearly 6,100 jobs in Minnesota are a result of Xcel Energy's nuclear operations.

Xcel Energy's nuclear operations result in a total tax impact of approximately $146 million to the local, state and federal governments each year.

Clean electricity for Minnesota. Xcel Energy's nuclear facilities generate about 21 percent of Minnesota's electricity and about 54 percent of the state's carbon-free electricity. Without the carbon-free electricity produced by these nuclear plants, an estimated 12 million metric tons of carbon dioxide would be released annually, the equivalent of putting more than 2.6 million additional cars on Minnesota's roadways each year, or double the number of passenger cars in all of Minnesota. By 2030, these nuclear plants will have provided almost $9 billion in avoided emissions benefits.

Reliability leaders. During full-power operations, the three reactors provide 1,770 megawatts of around-the-clock electricity for Minnesota homes and businesses. Over the last 10 years, the facilities have operated at approximately 85 percent of capacity, which is significantly higher than all other forms of electric generation. This reliable production helps offset potential price volatility of other energy sources (e.g., natural gas) and the intermittency of renewable electricity sources. Nuclear energy provides reliable electricity to businesses and consumers and helps prevent power disruptions which could lead to lost economic output, higher business costs, potential loss of jobs, and losses to consumers.

Without the carbon-free electricity produced by these nuclear plants, an additional 12 million metric tons of carbon dioxide would be released annually, the equivalent of the emissions from over 2 million cars each year.

Community and environmental leadership. Xcel Energy is a corporate leader in its neighboring communities, supporting education initiatives, environmental and conservation projects, and numerous charitable organizations.

Section 1
Background and Generation History

Monticello Nuclear Generating Plant

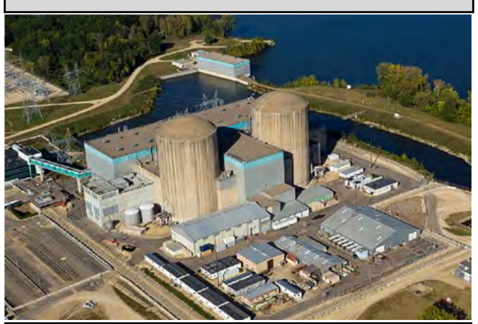
Dates of commercial operation
1971

Location
40 miles northwest of the Twin Cities

License Expiration Year
2030

Reactor Type
Boiling water

Total Electrical Capacity (Megawatts)
671



Prairie Island Nuclear Generating Plant

Dates of commercial operation
Prairie Island 1 - 1973
Prairie Island 2 - 1974

Location
40 Miles southeast of the Twin Cities

License Expiration Years
Prairie Island 1 - 2033
Prairie Island 2 - 2034

Reactor Type
Pressurized water

Total Electrical Capacity (Megawatts)
Prairie Island 1 - 550
Prairie Island 2 - 550

The Monticello Nuclear Generating Plant (Monticello) is located on 215-acre site in Monticello, Minnesota. It consists of a single, Boiling Water Reactor (BWR) that produces 671 MW of non-emitting baseload power.

The Prairie Island Nuclear Generating Plant (Prairie Island) is located on a 575-acre site in Red Wing, Minnesota. It consists of two Pressurized Water Reactors (PWRs) that together produce 1,100 MW of non-emitting base-load power.

Reliable Electricity Generation

Over the past decade, the three reactors operated at an average capacity factor of 85 percent. Capacity factor, a measure of electricity production availability, is the ratio of actual electricity generated to the maximum possible electric generation during the year.

Xcel Energy's nuclear plants typically generate nearly over 13 million megawatt-hours of electricity ever year. In 2015, Xcel Energy's reactors generated over 20 percent of the electricity in Minnesota. The three reactors provide enough electricity for approximately 1.4 million Minnesota households (if all of the electricity went to the residential sector).

Monticello and Prairie Island operate in the Midcontinent Independent System Operator (MISO) region, which stretches from Louisiana to Canada which covers portions of 15 states and Manitoba. Along with 14 other nuclear reactors in that operate in MISO, nuclear power keeps wholesale prices 9 percent lower in MISO than they would be without nuclear power.[1]

Thousands of High-Skilled, Well-Paying Local Jobs

Xcel Energy's nuclear operations employ nearly 1,600 full-time workers at the plants, and 140 support and executive positions at its Minneapolis headquarters. This employment supports an additional 4,200 jobs in other economic sectors in Minnesota. In total, these plants support 6,100 jobs across Minnesota (including those at the plant). The annual payroll for the direct jobs is approximately $240 million. Most jobs at nuclear power plants require technical training and are typically among the highest-paying jobs in the area. Nationwide, nuclear energy jobs pay 36 percent more than average salaries in a plant's local area according to an NEI analysis.[2]

[1] *The Nuclear Industry's Contribution to the U.S. Economy*, The Brattle Group, July 2015.

[2] *NEI Factsheet: Job Creation and Economic Benefits of Nuclear Energy.*

Safe and Clean for the Environment

Nuclear facilities generate large amounts of electricity without emitting greenhouse gases or other air pollutants. State and federal policymakers recognize nuclear energy as an essential source of safe, reliable electricity that meets both our environmental needs and the state's demand for electricity.

In 2015, the operation of these three reactors prevented the emission of 12 million metric tons of carbon dioxide,[3] about the same amount emitted by over 2 million cars each year. Overall, Minnesota's electric sector emits more than 32 million metric tons of carbon dioxide annually. The three reactors also prevent the emission of more than 11,100 tons of nitrogen oxide, equivalent to that released by 1.2 million cars, and 16,800 tons of sulfur dioxide. Sulfur dioxide and nitrogen oxide are precursors to acid rain and urban smog.

[3] Emissions prevented are calculated using regional fossil fuel emission rates from the U.S. Environmental Protection Agency and plant generation data from the U.S. Energy Information Administration.

Section 2

Economic Benefits in Minnesota

NEI used the REMI PI+ model to analyze economic and expenditure data provided by the plants to develop estimates of their economic benefits (more information on REMI can be found in Section 5).

The economic impacts of the Monticello and Prairie Island plants and the nuclear operations at Xcel Energy headquarters consist of direct and secondary impacts. The main variables used to analyze these impacts are:

Output
The direct output is the value of power produced by the Xcel Energy facilities. In the case of Xcel Energy's headquarters, it is the value of the nuclear support operations. The secondary output is the additional economic activity created as a consequence of the electricity generation. The direct output will impact the economic activity in other industries and how those employed at the facilities influence the demand for goods and services within the community.

Employment
The direct employment is the number of jobs at the Xcel Energy facilities. Secondary employment is the number of jobs in the other industries supported as a result of Xcel Energy's operations.

Gross State Product
Gross state product is the value of goods and services produced by labor and property at the Xcel Energy facilities—e.g., sales (i.e., output) minus intermediate goods. In the REMI model, operations is the final good from an Xcel Energy nuclear plant. Intermediate goods are the components purchased to make that electricity due to projected increases in electricity prices.

Xcel Energy's nuclear facilities are predicted to provide nearly $16 billion in economic benefits and $3.5 billion in disposable personal income benefits over the next 15 years.

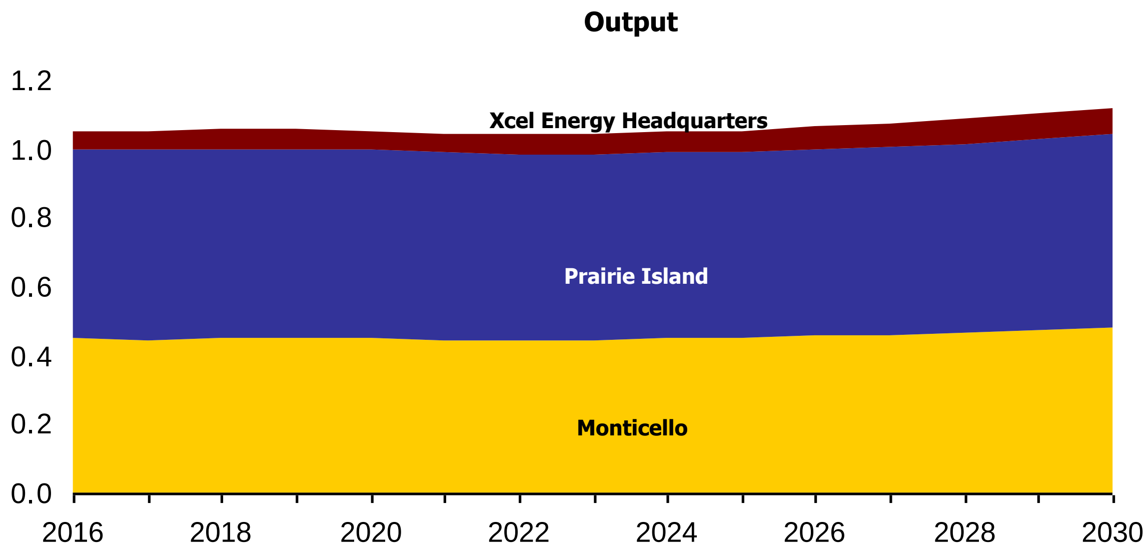
Disposable Personal Income
Disposable personal income is the total after-tax income that residents in the analyzed region would receive. This value is available for purchases on groceries and clothing or for saving and investing for the future in things like college education, retirement or a mortgage.

Substantial Economic Drivers

The direct output in 2016 of the Xcel Energy nuclear facilities were estimated to total $531 million (the value of the electricity produced at the plants), with a total economic output on the state of $1.05 billion. In other words, for every dollar of output, the state economy produced $1.98. By 2030, the total economic output is estimated to increase to $1.11 billion.

In 2016, Xcel Energy's nuclear facilities were estimated to contribute $595 million to Minnesota's gross state product (GSP) and, by 2030, the GSP stays constant at almost $600 million.

Figure 2.0
Xcel Energy Nuclear Operations' Total Output and Gross State Product Contributions to Minnesota
*(dollars in 2015 billions)**



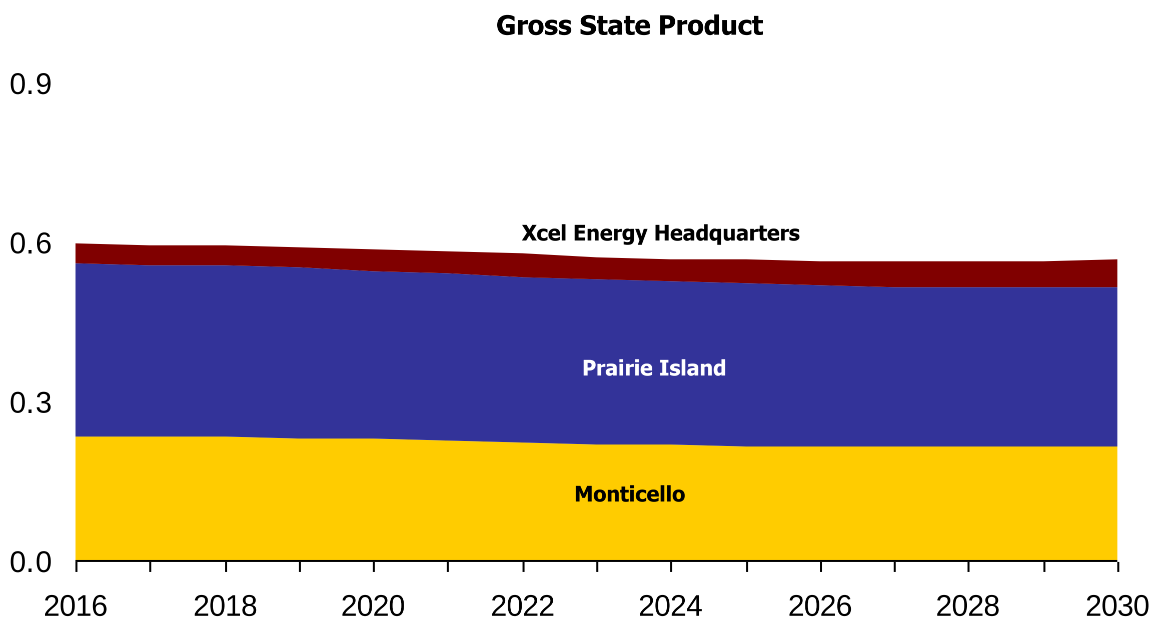


Figure 2.0 shows the value of total output and contributions to GSP from the operation of Xcel Energy's nuclear facilities through 2030, using spending data provided by Xcel Energy.

The three reactors' largest impacts are on the utilities sector, while the headquarters' greatest impact is on the corporate management sector. Xcel Energy's facilities have a substantial impact on the professional, scientific, and technical services sector—because of the volume of specialized services required to operate and maintain a nuclear power plant. Finally, there are beneficial impacts in Minnesota on the manufacturing and administrative and waste management sectors. Other sectors that benefit from the facilities' operations in Minnesota include finance and insurance, health care, retail trade, and real estate.
A full depiction of the sectors in Minnesota that benefit from the facilities is in Table 2.0.

Table 2.0
Estimated Total Output of Xcel Nuclear Operations on Minnesota's Economic Sectors in 2016 *(in millions of 2015 dollars)*

Sector Description	Monticello	Prairie Island	Xcel Energy HQ	Total
Utilities	220	311	0	531
Professional, Scientific, and Technical Services	51	52	3	106
Manufacturing	33	34	2	69
Administrative and Waste Management Services	32	32	1	65
Other Services, except Public Administration	27	28	1	56
Finance and Insurance	18	20	4	42
Management of Companies and Enterprises	3	4	31	38
Retail Trade	12	13	2	27
Health Care and Social Assistance	11	13	2	26
Real Estate and Rental and Leasing	11	12	3	26
All Other Industries	29	31	5	65
Total	**447**	**550**	**54**	**1,051**

Job Diversity and Creation

Xcel Energy's nuclear business activities stimulate the state's labor income and employment. Over 1,600 people work at Xcel Energy's nuclear plants and 140 more are employed at its Minneapolis headquarters for nuclear operations. These jobs stimulate another 4,200 jobs in other sectors in the state. All told, Xcel Energy's operations support nearly 6,100 jobs in Minnesota.

Table 2.1
Xcel Energy's Estimated Support in Direct and Secondary Jobs in Minnesota in 2016

Occupation	Monticello	Prairie Island	Xcel Energy HQ	Total
Utilities	807	870	1	1,678
Administrative and Waste Management Services	474	479	14	967
Professional, Scientific, and Technical Services	396	400	24	820
Other Services, except Public Administration	351	365	21	737
Retail Trade	159	185	33	377
Health Care and Social Assistance	133	154	25	312
Finance and Insurance	80	87	18	185
Management of Companies and Enterprises	16	17	147	180
Manufacturing	85	87	4	176
Accommodation and Food Services	64	73	16	153
Construction	66	66	2	134
Arts, Entertainment, and Recreation	34	38	9	81
Wholesale Trade	30	33	5	68
Transportation and Warehousing	28	30	4	62
Real Estate and Rental and Leasing	23	25	6	54
All Other Industries	31	37	9	77
Total	**2,777**	**2,946**	**338**	**6,061**

As discussed earlier in Section 2, the types of jobs supported by Xcel Energy's nuclear operations are diverse. Jobs supported range from office jobs in the professional, scientific, and technical services, finance and insurance, and public administration jobs to blue-collar jobs in construction and manufacturing to life-saving jobs in healthcare.

Table 2.1 details the numbers and types of jobs that Xcel Energy are supported in 2016. Xcel Energy's workers are included in the occupation categories in the table.

Economic Stimulus Through Taxes

Xcel Energy's nuclear operations resulted in an estimated annual total tax impact of $146 million to the local, state and federal governments. This includes the direct impact and secondary impacts, because plant expenditures increase economic activity, leading to additional income and value creation and, therefore, to additional tax revenue from other sectors.

Xcel Energy's impacts on the state economy are substantial. In addition to the $595 million in gross state product, the company is estimated to generate over $33 million in taxes from the plants and their activities for Minnesota and its local governments. See Table 2.2.

Extra Income for Residents

The economic activity and low-cost electricity the plants create, to which Xcel Energy's nuclear operations at its headquarters contributes, also provide a boost to incomes of residents of Minnesota. In a consumer-driven economy, this is of the utmost importance. This boost is estimated to be $237 million annually in disposable personal income greater than if the plants and headquarters did not exist. This extra income provides Minnesotans with extra money to purchase necessities such as groceries and clothing for their families or save for college or retirement. More detail of this contribution to disposable personal income is in Table 2.3.

Large Multiplier Effects for Economic Activity and Jobs

By producing affordable, reliable electricity, Xcel Energy's nuclear operations are hubs of economic activity for Minnesota. Table 2.4 provides the multipliers and summarizes the total effects from each plant. The multipliers show that for every dollar of output generated, the plants stimulate between $2.03 and $2.30 in economic output in the state, while Xcel Energy headquarters produces $1.74 for every dollar. Minnesota employment multipliers range between 3.39 and 3.44 at the plants and 2.49 at Xcel Energy headquarters.

Table 2.2
Estimated Total Tax Impacts in 2016
*(in 2015 millions of dollars)**

Facility	State and Local	Federal	Total
Monticello	12	44	56
Prairie Island	18	62	80
Xcel Energy HQ	2	7	9
Total Taxes	**33**	**113**	**146**

** Calculated based on a percentage of gross state product.*

Table 2.3
Estimated Total Personal Disposable Income Impacts in 2016
(in 2015 millions of dollars)

Facility	Total
Monticello	96
Prairie Island	116
Xcel Energy HQ	25
Total	**237**

Table 2.4
Xcel Energy's Impacts on the Minnesota Economy in 2016 *(in 2015 millions of dollars)*

Facility (Description)	Direct	Secondary	Total	Multiplier
Monticello				
Output (Utilities)	$220	$227	$447	2.03
Employment	807	1,970	2,777	3.44
Gross State Product			$232	
Prairie Island				
Output (Utilities)	$311	$239	$550	2.30
Employment	870	2,076	2,946	3.39
Gross State Product			$326	
Xcel Energy Headquarters				
Output (Management of Companies and Enterprises)	$31	$23	$54	1.74
Employment	136	202	338	2.49
Gross State Product			$37	

Section 3
Protecting the Environment

Like all nuclear power plants, Monticello and Prairie Island produce carbon-free electricity. Nuclear power produces 62 percent of the United States' carbon-free electricity and nearly 20 percent of total electricity generated. Hydro, wind and solar produce 19, 15, and 2 percent of carbon-free electricity, respectively. Nuclear power plants avoided 564 million metric tons of carbon dioxide in 2015, while hydro, wind and solar avoided 327 million metric tons combined. Annually, the avoided emissions from nuclear power is similar to adding 128 million cars to the nation's roads. Nuclear power plants also avoided hundreds of thousands of tons of nitrogen oxide and sulfur dioxide. The Environmental Protection Agency estimates that the Clean Power Plan will reduce carbon emissions by 414 million tons annually by 2030, or 73 percent of current carbon avoidance of the nuclear industry.

Xcel Energy employee holding a Peregrine Falcon chick.

Xcel Energy's Nuclear Plants Contribution

In 2015, the operation of these three reactors prevented the emission of 12 million metric tons of carbon dioxide, about the same amount emitted by over 2 million cars each year. According to the Minnesota Pollution Control Agency's most recent data from 2012, Minnesota's electric sector emitted 47.6 million tons of carbon dioxide. The three reactors also prevent the emission of more than 11,100 tons of nitrogen oxide, equivalent to that released by 1.2 million cars, and 16,800 tons of sulfur dioxide. Sulfur dioxide and nitrogen oxide are precursors to acid rain and urban smog.

Clean Air Benefits of Xcel Energy Nuclear

Monticello and Prairie Island are the two largest carbon-free sources of generation in Xcel Energy's portfolio. In 2015, Monticello and Prairie Island produced over 12 million megawatt hours of electricity which avoided the emission of 11.6 million metric tons of carbon dioxide. They also prevent the release of thousands of tons of Nitrogen Oxide and Sulfur Dioxide.

In August 2016, the U.S. Court of Appeals for the Seventh Circuit validated the Social Cost of Carbon as a legitimate method to place a value on the benefits of carbon reduction.[1] Between 2016 and 2030, assuming Monticello and Prairie Island avoid the emission of 11.6 million metric tons of CO2 every year, these avoided emissions would represent an $8.67 billion in cumulative benefits. NEI calculated this value using the Social Cost of Carbon values from the Interagency Working Group Technical Support Document that was revised in July 2015. The values are in 2007 dollars and were inflated using the GDP deflator to 2015 dollars. The calculation is based on the 2015 carbon intensity of electricity generation in NERC's Midwest Reliability Organization.[2]

[1] *Zero Zone, Inc., et al., v. U.S. Department of Energy*

[2] *The Minnesota Public Utilities Commission is currently updating its CO2 externality range. Therefore, NEI has used the federal Social Cost of Carbon values as the Commission has not yet finalized its decision. The specific reference to the docket is: In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3. Minnesota Public Utilities Commission Docket No. E-999/CI-14-643.*

Section 4
Community Leadership and Environmental Protection

In addition to the economic benefits that Xcel Energy's nuclear operations contribute to Minnesota in the form of jobs, income and taxes, the company and its employees contribute to local communities in many other beneficial ways. Xcel Energy strengthens Minnesota communities through hiring veterans, charitable contributions, educational programs that teach and promote the benefits of nuclear energy, environmental programs that improve the quality of the environment, and civic engagement activities that build trust and goodwill.

Children using Monticello mobile simulator at open house event.

Corporate Citizenship

At a corporate level, Xcel Energy contributes significant time and resources to charitable endeavors. Over the past 10 years, Xcel Energy has raised $2.5 million annually for the United Way. Xcel Energy matches this amount, which means over $50 million has been contributed to local communities in the past decade. This annual campaign raises money with various events such as chili cook-offs and sporting tournaments. Each year, employees, contractors and retirees continue the tradition of giving, advocating and volunteering in the community.

The 2016 United Way campaign broke all previous records with the highest combined total of donations, surpassing the goal of $3 million. The result will be more than $5.6 million in matched contributions.

Prairie Island employees volunteering at Red Wing Memorial Park.

Below are further examples of contributions of Xcel Energy and its employees:

- In September 2015, more than 3,500 volunteers pitched in and spent 10,300 hours painting, sorting, planting and otherwise supporting 80 local non-profits during Xcel Energy's fifth annual Day of Service, making it the company's largest event ever.
- The Xcel Energy Foundation awarded $3.8 million in grants to nearly 430 non-profits benefitting four community focus areas that include STEM education, economic sustainability, environmental stewardship and access to arts and culture.
- Even after they retire, former Xcel Energy employees are giving back. The Pioneers in Public Service (PIPS) retiree volunteer program has been operating for over 30 years. PIPS members have dedicated more than 80,000 volunteer hours serving in communities.

Environmental Stewardship

Xcel energy generates 55 percent of its Upper Midwest electricity using carbon-free generation. Thirty percent of that generation is from its two nuclear plants in Minnesota, 15 percent is from wind energy, and 10 percent is from a combination of hydro/biomass/solar sources. Beyond its nuclear program, Xcel Energy has been the number one utility provider of wind energy for 12 straight years.

Xcel Energy employees volunteering for Habitat for Humanity.

In 2016, the U.S. Environmental Protection Agency awarded Xcel Energy the Climate Leadership Award for achieving its self-identified goal of 20 percent reduction in carbon by 2020 (which it achieved in 2014). Xcel Energy achieved these reductions through increasing renewable energy investment, modernizing its generation fleet, and offering incentives for customers to save energy.

Employment of Veterans

In 2016, Xcel Energy set a goal of hiring veterans as 15 percent of new hires. The company exceeded this goal. Military Times Magazine rated Xcel Energy as a top company for hiring veterans. Xcel Energy was listed among the Top 100 Military Friendly Employers by GI Jobs Magazine and ranked number 8 on Monster and Miltary.com's list of best companies for veteran hiring. Also, in 2016, the Minnesota Employer Support of the Guard and Reserve recognized Xcel Energy with the Pro Patria and Above and Beyond Awards for providing beneficial leave and support rules for military members required to perform military duties.

Contributions & Sponsorships

Xcel Energy nuclear plant employees volunteer and contribute to numerous community and local organizations and events. For example, Prairie Island engages in an annual golf tournament that benefits the United Way and a Make-A-Wish summer series. Both plants support Habitat for Humanity and both the Boy and Girl Scouts of America.

Section 5

Xcel Energy Nuclear Operations and the U.S. Nuclear Energy Industry

The three reactors play a vital role in helping Minnesota meet its demand for affordable, reliable and sustainable energy.

In 2015, electricity production from U.S. nuclear power plants was about 800 billion kilowatt-hours—nearly 20 percent of America's electricity supply. In Minnesota, nuclear energy generates approximately 21 percent of the state's electricity, and Xcel Energy's three reactors generated about 13 billion kilowatt-hours of electricity, which is approximately 54 percent of Minnesota's carbon-free electricity generation.

Xcel Energy's nuclear plants provide 54 percent of the carbon-free electricity generation in Minnesota.

Over the past 25 years, America's nuclear power plants have increased output and improved performance significantly. Since 1990, the industry has increased total output equivalent to that of 26 additional 1,000-MWe nuclear power plants, when in fact only five new reactors have come online. This is due to the fact that in 1990, U.S. nuclear plants were operating approximately 66 percent of the time compared to achieving a record capacity factor of over 92 percent in 2015.

Nuclear Energy's Value Proposition

Nuclear energy's role in the nation's electricity portfolio was especially valuable during the 2014 "polar vortex," when record cold temperatures gripped the United States and other sources of electricity were forced off the grid. Nuclear power plants nationwide operated at an average capacity factor of 96 percent during the period of extreme cold temperatures. During that time, supply volatility drove natural gas prices in many markets to record highs and much of that gas was diverted from use in the electric sector so that it could be used for home heating.

Some of America's electricity markets, however, are structured in ways that place some nuclear energy facilities at risk of premature retirement, despite excellent operations. It is imperative that policymakers and markets appropriately recognize the full strategic value of nuclear energy in a diverse energy portfolio.

That value proposition starts with the safe and reliable production of large quantities of electricity around the clock.

One of nuclear energy's key benefits is the availability of low-cost fuel (which does not need to be delivered continuously and the ability to produce electricity under virtually all weather conditions.   Renewable energy, an emerging part of the energy mix, is intermittent (the sun doesn't always shine and the wind doesn't always blow when generation is needed) and therefore cannot be readily dispatched to meet demand; natural gas-fired generation depends on fuel being available (both physically and at a reasonable price); and on-site coal piles can freeze.

Nuclear power plants also provide clean-air compliance value. Minnesota's Next Generation Energy Act of 2007 set a goal that would reduce greenhouse gas emissions 15 percent below the 2005 level in 2015, and 30 and 80 percent below that level in 2025 and 2050, respectively.

Nuclear plants provide voltage support to the grid, helping to maintain grid stability. They have portfolio value, contributing to fuel and technology diversity. And they provide a tremendous local and regional economic development opportunity, including large numbers of high-paying jobs and significant contributions to the local and state economies and tax base.

Based on more than 50 years of experience, the nuclear industry is one of the safest industrial working environments in the nation.

Stable Prices for Consumers

In addition to increasing electricity production at existing nuclear energy facilities, power from these facilities is affordable and stable for consumers. Compared to the cost of electricity produced using fossil fuels—which are heavily dependent on market fuel prices—nuclear plants' fuel costs are relatively stable, making consumers' electric bills more predictable. Uranium fuel is only about one-third of the production cost of nuclear energy, while fuel costs have historically made up between 75-85 percent of coal-fired and natural gas production costs. Production costs for a nuclear plant have historically been $0.03/kWh or lower. Natural gas production costs are currently historically low at $0.03/kWh, but have been over $0.08/kWh in 2000, 2001, 2005 and 2008.

Safety and Security

Safety is the highest priority for the nuclear energy industry. Based on more than 50 years of experience, the industry is one of the safest industrial working environments in the nation. Through rigorous training of plant workers and increased communication and cooperation among nuclear plants and federal, state and local regulating bodies, the industry is keeping the nation's 99 nuclear plants safe for their communities and the environment.

The U.S. Nuclear Regulatory Commission (NRC) provides independent federal oversight of the industry and tracks data on the number of "significant events" at each nuclear plant. (A significant event is any occurrence that challenges a plant's safety systems.) The average number of significant events per reactor declined from 0.45 per year in 1990 to 0.01 in 2014, illustrating the emphasis on safety throughout the nuclear industry.

General worker safety is also excellent at nuclear power plants—far safer than in the manufacturing sector. U.S. Bureau of Labor Statistics data show that, in 2013, nuclear energy facilities achieved an incidence rate of 0.3 per 200,000 work hours, compared to 1.8 for fossil-fuel power plants, 1.8 for electric utilities and 4.0 for the manufacturing industry.

All American nuclear plants are designed and operated with public safety first and foremost in mind. The plants have redundant and diverse safety systems which are backed by multiple power sources.

U.S. nuclear plants also have over 9,000 highly trained paramilitary personnel protecting the plants from external threats. These plants also maintain emergency response plans that are reviewed and approved by the Nuclear Regulatory Commission and coordinated with the Federal Emergency Management Agency. In order to maintain this high level of safety and security within its community, each plant coordinates with its local police, fire, and EMS departments.

Industry Trends: License Renewal and New Plants

The excellent economic and safety performance of U.S. nuclear power plants has demonstrated the value of nuclear energy to the electric industry, the financial community and policymakers. This is evidenced by the increasing number of facilities seeking license renewals from the NRC.

Of the currently operating reactors nationwide, 84 out of 99 have received license renewal. The Nuclear Regulatory Commission found no technical limitations to prevent a nuclear plant from operating for 80 years.

Originally licensed to operate for 40 years, nuclear energy facilities can operate safely for longer. The NRC granted the first 20-year license renewal to the Calvert Cliffs plants in Maryland in 2000. As of March 2017, 84 currently operating reactors had received license extensions, and operators of 13 additional reactors either had submitted applications or announced that they will seek renewal. License renewal is an attractive alternative to building new electric capacity because of nuclear energy's low production costs and the return on investment provided by extending a plant's operational life.

The Nuclear Regulatory Commission has found that there are no technical reasons to prevent a nuclear plant from operating for 80 years. In 2014, the Nuclear Regulatory Commission found that its current regulatory structure regarding initial license renewal is suitable for second license renewal. In 2015, Dominion announced that it will apply in 2019 for a second license renewal for its Surry Power Station in Virginia. If granted, this will allow the plant to operate for an additional 20 years (80 years in total). Exelon announced in June 2016 that it will pursue second license renewal for its Peach Bottom plant.

Besides relicensing nuclear plants, energy companies are building new, advanced-design reactors. Georgia Power and South Carolina Electric & Gas are building two advanced reactors each, near Augusta, Ga., and Columbia, S.C. These facilities are nearly halfway through their construction programs. These projects employ more than 5,000 workers each now that construction is peaking. In addition, Tennessee Valley Authority began operation of the Watts Bar 2 reactor in Tennessee in June 2016.

Section 6
Economic Impact Analysis Methodology

This analysis uses the REMI model to estimate the economic and fiscal impacts of Xcel Energy's nuclear facilities.

Regional Economic Models, Inc. (REMI)

REMI is a modeling firm specializing in services related to economic impacts and policy analysis, headquartered in Amherst, Mass. It provides software, support services, and issue-based expertise and consulting in almost every state, the District of Columbia, and other countries in North America, Europe, Latin America, the Middle East and Asia.

REMI's software has two main purposes: forecasting and analysis of alternatives. All models have a "baseline" forecast of the future of a regional economy at the county level. Using "policy variables," in REMI terminology, provides scenarios based on different situations. The ability to model policy variables makes it a powerful tool for conveying the economic "story" behind policy. The model translates various considerations into understandable concepts like GDP and jobs.

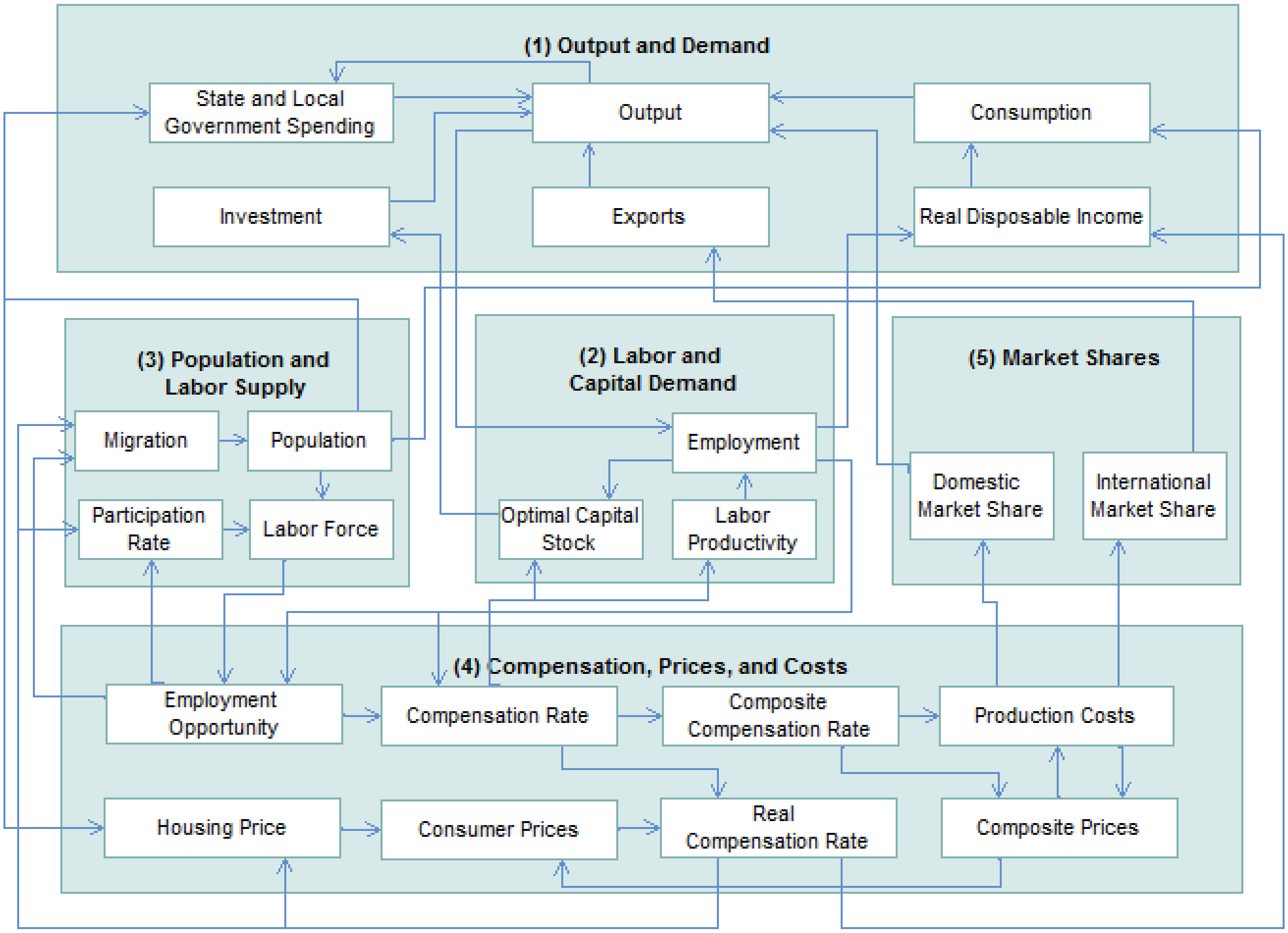
REMI relies on data from public sources, including the Bureau of Economic Analysis, Bureau of Labor Statistics, Energy Information Administration and the Census Bureau. Forecasts for future macroeconomic conditions in REMI come from a combination of resources, including the Research Seminar in Quantitative Economics at the University of Michigan and the Bureau of Labor Statistics. These sources serve as the main framework for the software model needed to perform simulations.

Policy Insight Plus (PI+)

REMI's PI+ is a computerized, multiregional, dynamic model of the states or other sub-national units of the United States economy. PI+ relies on four quantitative methodologies to guide its approach to economic modeling:

1. Input/output tabulation (IO)—IO models, sometimes called "social accounting matrices" (SAM), quantify the interrelation of industries and households in a computational sense. It models the flow of goods between firms in supply-chains, wages paid to households, and final consumption by households, government and the international market. These channels create the "multiplier" effect of $1 going farther than when accounting for its impact on enabling subsequent value..
2. Computable general equilibrium (CGE)—CGE modeling adds market concepts to the IO structure. This includes how those structures evolve over time and how they respond to alternative policies. CGE incorporates con-

Figure 6.0



This diagram represents the structure and linkages of the regional economy in PI+. Each rectangle is a discrete, quantifiable concept or rate, and each arrow represents an equation linking the two of them. Some are complex econometric relationships, such as the one for migrant, while some are rather simple, such as the one for labor force, which is the population times the participation rate. The change of one relationship causes a change throughout the rest of the structure because different parts move and react to incentives at different points. At the top, Block 1 represents the macroeconomic whole of a region with final demand and final production concepts behind GDP, such as consumption, investments, net exports and government spending. Block 2 forms the "business perspective": An amount of sales orders arrive from Block 1, and firms maximize profits by minimizing costs when making optimal decisions about hiring (labor) and investment (capital). Block 3 is a full demographic model. It has births and deaths, migration within the United States to labor market conditions, and international immigration. It interacts with Block 1 through consumer and government spending levels and Block 4 through labor supply. Block 4 is the CGE portion of the model, where markets for housing, consumer goods, labor and business inputs interact. Block 5 is a quantification of competitiveness. It is literally regional purchase coefficients (RPCs) in modeling and proportional terms, which show the ability of a region to keep imports away while exporting its goods to other places and nations.

cepts on markets for labor, housing, consumer goods, imports and the importance of competitiveness to fostering economic growth over time. Changing one of these will influence the others—for instance, a new knife factory would improve the labor market and then bring it to a head by increasing migration into the area, driving housing and rent prices higher, and inducing the market to create a new subdivision to return to "market clearing" conditions.

3. Econometrics—REMI uses statistical parameters and historical data to populate the numbers inside the IO and CGE portions. The estimation of the different parameters, elasticity terms and figures gives the strength of various responses. It also gives the "time-lags" from the beginning of a policy to the point where markets have had a chance to clear.

4. New economic geography—Economic geography provides REMI a sense of economies of scale and agglomeration. This is the quantification of the strength of clusters in an area and their influence on productivity. One example would include the technology and research industries in Seattle. The labor in the area specializes to serve firms like Amazon and Microsoft and, thus, their long-term productivity grows more quickly than that of smaller regions with no proclivity towards software development (such as Helena, Mont.). The same is true on the manufacturing side with physical inputs, such as with the supply-chain for Boeing and Paccar in Washington in the production of transportation equipment. Final assembly will have a close relationship and a high degree of proximity to its suppliers of parts, repairs, transportation and other professional services, which show up in clusters in the state.

Conclusion

The estimated total economic impacts (direct and secondary) to Minnesota from Xcel Energy's nuclear operations at its three reactors and support operations at Xcel Energy headquarters are over $1 billion in output and approximately $600 million in gross state product every year. These operations also contribute $240 million in after-tax income to residents of Minnesota. The nuclear operations and their secondary effects also account for over 6,000 jobs in Minnesota.

The plant's economic benefits—on taxes and through wages and purchases of supplies and services—are considerable. In addition, plant employees further stimulate the local economy by purchasing goods and services from businesses around the area, supporting many small businesses throughout the region.

The facilities generated nearly 13 billion kilowatt-hours of emission-free electricity in 2015, enough to serve the yearly needs for 1.4 million homes. This low-cost, reliable electricity helped keep electricity prices in check in Minnesota.

Xcel Energy's nuclear plants are leaders economically, fiscally, environmentally and socially within Minnesota.

■

Nuclear Fuel Process

The following summarizes how nuclear fuel expenditures and additions are determined.

Commodities - Nuclear fuel commodities (uranium, uranium conversion services and uranium enrichment services) are purchased by NSP as needed under contracts in force at the time of purchase to meet future reload specific energy requirements. These commodities are fungible. The actual uranium content of the new nuclear fuel assemblies received is identified by the nuclear fuel fabrication vendor at the time the new nuclear fuel assemblies are shipped to the nuclear plant site.

Processing - Each processing stage (uranium mining, uranium conversion services, uranium enrichment services and fuel assembly fabrication) in the nuclear fuel construction period has contractually agreed upon lead times for the delivery of the prior processing stage's unfinished nuclear materials. Consequently, a typical construction period for new nuclear fuel assemblies ranges from 18 months to 24 months.

Service Providers - Westinghouse Electric Co., LLC provided or will provide the nuclear fuel fabrication and engineering services required to manufacture the new nuclear fuel assemblies placed in service during the years 2020 through 2024 for the Prairie Island Nuclear Generating Plant. Framatome Inc. provided or will provide the nuclear fuel fabrication and engineering services required to manufacture the new nuclear fuel assemblies placed in service in 2021 through 2025 for the Monticello Nuclear Generating Plant.

Cost Accounting - Nuclear fuel commodities are assigned to the new nuclear fuel assemblies at average unit cost when they arrive at the nuclear plant site based on the uranium content in the new nuclear fuel assemblies. Current year nuclear fuel commodity expenditures may remain in the nuclear fuel construction in process accounts for up to two years before assignment to a specific nuclear fuel reload (at average cost of all fuel in-process), at which time they are classified as completed construction through a capital addition to plant in service. Reload fabrication and engineering costs are specifically identifiable and assigned to each new nuclear fuel reload.

Nuclear Fuel Expenditures and Costs of Reloads Being Amortized

The following summarizes nuclear fuel capital expenditures and costs of completed fuel reloads beginning amortization for the years shown:

Xcel Energy Nuclear Fuel *$ in millions*	**Actual 2020**	**Forecast 2021**	**Budget 2022**	**Prelim 2023**	**Prelim 2024**
Capital Expenditures (excluding AFUDC) – Table NF-1	$52.2	$104.7	$86.8	$104.4	$83.0
Completed Reload Costs Beginning Amortization – Tables NF-2 (summary) & NF-3 (detail)	$79.2	$147.3	$77.6	$158.2	$70.8

The differences in reload expenditures and completed reload costs beginning amortization each year are driven by variations in the number of reactors and the specific reactors refueled in each year, and which reloads are in process vs. completed in each year. Similarly, expenditures in a given year may vary significantly from other years based on ongoing expenditures for commodities and processing needed for upcoming reload requirements planned for each unit.

- Monticello operates on a 2-year cycle and is planning reloads every other year, in 2021 and 2023.
- Prairie Island operates on a 2-year cycle and would have one reload for each of its units every other year, resulting in one reload completed for the site each year.

The components of annual capitalized expenditures, excluding AFUDC, charged to nuclear fuel construction in process for the years 2020 through 2024 are provided in the attached Table NF-1.

The number of fuel assemblies, average costs of fuel assemblies, and all other costs that make up the completed nuclear fuel reloads moved from construction in process accounts and beginning amortization are provided in the attached Tables NF-2 (summary) and NF-3 (detail). Note that there can be timing differences between the date the fuel assemblies are placed in service as a capital addition and the date they begin use in the reactor for fuel amortization purposes. Nuclear fuel expense amortization begins when the reloaded fuel is in the reactor and being consumed from the unit being online.

in millions of $

Table NF-1: Annual Nuclear Fuel Capital Expenditures - Direct (excluding AFUDC)

Cost Component	Actual 2020	Projected 2021	Projected 2022	Projected 2023	Projected 2024	Total 2020-2024
Uranium	$ 12.4	$ 32.8	$ 21.3	$ 34.7	$ 28.8	$ 129.9
Conversion	4.6	5.6	6.2	7.1	6.1	29.6
Enrichment	20.9	34.6	41.2	33.4	34.4	164.5
Fabrication	8.9	20.9	9.0	22.2	9.6	70.6
Labor	1.5	1.9	2.1	1.8	1.7	9.1
Engineering	4.0	8.8	7.0	5.2	2.4	27.4
Total	**$ 52.2**	**$ 104.7**	**$ 86.8**	**$ 104.4**	**$ 83.0**	**$ 431.1**

in millions of $

Table NF-2: Summary - Costs of Completed Nuclear Fuel Reloads Beginning Amortization

Reload	Actual 2020	Projected 2021	Projected 2022	Projected 2023	Projected 2024	Total 2020-2024
PI2 Cycle 31	$ 0.5					$ 0.5
PI1 Cycle 32	$ 78.7					$ 78.7
Monticello Cycle 31		$ 74.0				$ 74.0
PI2 Cycle 32		$ 73.3				$ 73.3
PI1 Cycle 33			$ 77.6			$ 77.6
Monticello Cycle 32				$ 85.3		$ 85.3
PI2 Cycle 33				$ 72.9		$ 72.9
PI1 Cycle 34					$ 70.8	$ 70.8
Other						$ -
Total	**$ 79.2**	**$ 147.3**	**$ 77.6**	**$ 158.2**	**$ 70.8**	**$ 533.1**

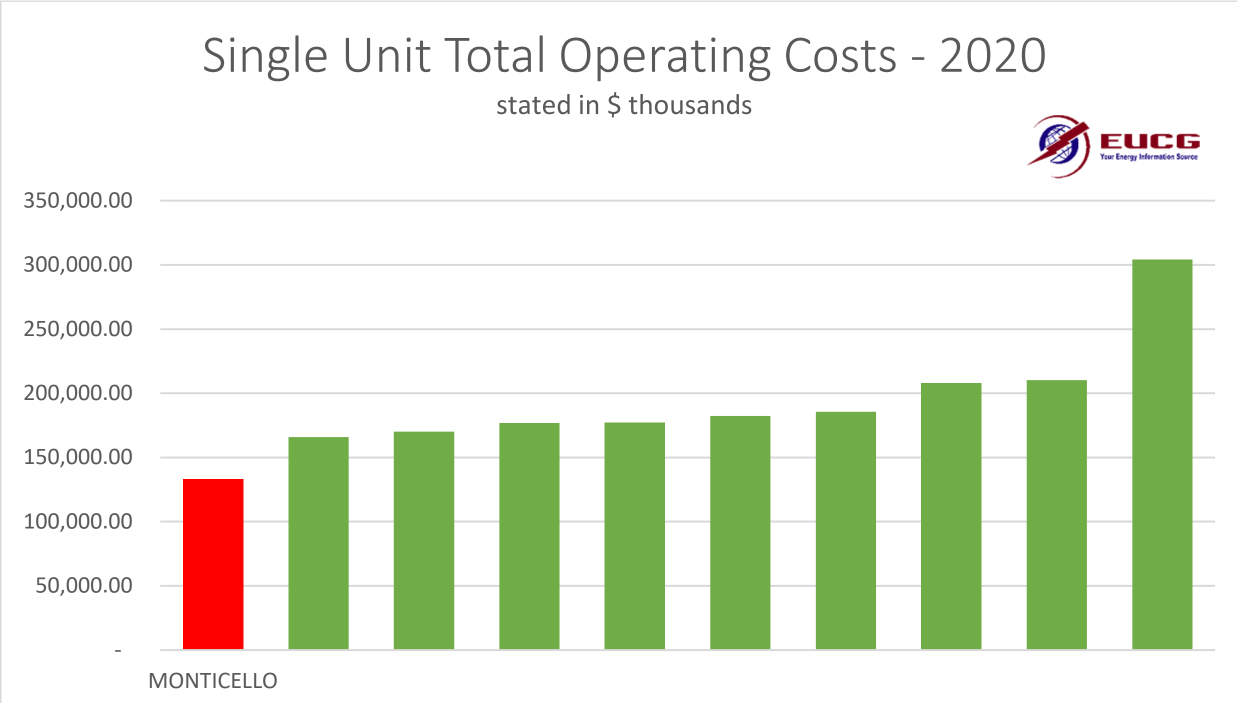
Table NF-3: Detail of Completed Nuclear Fuel Reload Costs Beginning Amortization - 2020 through 2024 ($ in millions)

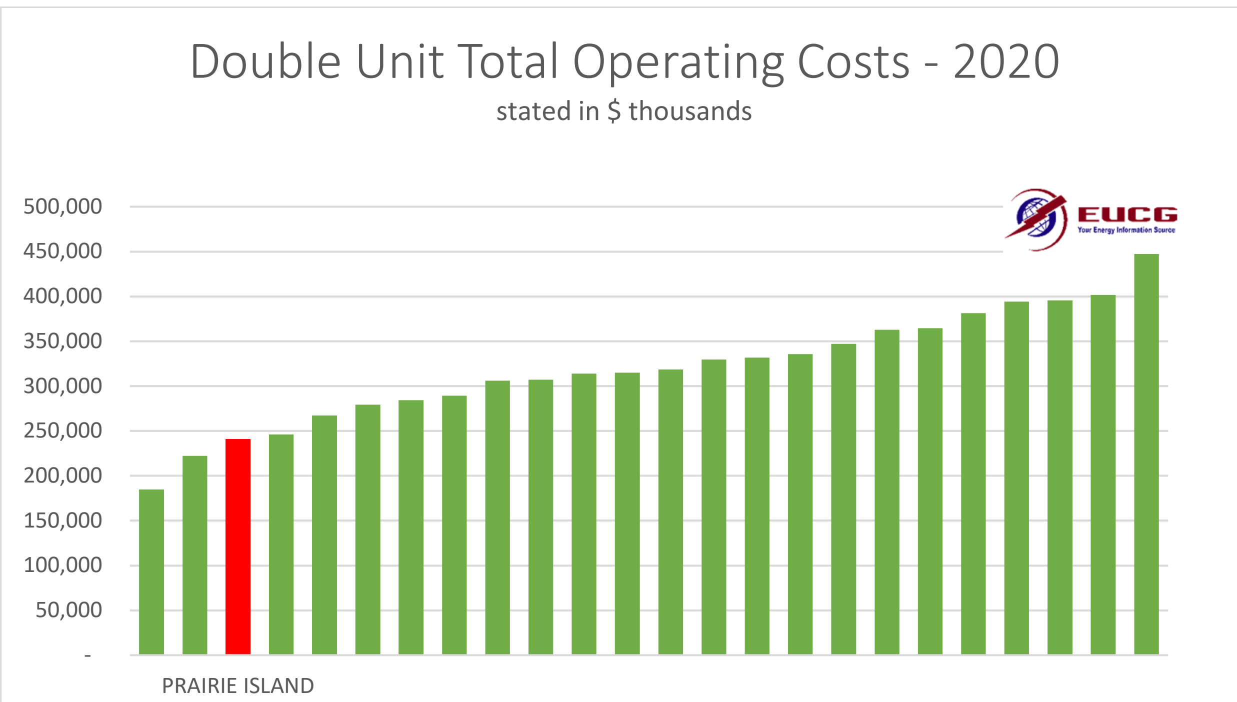
Unit & cycle	Year In-Service	Batch ID	Assemblies	Average wt% U235	Average Kg U/Assembly	Uranium	Conversion	Enrichment	Fabrication	Labor	Engineering	AFUDC	A&G	Reload Total	Average $/Assembly
Pl 2 Cycle 31	2019				2020 Trailing Additions					$ 0.3	$ 0.2			**$ 0.5**	
Pl1 Cycle 32	2020	132A	4	4.8143	393.244	$ 1.9	$ 0.3	$ 1.5	$ 0.6	$ 0.1	$ 0.2	$ 0.6	$ 0.0	$ 5.1	$ 1.29
		132B	4	4.8406	393.518	$ 2.0	$ 0.3	$ 1.5	$ 0.6	$ 0.1	$ 0.2	$ 0.6	$ 0.0	$ 5.2	$ 1.29
		132C	8	4.8651	392.550	$ 3.9	$ 0.5	$ 3.1	$ 1.2	$ 0.1	$ 0.3	$ 1.2	$ 0.0	$ 10.4	$ 1.30
		132D	4	4.9078	393.585	$ 2.0	$ 0.3	$ 1.6	$ 0.6	$ 0.1	$ 0.2	$ 0.6	$ 0.0	$ 5.2	$ 1.31
		132E	12	4.9274	393.719	$ 6.0	$ 0.8	$ 4.7	$ 1.8	$ 0.2	$ 0.5	$ 1.9	$ 0.0	$ 15.8	$ 1.32
		132F	28	4.9422	394.164	$ 14.0	$ 1.9	$ 11.0	$ 4.2	$ 0.4	$ 1.2	$ 4.4	$ 0.0	$ 37.0	$ 1.32
			60	4.9114	**393.717**	$ 29.7	$ 4.0	$ 23.5	$ 8.9	$ 0.8	$ 2.5	$ 9.3	$ 0.0	**$ 78.7**	$ 1.31
Monticello Cycle 31	2021	331A	108	4.0349	176.492	$ 16.5	$ 2.6	$ 17.0	$ 8.1	$ 0.6	$ 1.9	$ 3.2	$ 0.0	$ 50.0	$ 0.46
		331B	52	4.0268	176.461	$ 7.9	$ 1.2	$ 8.2	$ 3.9	$ 0.3	$ 0.9	$ 1.6	$ 0.0	$ 24.0	$ 0.46
			160	4.0323	**176.482**	$ 24.4	$ 3.8	$ 25.2	$ 12.0	$ 0.9	$ 2.9	$ 4.8	$ 0.0	**$ 74.0**	$ 0.46
Pl 2 Cycle 32	2021	232A	12	4.7499	394.872	$ 5.2	$ 0.8	$ 5.1	$ 1.9	$ 0.2	$ 0.5	$ 1.4	$ (0.0)	$ 15.2	$ 1.27
		232B	24	4.8983	394.872	$ 11.0	$ 1.7	$ 10.5	$ 3.8	$ 0.4	$ 0.9	$ 3.0	$ (0.0)	$ 31.4	$ 1.31
		232C	4	4.9242	395.338	$ 1.8	$ 0.3	$ 1.8	$ 0.6	$ 0.1	$ 0.2	$ 0.5	$ (0.0)	$ 5.2	$ 1.31
		232D	16	4.9500	395.801	$ 8.1	$ 1.3	$ 6.6	$ 2.6	$ 0.3	$ 0.6	$ 2.1	$ (0.0)	$ 21.5	$ 1.34
			56	4.8832	**395.171**	$ 26.1	$ 4.1	$ 24.0	$ 8.9	$ 1.0	$ 2.1	$ 7.1	$ (0.0)	**$ 73.3**	$ 1.31
Pl1 Cycle 33	2022	133A	24	4.9323	395.556	$ 11.3	$ 1.9	$ 9.6	$ 3.9	$ 0.7	$ 1.8	$ 4.1	$ (0.0)	$ 33.3	$ 1.39
		133B	32	4.9500	395.801	$ 14.5	$ 2.5	$ 13.3	$ 5.2	$ 1.0	$ 2.4	$ 5.4	$ (0.0)	$ 44.3	$ 1.38
			56	4.9424	**395.696**	$ 25.9	$ 4.4	$ 22.9	$ 9.0	$ 1.7	$ 4.2	$ 9.5	$ (0.0)	**$ 77.6**	$ 1.39
Monticello Cycle 32	2023	332A	108	4.0212	176.625	$ 15.7	$ 3.2	$ 17.1	$ 8.4	$ 1.0	$ 7.9	$ 2.7	$ 0.0	$ 56.1	$ 0.52
		332B	56	4.0362	177.140	$ 8.2	$ 1.7	$ 8.9	$ 4.4	$ 0.5	$ 4.1	$ 1.4	$ 0.0	$ 29.2	$ 0.52
			164	4.0263	**176.801**	$ 23.9	$ 4.9	$ 26.0	$ 12.8	$ 1.5	$ 12.1	$ 4.1	$ 0.0	**$ 85.3**	$ 0.52
Pl 2 Cycle 33	2023	233A	36	4.9242	395.338	$ 17.2	$ 3.5	$ 14.8	$ 6.0	$ 0.7	$ 1.3	$ 3.2	$ (0.0)	$ 46.7	$ 1.30
		233B	20	4.9500	395.801	$ 9.6	$ 1.9	$ 8.3	$ 3.3	$ 0.4	$ 0.7	$ 1.8	$ (0.0)	$ 26.1	$ 1.31
			56	4.9334	**395.503**	$ 26.8	$ 5.4	$ 23.1	$ 9.3	$ 1.2	$ 2.0	$ 5.0	$ (0.0)	**$ 72.9**	$ 1.30
Pl1 Cycle 34	2024	134A	4	4.9145	395.305	$ 1.6	$ 0.3	$ 1.8	$ 0.7	$ 0.1	$ 0.2	$ 0.4	$ (0.0)	$ 5.0	$ 1.26
		134B	32	4.9323	395.556	$ 13.0	$ 2.5	$ 14.1	$ 5.5	$ 0.7	$ 1.2	$ 3.4	$ (0.0)	$ 40.3	$ 1.26
		134C	20	4.9500	395.801	$ 8.6	$ 1.7	$ 8.4	$ 3.4	$ 0.5	$ 0.8	$ 2.2	$ (0.0)	$ 25.5	$ 1.27
			56	4.9373	**395.626**	$ 23.2	$ 4.5	$ 24.2	$ 9.6	$ 1.3	$ 2.1	$ 6.0	$ (0.0)	**$ 70.8**	$ 1.27

Schedule 4
Nuclear Operations Non-Outage O&M Costs
($ in millions)

$ in millions	2018 Actual	2019 Actual	2020 Actual	2021 Act/ Fcst	2022 Test Year Budget	2023 Test Year Budget	2024 Test Year Budget	Avg Chg per Year 2018 to 2020	Avg Chg per Year 2020 to 2022	Avg Chg per Year 2018 to 2024
Workforce Costs										
A. Internal Labor	$ 125.3	$ 123.3	$ 122.5	$ 121.2	$ 118.7	$ 119.8	$ 121.6	-1.1%	-1.6%	-0.5%
B. External Labor (Contractors & Consultants)	27.4	24.3	19.4	19.2	22.0	20.0	20.5	-15.7%	6.8%	-4.1%
C. Security	31.1	31.1	30.7	28.1	28.7	30.2	31.2	-0.6%	-3.2%	0.2%
Subtotal Workforce Costs	$ 183.8	$ 178.7	$ 172.6	$ 168.5	$ 169.4	$ 170.0	$ 173.3	-3.1%	-0.9%	-1.0%
Non-Workforce Costs										
D. Materials & Chemicals	15.3	15.6	11.4	10.3	10.6	11.0	10.8	-12.5%	-3.4%	-5.0%
E. Employee Expenses	3.0	3.6	1.8	1.8	1.9	1.9	1.9	-15.0%	2.8%	-4.1%
F. Nuclear-related fees	33.9	34.7	34.9	35.4	36.4	36.8	37.1	1.5%	2.1%	1.5%
G. Other	7.6	6.5	5.9	6.0	6.0	6.1	6.1	-11.9%	0.8%	-3.4%
Subtotal Non-Workforce Costs	$ 59.8	$ 60.4	$ 54.0	$ 53.5	$ 54.9	$ 55.8	$ 55.9	-4.8%	0.8%	-1.0%
Total Non-Outage O&M	**$ 243.6**	**$ 239.1**	**$ 226.6**	**$ 222.0**	**$ 224.3**	**$ 225.8**	**$ 229.2**	**-3.5%**	**-0.5%**	**-1.0%**

Schedule 5 – EUCG Operating Cost Data





Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

Last Updated: November 28, 2007

Statement of Purpose

This accounting policy addresses the operations and maintenance (O&M) expenditures that are associated with the routine refueling of a nuclear unit and are categorized as planned major maintenance activities. Please refer to the attached list of definitions for any terminology used in this policy. Xcel Energy's utility subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC) and by various state commissions. All of the utility subsidiaries' accounting records must conform to the FERC Uniform System of Accounts. Additionally, Xcel Energy is subject to regulation by the Securities and Exchange Commission (SEC).

The overall goal of this document is to achieve a consistent policy that defines common procedures to ensure correct and consistent accounting that complies with FERC guidelines and SEC regulations for the proper handling of planned major maintenance activities associated with routine nuclear refueling across all applicable entities. It is common practice across the industry to allow expenditures to be charged to a deferred work order associated with a routine nuclear refueling in order to amortize the costs over the next fuel cycle. Due to the magnitude of this issue, it is necessary that the proper accounting be defined to assure accurate books and records of the Company. Currently, Northern States Power Company, a Minnesota corporation (NSPM) is the only Xcel Energy operating company with nuclear facilities, but the policy would apply to any subsidiary with such facilities.

Applicability

This Uniform Policy is effective on the date stated below and on that date, this policy became effective for all utility subsidiary companies. This Uniform Policy is applicable to all Xcel Energy utility subsidiaries that deal with nuclear facilities.

Summary

Because Xcel Energy is regulated by various government entities, the Corporate Controller is responsible for accounting policies for Xcel Energy within the framework of the SEC, FASB, FERC, and state regulatory requirements. These policies will include establishing and maintaining effective internal controls as it relates to the books and records of Xcel Energy and the preparation of all consolidated external reports as required by the SEC, FERC, and the state regulators.

Within this framework, Regulatory Accounting will establish appropriate accounting policies in order to meet the FERC and GAAP/SEC accounting requirements. At the end of each month, in order to recognize the regulatory assets correctly on the Company's balance sheet and to provide for the proper amortization to the income statement, only those refueling O&M expenditures that satisfy the criteria defined herein should be recognized to the appropriate deferred work orders.

This policy defines the expectations surrounding treatment of routine refueling O&M expenditures as planned major maintenance activities that should be charged to deferred work orders to assure proper internal controls are in place and a proper audit trail exists. Where allowed by a regulatory jurisdiction, the deferral and subsequent amortization of these expenditures meet the guidance issued under FASB Staff Position No. AUG AIR-1 (FSP AUG AIR-1), *Accounting for Planned Major Maintenance Activities*. It is Regulatory Accounting's responsibility to maintain this policy and to ensure, in conjunction with the business unit personnel, consistent application of the procedures contained in the policy. Regulatory Accounting will monitor FERC regulations and other accounting rules that impact this policy and make changes as necessary to maintain accounting compliance. Thus, business areas are responsible to understand and to adhere to the policy. Regulatory Accounting will assist business areas to appropriately apply the policy.

Definitions

Capital – The purchase or construction of a retirement unit that will be recorded on the balance sheet as an asset after meeting the GAAP criteria for being an asset

FASB – Financial Accounting Standards Board

FERC – Federal Energy Regulatory Commission

FSP – FASB Staff Position

GAAP – Generally Accepted Accounting Principles

O&M Expenditure – Expenditure incurred in the normal operations of the assets or restores the fixed asset to operating status and assists in assuring that the fixed assets achieve useful life expectations

SEC – Securities and Exchange Commission

Work Order – An account numbering system used to group costs (often referred to as a subledger in the JD Edwards general ledger system)

Content

Characterization

This policy is based on the FSP AUG AIR-1 that modifies certain positions of AICPA Industry Audit Guide, Audits of Airlines, which defines three allowable treatments for planned major maintenance activities: direct expense, built-in overhaul, or deferral. Xcel Energy uses two methods: direct expensing and deferral with an amortization, often referred to as a "deferral-and-amortization method". The deferral-and-amortization method is used only when authorized by a specific regulatory jurisdiction. Thus, if no approval exists for a specific jurisdiction, the jurisdiction must use the direct expense method. As the costs for planned major maintenance activities provide value to the constructed asset over the next cycle to which the refueling relates (typically the next 18 to 24 months), the deferral-and-amortization method has the benefit of better matching costs to the period in which it relates. These costs include, but are not limited to; contract labor, company labor and benefits, materials and supplies, transportation, machine equipment, tool usage, permits, equipment rental, taxes, and various incurred for planned major maintenance activities such as cleaning, servicing, replacement, or repair, as well as costs of replacement components, minor parts, and interactive agents (such as certain fluids or elements).

In general, those nuclear refueling outage costs that are properly includable to a regulatory asset under the deferral-and-amortization method should be charged to the appropriate reload-specific set of deferred work orders. A series of deferred work orders will be established for each reload to align with the applicable FERC Account to which the O&M cost would have been charged if it had been expensed, such that the amortization is expensed to those same O&M FERC Accounts. Any work done during a refueling outage that meets the requirements for capitalization is not includable in the deferred work orders. In addition, costs for standard maintenance or normal operations, which occur during a refueling outage and which are **not** listed in the definition of includable expenses shown below, are to be expensed to the appropriate O&M accounts. This policy defines the expenses allowed to the deferred work orders established for refueling outage costs and helps one understand the limits in the use of these deferred work orders.

Definition

Nuclear reactors are typically shut down once every 18 to 24 months to refuel approximately one third of the reactor core. There are many costs associated with a refueling outage. These include the following O&M costs:

- Replacement of approximately one third of the nuclear fuel assemblies in the reactor core;
- Numerous inspections on equipment to ensure safety and compliance with requirements;
- Test and maintenance jobs that can be performed only when the reactor is shut down; and
- Repairs and refurbishment of major nuclear and non-nuclear components of the plant (e.g., control rods, main coolant pumps, steam generators, turbine valves and blading, main electric generator).

This is a general list of items. However, other costs arise during a refueling outage that may be appropriate for deferral and amortization. Such costs may only be deferred following a review of the new charges for compliance with this policy and, upon compliance, approval by the outage manager and the site accounting manager (with retention of the appropriate documentation). If work begins on these activities prior to receiving approval, the expenditures will be treated as an O&M expense. However, certain costs occurring before and after the actual period when the unit is off-line are allowable to deferred work orders. Descriptions of allowed pre-outage costs and post-outage costs are included below.

In addition to the work performed in a "base" refueling outage, more extensive work is required during refueling outages, usually staggered over a 10-year period, to comply with periodic Nuclear Regulatory Commission (NRC) and insurance requirements. In addition, it is anticipated that more extensive refueling outages occasionally will be needed as larger projects are completed. These more extensive outages will require longer periods and higher costs than typical refueling outages, but are one-time expenses not anticipated to be repeated over the license renewal period. Because each unit has different operating characteristics and parameters, each has its own fuel cycle, ranging from 18 to up to 24 months. Thus, the number of refueling outages scheduled in any given year will vary, with two outages occurring in most years, one in others, and the potential for even three refueling outages occurring in some years. Extensive planning goes into the preparation and execution of these outage schedules.

The deferral-and-amortization method of accounting will include only costs directly associated with a planned refueling outage. All other work, albeit done at the time of the outage, will be directly charged to the appropriate O&M or capital accounts as has been traditionally done. Planned outage costs for the next refueling can begin soon after the unit returns to service as contracts are being set and material is being ordered. However, most of the costs associated with planned outage work occur within the actual outage period. An activity or work order is considered planned outage work if one of the following conditions applies:

- The plant impact of the work scope requires an outage to complete;
- The work scope is required by Technical Specifications, license-based provisions, or other regulatory requirements to be performed during the outage timeframe;
- The work scope duration required exceeds greater than 75% limited condition operations ("LCO") duration;
- The work scope requires a preventative maintenance test ("PMT") or a test that can only be performed during an outage, and the work that is required ensures unit reliability for the next cycle.

Pre-outage Costs

As with any large project, capital or maintenance, there is considerable planning that occurs in order for the outage to be as efficient as possible. These planning costs are allowed as part of the deferred work order even if the costs occur in a prior year. The earliest that outage costs can occur is shortly after the unit comes on-line from the last outage. Costs cannot be deferred that occur any earlier than the beginning of the operating cycle immediately before the outage being planned.

Allowable costs during the pre-outage period include the following:

- Outage milestone planning to develop a systematic approach for preparing for an outage;
- Surveillance and special testing of equipment;
- Any work issues identified for performance prior to a planned outage.

As with all the costs, proper documentation must exist to support the appropriateness of the charge to the FERC specific deferred work order. Any charge that does not meet the above requirements should be charged directly, in the current period, to the appropriate O&M account.

Post-outage Costs

Typically, costs continue to come in throughout the month following the return to service. This is expected, however any costs that are known and measurable in the month when the unit returns to service should be recorded as an unvouchered liability in that month. The month when the bill is received will then contain a reversal of the unvouchered liability and recognition of the actual expense. This true up from estimate to actual is often referred to as a "pick up".

Allowable costs during the post-outage period include the following:

- Resolution of disputed outage contractor issues;
- Delay charges;
- Costs associated with the removal of equipment to support outage activities.

As with all the costs, proper documentation must exist to support the appropriateness of the charge to the FERC specific deferred work order. Any charge that does not meet the above requirements should be charged directly, in the current period, to the appropriate O&M account.

Non-outage Costs

Non-outage activities may be added to the outage schedule based on work benefits that can be gained by delaying the work until the outage. Although this work is performed at the same time as the refueling outage, it is not included in the deferral and amortization. This includes the following, but is not limited to these examples:

- Personnel exposure to radiation that can be measurably reduced by performing the work when the unit is shutdown rather than at power assuming the work can be deferred to a planned outage;
- Regular maintenance work on the same component that is scheduled for work during the outage and the work can be safely delayed until the outage;

- Work based on economic considerations and surveillance or preventative maintenance tasks that are scheduled during the outage period and cannot be rescheduled outside of the outage period.

Unplanned Outage Costs

Unplanned outages include the work that cannot be delayed until the next planned outage and requires the unit to be shutdown in order for the work to be completed. Also included in unplanned outages is any work done when the unit is brought off line for safety reasons. Costs related to these unplanned outages, as well as all non-outage activity costs, are not eligible for the deferral-and-amortization method of accounting, and will continue to use the direct expense accounting method.

Accounting

Deferred Work Order

Each outage for each unit is assigned a separate set of FERC specific deferred work orders. Before the first refueling outage charge is anticipated, the business area will request a series of deferred work orders be issued. The set of deferred work orders will include one work order for each nuclear production FERC O&M account anticipated to be charged (the same FERC accounts used to record the refueling outage costs to expense). As costs are incurred during the outage, the FERC specific deferred work order will accumulate costs previously charged to the specific FERC O&M account. The use of work orders facilitates the accumulation of charges, but it also facilitates review for audit purposes.

Other Regulatory Assets

The accumulation of refueling outage costs for those jurisdictions allowing the deferral-and-amortization method will be cleared from the deferred work order to FERC Account 182.3, *Other Regulatory Assets*. The subsequent amortization of each balance reduces the regulatory asset to zero over the period the plant is operating until the next reload outage. The regulatory asset account will be maintained separate for each reload at each unit and also by each applicable nuclear production FERC O&M account. It is anticipated that this information will be segregated via a work order tag in the regulatory asset account.

Various Jurisdictions

For any rate jurisdiction that has not approved the use of the deferral-and-amortization method for nuclear refueling outage costs, that jurisdiction will continue to use the direct expensing method for its portion of the nuclear refueling outage costs. Therefore, unless all rate jurisdictions authorize use of the deferral-and-amortization method, the accounting will be maintained by rate jurisdiction.

Assuming there are some rate jurisdictions that will allow the use of the deferral-and-amortization method and others that will not, the following steps generally will occur:

1. The nuclear plant personnel identify the refueling expenses that are appropriate to be deferred. Plant personnel do not allocate jurisdictional costs and thus gather total company charges only under this policy.
2. The plant personnel assign the identified costs in step 1 to a deferred work order, with each work order being specific to a FERC account and a particular reload.
3. The charges in the deferred work order are allocated to the various rate jurisdictions each month (based on the appropriate jurisdictional allocation factor in use at the time for each nuclear production FERC O&M account).
4. For those jurisdictions using the deferral-and-amortization method, the jurisdictional work order will set up the regulatory asset for amortization.
5. For those jurisdictions using the direct expense method, the costs in the jurisdictional work order are expensed in the month incurred.
6. The regulatory asset is maintained by each reload and by each applicable FERC O&M account such that the amortization is charged to the appropriate FERC O&M account each month

Amortization

The monthly amortization is calculated for each nuclear production FERC account for each reload for each unit separately. The amortization is a straight-line calculation derived by dividing the amount accumulated for the refueling outage by the number of months in the amortization period. The following method is used to calculate the amortization period.

<u>Amortization Period</u>
The amortization begins with the month the unit comes on-line, and continues through the month before it comes back on-line with the next refueled core. The intent behind using this period is to be assured that the previous deferral finishes the month prior to the next one beginning, leaving no months without an amortization or having amortizations from the previous and current reload overlapping. For example, the unit comes off line in February 2008 to refuel and comes back on-line March 2008. The plant operates through the rest of 2008, all of 2009, and comes off-line in February 2010 for the next refueling. This refueling is complete in March 2010. The amortization period is the number of months from March 2008 to February 2010, or 24 months in this example.

The number of months in the amortization is set based on the expected future refueling date for the next outage. The date, although a forecast, is a fairly certain date that will usually only fluctuate by one or two months on either side of the forecast date. When it is known that the next reload date has moved, the amortization period is adjusted. The amortization is adjusted for the remaining months by dividing the current balance by the remaining months in the amortization period. Continuing the above example, if the refueling date is revised from February 2010 to April 2010 in January 2010, then the remaining amortization period is lengthened by two months. In January 2010, the remaining amortization was 2 months and is lengthened to 4 months based on the revised date for refueling.

FERC O&M Accounts

Based on accumulating the charges to a FERC specific deferred work order, the amortization is calculated for the month for each applicable O&M account. Each refueling operation may have a different spread of the costs incurred across the various nuclear O&M accounts; therefore, there may be many amortizations being calculated for each reload to effectively charge the correct FERC O&M account. The amortization is charged to the same nuclear production O&M expense account as would be used for direct expensing. The amortization period is the same across all FERC O&M account amortizations.

Applicable FERC O&M Accounts to Nuclear Refueling Outages

FERC Account	Account Title
Operations	
517	Operation Supervision and Engineering
519	Coolants and Water
520	Steam Expenses
523	Electric Expenses
524	Miscellaneous Nuclear Power Expenses
Maintenance	
528	Maintenance Supervision and Engineering
529	Maintenance of Structures
530	Maintenance of Reactor Plant Equipment
531	Maintenance of Electric Plant
532	Maintenance of Miscellaneous Nuclear Plant

Pick-ups

The term "pick-ups" is used to refer to the trailing costs that occur subsequent to the completion of the work. Business unit personnel are expected to book all known or estimable costs in the final month of the outage work. By recognizing an estimate of work completed to date, the amortization can begin with a very close approximation of total costs in the deferred work orders. The costs incurred in the "post-outage" phase are recognized in the deferred work orders with a debit offset by a credit to account payable or unvouchered liabilities. When the final costs are determined, the entire estimate is reversed with the actual payment being recognized to the appropriate deferred work order.

There is a time limit on this process. Costs not finalized within three months after the unit begins operating are settled to expense.

Direct Expensing

Assuming a jurisdiction may not adopt this change of accounting for its customers, their portion of the O&M costs will be expensed when incurred. The jurisdictional split is determined at the time the set of FERC specific deferred work orders is requested for the outage. Every charge booked to the deferred work order will be allocated between jurisdictions that allowed the deferral-and-amortization method of accounting and those jurisdictions using the direct expense method. For example, if 75% of the jurisdictions allow deferred accounting and 25% do not, for every dollar incurred, 25 cents is expensed immediately and 75 cents is deferred and amortized. See steps defined under the "*Various Jurisdictions*" section above.

Tax Treatment

The treatment described to this point deals with the financial treatment of these costs for book purposes. The treatment of these costs for tax purposes is not impacted by whether the costs are deferred and amortized or expensed as incurred. The amount spent in a given year on refueling costs is what is deducted for income tax purposes. Therefore, choosing to defer some of the O&M costs for the books creates a timing difference between the book and tax recognition for these refueling costs. To recognize this difference, a deferred tax liability is created, setting up when the costs are expensed for taxes and flowing back when the amortization is complete.

Policy Application

Making the decision of where a particular cost should be charged may not always be clear and concise and interpretations will have to be made. Nuclear refueling costs meeting the above criteria for deferral can be charged to a deferred work order while all routine maintenance and standard operating costs should be charged to the appropriate O&M expense accounts. Any uncertainty about this policy should be directed to Regulatory Accounting for resolution.

Regulatory

Interchange Agreement

Costs incurred in the nuclear production O&M FERC accounts are shared between the two Northern State Power companies through the FERC jurisdictional "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)" (Interchange Agreement). Costs are shared based on assignment to specific FERC accounts using a ratio of either the 36 month coincident peak demand or current year energy requirements. Through the Interchange Agreement, NSPM bills a proportionate share of the nuclear production O&M expense to NSPW. The use of the deferral-and-amortization method of accounting for nuclear production O&M costs will change the pattern of expensing, however, the content of what is being expensed as well as the FERC accounts used to record those same expenses has not changed. Therefore, there is no impact to the Interchange Agreement resulting from this use of the deferral-and-amortization method.

Internal Controls

Regulatory Accounting has initiated the following tasks to assure that a valid work order for the regulatory assets resulting from this process exists from month to month:

- Working with the nuclear plant personnel to assure that proper documentation of cost assignment is being maintained;
- Periodically reviewing deferred work orders to assure that only proper costs are being included;
- Establishing the appropriate jurisdictional allocations for each deferred work order;
- Communicating this policy and its implications for the budgeting process for departmental operating expenses to all business unit personnel responsible for departmental budgets;
- Providing forecast information for the future amortizations applicable to this method based on the business area's budget of deferred costs.

Accountabilities

Business Unit Personnel

Business unit personnel are responsible for the following:

- Requesting set of deferred work orders prior to the first refueling outage charge;
- Making sure all costs are being appropriately tracked based on the rules stated above;
- Assuring unvouchered liabilities are booked timely;
- Providing all supporting documentation for the costs contained in any deferred work order;
- Keeping Regulatory Accounting aware of any changes to the refueling schedule in time to affect the monthly amortization.

Regulatory Accounting

Regulatory Accounting is responsible for the following:

- Performing the compliance accounting associated with this deferral;
- Providing the appropriate jurisdictional allocators for the various accumulating work orders;
- Calculating and documenting the monthly amortization;
- Providing all relevant deferral related information for the amortization for the forecast and for rate case preparations;
- Periodically reviewing work orders for the appropriateness of charges and working with the business unit personnel to resolve any issues.

References

FASB Staff Position No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*, September 2006

Supercedure

This is the first issuance of this policy.

Appendices

There are no appendices to this policy

Prairie Island Unit 1 - Fall 2020 Actual Outage Costs

Cost Description	Total Cost
[PROTECTED DATA BEGINS…	
	…PROTECTED DATA ENDS]

Total Contractor		**$ -**
Utility/Other Expense	$ 63,112	
Total Other		**$ 63,112**
Materials	$ 1,636,400	
Total Materials		**$ 1,636,400**
Employee Labor	$ 5,806,514	
T&D Labor	$ 858,332	
Total Labor		**$ 6,664,846**
Employee Expenses	$ 145,460	
Outage Employee Expenses from Other Sites	$ 409,040	
Total Empl/Oper		**$ 554,500**
GRAND TOTAL		**$ 8,918,858**

Prairie Island Nuclear Generating Plant

Outage Labor Costs - Unit 1 Refueling Outage 31 (1R32) - Fall 2020 Actual

Sum of Amount			
Res2	**Cost Center**	**Cost Center Description**	**Total**
Base Labor	**100653**	PI Site Management	-
	100656	PI Quality Control	(0.00)
	100658	PI Plant Management	-
	100659	PI Chemistry	-
	100660	PI Chemistry Tech Sup	(0.00)
	100661	PI Chemistry Operations	(0.00)
	100666	PI Maintenance Support	0.00
	100669	PI Planning	(3,655.56)
	100670	PI Radiation Protection	-
	100671	PI Raditaion Protection Support	0.00
	100672	PI Radiation Protect Operations	-
	100676	PI Operations Support	0.00
	100677	PI Work Control Center	0.00
	100679	PI Outage	0.00
	100692	PI Eng FIN Mechanical	-
	100695	PI Engineering Systems	3,012.21
	100696	PI Eng Nuc Safety Systems	164.36
	100701	PI Engineering Programs	0.00
	100707	PI Eng FIN Electrical	-
	100711	PI Doc Control and Procedures	-
	100713	PI Administration Services	-
	100715	PI Emergency Planning	-
	100717	PI Security	0.00
	102799	PI Shift Operations- Bargaining	(68,359.26)
	102800	PI Maint-Instr&Cntrl - Bargaining	2,785.00
	102801	PI Maint-Electrical - Bargaining	0.00
	102802	PI Maint-Mechanical - Bargaining	833.76
	102803	PI Maint-Facilities - Bargaining	244,454.52
	102924	PI Maint-Electrical	378,015.60
	102925	PI Maint-Instr&Cntrl	0.00
	102926	PI Maint-Mechanical	4,106.79
	102928	PI Shift Operations	68,359.26
	103082	PI Component Maintenance	-
	300837	PI Business Support-Final	344.32
	300898	PI Com Radiation Protection-Final	-
Base Labor Total			**630,061.00**
Overtime	**100653**	PI Site Management	16,655.20
	100654	PI Employee Concerns Prog	2,686.74
	100656	PI Quality Control	30,310.87
	100658	PI Plant Management	4,065.17
	100659	PI Chemistry	24,467.15
	100660	PI Chemistry Tech Sup	64,080.98

Overtime	**100661**	PI Chemistry Operations	143,279.56
	100666	PI Maintenance Support	18,363.24
	100669	PI Planning	161,516.89
	100670	PI Radiation Protection	150,809.65
	100671	PI Raditaion Protection Support	59,855.12
	100672	PI Radiation Protect Operations	278,514.71
	100676	PI Operations Support	126,317.78
	100677	PI Work Control Center	40,680.49
	100679	PI Outage	47,926.22
	100680	PI Scheduling	15,106.45
	100692	PI Eng FIN Mechanical	60,763.64
	100695	PI Engineering Systems	81,690.08
	100699	PI Eng Support	10,875.59
	100701	PI Engineering Programs	136,225.42
	100705	PI Engineering Design	38,859.65
	100707	PI Eng FIN Electrical	88,013.67
	100711	PI Doc Control and Procedures	3,188.00
	100713	PI Administration Services	43,014.29
	100715	PI Emergency Planning	6,337.59
	100717	PI Security	13,441.86
	102799	PI Shift Operations- Bargaining	605,558.99
	102800	PI Maint-Instr&Cntrl - Bargaining	180,352.16
	102801	PI Maint-Electrical - Bargaining	151,004.12
	102802	PI Maint-Mechanical - Bargaining	369,841.84
	102803	PI Maint-Facilities - Bargaining	316,988.95
	102924	PI Maint-Electrical	558,851.81
	102925	PI Maint-Instr&Cntrl	143,484.16
	102926	PI Maint-Mechanical	207,435.99
	102927	PI Maint-Facilities	7,508.48
	102928	PI Shift Operations	124,750.80
	103081	PI Maintenance-FIN	17,492.73
	103082	PI Component Maintenance	3,395.79
	300837	PI Business Support-Final	14,224.75
	300898	PI Com Radiation Protection-Final	-
Overtime Total			**4,367,936.58**
Premium	**100653**	PI Site Management	6,689.02
	100656	PI Quality Control	9,875.44
	100658	PI Plant Management	252.42
	100659	PI Chemistry	7,090.19
	100660	PI Chemistry Tech Sup	37,058.06
	100661	PI Chemistry Operations	78,100.43
	100670	PI Radiation Protection	59,223.52
	100671	PI Raditaion Protection Support	31,924.89
	100672	PI Radiation Protect Operations	139,583.76
	100676	PI Operations Support	37,319.60
	100711	PI Doc Control and Procedures	1,564.19
	100713	PI Administration Services	15,338.87

Premium	**100717**	PI Security	959.88
	102799	PI Shift Operations- Bargaining	495,837.77
	102800	PI Maint-Instr&Cntrl - Bargaining	124,455.38
	102801	PI Maint-Electrical - Bargaining	117,553.74
	102802	PI Maint-Mechanical - Bargaining	251,782.04
	102803	PI Maint-Facilities - Bargaining	50,546.42
	102924	PI Maint-Electrical	80,414.85
	102925	PI Maint-Instr&Cntrl	52,825.19
	102926	PI Maint-Mechanical	68,452.98
	300898	PI Com Radiation Protection-Final	-
Premium Total			**1,666,848.64**
Grand Total			**6,664,846.22**

Monticello - Spring 2021 Outage Forecast

Cost Description	Total Cost
[PROTECTED DATA BEGINS…	
CONTRACTORS	
	…PROTECTED DATA ENDS]

Monticello - Spring 2021 Outage Forecast

Cost Description	Total Cost
Total Contractor	**$ -**
LEASES/RENTS	
Biffs - Outage Bathrooms	$ 8,182
Trailer Rental	$ 371,392
Rental Equipment	$ 107,554
Total Leases	**$ 487,128**
MATERIALS	
Outage Materials	$ 1,531,823
Total Materials	**$ 1,531,823**
LABOR	
Employee Labor	$ 4,441,608
T&D Labor	$ 674,000
Traveler Labor	$ 2,080,159
Total Labor	**$ 7,195,767**
EMPLOYEE EXPENSES & OTHER	
Employee Expenses	$ 688,318
Total Empl/Oper	**$ 688,318**
CONTINGENCY - Mainly related to uncertainty from inspection discovery and possible emergent issues	**$ -**
GRAND TOTAL	**$ 9,903,036**

Monticello Nuclear Generating Plant

Outage Labor Costs - Refueling Outage 30 (1R30) - Spring 2021 Actual

Sum of Amount Description	XE1_CE_Tier1	Cost Cente	Labor Description	Total
Base Labor	**1 Labor**	100607	MT Site Management	73
		100610	MT Quality Control	78
		100612	MT Plant Mgmt	-25
		100613	MT Chemistry	-1,517
		100617	MT Planning	389
		100620	MT Radiation Protection	26,583
			MT Radiation Prtctn	-112,567
		100623	MT Outage	1,041
		100632	MT Licensing	-74
		100633	MT Strategic & Prgms	39
		100637	MT Eng Strat/Prgms	269
		100639	MT Engineering Dsgn	14
		100643	MT Doc Cntrl Procur	310
		100645	MT Admin Svcs	147
		102759	MT NGS Cnstr - B	100,711
		102804	MT Shift Ops - Barg	-147,937
		102805	MT Mnt-Inst&Cnt-Bg	5,852
		102806	MT Maint-Elec - Barg	4,119
		102807	MT Maint-Mech- Barg	143,664
		102808	MT Maintenance Fac	1,057
		102916	MT Mtce Elec	357,881
		102917	MT Maint Fac	13
		102918	MT Mtce I&C	-867
		102919	MT Maint Support	4,665
		102920	MT Shift Ops	-2,279
		102921	MT Maint-Mech	-127,182
		103068	MT EFIN Elect	-485
		103069	MT EFIN Mech	-22
		103078	Component Maint	162
		300834	Final Bus Suppt MT	2,328
	1 Labor Total			**256,440**
Base Labor Total				**256,440**
Other Comp	**1 Labor**	102759	MT NGS Cnstr - B	121,208
		102916	MT Mtce Elec	5,784
		102919	MT Maint Support	565
		102921	MT Maint-Mech	106
	1 Labor Total			**127,662**
Other Comp Total				**127,662**
Overtime	**1 Labor**	100607	MT Site Management	149,697
		100610	MT Quality Control	12,537
		100611	MT Perform Improv	7,453

Overtime	**1 Labor**	100612	MT Plant Mgmt	3,627
		100613	MT Chemistry	163,884
		100617	MT Planning	188,374
		100620	MT Radiation Protection	606,875
			MT Radiation Prtctn	-163,188
		100623	MT Outage	71,080
		100624	MT Scheduling	71,811
		100632	MT Licensing	8,134
		100633	MT Strategic & Prgms	85,769
		100637	MT Eng Strat/Prgms	98,241
		100639	MT Engineering Dsgn	14,433
		100643	MT Doc Cntrl Procur	2,013
		100645	MT Admin Svcs	41,864
		100649	MT Security	7,444
		102759	MT NGS Cnstr - B	165,505
		102804	MT Shift Ops - Barg	719,940
		102805	MT Mnt-Inst&Cnt-Bg	454,366
		102806	MT Maint-Elec - Barg	348,398
		102807	MT Maint-Mech- Barg	1,142,081
		102808	MT Maintenance Fac	122,962
		102916	MT Mtce Elec	407,759
		102917	MT Maint Fac	16,970
		102918	MT Mtce I&C	24,283
		102919	MT Maint Support	11,242
		102920	MT Shift Ops	240,613
		102921	MT Maint-Mech	28,673
		103068	MT EFIN Elect	-534
		103069	MT EFIN Mech	82,357
		103078	Component Maint	47,335
		300834	Final Bus Suppt MT	22,786
	1 Labor Total			**5,204,781**
Overtime Total				**5,204,781**
Premium	**1 Labor**	100610	MT Quality Control	2,331
		100612	MT Plant Mgmt	465
		100613	MT Chemistry	83,923
		100617	MT Planning	6,086
		100620	MT Radiation Protection	259,314
			MT Radiation Prtctn	-72,883
		100623	MT Outage	1,596
		100643	MT Doc Cntrl Procur	333
		100645	MT Admin Svcs	11,689
		102804	MT Shift Ops - Barg	446,447
		102805	MT Mnt-Inst&Cnt-Bg	239,055
		102806	MT Maint-Elec - Barg	170,585
		102807	MT Maint-Mech- Barg	374,384
		102808	MT Maintenance Fac	52,374
		102916	MT Mtce Elec	38,406

Premium	**1 Labor**	102918	MT Mtce I&C	447
		102919	MT Maint Support	3,030
		102920	MT Shift Ops	457
		102921	MT Maint-Mech	-11,671
		103068	MT EFIN Elect	-267
		103069	MT EFIN Mech	-59
		300834	Final Bus Suppt MT	841

Prairie Island Unit 2 - Fall 2021 Outage Budget

Cost Description	Total Cost
[PROTECTED DATA BEGINS…	
CONTRACTORS	

...PROTECTED DATA ENDS]

GRAND TOTAL	**$ -**

Prairie Island Nuclear Generating Plant

Outage Labor Costs - Unit 2 Refueling Outage 32 (2R32) - Fall 2021

[PROTECTED DATA BEGINS…

Cost Center	Cost Center Description	Total
100653	PI Site Management	
100654	PI Employee Concerns Prog	
100656	PI Quality Control	
100658	PI Plant Management	
100659	PI Chemistry	
100660	PI Chemistry Tech Sup	
100661	PI Chemistry Operations	
100666	PI Maintenance Support	
100669	PI Planning	
100670	PI Radiation Protection	
100671	PI Raditaion Protection Support	
100672	PI Radiation Protect Operations	
100676	PI Operations Support	
100677	PI Work Control Center	
100679	PI Outage	
100680	PI Scheduling	
100686	PI Training Maintenance	
100689	PI Licensing	
100692	PI Eng FIN Mechanical	
100695	PI Engineering Systems	
100701	PI Engineering Programs	
100705	PI Engineering Design	
100707	PI Eng FIN Electrical	
100711	PI Doc Control and Procedures	
100713	PI Administration Services	
100715	PI Emergency Planning	
100717	PI Security	
102799	PI Shift Operations- Bargaining	
102800	PI Maint-Instr&Cntrl - Bargaining	
102801	PI Maint-Electrical - Bargaining	
102802	PI Maint-Mechanical - Bargaining	
102803	PI Maint-Facilities - Bargaining	
102924	PI Maint-Electrical	
102925	PI Maint-Instr&Cntrl	
102926	PI Maint-Mechanical	
102927	PI Maint-Facilities	
102928	PI Shift Operations	
103081	PI Maintenance-FIN	
300837	PI Business Support-Final	
Grand Total		

…PROTECTED DATA ENDS]

Prairie Island Unit 1 - Fall 2022 Outage Budget

[PROTECTED DATA BEGINS…

Cost Description	Total Cost

…PROTECTED DATA ENDS]	
GRAND TOTAL	$28,834,337.48

Prairie Island Nuclear Generating Plant

Outage Labor Costs - Unit 1 Refueling Outage 33 (1R33) - Fall 2022

[PROTECTED DATA BEGINS…

Cost Center	Cost Center Description	Total
100585	HQ Training	
100653	PI Site Management	
100654	PI Employee Concerns Prog	
100656	PI Quality Control	
100657	PI Perform Improvement	
100658	PI Plant Management	
100659	PI Chemistry	
100660	PI Chemistry Tech Sup	
100661	PI Chemistry Operations	
100666	PI Maintenance Support	
100669	PI Planning	
100670	PI Radiation Protection	
100671	PI Raditaion Protection Support	
100672	PI Radiation Protect Operations	
100676	PI Operations Support	
100677	PI Work Control Center	
100679	PI Outage	
100680	PI Scheduling	
100684	PI Training Operations	
100685	PI Training Technical	
100686	PI Training Maintenance	
100688	PI Training Support	
100692	PI Eng FIN Mechanical	
100695	PI Engineering Systems	
100701	PI Engineering Programs	
100705	PI Engineering Design	
100707	PI Eng FIN Electrical	
100711	PI Doc Control and Procedures	
100713	PI Administration Services	
100715	PI Emergency Planning	
100717	PI Security	
102799	PI Shift Operations- Bargaining	
102800	PI Maint-Instr&Cntrl - Bargaining	
102801	PI Maint-Electrical - Bargaining	
102802	PI Maint-Mechanical - Bargaining	
102803	PI Maint-Facilities - Bargaining	
102924	PI Maint-Electrical	
102925	PI Maint-Instr&Cntrl	
102926	PI Maint-Mechanical	
102927	PI Maint-Facilities	
102928	PI Shift Operations	

103081	PI Maintenance-FIN
103082	PI Component Maintenance
Grand Total	

…PROTECTED DATA ENDS]

NRC Oversight and Performance Ratings

NRC Reactor Oversight Process (ROP) and Action Matrix

The NRC has instituted a Reactor Oversight Process (ROP) to evaluate the safety and security performance of the nuclear power reactors in the U.S.[1] The NRC's ROP uses seven "cornerstones" to describe the essential features of its strategic performance areas: reactor safety, radiation protection, and security[2]. Performance in these cornerstones is assessed on a quarterly basis using nearly 20 discrete performance indicators reported by the reactor owners, supplemented by findings from NRC inspections. The link between the assessment component of the ROP and mandated NRC responses is called the Action Matrix.

The Action Matrix features five columns of performance, as rated by the NRC:

- **Column I** - When the performance indicators and inspection findings all fall in expected ranges, a reactor is placed in Column I, or "Licensee Response," reflecting the fact that the licensee takes responsibility for addressing these minor problems and the NRC continues with its normal inspections.
- **Column II** - If performance in a cornerstone drops a little below expectations, the reactor moves into Column II "Regulatory Response," reflecting the fact that the NRC now responds by increasing inspections.
- **Column III** - If performance drops further in a cornerstone or declining performance is detected in another cornerstone, a reactor moves into Column III, "Degraded Cornerstone," where the ROP mandates additional NRC inspections.
- **Column IV** - If declining performance deepens and/or broadens, a reactor moves into Column IV, "Multiple/Degraded Cornerstone," where the NRC takes further action.
- **Column V** - If performance problems reach epidemic proportions, a reactor enters Column V, "Unacceptable Performance," and is shut down by the NRC.

[1] The NRC has summarized its *Reactor Oversight Process* in a diagram included as Attachment A.

[2] The NRC's cornerstones are listed on Attachment B, the NRC's *Reactor Oversight Framework*.

NRC Ratings for Inspection Findings and Performance Reviews

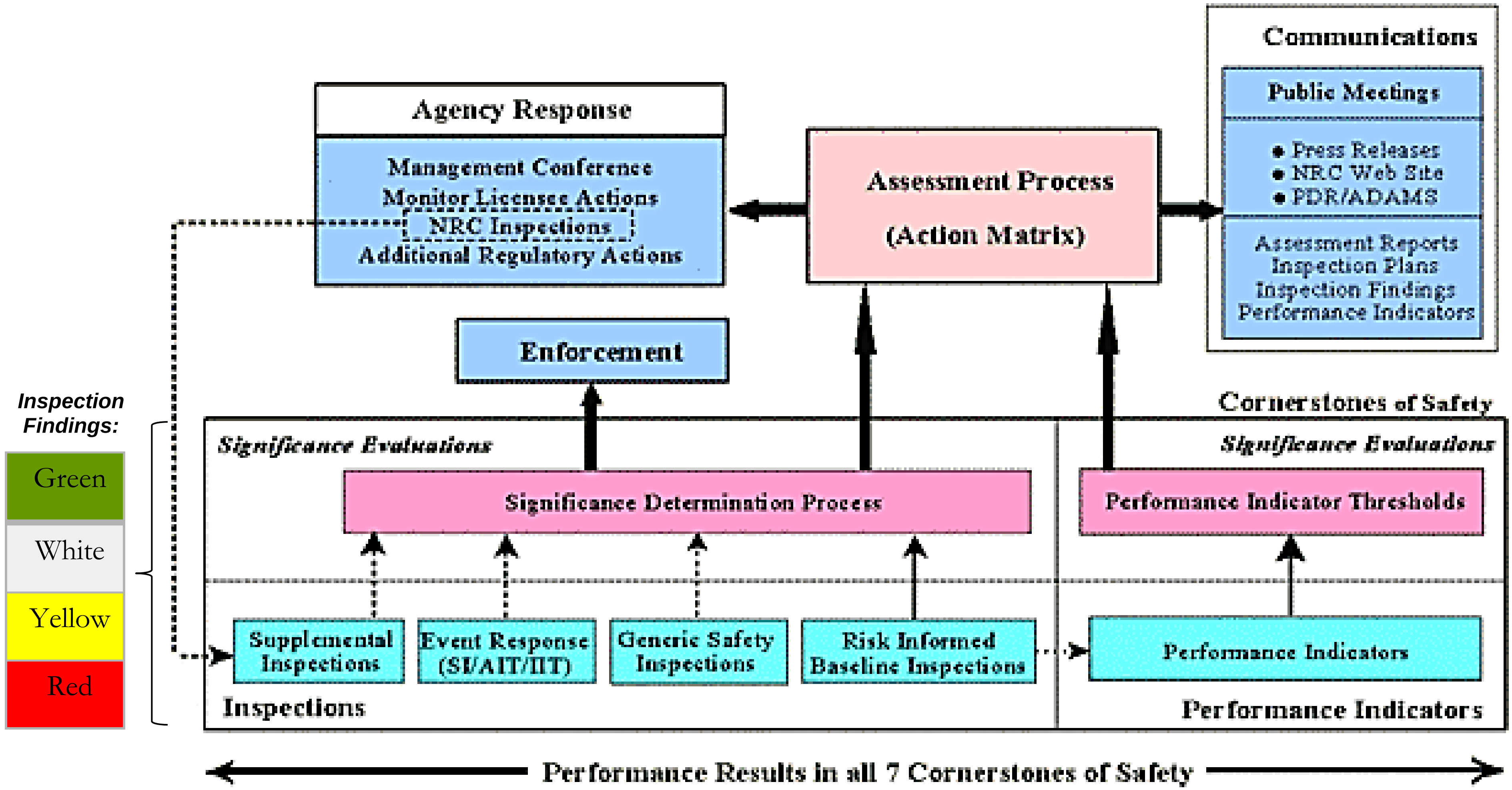
The NRC uses a color-coding scheme to rank the level of concern for issues it identifies for nuclear operators, either through inspections or through review of quarterly performance reporting. These rankings range as follows:

- **Green** - lowest level of concern
- **White** – second lowest level of concern
- **Yellow** – second highest level of concern
- **Red** - highest level of concern

The number and severity of issues identified for a plant unit at a point in time determine its Column rating under the ROP Action Matrix. For example, if only green (lowest level) issues are outstanding, the unit remains at Column I. If a single white finding/issue is outstanding, the unit is moved to Column II and requires more NRC oversight and inspections until the issue is considered resolved, or "closed". If multiple white findings, or a single yellow finding, is outstanding, the unit is moved to Column III, with more oversight and inspections, and so on.

The column status of a nuclear unit remains in place for each calendar quarter, and is only moved upward (i.e. from II to I) at the beginning of the next quarter after an outstanding issue is closed by the NRC. Column status can move downward (e.g. from I to II) immediately when an issue is officially determined by the NRC to be outstanding. The NRC has an appeals and review process for operators to challenge a proposed inspection or performance review finding, including conferences, public hearings and other procedures. The NRC does not announce the official change in column status for a unit until after this process concludes.

NRC's
REACTOR OVERSIGHT PROCESS



NRC's
REGULATORY FRAMEWORK