STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-cycle Management/ Extended Power Uprate Project and Request for Recovery of Cost Overruns	MPUC Docket No. E002/CI-13-754 OAH Docket No. 48-2500-31139

XCEL ENERGY'S
INITIAL BRIEF

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I. INTRODUCTION AND SUMMARY

Northern States Power Company, d/b/a Xcel Energy ("Xcel Energy" or the "Company") submits its Initial Brief in this prudence investigation of the Life-Cycle Management ("LCM") and Extended Power Uprate ("EPU") program ("LCM/EPU Program", "Program") at the Monticello Nuclear Generating Plant ("Monticello" or the "Plant"). For the reasons provided in this Initial Brief, we respectfully request the Commission and ALJ find that the Company's decisions regarding the Program were prudent and that no disallowance of Program costs is appropriate.

The LCM/EPU Program is a long-term project which installed 10 major modifications to facilitate the continued safe and reliable operation of Monticello until at least 2030, while also achieving an additional 71 MW of carbon-free baseload capacity. Since the overall Program required modifying or replacing many of the same pieces of equipment for life extension and power uprate, the LCM/EPU Program was pursued as an integrated initiative. Construction began in 2009 and the installations completed during the 2013 refueling outage. The Company also received in 2013 and 2014, the license amendments necessary to operate at uprate conditions from the Nuclear Regulatory Commission ("NRC").

We initially estimated that the Program costs would be about $346 million ($2008$) without AFUDC. The installed costs were ultimately $665 million, roughly double what we estimated in 2008. We recognize that this disparity between estimated and actual costs raises questions with respect to our implementation of the Program. In fact, in our recent electric rate cases, our stakeholders, including the Department of Commerce and Xcel Large Industrials raised concerns about the prudency of the Program costs. Consequently, the Commission initiated this proceeding.

When initiating this investigation, the Commission specifically asked that the following three issues be addressed:

- whether Xcel Energy's handling of the LCM/EPU was prudent;
- whether the Company's request for recovery of the Monticello LCM/EPU project cost overruns is reasonable; and
- which cost increases are due 1) solely to the EPU, 2) solely to the LCM and 3) both projects.[1]

We believe the record has been developed so that each of the issues posed by the Commission can be thoroughly addressed.

In addition to having a thorough record, in order to address these issues, it is necessary to consider our decisions and actions at the time and under the circumstances they were made, consistent with the appropriate legal standard. When this is done, the only conclusion that can be reached from this record is that the Company's decision to embark on the Program was prudent; the Company's management and implementation of the Program was prudent; and it is unnecessary to allocate the costs between the LCM and EPU components.

To develop this record, the Department and the Office of Attorney General have actively participated in this proceeding. XLI is a party but did not file any testimony. Both the Department and OAG recommend significant disallowances; however, neither party takes into account the Company's decisions at the time and under the circumstances they were made, as is required under the appropriate legal standard. Instead they use hindsight and the assumption of some mismanagement because the costs doubled from what was estimated for modeling in the Certificate of Need.

The Department is recommending an approximately $71 million disallowance. The Department supports its recommendation with the testimony of their retained expert,

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[1] *In the Matter of a Comm'n Investigation into Xcel Energy's Monticello Life Cycle Mgmt./Extended Power Uprate Project and Request for Recovery of Cost Overruns,* Docket E/002-CI-13-754, ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING, p. 3 (Dec. 18, 2013).

Mr. Mark W. Crisp, who relied on only a single document in the record to generally opine that the Program was not managed well. Yet Mr. Crisp specifically declined to find any of the Company's costs were imprudent.[2] The Department also raises concerns about the Company's general operation of Monticello, regulatory communications, and the accounting methodology used to track the Program costs. The Department calculated its proposed remedy by relying upon a cost allocation analysis performed by its other expert, Dr. William R. Jacobs Jr. This split analysis is based on hindsight and relies on a single document in the record to the exclusion of many other contemporaneous documents.[3]

The OAG recommends an approximate $320 million disallowance, along with stripping away the Company's opportunity to earn a return on all capital costs over the Certificate of Need estimate, a remedy that is disproportionate and unsustainable.[4] The OAG relies solely on Mr. Crisp's testimony, who does not opine whether the Company was prudent or imprudent. Simply put the OAG did not do any independent analysis of the Company's decisions regarding the LCM/EPU Program.

While we appreciate the temptation to draw similar conclusions, we remain steadfast in our belief that a thorough examination of our performance will confirm that our actions were prudent given the facts and information reasonably available at the time.

The balance of our Initial Brief is organized as follows:

- *Overview* – for context we provide a high-level, holistic backdrop against which the Company made its decision to embark on the LCM/EPU, as well implemented the Program.

- *Standard of Review* – we provide the applicable legal standards that must be used.

[2] Tr. Vol. III (Crisp) at 22:21-23.

[3] Tr. Vol. III (Jacobs) at 121:1-18.

[4] Ex. 15, Alders Surrebuttal at 24:15-16.

- *Company's Affirmative Case* – we demonstrate the prudence of our decisions by applying the relevant facts in the record to the standard of review; we utilize the following five key questions as the guidepost for this discussion:
    - Was our decision to embark on the Program prudent?
    - Did we build the right project?
    - Why did our costs double?
    - Did we prudently manage and implement the Program?
    - Is the split still relevant?
- *Response to Criticisms* – we rebut the current positions of the Department and OAG.

II. OVERVIEW

Prior to and throughout this proceeding, the Company has maintained that its decisions regarding the Monticello LCM/EPU Program have been prudent. As a result, the Company believes that there should not be any disallowance for imprudence of the approximately $665 million spent on this Program.

With that said, the Company recognizes that it may be not feel quite right to allow 100 percent of our cost increases in customer's rates and that when costs increase by this magnitude, that somewhere along the line the Company must have failed in its duty to make prudent decisions.

The Company believes that considering the context in which the Program was developed and implemented, the applicable legal standard and, most importantly, the substantial evidence of reasonable decisions the Company made throughout the Program, the Commission can move beyond finding mismanagement simply because costs went up. We believe the record is clear that we met our burden of showing that the costs we incurred were necessary and appropriate as they resulted from reasonable decisions based on the information knowable at the time. This may not feel like a satisfying result, but it is the right one under the circumstances.

As it pertains to context, the Company conceived of the overall LCM/EPU Program in the 2003-08 timeframe. At that time, which was after 9/11 but before the Great Recession, the State of Minnesota was experiencing positive financial growth. Our demand forecasts confirmed the growth was significant, and required preservation of existing baseload resources and the addition of significant new capacity in the near term to maintain reliability. In that era of high natural gas prices, our Resource Plans confirmed the need for significant baseload capacity additions, beyond retaining the existing low cost energy resources such as Monticello.

The State's attitude toward extending the use of nuclear generation also was thawing. This shift in attitude coincided with a national renaissance in the nuclear industry which indicated nuclear generation was once again a long-term base load generation option. Natural gas, on the other hand, was not in favor and natural gas prices were hovering between $8 and $10 per MMBTU in 2006-08 while our uprate request was being developed and considered.

All of these factors supported moving forward with the LCM/EPU Program. In fact, we were not the only nuclear operators advancing license extension and up-rate projects against this backdrop. Many such projects had been completed prior to the rollout of our effort and the generally positive experience of those projects influenced our thinking and decision making.

Over the decade that has transpired since we embarked on the LCM/EPU Program, the landscape against which we finished developing and implementing the Program changed dramatically. From a macroeconomic perspective, as we were beginning to implement the Program, the country experienced the worse financial market set-back since the Great Depression. During that same period, horizontal drilling and hydraulic fracturing ("fracking") led to a steep and sustained decline in natural gas prices, and technology changes also substantially reduced the cost of renewable resources in this same timeframe. But this information was not available in 2008 and based on what was reasonably known at the time, moving forward with the Program created substantial benefits for our customers.

Further, owning, operating, maintaining and constructing nuclear power plants has become significantly more complicated and more expensive. This inescapable fact has been borne out, not only by our experience, but by the experience of several other utilities who undertook this type of work at the same time as us and who had similar cost increases to what we experienced.

For example, three years prior to the incident at Fukushima Daiichi, the federal nuclear regulatory environment was in the process of gradually applying its oversight in a more intensive and comprehensive manner than in the years before 2008. As we explain later in this Initial Brief, we believe this to be important because many new regulations and interpretations were implemented and the application of existing regulations were held to an ever higher standard, and these had impacts both directly and indirectly on our ultimate Program costs. After the incident at Fukushima Daiichi in 2011, this new trajectory of federal oversight became an even more confirmed part of our new reality as a nuclear operator.

The nuclear industry also experienced significant workforce retirements at all levels. As a result, the quality of work from engineering design to craft labor was substantially less experienced than in the past. This degraded design and equipment quality contributed to loss of productivity on the implementation effort. New "fatigue" rules from the NRC limited the work hours on nuclear projects which required replacing staff and performing additional training to new personnel.

The evolving nuclear labor market was also affected by Monticello's configuration as a 'boiling water reactor,' which caused much of the work we had to do be performed in radiological or "hot" zones. It often required our workers to install equipment in very confined spaces not easily accessible for construction. This dynamic of working in such a difficult environment, when combined with the fact that we had less experienced and more turnover in craft labor, had a material impact on the productivity of our work-force.

These broader landscape changes have become a fabric of the lens through which we evaluate resource choices; making it more difficult to recall the environment in which the LCM/EPU Program was conceived, designed and installed. Many of these evolutionary changes became tangible only after implementation had gone beyond the point of no return. Additionally, other nuclear operators that embarked on and implemented these projects during the same time frame experienced similar cost increase trends. Other similarly-sized efforts during the same time had similar experiences to ours.[5] These changes are important in understanding that our cost increases does not lead to a conclusion that there was any imprudence.

In addition to the change in context, application of the relevant legal standard is integral to understanding the Company's perspective that significant increase in costs should not lead to any finding that the Company was imprudent. The applicable legal standard is the prudent investment standard, which focuses on allowing recovery of costs when the utility made reasonable decisions, regardless of the after the fact outcome of the decisions. The law recognizes that in order to recover all of its costs the utility is not required to have acted perfectly and as a result the test focuses more on the process and decisions that were made based on what was knowable at the time. Hindsight about factors such as the ultimate cost should not be the focus in a

[5] Exhibit 3, O'Connor Direct at 24:11 and Table 3.

prudence analysis. And the fact that a party is dissatisfied with the conduct of a public utility does not meet the test for costs to be disallowed.

The prudence standard is similar to a negligence standard and there must be a causal connection between the concerns raised and some actual harm to customers, in the form of higher costs than necessary, not just higher costs than expected. This will eliminate from consideration many of the concerns raised in this proceeding such as the current NRC concerns about general plant operations; the manner of accounting for costs; or the communications with the Commission. It also makes claims about what the Company should have better anticipated with respect to higher costs less relevant to the inquiry over the management of the initiative.[6]

And while context and the law are helpful in becoming comfortable with our ultimate costs, the most important aspect of any Commission decision is whether there is substantial evidence that supports the reasonableness of costs and decisions that were made. The Company has created a very detailed and complete factual record supporting our request to obtain cost recovery. We believe that the Commission should determine that we met the applicable burden of proof. In making that finding, the following four critical elements are important:

The Initial Decision to Move Forward Was Prudent: The Company provided testimony supporting the reasonableness of the development of its initial cost estimates. We relied on General Electric (the Plant's designer and original equipment manufacturer), which is consistent with industry practice. The Company went through the process of formal and informal benchmarking against other projects that had been performed in the early part of the decade and provided this Commission with a cost-estimate that

[6] As Dr. Jacobs acknowledged, "St. Lucie and Turkey Point were significantly more than the cost increases at Monticello, but they had the same -- similar challenges." Tr. Vol. III (Jacobs) at 105:2-5. Despite all of the challenges encountered in Florida and despite Dr. Jacobs recommending significant disallowances in the Florida proceedings, FPL was authorized to recover 100 percent of its costs. Tr. Vol. III (Jacobs) at 105:19.

was 75% higher than any of the highest of the benchmarked projects. The Company refined its estimate to a high end estimate of $346 million ($2008$). While we believe our estimate presented to the Commission was reasonable, the Company also provided an assessment of items where it could have done a more robust and conservative estimate and targeted a range of reasonably foreseeable costs of $360-$420. While the Department consultants were critical of the high level nature of initial cost estimate, they did not dispute the high-end estimate we provided.

Based on the highest reasonably knowable cost estimate and the 58.4/41.6 percent LCM/EPU split used for modeling alternatives in the 2008 Certificate of Need proceeding, the Program was cost effective both as a whole and for the EPU portion alone. That cost split was reasonable and, in fact, was conservative, as borne out by (i) contemporaneous documents; (ii) our after-the-fact avoided-cost analysis; and (iii) our substantial evidence on the need to replace the aging equipment at the Plant to obtain the benefit of an additional 20 years of operation. We also demonstrated that Dr. Jacob's 85% assignment of costs to the EPU effort was (i) biased in favor of assigning as many costs as possible to the EPU; (ii) ignored contemporaneous documents contradicting his position; (iii) ignored the condition of the facility; and (iv) contradicted the approach he took in a different jurisdiction.

We Constructed the Right Project: The Company's nuclear team had two overriding objectives: make improvements that would extend the life of the Plant for an additional 20 years; and increase the output of the facility by 71 MWs. To achieve the first objective, we focused on recapturing safety margin that had been lost due to age and condition of equipment in the Plant. The Company showed that it had not made substantial investments in the Plant because of Minnesota law prior to 2003 that prohibited long-term nuclear operations. After the nuclear moratorium was lifted we identified many components that needed to be replaced for lifecycle management in our long range plan. For example, we needed to expand our distribution capacity as the addition of electrical loads over the years had left us with essentially no margin. This led to the 13.8 kV project which while costly to implement was essential to the long-term safe operations of the Plant. Simply put, we wanted to address equipment that was not performing well.

While the scope seems large, the Company wanted to ensure that the Plant would be able to operate effectively through at least 2030 without risking the extended license if major investments were required later in the remaining life. Acceleration of some components to avoid this risk and capture depreciation over a longer period of time, was a good choice. While some of this work was necessarily modified to achieve the uprate potential, it was the condition of the old equipment, and not the uprate that drove the large majority of our costs. Hence, the reason why we approached the Program as an integrated effort. From that perspective, the State and our customers obtained a carbon-free baseload resource for roughly $1,000/kW from this effort.

We Explained Why Costs Increased: We provided evidence of the cost increases for each of the 10 major modifications as well as for the various contributors to these projects, such as materials; design and implementation. Three primary drivers were identified: (1) the impact of a changing nuclear regulatory environment; (2) the shortage of experienced labor at all levels and the impact of this and the difficulties of the Monticello facility on the implementation effort; and (3) the evolving scope of the work required. Several of these are overlapping and thus it is not easy to quantify a specific cost overrun to only one of these categories.

- *Nuclear Regulatory Environment:* We described the impact of the evolving regulatory environment as described above. While we agree with the Department that the NRC is properly focused on nuclear safety, the record reflects that this focus comes at a significant and increasing cost.

- *Evolving Scope of the Project*: The scope of the project evolved as the Company made design choices to support overall Plant viability. We also encountered circumstances that were not knowable until we completed detailed design work and many changes became known during the actual course of construction. And we had to deal with interferences that could not be identified ahead of time. These are typical of major reconstruction projects, and contributed to our ultimate costs.

- *Difficulty in Workforce and Conditions:* We explained how workforce challenges impacted our effort and the entire industry, as described above. While the Department is critical that we should have known about these conditions, they do not dispute that these factors were real contributors to our ultimate costs.

The Company Made Good Decisions Along the Way: This question is probably the most important and contentious one among the parties. The Company provided a chronology of key decisions and why it made them. The Department and OAG (through the testimony of Mr. Crisp) criticized our overall management but acknowledged that costs can increase without any imprudence. Of the key management decisions, three stand out and are discussed in more detail below:

- *The Selection Of General Electric to Assist with Design:* General Electric designed the Plant. It had proprietary information regarding the Plant and had developed the topical reports supporting the uprate of boiling water reactors. Consequently, starting with GE was the only rational decision.

- *The Decision To Move Forward in the 2009 Outage:* This decision was made by the nuclear group in conjunction with our resource planning group. The resource plan at the time identified a need for over 1000 MW of new baseload resources and natural gas prices from 2005 through 2008 were both substantially higher and more volatile than today. The potential to move forward in 2009 offered the opportunity to meet capacity needs and avoid higher energy prices.

    - Our ability to be ready by 2009 required moving forward on certain designs and pre-ordering of equipment, but a later schedule beginning in 2011 would not have lessened any of the work effort done in this period.

- In fact as designs and equipment came through that did not meet the high quality assurance standards of the team, we rejected them. We added a third outage to ensure quality and success. The work got done right and there have not been equipment issues, further evidence that the project was not rushed and was prudently constructed.

- *Decisions Associated with Vendors:*

  - The Company received bids for installation services from General Electric/Shaw and from Day Zimmerman/Sargent & Lundy. We determined that Day Zimmerman offered more experience in implementation work and Mr. Crisp did not criticize this choice, agreeing that construction is not within General Electric's "wheelhouse."

  - The Company retained Day Zimmerman for the 2011 outage as the 2009 outage went smoothly and Mr. O'Connor personally met with Day Zimmerman executives to assess their prior performance.

  - After the 2011 outage, we determined the remaining complex modifications called for greater coordination skills so we brought in Bechtel, an internationally-recognized firm, to coordinate the final installations. To provide continuity, Bechtel retained Day Zimmerman as the lead mechanical subcontractor. The Company provided evidence that overall productivity based on the cost per outage day from the 2011 and 2013 outages for these key contractors were virtually the same. We also demonstrated that both Day Zimmerman and Bechtel faced challenges in meeting the projected outage cost and duration.

  - The Company hired different design contractors when needed. We provided an analysis of these costs and the limited amount of dollars that were within the scope of the original GE contract.

  - Reviewing the status of contractor work and the availability of alternatives, demonstrates active and prudent management oversight of the project intended to reduce overall project costs.

Finally, despite incurring higher costs than we anticipated, the overall initiative has achieved significant benefits to our customers, communities and the State, including:

- an additional 20 years (from the 2010 original license expiration) of carbon-free, baseload generation at about $1,000/kW installed.[7]

- a valuable hedge against evolving fossil-fuel regulations that make new coal plants infeasible and may require existing plants to shut down.[8]

- maximizes the use of existing infrastructure and takes advantage of the substantial transmission system in the area.[9]

- contributes to the diversity of our fuel mix and reduces our reliance on historically volatile natural gas and market energy.[10]

- several hundred high-quality craft labor and other jobs, both for general operations and during our periodic refueling outages.[11]

We also made the Plant safer and more reliable for our employees, communities and stakeholders.

- We made the new systems compatible with prior protocols for the benefit of Plant operators,[12] and restores and increases safety margins and reduces the likelihood of trips and forced outages.[13]

- Replacement of components near the end of their useful lives improves reliability,[14] and directly lower the operating and maintenance costs.[15]

- While we do not currently have authority to operate Monticello beyond 2030, our work positions us well for potential future life extensions.[16]

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[7] Ex. 12, Sparby Rebuttal at 4:19-21.

[8] Ex. 9, O'Connor Rebuttal at 3:17-24.

[9] Ex. 2, Alders Direct at 3:14-16.

[10] Ex. 2, Alders Direct at 3:16-19.

[11] Ex. 12, Sparby Rebuttal at 5:8-11.

[12] Ex. 3, O'Connor Direct at 143:12-13.

[13] Ex. 3, O'Connor Direct at 143:17-22.

[14] Ex. 3, O'Connor Direct at 144:7-12.

[15] Ex. 3, O'Connor Direct at 143:26-144:2.

[16] Ex. 9, O'Connor Rebuttal at 9:21-10:11 and Schedule 2. The NRC is currently reviewing the issues surrounding the potential for civilian nuclear reactors continuing operations after 60 years.

In closing, we respectfully believe that while it is understandable to presume that the significant cost increases suggest a remedy is needed, there is not a record to support any adjustment. When the overarching context and legal standard is properly considered applied to this record, we believe we have satisfied our burden of proof that we acted prudently in undertaking and managing the project. Our position of finding that no disallowance is appropriate and should be accepted.

III. STANDARD OF REVIEW

We begin our analysis by setting forth the nature and scope of the applicable standard of review – the prudent investment standard. We also provide a brief discussion of the applicable burden of proof and the application of that burden to this record.

A. The Prudent Investment Standard

The prudent investment standard focuses on compensating a utility "for all prudent investments at their actual cost when made (their 'historical' cost), irrespective of whether individual investments are deemed necessary or beneficial in hindsight."[17] It does not erect an insurmountable barrier to cost recovery or use hindsight or expect perfection. Performance need only be within a "zone of reasonableness."[18]

> The term "prudent investment" is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures.[19]

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[17] *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 309 (1989).

[18] *See Fed. Power Comm'n v. Conway Corp.*, 426 U.S. 271, 278 (1976).

[19] *State ex rel. Sw. Bell Tel. Co. v. Pub. Serv. Comm'n of Mo.*, 262 U.S. 276, 289 n.1 (1923) (Brandeis, J., concurring).

The Minnesota Supreme Court has likewise noted that "[r]easonableness is a concept of some flexibility and moderation, not exclusivity; a determination that one course of conduct is reasonable is not a determination that any other course is unreasonable."[20]

The prudent investment standard: (i) requires review of the information the utility knew or should reasonably have known at the time decisions were made, and not hindsight;[21] (ii) considers the process, rather than the results;[22] (iii) addresses only events over which the utility had control;[23] and (iv) imposes a remedy only if imprudence proximately caused damages to customers.[24]

Notably, the Department and OAG do not specifically find imprudence and do not find specific damages. Neither Mr. Crisp nor Dr. Jacobs do not identify even a range of costs that would have been saved if the Company had made any decision differently. While the parties claim tying imprudence to damages is difficult, a

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[20] *Application of Peoples Natural Gas Co.*, 389 N.W.2d 903, 908 (Minn. 1986).

[21] *Gulf States Utils. Co. v. La. Pub. Serv. Comm'n*, 578 So.2d 71, 85 (1991); *see* 73B C.J.S. Public Utilities § 45 (2004) (stating that "[w]hether or not the investment was prudent must be determined as of the time when it was made"); *In re GPU, Inc.*, 96 Pa. P.U.C. 1, 91-92 (Jun. 20, 2001); *In re Long Island Lighting Co.*, 24 N.Y.P.S.C. 4927, at *6 (Aug. 19, 1981); *Pa. Pub. Util. Comm'n v. Philadelphia Elec. Co.*, 71 Pa. P.U.C. 42 (1989) (noting that the Commission "must assess the reasonableness of a utility's decision-making based on the state of information available when decisions had to be made and without reliance on hindsight.").

[22] *Gulf States Utils. Co.*, 578 So. 2d at 85; *see Kuhl v. Heinen*, 672 N.W.2d 590 (Minn. Ct. App. 2003) (stating that the duty to exercise care is dictated by the exigencies of the occasion, and if no harm is foreseeable, there can be no negligence); *In re GPU, Inc.*, 96 Pa. P.U.C. at 91-92.

[23] *Gulf States Utils. Co.*, 578 So.2d at 85 (citing *Metzenbaum v. Columbia Gas Transmission Corp.*, 4 FERC 61,277 (1958)).

[24] *See Potomac Elec. Power Co. v. Pub. Serv. Comm'n of the Dist. of Columbia*, 661 A.2d 131, 141-42 (D.C. 1995); *State ex. rel. Associated Nat. Gas Co. v. Pub. Serv. Comm'n of the State of Mo.*, 954 S.W.2d 520, 530 (Mo. Ct. App. 1997) (stating that to disallow a utility's recovery costs from its ratepayers, a regulatory agency must find that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers); *New England Power Co.*, 31 FERC 61,047 at 61,089 n.38 (noting that the issue of the utility's prudence was relevant only if it caused harm to the utility's consumers). This principle is comparable to the negligence standard in that, even if imprudence is found, a cost disallowance is not permitted unless the imprudence is the real and proximate cause of injury. *See Pa. Pub. Util. Comm'n v. Duquesne Light Co.*, 63 Pa. P.U.C. 337, 352 (1987); *In re GPU, Inc.*, 96 Pa. P.U.C. at 91-92 ("Even if imprudence is found, a cost disallowance cannot be justified unless the utility's imprudent conduct was the real and proximate cause of some injury to customers."); *Pa. Pub. Util. Comm'n v. Philadelphia Elec. Co.*, 71 Pa. P.U.C. 42, 45-46 (Pa. P.U.C. 1989).

disallowance is not sustainable if there is no imprudence, let alone a tie between imprudent actions and higher costs.

B. Burden of Proof

The general rule is that "the burden of proof rests on the party seeking to benefit from a statutory provision."[25] The burden of proof generally has two aspects: "the burden of persuasion and the burden of producing evidence."[26] Both are important.

Although the burden of proof acts as a shield against customers paying unreasonable rates, it does not create a sword that reduces the utility's recovery of legitimate and reasonable costs. Nor does it create an insurmountable burden.[27] It does not allow parties to reject evidence simply by asserting the they are not convinced or making

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[25] *C.O. v. Doe*, 757 N.W.2d 343, 352 (Minn. 2008); *Reliance Life Ins. Co. v. Burgess*, 112 F.2d 234, 238 (8th Cir. 1940) ("It is a fundamental rule that the burden of proof in its primary sense rests upon the party who, as determined by the pleadings, asserts that the affirmative of an issue and it remains there until the termination of the action. It is generally upon the party who will be defeated if no evidence relating to the issue is given on either side.").

[26] 11 Minn. Prac., Evidence § 301.01, at 128 (4th ed. 2012). *See also Schaffer ex. rel. Schaffer v. Weast*, 546 U.S. 49, 56 (2005) (determining which party bears the burden of proof in an administrative hearing); *Stockton E. Water Dist. v. United States*, 583 F.3d 1344, 1360 (Fed. Cir. 2009) ("When dealing with burdens of proof it is essential to distinguish between two distinct burdens, the burden of persuasion and the burden of production (sometimes described as the burden of going forward").

[27] Indeed, many jurisdictions recognize a presumption of prudence, such that the expenses incurred by the public utility are reasonable and incurred in good faith until "a serious doubt is created with regard to the prudence of the expenditure." 73B C.J.S. Public Utilities § 130; *see, e.g.*, *Nat'l Fuel Gas Distrib. Corp. v. Pub. Serv. Comm'n of N.Y.*, 947 N.E.2d 115, 120-21 (N.Y. 2011); *Nevada Power Co. v. Pub. Utils. Comm'n of Nev.*, 138 P.3d 486, 495-96 (Nev. 2006); *Hamm v. S.C. Pub. Serv. Comm'n*, 422 S.E.2d 110, 112 (S.C. 1992); *Gulf States Utils. Co. v. La. Pub. Serv. Comm'n*, 578 So.2d 71 (La. 1991); *Potomac Elec. Power Co. v. Pub. Serv. Comm'n of Dist. of Columbia*, 661 A.2d 131 (D.C. 1995); *States ex. rel. GS Techs. Operating Co. v. Pub. Serv. Comm'n of State of Mo.*, 116 S.W.3d 680 (Mo. Ct. App. 2003); *New England Power Co.*, 31 F.E.R.C. ¶ 61,047 at 61,082-83; *Application of Tex. Utils. Elec. Co. for Auth. To Change Rates*, Docket No. 9033, 17 Tex. P.U.C. Bull. 2057, 1991 WL 790285, at *34 (Sept. 27, 1991) (stating that "[t]he law has long recognized . . . that a utility's capital investments are presumed to be prudent") (citing *Mo. ex. rel. S.W. Bell Tel. Co.*, 262 U.S. at 289 n.1 (Brandeis, J., concurring)); *Re Cent. Vt. Pub. Serv. Corp.*, 83 P.U.R.4th 532, 568 (Vt.P.S.B. 1987) *Re Pub. Serv. Co. of N.M.*, 50 P.U.R.4th 416, 427 (N.M.P.S.C. Dec. 30, 1982). With respect to the determination of prudence, as opposed to the ultimate question of the reasonableness of costs included in rates, the Company respectfully submits that management prudence should be presumed absent substantial evidence to the contrary.

general criticisms of the information provided,[28] or asking the utility to "prove the negative" that it was not imprudent.[29] To overcome our showing of prudence, they must offer evidence (not just conjecture or supposition) in opposition.[30]

In the next section we provide a summary of the ways in which we met the burden of proof in this case. By comparison, and as an example, Dr. Jacobs developed his LCM/EPU split on the basis of a single document (Enclosure 8) applied to after-the-fact total costs, and Mr. Crisp relied on another single, after-the-fact document (the 2011 Cost History) to make sweeping generalizations about the Company's approach. This is not the type of evidence that meets an intervening party's burden to produce facts in opposition – let alone rebut our *prima facie* case.

C. The Company's Substantial Evidence

The Company provided significant substantive information on what we spent and why. The Company's initial case included all of the accounting records covering the entire initiative, comprising over 140,000 separate transactions from over 40 separate subproject work orders that resulted in the overall capital cost of the Program.[31] This data was provided in searchable electronic format to give the Department the

[28] *See, e.g.*, Tr. Vol. I at 56:14-16 (J. Anderson question to D. Sparby) ("And you agree that – do you not, that the Department has no burden of proof here to demonstrate that you did not [prove costs were reasonably incurred]? Would you agree with that?"). Department witness Ms. Campbell states that "it is not the Department's burden" to tie costs to imprudent conduct. Tr. IV (Campbell) at 117:14-17.

[29] *See In re Application of Hutchinson,* No. A03-99, 2003 WL 22234703, at *7 (Minn. Ct. App. Sept. 23, 2003) (citing *State v. Paige*, 256 N.W.2d 298, 304 (Minn. 1977)) (recognizing legal impossibility of proving a negative).

[30] *Id.*; 73B C.J.S. Public Utilities § 131; *Gulf States Utils. Co.*, 578 So.2d at 85; *See also* Tr. Vol. I at 57:11-15 (J. Mihalchick) ("Burden of proof is to demonstrate that whatever the issue is by a preponderance of the evidence. I always tell students, though, that if you're defending that, you better put some evidence in. You've got some burden . . . .").

[31] *See* Ex. 6, Weatherby Direct at Schedule 2; Ex. 16, O'Connor Surrebuttal at Schedule 1.

opportunity to audit and confirm our costs.[32] There is no dispute that the Program cost the $665 million at issue in this case.[33]

On the "why" question, Company witnesses provided extensive testimony and schedules detailing our course of action with respect to each of the decision points:

- Direct, Rebuttal and Surrebuttal Testimonies of Timothy J. O'Connor, Xcel Energy's Chief Nuclear Officer ("CNO") detailing our costs and the reasons for them, including timelines and chronologies, cost categorization, and analysis of the 10 major modifications and their costs;

- Direct and Rebuttal Testimonies of J. Arthur Stall, the retired CNO of FPL, who compares the quality of the Company's effort to his experience and concludes we produced a quality product and reacted appropriately;

- Rebuttal Testimony of Richard J. Sieracki, a construction expert, who reviewed the Company's Program implementation and concluded that our performance was overall reasonable under the circumstances; and

- Direct, Rebuttal and Surrebuttal Testimonies of James R. Alders and Rebuttal Testimony of David M. Sparby, all of which provide background and context for our decisions and explain why we proceeded the way that we did.

In addition, the Company responded to over 160 Information Requests from the Department, about 20 Information Requests from other parties, and provided several hundred pages of analysis and attachments. We produced over 3,000 documents, comprised of tens of thousands of pages, including: system conditions assessments, oversight committee presentations, daily status reports, lessons learned reports, Plant operating review committee packages, and nuclear project authorizations.[34]

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[32] The Department conducted an analysis of our records, and while they have been critical about our accounting for the LCM and EPU aspects together, they acknowledged that our accounting records were substantially complete, accurate and appropriate. Ex. 313, Campbell Direct at 15:27-16:17.

[33] Tr. Vol. IV (Campbell) 134:7-18 (agreeing with the total costs provided by the Company).

[34] Tr. Vol. III (Jacobs) at 100:15-103:3.

Far from being "voluminous but not substantive,"[35] the Company produced precisely the kinds of documents and detailed testimony one would expect in relation to a project of this type, including contemporaneous source documents depicting and addressing Plant needs,[36] cost drivers,[37] project planning,[38] project management,[39] decision points,[40] contractual arrangements,[41] cost-benefit analyses, resource planning needs, and evolving circumstances.[42] This provided the parties with ample opportunity to investigate the propriety of the Company's performance.

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[35] Ex. 421, Jacobs Opening Statement at 3.

[36] *E.g.*, Ex. 10, O'Connor Rebuttal at Schedule 6 (Certificate of Need Application for Independent Spent Fuel Storage Installation from January 2005 showing a representative list of necessary LCM modifications) and Schedule 32 (capital project summary sheets from 2003 showing need for replacement feedwater heaters, reactor feed pumps and motors, distribution infrastructure and 2012 Equipment Improvement Long Range Plan Request forms for changes to the 4 kV breaker and switchgear).

[37] *E.g.*, Ex. 9, O'Connor at Schedule 12 (providing detailed information about the Containment Accident Pressure ("CAP") issue and communications from the NRC from March 2009 through June 2010 regarding the status of the CAP issue); Ex. 3, O'Connor Direct 30:16-42:22 and Schedule 8 (identifying and explaining cost drivers); Ex. 9, O'Connor Rebuttal at 75:16-76:8 and Schedule 27 (explaining costs associated with as-found conditions).

[38] *E.g.*, Ex. 9, O'Connor at Schedule 35 (contemporaneous documentation from 2007 regarding project planning and decision to proceed with the 13.8 kV system upgrade); Ex. 16, O'Connor Surrebuttal at Schedule 6 (contemporaneous document showing that the Company always considered the LCM/EPU as an integrated project).

[39] *E.g.*, Ex. 3, O'Connor Direct at Schedule 14 (contemporaneous document depicting the project organizational structure in 2007). Ex. 9, O'Connor Rebuttal at 61:13-62:3 (discussing examples of project management decisions that made work during outages more efficient).

[40] *E.g.*, Ex. 9, O'Connor at Schedule 4 (presentation slides from when the Governance Council approved the Monticello relicensing strategy in July 2003) and Schedule 5 (contemporaneous documents of the information used by the Financial Council in August 2006 to recommend a unified LCM/EPU Program); O'Connor Rebuttal at 69:14-70:3 (Company decision to change implementations vendors for the 2013 outage).

[41] *E.g.*, Ex. 3, O'Connor Direct at 46:14-49:3 (explaining decision to contract with General Electric and scope of contractual arrangements); Ex. 9, O'Connor Rebuttal at Schedule 17 (discussing documents such the 2004 General Electric Contract provided to parties during document production).

[42] *E.g.*, Ex. 3, O'Connor Direct at 91:20-92:22 (explaining how the NRC's new "Fatigue rule" exacerbated the pre-existing shortage of experienced craft labor).

IV. THE COMPANY'S AFFIRMATIVE CASE

A. Introduction

In setting up this investigation, the Commission required consideration of the causes and reasons for our cost increases with particular emphasis on whether our costs incurred for this initiative were "prudent and whether the Company's request for recovery of Monticello LCM/EPU project cost overruns is reasonable."[43] The Company recognizes that the record developed in response to this Order is voluminous and the underlying situation is complex. Nevertheless, the ultimate questions that needs to be answered are straightforward. The key questions are:

- Was it prudent for the Company to embark on the Program?
- Were the modifications to the Plant necessary under the circumstances?
- Why did the capital costs of the Program roughly double from initial estimates?
- Was our management of the Program reasonable under the circumstances?
- Is an allocation of costs between LCM and EPU relevant to this proceeding?

These questions, their answers and the record support for them provide a roadmap for assessing our performance. In this Section, we answer each of the five questions to demonstrate that the answer to the ultimate question of "whether Xcel Energy's handling of the LCM/EPU Program was prudent" should be "yes."

Before doing so, however, we note that the record facts which support our answer to each of the five questions above often-times overlap with one another. In fact, these five questions, and the facts supporting our answers to them, should be viewed as concentric circles that overlap with one another. To simplify our presentation, we

[43] *In the Matter of a Comm'n Investigation into Xcel Energy's Monticello Life Cycle Mgmt./Extended Power Uprate Project and Request for Recovery of Cost Overruns,* Docket E/002-CI-13-754, ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING, p. 3 (Dec. 18, 2013).

worked to segregate the relevant facts on the record so that they answer each issue in isolation. Stated differently we attempted to separate the overlapping concentric circles so that they could stand alone. We mention this now because it is important to keep in mind that each relevant fact may be helpful to understanding our answer to multiple questions.

B. Responses to Key Questions

1. Was it prudent for the Company to embark on the Program?

Yes, based on what we knew or reasonably should have known in 2006-08 (when we made our decision to proceed), it was prudent for us to embark on the Program. The key facts for understanding that the answer to this question must be "yes" involve: (1) the resource planning context for the initiative; (2) the integrated nature of the initiative involving work on the same Plant components for two purposes, and (3) the quality of our initial cost estimates.

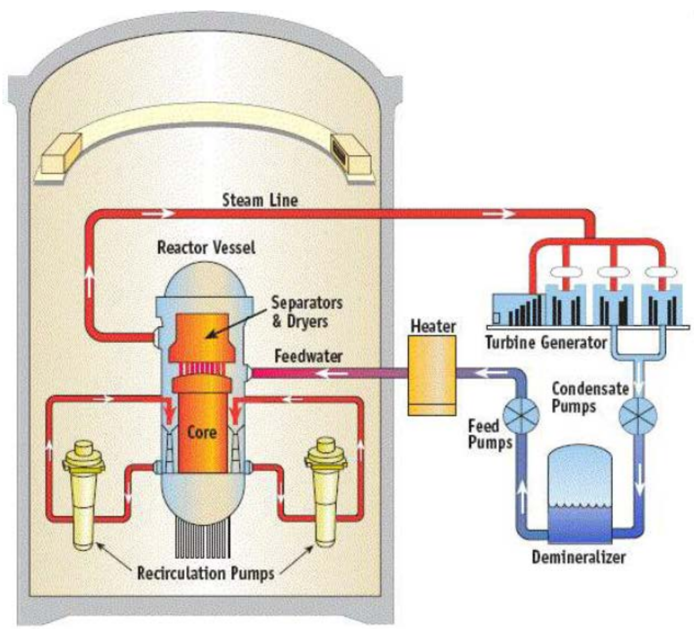
a. Resource Planning

For a variety of reasons described in detail in this proceeding, preserving carbon-free nuclear generation became a top priority and increasing the capacity of the existing resource an added benefit. This was because the Company faced a resource planning environment in the 2001-08 timeframe that saw (i) removal of legal impediments to continued nuclear operations, (ii) the near-term need both to preserve and expand existing baseload capacity to serve rapidly increasing forecast demand, (iii) historically high natural gas prices coupled with evolving coal policies, and (iv) challenging timing considerations to complete the necessary long-lead-time work involved.

(1) *Pre-2003 History of Monticello*

Monticello is a boiling water reactor ("BWR") nuclear plant that was constructed in the late 1960s.[44] It produces electricity by boiling water through nuclear fission and producing steam. The steam is used to drive a turbine, after which it is cooled in a condenser and converted back to water.[45] A BWR configuration is illustrated in Figure 1[46] to Mr. O'Connor's Direct Testimony:

BWR Configuration



It is distinguished from a pressurized water reactor ("PWR") plant[47], such as the units at Prairie Island. One feature of a BWR (as distinct from a PWR) is that many systems in a BWR become radiological and cannot be accessed during operations.[48]

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[44] Ex. 3, O'Connor Direct at 32:26.

[45] Ex. 3, O'Connor Direct at 14:10-13.

[46] Ex. 3, O'Connor Direct at 15.

[47] Ex. 3, O'Connor Direct at 16:1-10.

[48] Ex. 3, O'Connor Direct at 39:21; 80:16; 91:3; 108:8; and 109:15-27; Tr. Vol. II (Stall) at 72:13-19: "And I would just add that there's an increase level of difficulty for Monticello over what we had at FPL because this

In 1970, Xcel Energy obtained a 40-year operating license from the NRC, which allowed operation of Monticello until September 2010.[49] The Plant was not designed with license renewal in mind as this was not allowed under the NRC regulations of the day. It was assumed at the time of construction, that original equipment would last the duration of the license and then the Plant would be shut down.[50] In many instances, mechanical and electrical equipment was installed, with associated piping, wiring, hangars, and support field-run, and then containment or support concrete was poured around these components.[51] The electrical distribution system installed in the 1960s, which supported safety- and non-safety-related equipment throughout the Plant, was sized to support the Plant as it was designed in the 1960s and according to the regulatory margin and regulatory expectations in place at that time.[52]

In 1994, the Minnesota Legislature placed a moratorium on additional dry cask storage, effectively limiting the operation of Monticello to its original operating license.[53] Based on this statute, any possibility of extending the operating life of Monticello was foreclosed.[54] From the mid-1990s until 2003, the capital budget for non-regulatory projects was kept to around $5 million per year and the book value of

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whole side of the plant at FPL was what we call a clean plant [*i.e.*, PWR], nonradioactive, here it was all radioactive over there [at Monticello], radiation areas, much more difficult than what we had."

49 Ex. 3, O'Connor Direct at 43:6-7.

50 Ex. 3, O'Connor Direct at 33:5-8; Ex. 9, O'Connor Rebuttal at 18:17-23.

51 Ex. 3, O'Connor Direct at 33:6-11; Ex. 9, O'Connor Rebuttal at 18:19-21. "Field-run" means that the supporting wiring, piping, hangars, and electrical conduit were run according to what could be accomplished during construction and final placement of these systems were not necessarily documented on as-builts. Ex. 9, O'Connor Rebuttal at 18:25-19:6. This was common for plants of this vintage, resulting in discrepancies in as-built drawings. Ex. 4, Stall Direct at 62:9-14. In the 1980s, the Plant committed to document safety-related electrical systems and in 2008 began updating all mechanical, electrical, and civil as-built conditions when discrepancies are found. Ex. 9, O'Connor Rebuttal at 19:3-6.

52 Ex. 3, O'Connor Direct at 33:13-16.

53 1994 Minn. Laws ch. 641, art. 1, § 2(d).

54 Ex. 9, O'Connor Rebuttal at 4:5-9; Tr. Vol. II (Weatherby) at 36:22-37:21 (discusses LCM activity in context of potential 2010 plant shutdown).

Monticello had depreciated down to $153 million.[55] During this decade, the Plant was being actively managed to its retirement in 2010.[56]

(2) *Monticello Relicensing*

This approach continued until the statutory moratorium was lifted in 2003.[57] In early 2000, as we became aware of the potential change in Minnesota Law, we began an in-depth evaluation of the necessary steps to achieve license extension of the Plant from the NRC and the State of Minnesota.[58] The law was changed while the Company was investigating what it would take to keep the Plant in good working order for another 20 years if the license renewal was granted. The specifics of the new law required that the Company seek and obtain a Certificate of Need from the Commission for additional on-site dry-cask storage (the "ISFSI").[59] If granted, the ISFSI Certificate of Need would pave the way for us to obtain a license renewal from the NRC.

In 2004, the Company began preparing an ISFSI Certificate of Need application to authorize on-site spent-fuel storage at Monticello.[60] This Certificate of Need was necessary to seek a license renewal from the NRC to operate the Plan through 2030.[61] License renewal provided ratepayer value compared to other available alternatives, even though it would require investments necessitated by normal wear and tear, aging

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[55] Ex. 9, O'Connor Rebuttal at 4:13-16. These capital investments do not include the investment in 1996 to 1998 to increase the Monticello output by approximately 6.3 percent that did not require significant physical Plant modifications but took advantage of additional capacity already available through the installed equipment. Ex. 9, O'Connor Rebuttal at 15:22-16.22. This project cost approximately $31.2 million in capital expenses and $4.5 million in operation and maintenance costs. Ex. 9, O'Connor Rebuttal at 16:26-27. This investment reduced the cost to operate the Plant because it increased Monticello's generation at a very low capital cost. Ex. 9, O'Connor Rebuttal at 17:3-5.

[56] Ex. 9, O'Connor Rebuttal at 4:4-11.

[57] 2003 Minn. Laws 1st Spec. Sess. ch. 11, art. 1, § 2.

[58] Ex. 9, O'Connor Rebuttal at Schedule 33 and Schedule 34.

[59] Ex. 2, Alders Direct at 14:12-26.

[60] Ex. 2, Alders Direct at 16:2-7.

[61] Ex. 2, Alders Direct at 16:7-10.

equipment concerns, new or evolving regulatory requirements, operating experience at our nuclear plants or in the industry, obsolescence or new technologies, and our decade of managing Monticello to retirement in 2010.[62]

The cost estimates in the 2005 ISFSI Certificate of Need Application were not based on an exhaustive study, but were representative based on good faith estimates and prior experience at the time.[63] Until the ISFSI Certificate of Need was granted in 2006, all LCM activities undertaken during outages at Monticello were only those necessary to operate the Plant until 2010.[64] After receiving the ISFSI Certificate of Need from the Commission and the 20-year operating license extension from the NRC in 2006, we began the process of preparing Monticello to operate until 2030.

To obtain a renewed license from the NRC, the Company was required to comply with certain rules to ensure reactors and Plant systems remain safe for the duration of the extended license.[65] These rules include the Corrective Action Program, Aging Management Rule, Maintenance Rule, Back Fit and Forward Fit Rule.[66] While the Company was aware of these requirements when it applied for the license renewal and the ISFSI Certificate of Need, we did not foresee how those then would evolve.[67]

Fundamentally, these concepts require the Company to make modifications to, or replace, any equipment we found that did not meet the relevant design criteria or applicable safety requirements.[68] The condition of certain systems was unknown until

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[62] Ex. 2, Alders Direct at 16:12-19.

[63] Ex. 2, Alders Direct at 16:26-17:2.

[64] Ex. 9, O'Connor Rebuttal at Schedule 19; Tr. Vol. II (Weatherby) at 36:22-38:7.

[65] Ex. 3, O'Connor Direct at 18:3-6.

[66] Ex. 3, O'Connor Direct at 18:7-10; Ex. 4, Stall Direct at 17:13-18:16.

[67] Ex. 9 O'Connor Rebuttal at 24:9-13.

[68] Ex. 3, O'Connor Direct at 18:12-15.

in-depth equipment removal or replacement was initiated, resulting in more LCM work that needed to be performed on the Plant from that originally estimated.[69]

(3) *Evaluation of Resource Needs*

One of the main drivers for the LCM and license renewal development process in the early 2000s, and indeed the impetus for the 2003 law change, was the looming need for material amounts of incremental new baseload generation to serve rapidly-increasing forecast demand at the time.[70] And simultaneously with its consideration of options for Monticello, Xcel Energy was developing its 2004 Resource Plan, which had a material impact over the decisions we made in this circumstance.[71] At that time, Xcel Energy's forecasts indicated the need to add new baseload generation in the near-term.[72] The 2004 Resource Plan identified a forecasted increased demand of up to 1,125 MW of new baseload capacity.[73]

(4) *High Forecasts and Natural Gas Pricing*

During the early stages of the Commission's evaluation of the 2004 Resource Plan, in late 2004 and early 2005, the Company had not yet decided whether to pursue an uprate at Monticello. An initial feasibility study for the EPU was completed by General Electric in 2004, but no decision on further pursuing an uprate was made at that time.[74] The Company had only decided it would seek Commission and NRC permission to extend the operation of Monticello to 2030.[75]

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[69] Ex. 9, O'Connor Rebuttal at 54:9-16.

[70] Ex. 2, Alders Direct at 18:17-18.

[71] Ex. 9, O'Connor Direct at 2:25-3:3.

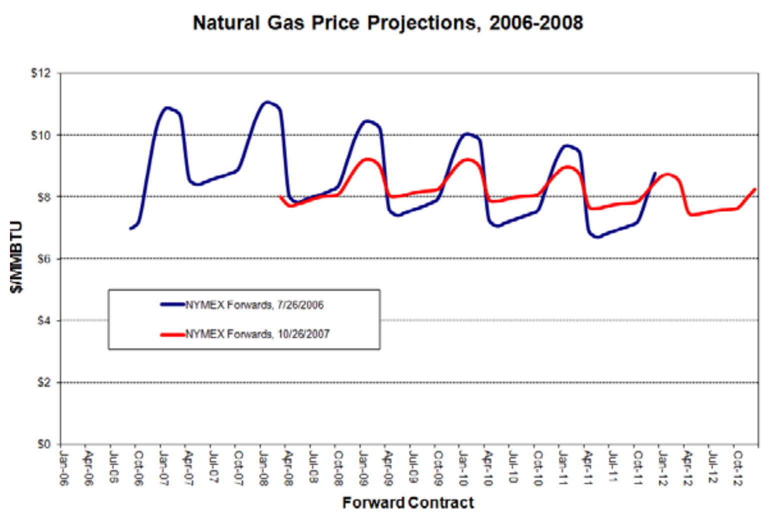
[72] Ex. 2, Alders Direct at 18:18-20.

[73] Ex. 2, Alders Direct at 18:20-21.

[74] Ex. 9, O'Connor Direct at 45:5-6.

[75] Ex. 9, O'Connor Rebuttal at 21:7-9. Even if the Company had decided that it wanted to pursue the EPU at Monticello, the issue could not have been decided by the NRC at the same time as the license renewal

An uprate at Monticello was first identified by the Company for the Commission in the Company's Report on Baseload Study Development Process Study and Options ("Baseload Report"), filed on November 23, 2005 in the 2004 Resource Plan docket.[76] In the Baseload Report, Xcel Energy identified the possibility of addressing a portion of the pending capacity need through uprates at Monticello and other units.[77] We were faced with deciding on baseload capacity upgrades in a volatile natural gas price environment.[78] Natural gas prices went to near $10 per MMBTU.[79] The natural gas forward price curves at the time show pursuing the uprate to be a good choice.[80]



These forward price curves were confirmed by our actual experience in 2008.[81]

application because the NRC will only process one application at a time so the license renewal application would have required processing before a license amendment request could have been submitted. Ex. 9, O'Connor Rebuttal at 21:4-9.

[76] Ex. 8, Alders Rebuttal at 8:8-11.

[77] Ex. 9, Alders Rebuttal at 8:13-15.

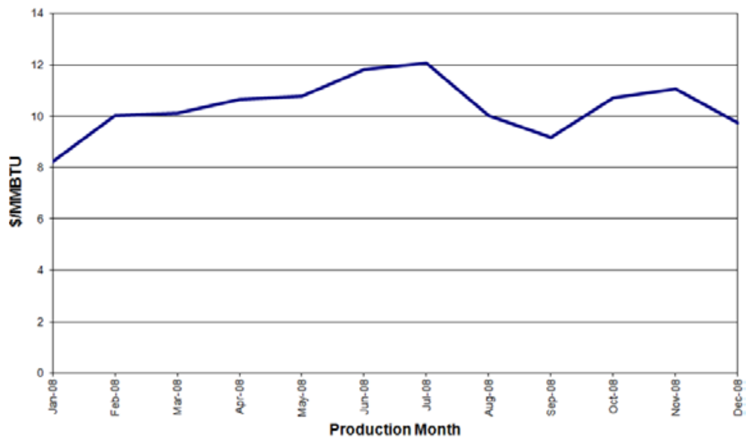
[78] Ex. 11, Sieracki Rebuttal at 13:4-9.

[79] Ex. 11, Sieracki Rebuttal at 13:6-9.

[80] Ex. 8, Alders Rebuttal at 11:3-5.

[81] Ex. 8, Alders Rebuttal at 12.

Natural Gas Costs, 2008



At the time we were evaluating resource options, the fracking revolution that has resulted in materially lower natural gas prices today could not have been foreseen.[82]

(5) *Long Planning Horizon*

The development of baseload resources "requires extremely long planning horizons, and the certificate-of-need-like process for selecting new baseload acquisition" is time- and labor-intensive.[83] The Commission issued its Order on the 2004 Resource Plan in July 2006 and in that Order "require[d] the Company to file for any required Commission review or approval of these upgrades" as promptly as possible.[84] We responded by filing in February 2008, Xcel Energy's Certificate of Need Application for the EPU at Monticello.[85] The Company felt a sense of urgency and the need to proceed expeditiously under the circumstances presented.[86]

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82 Ex. 11, Sieracki Rebuttal at 13:11-14.

83 *In the Matter of N. States Power Co. d/b/a Xcel Energy's Application for Approval of its 2005-2019 Resource Plan*, No. E002/RP-04-1752, ORDER APPROVING RESOURCE PLAN AS MODIFIED, FINDING COMPLIANCE WITH RENEWABLE ENERGY OBJECTIVES STATUTE, AND SETTING FILING REQUIREMENTS at 9 (July 28, 2006).

84 *In the Matter of N. States Power Co. d/b/a Xcel Energy's Application for Approval of its 2005-2019 Resource Plan*, No. E002/RP-04-1752, ORDER APPROVING RESOURCE PLAN AS MODIFIED, FINDING COMPLIANCE WITH RENEWABLE ENERGY OBJECTIVES STATUTE, AND SETTING FILING REQUIREMENTS at 9 (July 28, 2006). (emphasis added).

85 Ex. 2, Alders Direct at 21:14-15. While the Commission Order in the 2004 Resource Plan required the Company to submit its EPU Certificate of Need Application for Monticello by year end 2006, the preparation

b. Integrated Initiative

We undertook the LCM/EPU Program as an integrated initiative to serve two separate but interrelated goals. The first and most important goal was to undertake LCM activities to support the safe and reliable operation of the Plant through at least 2030. The second goal was to increase Monticello's capacity from 600 MW to 671 MW to meet additional baseload capacity needs identified in our resource plans.[87] This was a reasonable choice under the circumstances.

We concluded we should pursue the LCM and EPU activities as an integrated initiative.[88] We recognized that the two initiatives were sufficiently overlapping that it was most efficient to combine the LCM work with the EPU Program.[89] The accounting for the Program was established under a single work order, commensurate with the expectation at the time that vendors would undertake the major work and perform a central role in Program design.[90] Because the Program was viewed as a combined, but single, initiative as opposed to a collection of several related projects, a single parent work order was used to capture all costs incurred.[91]

When the Company decided to pursue the uprate in addition to the LCM work, it made sense to combine the work. As Mr. O'Connor explained, in 2003, the Company

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of the application required more than six months time and the Commission granted the Company extensions to file the application. Ex. 2, Alders Direct at 20:22-24.

86 The Company understood its obligation "to keep the lights on and build, buy, or otherwise secure the generating capacity required to fulfill its duty to serve." *In the Matter of N. States Power Co. d/b/a Xcel Energy's Application for Approval of its 2005-2019 Resource Plan*, No. E002/RP-04-1752, ORDER APPROVING RESOURCE PLAN AS MODIFIED, FINDING COMPLIANCE WITH RENEWABLE ENERGY OBJECTIVES STATUTE, AND SETTING FILING REQUIREMENTS at 9 (July 28, 2006).

87 Ex. 10, O'Connor Rebuttal at 11:24-25 and Schedule 4.

88 Ex. 16, O'Connor Surrebuttal at 23:24-25:5 and Schedules 3, 4, 5, and 6.

89 Ex. 9, O'Connor Rebuttal at 12:1-5 and Schedule 5; Ex. 16, O'Connor Surrebuttal at 24:2-20 and Schedules 3-6.

90 Ex. 5, Weatherby Direct at 8:4-7.

91 Ex. 5, Weatherby Direct at 8:7-10.

began looking at the two initiatives in more detail from a high-level strategy and accounting perspective. As we continued through the evaluation process and into 2006, the Company recognized that the initiatives were sufficiently overlapping that it was most efficient to combine [them]."[92] The reasons were clear:

> We knew we had to undertake LCM modifications to the equipment and our work with General Electric showed that much of this same equipment would be impacted if we moved to uprate conditions. The separate efforts involved so much overlap, we believed this combined approach was both reasonable and necessary to implement the Project.
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> . . .
>
> At the time of the ISFSI application, we estimated those LCM projects to cost approximately $135 million. At that time we noted that this was only a representative list. Multiple LCM modifications were affiliated with multiple EPU modifications and we identified an opportunity to take advantage of the efficiencies of a joint initiative and streamline the overall capital workload at Monticello.[93]

Any other approach would have been highly inefficient. Mr. O'Connor's Surrebuttal testimony and contemporaneous documents show how much of the equipment involved in the license extension had to be repaired or replaced regardless of whether we pursued the uprate. Thus it was logical to size the replacement equipment for an EPU.[94] Had the Company undertaken the work necessary to keep the Plant running without also considering EPU needs, we would have had to replace or modify the

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[92] Ex. 9, O'Connor Rebuttal at 12:2-13.

[93] Ex. 9, O'Connor Rebuttal at 12:17-21 and 13:4-9.

[94] Ex 16, O'Connor Surrebuttal at 23:23-25:5 and Schedules 3, 4, 5 and 6. Schedule 6 to Mr. O'Connor's Surrebuttal Testimony is particularly germane, as it provides a contemporaneous view into the Company's decision-making process in 2006 and graphically depicts the prudent decision to pursue the two efforts together to create synergies and avoid inefficiencies. As noted on the page marked NSP 0034146, we had identified synergies between the EPU and LCM projects early on, which resulted in the EPU becoming "an incremental cost for the total project."

same equipment when it did undertake the EPU. And conversely, had we not made the investments necessary for long-term operation of Monticello, we would not have been able to undertake the uprate.[95] Retaining the existing 600 MW was more important than adding 71 MW.[96] In light of these considerations and the efficiencies gained by an integrated approach, we appropriately managed the integrated project to ensure the continued operation of the Plant first and its expanded capacity second.

We note a 20-year life is not long for a large generating asset and major repairs midway through that life would have to be spread over a much shorter period of time and may not be cost-effective.[97] It was better to combine all of that work in a single initiative that maximized the value of the asset and also allowed for a longer depreciation schedule to lower customer costs.[98]

Further, the Company did not segregate its accounting mechanisms by function. Our accounting followed the FERC uniform system of accounts and correctly accounted for the work by unit of property modified or installed, not by function.[99] We did not maintain separate accounting for the LCM work and for the EPU work, since all of that work was fully integrated. As Mr. Sparby testified, the accounting should follow the project and not visa-versa.[100] And an allocation by functionality (LCM v. EPU) is not an accounting effort,[101] but rather an engineering effort.[102]

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[95] Ex. 9, O'Connor Rebuttal at 81:14-16.

[96] Ex. 10, O'Connor Rebuttal at 88:3-13 and Schedule 32.

[97] Ex. 3, O'Connor Direct at 8:16-18.

[98] Ex. 9, O'Connor Rebuttal at 121:16-23.

[99] Ex. 5, Weatherby Direct at 2:25-3:7.

[100] Ex. 12, Sparby Rebuttal at 8:25-9:12.

[101] Tr. Vol. III (Jacobs) at 99:1-4.

[102] Ex. 3, O'Connor Direct at Schedule 29 page 2 of 6: "[W]e relied on the judgment of the Monticello engineering to apportion the costs between unavoidable LCM and avoidable EPU based on the nature of the vendor services necessary to complete each modification.

c. Initial Cost Estimate

A significant area of criticism is the assertion that the Company's initial cost estimate of $320-346 million ($2008$) provided in the 2008 Certificate of Need to support our modeling effort was too low. The Company's $320-346 million ($2008$) estimate was based on information reasonably known at the time.[103]

We agree that our initial estimate was low. However, we disagree that this is a sign of mismanagement or imprudence. Rather, our initial estimate was reasonable under the circumstances. It was based on (1) information and advice we received from our lead designer, General Electric and its broad industry experience; (2) our formal and informal benchmarking of prior projects; and (3) our own internal review of the needs of Monticello that prompted us to proceed with an initial estimate that was 75 percent higher than the highest benchmarked plant.

The initial authorization for the Program was for $273 million ($2006$) which was designed to complete the necessary EPU work, certain additional LCM/EPU modifications that the Company identified, obtain a Certificate of Need from the Commission, and to prepare the NRC license amendment request with implementation of the Program.[104] This also included funds related to Xcel Energy's scope of work to complete certain additional life-extension modifications and provide project management and support.[105] This estimate did not include the cost of installation of components in, and modifications to, the Plant, which were to be provided by a third party and specifically did not include the Steam Dryer which was

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[103] Ex. 11, Sieracki Rebuttal at 17:8-10.

[104] Ex. 3, O'Connor Direct at 46:5-10. Given General Electric's history with EPU's, Xcel Energy reasonably relied upon the estimate for the EPU work developed by General Electric. Ex. 3, O'Connor Direct at 47:18-49:3.

[105] Ex. 3, O'Connor Direct at 46:10-12.

identified later.[106] Adding the steam dryer and escalation to 2008, made the estimate $320 million which is what was primarily used for modeling. The Company then also used a sensitivity of $346 million as added contingency in its modeling.[107]

(1) *General Electric Initial Scope*

Xcel Energy selected General Electric to prepare a scoping assessment for the EPU. We selected General Electric primarily because of the fact that General Electric was the original designer of Monticello and had an ample financial and operational record.[108] Many other utilities who undertake projects also retained the original designer to assist in those efforts.[109] General Electric also holds the proprietary rights for many of the critical systems for the Plant.[110] General Electric was most efficient given their prior knowledge of the Plant and experience for the work.[111]

In 2006, at Xcel Energy's request, General Electric prepared a study on the possibility of completing an EPU at Monticello.[112] General Electric prepared a high-level estimate and included the minimum amount of work (i.e., pinch points)[113] General Electric was able to identify to achieve uprate conditions.[114] The results of this study were provided to Xcel Energy in May 2006, just before the Commission issued its Order on the Company's 2004 Resource Plan.[115]

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[106] Ex. 3, O'Connor Direct at 47:1-3.

[107] Ex. 3, O'Connor Direct at 29:14-30:3 and Table 3.

[108] Ex. 3, O'Connor Direct at 47:21-23; See Tr. Vol. II (O'Connor) at 59:5-15.

[109] Ex. 3, O'Connor Direct at 47:24-25.

[110] Ex. 3, O'Connor Direct at 47:26-48:2.

[111] Ex. 3, O'Connor Direct at 47:26-48:2.

[112] Ex. 3, O'Connor Direct at 45:6-8.

[113] Ex. 3, O'Connor Direct at 65:5-9.

[114] Ex. 3, O'Connor Direct at 45:13-15.

[115] Ex. 3, O'Connor Direct at 45:8-9.

General Electric identified two potential implementation schedules for the Program: (i) 2009 and 2011 refueling outages, or (ii) 2011 and 2013 refueling outages.[116] Xcel Energy reviewed that assessment and the proposed implementation schedule.[117] Given the magnitude and timing of the capacity need identified in our resource plan proceedings, the Company's management decided to proceed with targeting Program implementation in the 2009 and 2011 refueling outages.[118]

(2) *Benchmarking*

During the 2006 review, Xcel Energy also benchmarked the costs incurred by other plants for similar programs to establish a reasonable estimate for the Program.[119] In benchmarking, we undertook a series of formal and informal steps to review the work of others. We adopted a series of programmatic controls for implementing the Program based on lessons learned at other BWRs, including:

- Benchmarking trips and reports from other plants;
- Review of pending EPU applications;
- Participation in the BWR Owners Group committee on EPU;
- Review of the Lessons Learned process; and
- Consultation with General Electric and other industry experts.[120]

Our benchmarking trips and reports were particularly helpful. Table 1 of Mr. O'Connor's Rebuttal Testimony provides a summary of that work:

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116 Ex. 3, O'Connor Direct at 49:7-11.

117 Ex. 3, O'Connor Direct at 45:26-46:1.

118 Ex. 3, O'Connor Direct at 49:11-13.

119 Ex. 9, O'Connor Rebuttal at 38 at Table 3.

120 Ex. 9, O'Connor Rebuttal at 37:11-18.

EPU Cost Comparisons for Early to Mid 2000s[121]

Project	Descrip-tion	Initial Cost Estimate	Latest Cost Estimate	Ratio of Final to Initial Cost	Estimate of Schedule Extension	Year Completed
Ginna	EPU	$33 million	$44 million	1.33	n/a	2006
Brunswick	EPU	$145 million + $2.5 million contingency	$180* million	1.22* (including contingency)	n/a	2002
Vermont Yankee	EPU	$75 million	$100 million	1.35	n/a	2006

* Progress Energy reported that the project cost nearly $180 million.

This led us to believe that the costs for our initiative would be comparable. In addition to formal benchmarking, we also reviewed the experience of other plants through informal contacts.

Because of employee contacts, we reviewed the experience at the Duane Arnold plant in Iowa. We knew that the uprate at Duane Arnold was undertaken in 2001 under a different regulatory environment and that it was narrower in scope than the work we undertook at Monticello. It is our understanding that Duane Arnold planned to phase-in both its uprates and equipment enhancements over an extended period.[122]

(3) *Internal Assessment*

Using the information in this Scoping Assessment and our own benchmarking analysis, the Company developed a budget and implementation plan to pursue the LCM/EPU Program.[123] Because of the smaller footprint of Monticello and the associated increased installation and implementation and the high-dose radiological

121 Ex. 9, O'Connor Rebuttal at 38:4 at Table 3.

122 Ex. 9, O'Connor Rebuttal at 40:18-25 and Schedules 12 and 14.

123 Ex. 3, O'Connor Direct at 45:26-46:12; Ex. 9, O'Connor Rebuttal at 65:6-8 and Schedule 24 (5-6 of 22 and 13 of 22).

environment of a BWR plant like Monticello, Xcel Energy decided to develop a cost estimate for the Program that was 75 percent higher than the most expensive benchmarked plant as shown in the table above.[124]

We thought this estimate was not only reasonable, but generous. Under the circumstances and with all of the prior experience we had canvassed, we could not reasonably have been expected to come up with a materially higher estimate.

The resource planning context shows the Company needed to proceed in parallel with design, licensing and construction to meet forecast customer needs.[125] Had the Company completed more design work before proceeding, its initial cost estimate might have been more accurate, but the Program would have been delayed possibly four years, which was not feasible given the forecasted baseload need at the time.[126] Figure 2 in Mr. O'Connor's Rebuttal Testimony provides a graphic depiction of what would have happened had we taken the time and spent the money to fully design the initiative prior to proceeding.

The Department criticizes our starting point estimate by relying on the 2011 Cost History document attached to Mr. Crisp's testimony.[127] However, the $362.5 million cost estimate suggested by the 2011 Cost History is not significantly higher than the starting point the Company used, and in any event merely suggests another opinion that would not have changed the cost-effectiveness of the Program.[128] And critically,

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[124] Ex. 9, O'Connor Rebuttal at 39:11-17.

[125] This was based on (1) Commission directives to submit a plan for additional baseload resources including nuclear uprates; (2) forecasted baseload need at the time; (3) high natural gas prices; and (4) the need to upgrade certain Monticello systems to support the Plant's continued operations over the next 20 years. Ex. 11, Sieracki Rebuttal at 11:11-21; Ex. 3, O'Connor Direct at 3:1-10; Ex. 8, Alders Rebuttal at 8:17-19 & n.17.

[126] Ex. 9, O'Connor Rebuttal at 52:17-54:5 and Figure 2, Ex. 11, Sieracki Rebuttal at 12:6-12.

[127] Ex. 301, Crisp Direct at 24:11-13.

[128] Ex. 9, O'Connor Rebuttal at 44:25-45:8.

the author of the 2011 Cost History was not personally aware of the all the information or discussions supporting the reasonableness at the time of the initial \$320-346 million cost estimate.[129]

The Company acknowledges that a somewhat higher range than \$320-346 million could have been created in 2008, but the potentially higher estimate of about \$420 million that might have been used would not have affected the final cost and no witness argued to the contrary.[130]

d. Conclusion of this Question

In summary as to this question, the Company believes that the record we have developed in this case satisfies the applicable burden of proof. We provided substantial and fact-based reasons explaining why we chose to proceed in the way that we did and why our initial cost estimates, while low, were reasonable. Under the circumstances that we faced, our cost estimates and initial approach were appropriate.

And we were not alone in underestimating these costs. Other recent nuclear utilities have encountered similar costs and delays to us, as the entire industry came to grips with challenging circumstances and rising costs. Table 3 from Mr. O'Connor's Direct Testimony depicts the experience other recent nuclear projects have experienced.[131] This Table shows the Company's experience at Monticello was roughly comparable to other utilities in roughly the same timeframe as us, including major upgrade work by Florida Power & Light ("FPL") at their Turkey Point and St. Lucie units, which also experienced a doubling effect on their costs for the same reasons as us. As Dr. Jacobs acknowledged, "the cost increases at the St. Lucie and Turkey Point were significantly more than the cost increases at Monticello, but they had the same -- similar

[129] Ex. 9, O'Connor Rebuttal at 64:8-12.

[130] Ex. 9, O'Connor Rebuttal at 44:25-45:3.

[131] Exhibit 3, O'Connor Direct at 24:11 and Table 3.

challenges."[132] Despite all of the challenges encountered in Florida and despite Dr. Jacobs recommending significant disallowances in the Florida proceedings, FPL was authorized to recover 100 percent of its costs.[133]

2. Were the Modifications to the Plant Necessary?

Yes. In fact, this answer is essentially undisputed. The Company designed modifications needed both to support the long-term operation of the Plant as well as supporting the uprate.[134] The Company's design was appropriate and targeted to serve the purposes identified for the Program.[135]

a. Design Was Strong from an Engineering Perspective

Ten major modifications comprised about 95 percent of the costs.[136] They are depicted in Figure 2 of Mr. O'Connor's Direct Testimony.[137] Mr. Crisp admitted that he takes no issue with the work the Company did.[138] And the Department does not challenge the need for these upgrades.

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132 Tr. Vol. III (Jacobs) at 105:2-5.

133 Tr. Vol. III (Jacobs) at 105:19.

134 Ex. 4, Stall Direct at 4:9-6:2.

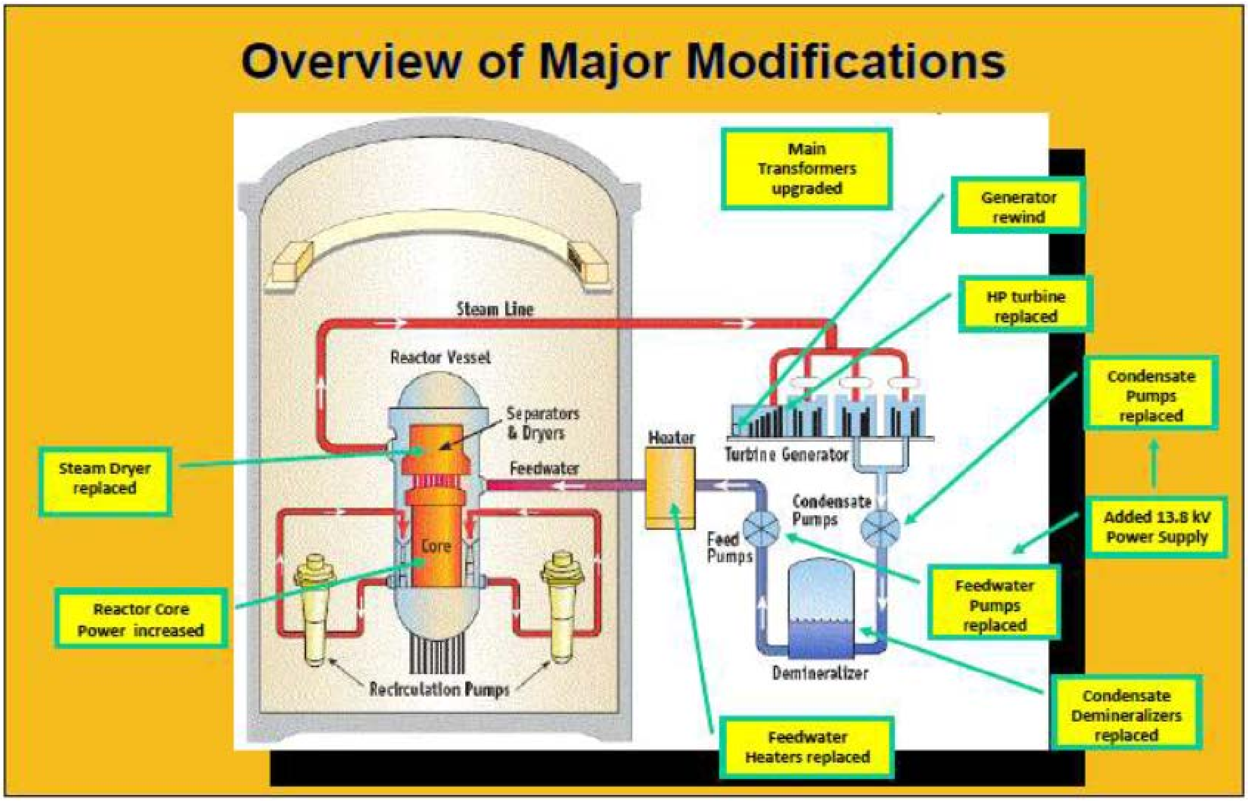
135 Ex. 4, Stall Direct at 4:9-6:2.

136 Ex. 3, O'Connor Direct at 21:8-9.

137 Ex. 3, O'Connor Direct at 22.

138 Tr. Vol. III (Crisp) at 24:10-27:14.

Monticello 10 Major Modifications



Mr. Stall was retained by the Company to review our Program design and to provide opinions about the appropriateness of our choices. His Direct Testimony supports the Company's approach and the value we achieved for the Plant and for our customers. We note Mr. Stall's Direct Testimony was unrebutted in this matter.

We provide the following excerpt from Mr. Stall's unrebutted testimony as to the value of the Company's approach:

> Xcel Energy's approach appropriately combined attributes of a prudent life-cycle management to maximize the 20-year license extension with a prudent uprate plan necessary to achieve the added capacity once the EPU license amendment is granted. I am supportive of designing a program that addresses both life extension and the increased capacity simultaneously as this is a more efficient way to implement upgrades and also reflects the practical

> reality that many upgrades in a 40-year-old power plant will need to be made at some point. It provides good economies of scale and synergies to implement those upgrades along with the installations necessary to support the uprate. By doing the upgrades in the same timeframe, you create an integrated design for the project with fewer future modifications required than if portions were installed over a longer timeframe.
>
> The LCM capital project replaced obsolete instruments and controls in several critical plant control systems. In many cases, dated analog technology was replaced with digital technology. Maintenance costs increase as the equipment ages. The old equipment utilized largely obsolete technology that required special training. Additionally, many parts are not available and custom refurbishment of existing parts is necessary. New modern control equipment will minimize the potential for extended plant shutdowns, maintain plant reliability, and reduce ongoing maintenance costs.[139]

At the hearing, Mr. Stall reinforced this point in his response to the ALJ's question about the work that was done:

> Now, my role was to come in and look at the decision-making that was made for the various scopes of the projects. And to your question earlier, were the right alternatives considered, did they balance safety with cost, did they make the right decisions, and I stepped through that on each of these projects with them and in the end I came to the decision that really they did exactly what they needed to do.[140]

b. Options and Alternatives Considered

There is considerable data in the record that describes the options and alternatives the Company considered in designing the 10 major modifications. The options and

[139] Ex. 4, Stall Direct at 35:10-36:3.

[140] Tr. Vol. II (Stall) at 73:2-10.

alternatives we considered are described throughout the filing, with particular emphasis on pages 93-146 and Schedules 17, 19, 21-28 of Mr. O'Connor's Direct Testimony (Exhibit 3). In addition, Schedule 32 of Mr. O'Connor's Rebuttal Testimony (Exhibit 10) provides a 57-page detailed discussion of its analysis of its analysis in support of its decision to replace and upgrade systems at the Plant and the alternatives that were explored during that process.

In addition, the following material is in the record that identifies examples of the options we considered before and during the implementation of the Program:

- *Original Plant Equipment*: Much of the work was a direct result of aging capital infrastructure at the Plant. For these modifications the Company considered whether it would be more prudent to replace or repair the equipment. The Company found that much of the original Plant equipment, including the steam dryer,[141] feedwater heaters,[142] condensate demineralizer system,[143] main power transformer and 1AR emergency transformer,[144] reactor feed pumps and motors,[145] condensate pumps and motors,[146] and PRNM system,[147] was at the end of its operating life and required replacement.[148]

- *Generator Rewind*: Like the equipment discussed above, the existing generator was original Plant equipment. The Company considered repairing or replacing the equipment and determined that rewinding the generator would be a viable option for the continued operation of the Plant.[149] This is an example of the Company's consideration to repair rather than replace when appropriate.

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141 Ex. 3, O'Connor Direct at 103:4-104:4 and Schedule 5 (1 of 34).

142 Ex. 10, O'Connor Rebuttal at Schedule 32 (7 of 57).

143 Ex. 10, O'Connor Rebuttal at Schedule 32 (5 of 57).

144 Ex. 3, O'Connor Direct at 114:23-115:9; Ex. 9, O'Connor Rebuttal at 90:17-21; 114:7-15 and Schedule 33 and 34.

145 Ex. 10, O'Connor Rebuttal at Schedule 32 (9 of 57).

146 Ex. 10, O'Connor Rebuttal at Schedule 32 (10-11 of 57).

147 Ex. 3, O'Connor Direct at 99:24-100:6; Ex. 9, O'Connor Rebuttal at 112.

148 Ex. 10, O'Connor Rebuttal at Schedule 32 (1 of 57) (Trade Secret).

149 Ex. 10, O'Connor Rebuttal at Schedule 32 (22 of 57) (Trade Secret).

- *Rotating or Static Exciter*: The existing exciter was original Plant equipment that needed to be replaced. The Company considered replacing the exciter with a static excitation system, but found that the static exciter would be much more expensive and challenging to install than a rotating exciter.[150]

- *Turbine Replacement*: We determined the existing high-pressure turbine required replacement or major maintenance to operate until 2030.[151] We conducted a study in 2004 to evaluate either replacing the turbine or a reheat cycle to address limitations in the flow passing capability of the existing high-pressure turbine.[152] Replacing rather than repairing was appropriate because partial repairs can lead to vibration and imbalance issues.[153] And turbine technology had greatly improved and the existing turbine had vibration issues.[154]

- *Reactor Feed Pumps and Motors*: The main two options evaluated by the Company were whether to replace the original two pumps with two larger pumps or supplement the original two pumps with a third pump.[155] Both options had recognized challenges, and the Company determined the two pump solution presented fewer challenges and provided greater operating continuity without the need to develop new protocols and training for our licensed operators.[156]

- *Condensate Demineralizer*: The Company initially planned to replace the vessels. However, on analysis, we concluded that it was important to upgrade the panel and wiring to modern standards.[157] When it came time for installation, we weighed whether to continue with the replacement during the 2011 outage or push the modification back until the 2013 outage. Given the system conditions at the time the Company determined that even with the challenges, proceeding with the replacement in 2011 was preferable to waiting until 2013.[158]

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150 Ex. 10, O'Connor Rebuttal at Schedule 32 (22 of 57) and Schedule 32 (57 of 57) (2003 Capital Project Summary Sheet for Excitation System).

151 Ex. 3, O'Connor Direct at 96:14-19; Ex. 9, O'Connor Rebuttal at 103:3-6.

152 Ex. 3, O'Connor Direct at 96:21-25.

153 Ex. 10, O'Connor Rebuttal at Schedule 32 (16 of 57).

154 Ex. 10, O'Connor Rebuttal at Schedule 32 (17 of 57). The Company was concerned that the vibrations issues could result in fatigue failure; Ex. 9, O'Connor Rebuttal at 103:13-15.

155 Ex. 4, Stall Direct at 48:12-14.

156 Ex. 4, Stall Direct at 48:10-49:5; 49:21-50:19; 52:1-54:6.

157 Ex. 10, O'Connor Rebuttal at Schedule 32 (5-6 of 57).

158 Ex. 3, O'Connor Direct at 111:1-26.

- *Internal Distribution System Options*: The Company originally examined three main options for the original 4 kV distribution system: replace the original 4 kV system; add capacity to the existing system; or add a new primary power source.[159] Then at the 2007 Electrical Summit, the Company narrowed down to two options: replace the 1R transformer with a similar design, replace the 4 kV breakers with 3305 MVA breakers and add additional bus bracing; or replace the 1R and 2R transformers to 13.8 kV transformers and adding new 13.8 kV busses.[160] Many components of the existing 4 kV distribution system needed to be replaced to ensure the system was safe and reliable and additional distribution capacity was required to meet mandatory operating margins.[161] The Company determined adding busses at 13.8 kV addressed all the design requirements and was safer to install than modifying or replacing the 4 kV system on a piecemeal basis.[162] The Company's estimates also indicated that the incremental additional cost associated with the 13.8 kV option was less than one percent over the new 4 kV bus option.[163]

c. Conclusion of this Question

In summary as to this question, the Company believes that the record we have developed in this case satisfies the applicable burden of proof. The Company has provided substantial and fact-based reasons explaining the designs we chose and some of the options and alternatives we considered.

No one on this record has challenged our choices and no one has suggested that we built the wrong modifications. While the Department and the OAG argue about our cost estimating, there is nothing in the record to suggest that the modifications we chose were more expensive than they needed to be to serve the purposes we identified or to provide strong designs for the Plant.

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159 Ex. 4, Stall Direct at 55:12-21; Ex. 3, O'Connor Direct at 131: 8-14 and Schedule 28.

160 Ex. 9, O'Connor Rebuttal at Schedule 35 (6 of 77).

161 Ex. 10, O'Connor Rebuttal at Schedule 32 (11 of 57 and 28 of 57) (need to replace switchgears and breakers) and Schedule 32 (12-13 of 57 and 42 of 57) (need to replace 1R and 2R transformers)

162 Ex. 10, O'Connor Rebuttal at Schedule 32 (11 of 57).

163 Ex. 9, O'Connor Rebuttal at Schedule 35 (6 of 77).

3. Why did the capital costs of the Program roughly double from initial estimates?

Another key question in this proceeding is why the capital costs of the Program roughly doubled from the Company's initial estimate of $320 million ($2008$) to our final cost of $665 million ($2013$). The cost increases we experienced over the eight years of the Program were primarily driven by three factors: (1) regulatory compliance challenges; (2) necessary design changes; and (3) installation complexities. The record in this case provides significant justification as to why these three factors (and not imprudence) contributed to additional costs to the Program such that the final costs that we incurred were reasonable under the circumstances.

a. *Regulatory Compliance Challenges*

The federal nuclear regulatory environment evolved dramatically over the course of the eight years the Program was implemented. This changing regulatory environment had direct and indirect cost impacts. The table below provides examples of some of these cost impacts that we were able to quantify.[164]

NRC Related Costs for the Program

Cause	Cost
Increase in Licensing Costs	$30+ million
Additional Calculation Costs	$16+ million
CAP Issues	$1 million
Addition of New Steam Dryer	$30+ million
Addition of New Steam Dryer Monitoring Equipment	$7 million

(1) *Direct NRC Costs:*

We incurred additional licensing and design costs necessary to demonstrate Monticello's compliance with the evolving regulatory requirements.[165] Further, the

[164] Ex. 9, O'Connor Rebuttal at 24:17 and Table 1.

[165] Ex. 9, O'Connor Rebuttal at 24:9-13.

NRC's regulatory expectations and staff interpretations have also increased in recent years, further adding to our work and costs.

An example of a direct cost increase resulting from changing NRC regulations and expectations is the change to our NRC licensing costs. The NRC licensing process consists of a highly detailed and technical review of the proposed construction and operating characteristics of the facility to ensure the safety of operation under these uprate conditions.[166] The Company submitted its license amendment request for the EPU to the NRC in November 2008.[167] When it submitted its license amendment request, the Company estimated that its licensing costs alone would total approximately $47.9 million, but these costs have totaled nearly $66 million.[168]

Prior to submitting its application, the Company spent considerable time evaluating available EPU operating experience, regulatory issues found in transcripts, NRC notices and areas of review in the NRC Review Standard for EPU applications, and NRC inquiries and responses for previous EPUs to ensure those issues were addressed in the license amendment request.[169]

However, the Company's preparation did not take into account the NRC's increasing additional analysis and evaluations related to equipment safety as part of EPUs.[170] For example, the NRC issued over 400 requests for information on the license amendment request related to two main areas of the EPU license amendment request analysis: 1) credit in safety analysis for containment accident pressure ("CAP"), and 2)

[166] Ex. 3, O'Connor Direct at 51:7-16.

[167] Ex. 3, O'Connor Direct at Schedule 17.

[168] Ex. 3, O'Connor Direct at Schedule 17; Ex. 16, O'Connor Surrebuttal at Schedule 1.

[169] Ex. 3, O'Connor Direct at 23:8-16.

[170] Ex. 9, O'Connor Rebuttal at 22:12-16.

ongoing structural analysis of the new steam dryer.[171] The Company estimated that the additional calculations required by the NRC during its review of the license amendment request, including the CAP analysis, increased licensing costs by approximately $17 million.[172]

(2) *Indirect NRC Impacts:*

Far more significant than the direct costs we incurred with the NRC, evolving regulatory expectations had a material impact on our approach for designing and implementing the Program, and as a result, and the costs we incurred. The Company faced increased costs throughout the Program because of compliance with evolving NRC expectations.[173] These requirements include: (i) Corrective Action Program; (ii) Aging Management Rule, 10 CFR Part 54.21; (iii) Maintenance Rule, 10 CFR Part 50-65; (iv) NRC Review Standard RS-001 for extended power uprates; (v) the Back Fit rule and the Forward Fit concept as applied by NRC staff and (vi) Fatigue rule, 10 CFR Part 26.[174] While the Company was aware of these requirements when it initiated the Program, except for the Fatigue rule which became effective later, it did not foresee that the interpretation and enforcement of these rules would change over time.[175] Consequently, Program costs increased.[176]

Mr. Stall described this dynamic at the hearing:

> The reality of the nuclear industry today is that all of these considerations have become much more complex and

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171 Ex. 3, O'Connor Direct at 54:15-23.

172 Ex. 16, O'Connor Rebuttal at 24:17 at Table 1. Additional Calculation Costs total $16 million and CAP Issues total another $1 million.

173 Ex. 9, O'Connor Rebuttal at 24:9-10; Ex. 4, Stall Direct at 17:13-18:24.

174 Ex. 4, Stall Direct at 17:4-8; Ex. 3, O'Connor Direct at 18:1-17.

175 Ex. 3, O'Connor Direct at 18:22-24.

176 Ex. 9, O'Connor Rebuttal at 24:9-16; Ex. 418, Stall Opening Statement at 2 ("Nuclear safety, operations, and regulatory considerations drive the scope of the work to be undertaken.").

> expensive. Similar to my work in Florida, Xcel Energy faced changing NRC compliance issues that caused significantly more work[,] which resulted in higher costs; evolving designs to ensure that the plant could be operated safely and reliably for the long term; and difficult installation of components in a small footprint such as Monticello (similar to what I experienced at Turkey Point) that was much harder than the external construction specialists we all relied on expected or foresaw.[177]

Mr. Stall expanded on how evolving NRC expectations indirectly had significant impacts on Program costs during the evidentiary hearing:

> And in today's environment, the whole NRC oversight structure of these utilities and owner-operators, as Xcel is, is predicated on a probabilistic risk assessment assumption that you are managing and controlling these initiated events that can lead to core damage. So what that means in a project like this of this complexity is that when Tim O'Connor and his staff are out in that plant doing these upgrades, they're going to find what we call discovery items, things that could not have been foreseen until the plant was well into this project. And I would just add that there's an increase level of difficulty for Monticello over what we had at FPL because this whole side of the plant at FPL was what we call a clean plant, nonradioactive, here it was all radioactive over there, radiation areas, much more difficult than what we had.
>
> When you find these degraded pieces of equipment you have to -- you have to deal with those on the spot and you have to fix them and correct those deficiencies per the regulations. And there are a number of regulations which I could recite up here that drive those decisions. So they had no opportunity to do otherwise.[178]

[177] Ex. 418, Stall Opening Statement at 2.

[178] Tr. Vol. II (Stall) at 72:2-73:1.

An example directly related to the LCM/EPU Program is the application of the forward fit concept. This concept is relatively new and has evolved in recent years.[179] By way of background, the NRC has a process by which it monitors and analyzes nuclear power plants for compliance with the design of the plant. Under the back fit rule, the NRC "generally does not require nuclear operators to "back fit" systems (apply a change in criteria retroactively to an existing licensee) unless the NRC can demonstrate that there is a substantial increase in the overall protection of the public health and safety or the common defense and security to be derived from the back fit and that the direct and indirect costs of implementation for that facility are justified in view of this increased protection."[180]

With regard to voluntary license amendments, however, the NRC now takes the position that it is not limited by this back fit rule and can instead require a licensee to "forward fit" systems.[181] Thus, an EPU opens a nuclear facility to regulatory scrutiny that may necessitate changes to a plant's original licensing basis, which may involve additional engineering changes and equipment upgrades beyond those initially envisioned to meet the EPU operating requirements.

Changes to the NRC's requirements for the steam dryer analysis required for the Monticello license amendment request was implemented under this forward fit rule.[182] During the time period the license amendment request has been pending, experiences at other facilities caused the NRC to require detailed structural analysis of the steam dryer before approving an EPU.[183] Ultimately, based on these events at other plants, the Company decided to replace rather than modify the existing steam dryer, which

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179 Ex. 4, Stall Direct at 19:19-20.

180 Ex. 4, Stall Direct at 19:6-16.

181 Ex. 4, Stall Direct at 19:25-26.

182 Ex. 9, O'Connor Rebuttal at Schedule 11 (8 of 10).

183 Ex. 3, O'Connor Direct at 57:18-27 and Schedule 22.

resulted in project costs of $31 million for the dryer, and approximately $3.5 million for repairs to associated equipment and removal of steam dryer instrumentation.[184]

In addition, our costs were impacted by the application of other NRC requirements, such as application of the fatigue rule.[185] This rule limits the number of hours craft labor can work to ensure that no worker becomes unduly fatigued on the job. As discussed in response to the next question (*i.e.*, management prudence), this impacted both our productivity and our ability to attract and retain qualified craft labor.[186]

In short, the Company relied upon available precedent, worked through formal and informal industry contacts, and developed a plan for NRC compliance that was consistent with prior experiences of other utilities. The Company could not have foreseen the dramatic changes that were going to occur and the additional costs that would arise out of those changes.

b. Necessary Design Changes

Our cost increases were also the result of necessary design changes that we made primarily to four major modifications: (i) feedwater heaters and associated equipment; (ii) reactor feed pumps and motors; (iii) condensate demineralizer system; and (iv) electrical distribution system. These four major modifications account for $406 million, or more than half of the total capital costs of $665 million.[187] Our initial cost estimates for these modifications were based on high-level conceptual designs for the Program. As the Program moved forward, it became apparent that several key components that we initially expected to repair or recertify required replacement to ensure safe and reliable operations for the extended license period. In addition, when

184 Ex. 9, O'Connor Rebuttal at Schedule 11 (5 of 10).

185 Ex. 16, O'Connor Surrebuttal at 7:13-15.

186 Ex. 16, O'Connor Surrebuttal at 17:10-16.

187 Ex. 3, O'Connor Direct at 32:8-9.

we began to install the necessary equipment, we also discovered additional design work was required based on the as-found conditions of certain equipment.

These items are outlined on pages 58-59 of Mr. O'Connor's Rebuttal Testimony (Exhibit 9). As shown there, the subsequent design and scope changes were all driven by particular issues we encountered during implementation and all were necessary.

(1) *Feedwater Heaters*

The cost of this modification increased fundamentally because we replaced them, rather than just rerate the old ones (as was minimally necessary for the uprate).[188] During the design phase we determined that we needed to replace rather than rerate six feedwater heaters due to their aging condition.[189] The 14 and 15 A/B feedwater heaters were original 40-year old equipment and the Company's testing confirmed that they required replacement.[190] In addition, the Company determined during an inspection that the condition of the 30-year old 13 A/B feedwater heaters also warranted replacement.[191] While the decision to replace these heaters was necessary, it resulted in additional costs not just associated with the new feedwater heaters but also with unanticipated costs with interferences (piping and wiring) related to replacement of the 13 A/B feedwater heaters.[192] The Company's decision to replace rather than rerate the feedwater heaters was appropriate and in the best interest of the Plant as this aging equipment would have required substantial maintenance requiring

188 Ex. 3, O'Connor Direct at 118:12-18.

189 Ex. 4, Stall Direct at 46:22-24.

190 Ex. 10, O'Connor Rebuttal at Schedule 32 (7 of 57).

191 Ex. 10, O'Connor Rebuttal at Schedule 32 at (7 of 57).

192 Ex. 3, O'Connor Direct at 120:16-18.

longer refueling outages to re-tube the heat exchangers if they had not been replaced.[193]

(2) *Reactor Feedpumps and Motors*

The cost of this modification increased because of our decision to replace the two existing pumps and motors.[194] This increased costs due to the need to procure two new pumps and motors, but this also increased design and installation costs.[195]

At the time, we believed it was a reasonable decision to replace the pumps and motors because of the chronic performance issues with the then existing two pumps and motors required their replacement.[196] Furthermore, the two existing reactor feedwater pumps were a custom redesign of a 3-stage fire pump into a 2-stage feedwater pump.[197] This one-of-a-kind design resulted in frequent maintenance issues during refueling outages.[198] Reliability of the Plant was also improved by replacing the worn and less than ideal design of the existing reactor pumps and motors.

The Company did evaluate an alternative approach that utilized a three pump design. Company determined, however, that this design was not workable due to size limitations and operating procedures.[199] The decision to stay with two pumps rather than three also allowed the Plant configuration and operations to remain unchanged and eliminated the need for procedure revisions and operational training.[200] Designing improvements that are user-friendly to our NRC licensed operators is an

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193 Ex. 10, O'Connor Rebuttal at Schedule 32 (8 of 57).

194 Ex. 3, O'Connor Direct at 123:22-27.

195 Ex. 3, O'Connor Direct at 125:9-11.

196 Ex. 10, O'Connor Rebuttal at Schedule 32 (8 of 57).

197 Ex. 10, O'Connor Rebuttal at Schedule 32 (8 of 57).

198 Ex. 10, O'Connor Rebuttal at Schedule 32 (8 of 57).

199 Ex. 3, O'Connor Direct at 124:8-9.

200 Ex. 3, O'Connor Direct at 126: 11-14.

important criterion in the nuclear environment as it minimizes the need for retraining and makes their work easier.[201]

(1) *Condensate Demineralizer System*

The costs for this modification increased because the scope changed to include the replacement of the entire condensate demineralizer system.[202] The scope changed significantly because of the degraded condition of the entire condensate demineralizer system, including the existing analog system, which was not known when the modification was first designed.

For example, the old vessels and filter systems supported resin for only six months before needing to be recharged.[203] Once it became clear that the vessels needed to be replaced, the Company determined that it was appropriate to also replace the existing analog controls to minimize the risk of sequencing errors that could have caused a reactor scram.[204] The Company also determined that the piping and valves showed signs of wear and needed replacement.[205] Additional work was required during installation when degraded wiring was discovered requiring immediate replacement.[206]

Wholesale replacement of this existing system was the sensible choice as this new condensate demineralizer system more efficiently removes fine debris and resin from the condensate and is expected to reduce operation and maintenance costs.[207] The

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201 Ex. 3, O'Connor Direct at 143:7-15.

202 Ex. 3, O'Connor Direct at 108:13-15.

203 Ex. 3, O'Connor Direct at 111:16-18.

204 Ex. 4, Stall Direct at 44:11-12; Ex. 10, O'Connor Rebuttal at Schedule 32 (6 of 57).

205 Ex. 4, Stall Direct at 44:12-14.

206 Ex. 4, Stall Direct at 43:7-8.

207 Ex. 3, O'Connor Direct at 112:23-27.

replacement of the existing analog system with an automated digital system reduces the reliance on individual operators and has made the Plant safer and more reliable.[208]

(2) *13.8 kV Distribution System*

The costs for this modification increased to accommodate the 13.8 kV switchgear room and the specific location of raceways for power or control cables.[209] While we understood the need for the switchgear room and raceways for power or control cables, the complexities around installing the switchgear room were not fully appreciated until installation work packages had been prepared.

Upgrading the existing distribution system was required because it did not have sufficient margin in its system to maintain safe and reliable operations over the extended operating life. Specifically, the existing 4 kV system was more likely to experience trips and additional equipment damage during a fault. As new electrical loads would be added, the margins would only get smaller.[210] And this upgrade was required irrespective of the uprate for all of the reasons outlined by Mr. O'Connor's Rebuttal Testimony. Notably, electric loads had to be sequenced to avoid low-voltage alarms, a condition that is a clear indication that work was needed irrespective of the uprate.[211] This situation was inconsistent with good nuclear practices.[212]

One of the major design changes that came about after the initial cost estimates was selection of the location of the switchgear room. During the design process the Company determined that the size of the new bus equipment, it would need to be located at a new location within the Plant. Given the space requirements for this new

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208 Ex. 3, O'Connor Direct at 112:23-27.

209 Ex. 3, O'Connor Direct at 132: 5-8; Ex. 3, O'Connor Direct at Schedule 28.

210 Ex. 9, O'Connor Rebuttal at 93:21-94:2.

211 Tr. Vol. IV (Jacobs) at 35:7.

212 Ex. 9, O'Connor Rebuttal at 117:23-24.

bus work to allow for adequate cooling of the equipment, the Company decided that the only feasible location was at the site of the old hot shop.[213]

This system required approximately 14 miles of new cable, conduit and raceway to run all the cables throughout the Plant.[214] Installation of the 14 miles of new cable required workers to pull two inch diameter cable that weighed in excess of 100 pounds per foot.[215] This required teams of ten electricians to pull these cables through the conduit 20 feet at a time.[216] While the actual cost of the modification turned out to be significantly higher than we expected, the work that was completed was necessary to address low voltage alarms and other margin degradation issues.[217]

As we moved into more integrated design work, we undertook work that was central to the long-term viability of the Plant, and that enhanced the Plant's safety and reliability. That effort resulted in new and expanded modifications and component replacements to ensure success of the integrated LCM/EPU Program.[218] We understood replacing equipment would result in additional costs, but we knew that much of this equipment needed to be replaced in any event for LCM purposes so concluded that the work should be done to support the overall initiative.[219]

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[213] Ex. 3, O'Connor Direct at 132:11-7; Ex. 9, O'Connor Rebuttal at 99:16-17.

[214] Ex. 3, O'Connor Direct at 132:16-17.

[215] Ex. 3, O'Connor Direct at 90:10-14.

[216] Ex. 3, O'Connor Direct at 90:10-14.

[217] Ex. 3, O'Connor Direct at 135:8-20.

[218] Ex. 3, O'Connor Direct at 31:30-32-4.

[219] We had also investigated whether it would have been possible to install additional distribution capacity at lower voltages. While, absent the uprate, it is possible we could have installed additional 4 kV distribution capacity, this solution was not optimal as 13.8 kV is now a more common voltage and it would be hard to support additional 4 kV capacity as the obsolete equipment and components were getting harder to obtain. Ex. 3, O'Connor Direct at 131:22-23. And in any event, adding 4 kV capacity would have been about the same cost and may have even been more expensive than the chosen 13.8 kV voltage. Ex. 3, O'Connor Direct at 131:15-25 and Ex. 9, O'Connor Rebuttal at 118:10-20.

c. Installation Complexities

We anticipated that we would encounter difficulty in construction and installation.[220] During the engineering and design phase for each of our modifications, we identified the areas that would be space-constrained and/or located in high-dose environments. We relied on our vendors' expertise and input as well as the experience of our engineering staff to develop the work packages for each modification. Although we considered that certain inefficiencies would be encountered because of the small spaces or high-dose environments, even using the expertise of our implementation vendors did not provide us with the information necessary to fully appreciate how long the work would take.[221] In the end, our installation costs were nearly $290 million which is more than 40 percent of our total costs for the Program.[222] The increase in our installation costs can be attributed to two key reasons: (i) emergent work and (iii) productivity. In the end, however, the installation costs that we incurred were necessary to implement the equipment needed to complete the LCM/EPU Program.

(1) Emergent Work

One of the cost drivers for our installation costs was the variety of issues that arose because of as-found conditions that we discovered during the implementation phase of the Project. In total, the Program had approximately 2,000 field changes.[223] These field changes took a variety of forms and required design and implementation adjustments that necessarily increased costs.

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[220] Ex. 3, O'Connor Direct at 33 and 81; Ex. 9, O'Connor Rebuttal at 46:16-47:2.

[221] Ex. 9, O'Connor Rebuttal at 45:16-46:2.

[222] Ex. 3, O'Connor Direct at 35:8-9.

[223] Ex. 9, O'Connor Rebuttal at Schedule 27.

As an example, during installation of the condensate demineralizer system vaults, the piping and electrical runs were rerouted due to the "as found" rebar locations within the walls and floors.[224] This system had limited "as built" drawings that were developed during the initial construction but these did not match the as found conditions.[225] This required a highly interactive approach to identify the piping routes while doing the engineering analysis to support the proposed reroute.

Another discovery that slowed the implementation of the condensate demineralizer system modification was the discovery of degraded wiring behind the walls that required immediate replacement. Similarly, we discovered during the 2009 outage that the as-built designs for the feedwater heater piping was incorrect.[226] This required in-outage design and constructability packages to avoid piping interferences.[227]

While we attempted to fully analyze and plan for the work required to complete all the modifications, we were not able to anticipate all of the necessary work given that some areas were inaccessible due to high radiological conditions and the fact that our as-built diagrams we reasonably relied on were inaccurate.[228]

(2) Productivity Challenges

The Company found that construction labor productivity (i.e., the number of person-hours required to complete defined installation tasks) during the implementation outages was substantially lower than predicted by the Company's installation vendors. The Company attributes this productivity challenge to several factors, including the

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[224] Ex. 9, O'Connor Rebuttal at Schedule 27.

[225] Ex. 9, O'Connor Rebuttal at Schedule 27.

[226] Ex. 3, O'Connor Direct at 39:14-16.

[227] Ex. 3, O'Connor Direct at 39:16-17.

[228] Ex. 4, Stall Direct at 62:10-14 ("With a 40-year old plant it is unsurprising that the as-built drawings did not completely match the actual as-found conditions.")

challenging work conditions, difficulties hiring experienced craft labor due to the competitive nuclear labor market, and restrictions on work schedules imposed by the NRC's fatigue rule, and difficulties with vendors.[229]

With regard to challenging working conditions, the Monticello Plant was a turn-key plant, and at the time it was constructed, it was not designed to facilitate major equipment replacements.[230] As a result, the Plant was designed on a small footprint with many tight and confined spaces. These confined, and in some cases highly radiological, spaces impacted our labor productivity. This is because workers have to do tasks sequentially (rather than in tandem) because space limitation preclude the number of workers in a given area.[231] For instance, the condensate demineralizer vessels are highly radioactive and are therefore contained in eight foot square concrete vaults.[232] These small vaults meant that only two workers could work in the vault at one time.[233] In addition, due to the radiological work environment, workers had to comply with work permit restrictions and other protocols that hampered productivity.[234] In such an environment, workers are required to limit their amount of time in radioactive contaminated areas and also have to wear protective clothing which can hamper their movements and pace of work.[235]

In addition to the challenging conditions, our productivity was also impacted by our difficulty in finding and retaining experienced craft laborers. Overall there is declining supply of qualified nuclear professionals, which is a result of a large percentage of this

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229 Ex. 3, O'Connor Direct at 40:3-12.

230 Ex. 3, O'Connor Direct at 32:26-33:11.

231 Ex. 4, Stall Direct at 32:13-17.

232 Ex. 3, O'Connor Direct at 109:15-20.

233 Ex. 3, O'Connor Direct at 109:20-26.

234 Ex. 3, O'Connor Direct at 109:25-120:2.

235 Ex. 4, Stall Direct at 32:25-33:2.

workforce approaching retirement age and fewer new workers taking their place.[236] The Company estimates that for the 2009 outage, 90 percent of our craft labor was nuclear experienced.[237] By the 2011, this number declined to 45 percent.[238]

The NRC fatigue rule also had an effect on our ability to attract and retain qualified workers. In the construction trades, a large project will sometimes deploy workforce on a 12-hour by 7-day schedule.[239] The NRC fatigue rule, 10 CFR Part 26, limits workers to a 6-day schedule and created a competitive disadvantage for the Program.[240] Tradesmen often prefer the more aggressive schedule to maximize job earning potential and the fatigue rule means that the Company had to compete for workers with jobs that were not nuclear projects and did not have to comply with the fatigue rule.[241] The NRC's fatigue rule also limited any extended hours for workers after the 60th day of an outage.[242] As a result, we had to limit workers' hours.[243]

Finally, our productivity was also impacted by issues with our design vendors. The Company rejected design drawings that were not up to our standards and took additional time to improve the constructability of certain designs.[244] While this may have increased costs, this was the prudent course of action and likely saved millions of dollars by not proceeding with suboptimal designs.[245]

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236 Ex. 4, Stall Direct at 63:10-11.

237 Ex. 9, O'Connor Rebuttal at 69:15-17.

238 Ex. 9, O'Connor Rebuttal at 69:17-19.

239 Ex. 3, O'Connor Direct at 92:3-4.

240 Ex. 3, O'Connor Direct at 92:6-7.

241 Ex. 3, O'Connor Direct at 92:4-8.

242 Ex. 3, O'Connor Direct at 92:10-15.

243 Ex. 3, O'Connor Direct at 68.

244 Ex. 9, O'Connor Rebuttal at 42:14-21.

245 Ex. 9, O'Connor Rebuttal at 42:18-21.

We thought that we already accounted for some of the challenges we knew we would face during implementation, like the smaller footprint, high-dose environment, and benchmarking. It was not reasonable for us to have thought our cost pattern would be significantly greater than we projected.

a. Conclusion of this Question

In summary as to this question, the Company believes that the record we have developed in this case satisfies the applicable burden of proof. The Company has provided substantial evidence explaining the reasons why our costs rose. None of those reasons – increasing NRC regulation, additional design to ensure success, and installation difficulties – are a sign of imprudence by the Company. Rather, these were circumstances largely beyond our control and were all issues that required us to adapt to keep the Program on track. And in any case, even if we had better foreseen the impact of these cost drivers sooner, it would not have eliminated the need for this work and it would not have impacted costs.

4. Was our management of the Program reasonable under the circumstances?

Yes, our management of the Program was prudent because we made appropriate choices to deliver the Program promptly, adapted to increasingly-difficult circumstances by, for example, utilizing a third outage to complete the work right, made well-reasoned key vendor selections based on the work at hand, and maintained ample control and oversight of Program implementation throughout its duration.

a. Early and Prudent Management Action

In the early stages of the Program during 2006 to 2008, when the initial cost estimate was developed, the design of the Program was not fully developed.[246] This is a

[246] Ex. 11, Sieracki Rebuttal at 11:26-12:2; Ex. 3, O'Connor Direct at 31:20-23.

normal and typical occurrence in major capital projects in the nuclear power industry.[247] Nevertheless, the Company set the overarching Program scope, which remained unchanged.[248] We always intended to undertake the work necessary to perform two separate but related functions: (1) allow for Monticello's continued safe and reliable operation to at least 2030, and (2) achieve uprate operating conditions.[249] While the twin goals of the Program did not change, the work required to accomplish those goals did. Company management responded to work changes and resultant challenging circumstances by adapting its management of the Program accordingly.

One of the first key Program management decisions the Company faced early involved deploying capital prior to the issuance of the Certificate of Need. This was necessary and prudent in order to capture the benefits of the Program as soon as possible. Given the immediacy of obtaining baseload capacity promptly,[250] the Company made the decision to proceed with its planning for the first outage in 2009 for both (1) implementation of the LCM work it had identified and (2) EPU implementation work it anticipated to be approved in the pending uprate Certificate of Need proceeding. This advanced preparation included procuring equipment and engineering and designing plans to take place during the first outage.[251]

From the time the Company launched the LCM/EPU Program in mid-2006 through obtaining the Certificate of Need in January 2009, Xcel Energy spent approximately $97 million on the combined LCM/EPU Program.[252] This included about $60

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[247] Ex. 11, Sieracki Rebuttal at 13:20-22; Ex. 3, O'Connor Direct at 24:4-14.

[248] Ex. 9, O'Connor Rebuttal at 57:7-8.

[249] Ex. 9, O'Connor Rebuttal at 57:9-11.

[250] *In the Matter of N. States Power Company d/b/a Xcel Energy's Application for Approval of its 2008-2022 Resource Plan*, No. E002/RP-07-1572, ORDER APPROVING FIVE-YEAR ACTION PLAN AS MODIFIED AND SETTING FILING REQUIREMENTS at 10 (Aug. 5, 2009).

[251] Ex. 3, O'Connor Direct at 59:4-12.

[252] Ex. 9, O'Connor Rebuttal at 52:3-6.

million in progress payments to General Electric, mainly for engineering and design work for the 2009 modifications.[253] The Company also incurred significant costs to obtain long-lead-time items, such as a firm order on a block of steel needed to fabricate the new turbine.[254] The Company had to make a business decision on whether to proceed with this work and these orders before obtaining the Certificate of Need.[255]

Had the Company not conducted this advanced planning prior to receipt of the Certificate of Need, we would not have been able to implement modifications during the 2009 outage.[256] Rather, the Company would have had to push back the implementation schedule, likely to 2013, which likely would have delayed final implementation until 2017.[257] As it was, the Company was able to commence active construction only two months after receiving the Certificate of Need.[258]

b. Initial Contractor Selection and Management

In conjunction with the Company's decision to expend funds prior to the issuance of a Certificate of Need, management need to decide two important questions: (1) who would serve as the chief Program designer and (2) who would serve as the 2009 implementation contractor. The thrust of the Company's contracting and management strategy to accomplish all the work within the Program centered on selecting the right contractor for the work at hand.[259]

253 Ex. 9, O'Connor Rebuttal at 52:6-9.

254 Ex. 9, O'Connor Rebuttal at 52:6-9.

255 Ex. 2, Alders Direct at 29:8-12.

256 Ex. 9, O'Connor Rebuttal at 55:11-15.

257 Ex. 9, O'Connor Rebuttal at 56 at Figure 3.

258 Ex. 9, O'Connor Rebuttal at 52:15-16.

259 Tr. Vol. I (O'Connor) at 97:22-23.

(1) *Design Contractors*

The Company began the Program by overseeing the efforts of its chief design engineer, General Electric, and its chief installation contractor, Day Zimmerman.[260] General Electric was the primary design architect of the Program.[261] The Company engaged General Electric, the original Plant designer, to assist with setting the conceptual design.[262] Because General Electric was the original Plant designer, General Electric held proprietary rights to the Plant's design basis.[263] This combined with being a nuclear industry leader made selecting General Electric as the chief design engineer an obvious choice.[264] General Electric's primary subcontractor was Shaw who served as General Electric's primary engineering subcontractor to support engineering and design of Program modifications.[265]

Given General Electric's prior work on Monticello and their control over proprietary design information, it was an efficient choice to utilize their prior knowledge and experience.[266] Mr. Crisp agreed, testifying that the Company's reliance on General Electric for such work was "absolutely" reasonable.[267]

Whenever design services provided by General Electric/Shaw were not up to Company standards, the Company undertook additional design efforts to improve on the design and constructability in accordance with "*The Engineering and Design Process,*

[260] Ex. 11, Sieracki Rebuttal at 28:13-15; Ex. 3, O'Connor Direct at 46:14-47:16; 49:15-50:10.

[261] Tr. Vol. I (O'Connor) at 93:21-23.

[262] Ex. 11, Sieracki Rebuttal at 45:5-14; Ex. 3, O'Connor Direct at 47:21-23.

[263] Ex. 11, Sieracki Rebuttal at 45:14-17; Ex. 3, O'Connor Direct at 47:26-48:2.

[264] Ex. 3, O'Connor Direct at 47:21-49:3.

[265] Ex. 3, O'Connor Direct at 48:33-49:2.

[266] Ex. 11, Sieracki Rebuttal at 45:14-17; Ex. 3, O'Connor Direct at 47:26-48:2.

[267] Tr. Vol. III (Crisp) at 32:17-19.

Xcel Energy Nuclear Department,"[268] which sometimes included engaging new design vendors.[269] Addressing design concerns and engaging added vendors to address designs that were not up to Company standards is proactive management.[270]

While the focus of this section is on our selection of the initial design contractor, the record establishes that the Company continued to make appropriate choices of designers and adapted when necessary. We provided an analysis of our design costs to show the potential amount of cost savings had the Company not moved some design work among vendors during the Program.[271] For example, we saved approximately $6.6 million dollars by pulling work from one designer (who had presented an infeasible design) and giving it to another.[272] We also saved about $2.2 million by changing HVAC system designs and moving the work to a different designer.[273] And we also designed a "contamination free" zone to facilitate access for our workers which resulted in material cost savings during the 2011 outage.[274]

(2) *Initial Installation Contractor*

Day Zimmerman was selected as the 2009 implementation contractor based on responses to a mid-2007 Request for Proposal (RFP).[275] Day Zimmerman is a widely-used and respected implementation contractor in the nuclear power industry.[276] The Company solicited responses to the RFP from Bechtel Corporation, Areva NP,

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[268] Ex. 9, O'Connor Rebuttal, Schedule 22.

[269] Ex. 9, O'Connor Rebuttal at 42:14-16; 63:16-17.

[270] Ex. 11, Sieracki Rebuttal at 44:19-21 (noting all decisions to change vendors were made for valid reasons); Ex. 9, O'Connor Rebuttal at 61:1-11.

[271] Ex. 9, O'Connor Rebuttal at 77 at Table 8.

[272] Ex. 9, O'Connor Rebuttal at 42:19-21; 62:25-63:8.

[273] Ex 9, O'Connor Rebuttal at 63:12.

[274] Ex. 9, O'Connor Rebuttal at 61:16-21.

[275] Ex. 3, O'Connor Direct at 49:24-50:10.

[276] Ex. 3, O'Connor Direct at 50:13-16.

General Electric/Shaw, Day Zimmerman/Sargent & Lundy, and received responses from the consortiums of General Electric/Shaw and Day Zimmerman/Sargent & Lundy.[277] Based on assessment of both proposals, the Company selected the response of Day Zimmerman/Sargent & Lundy.[278] There is nothing in the record to criticize or rebut the Company's selection. In fact, on the stand Mr. Crisp agreed "in general" with Mr. O'Connor's assessment that implementation work was not within General Electric's "wheelhouse" and was better suited to others.[279]

The Company decided, while the Commission was reviewing the EPU Certificate of Need Application, that it would target the 2009 outage to commence Program implementation and would complete six modifications during this outage.[280] The actual cost for Program implementation during the 2009 outage totaled $34 million.[281]

Under Day Zimmerman's direction, the 2009 modifications were implemented successfully.[282] The Company observed reasonably good productivity from its vendors and increases is budgeted amounts were related to the complexity of work.[283] Most of these costs were attributable to the need for additional labor and materials to complete the modifications.[284] During the 2009 outage, approximately 90 percent of the costs paid to Day Zimmerman were for craft labor expenses.[285]

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277 Ex. 3, O'Connor Direct at 49:24-50:10.

278 Ex. 3, O'Connor Direct at 49:24-50:10.

279 Tr. Vol. III (Crisp) at 36:14-37:2. Indeed, General Electric informed the Company that their expertise was not in implementation and recommended someone other than them take that role. Tr. Vol. I (O'Connor) at 107:15-23.

280 Ex. 3, O'Connor Direct at 71:25-27.

281 Ex. 3, O'Connor Direct at 71:27 and 72:4 at Table 10.

282 Ex. 3, O'Connor Direct at 72:7-73:3.

283 Ex. 3, O'Connor Direct at 73:19-21.

284 Ex. 3, O'Connor Direct at 73:21-23.

285 Ex. 9, O'Connor Rebuttal at 47:22-23.

c. Post-2009 Outage/Pre-2011 Outage Actions

After the 2009 outage, the Company performed a lessons learned evaluation and identified opportunities to work more efficiently with the lead design and engineering vendors and monitor quality control.[286] As part of this assessment, however, the Company determined that its project management practices were appropriate.[287]

Due in large part to the successful 2009 implementation, the Company decided to continue its relationship with Day Zimmerman as the lead installer for the planning phase into the 2011 outage.[288] Between the 2009 and 2011 outages, however, the Company identified issues with certain GE/Shaw design proposals for the 2011 outage.[289] As a result, we proactively rejected all engineering packages prepared for the 2011 outage that were presented in 2010.[290] During this time, the Company pursued recovery plans to complete designs that would meet our specifications and utilized internal engineering resources to address shortcomings in outage planning.[291]

Rejecting all engineering packages in 2010 was a prudent decision to make because it would be unreasonable the Company to accept marginal designs. This decision demonstrates the Company valued getting the work right, which is critical in the nuclear environment, over time pressures. This decision contributed to the decision not to complete all remaining work during 2011.

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286 Ex. 3, O'Connor Direct at 74:25-75:2.

287 Ex. 9, O'Connor Rebuttal at 67:15-17.

288 Ex. 3, O'Connor Direct at 75:13-18;

289 Ex. 9, O'Connor Rebuttal at 62:25-63:8.

290 Ex. 9, O'Connor Rebuttal at 68:3-4.

291 Ex. 3, O'Connor Direct at 75:22-25.

In addition to the design issues, three other issues led us to evaluate implementing the remaining work into two more outages instead of one.[292] First, the need to install the new electrical distribution system presented significant prolonged shutdown risk and required intricate work sequence planning.[293] If the work was not completed in the time allotted for the outage, the Company faced the risk of not having Monticello online during the 2011 summer peak.[294] Second, the NRC license amendment request was on hold while the agency and the Company resolved issues with the Containment Accident Pressure ("CAP") standards.[295] Third, the Company faced fabrications issues with certain equipment and had to work with vendors to identify action plans to correct these issues.[296]

Besides being the right thing to do, the decision to extend the final Program implementation also gave the Company an opportunity to do certain installations for modifications while the Plant was online and minimize the work to be performed during the final implementation outage.[297] The Company filed a Notice of Changed Circumstances on November 22, 2011 with the Commission to notify it of the change in timing.[298] The Commission notified the Company on January 6, 2012 that the change in timing of the Program implementation was acceptable without the need to reopen the Certificate of Need.[299]

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292 Ex. 3, O'Connor Direct at 76:15-24.

293 Ex. 3, O'Connor Direct at 76:17-18.

294 Ex. 3, O'Connor Direct at 76:18-19.

295 Ex. 3, O'Connor Direct at 76:20-21.

296 Ex. 3, O'Connor Direct at 76:22-24.

297 *See* Ex. 3, O'Connor Direct at Schedule 28.

298 Ex. 2, Alders Direct at 25:4-10; Ex. 3, O'Connor Direct at 77:4-5.

299 Ex. 2, Alders Direct at 25:10-12.

d. Work Transfers

Making contractor changes over the course of the Program is common because design and contractor performance issues have become more frequent in a complex industry like nuclear power plant construction.[300] Nuclear vendor performance has declined in recent years due to growing competition for talent in the nuclear industry, a shrinking skilled labor pool and high demand for skilled workers, general attrition related to retirements because of the aging nuclear workforce, the decrease in the number of U.S. nuclear engineering degree programs, and talent migration.[301]

As the Company moved through 2010, it faced design and performance challenges.[302] We responded to these challenges by occasionally moving some work to other contractors with more specialized expertise.[303] This comported with our strategy of selecting the right contractor for the work at hand. For example, we changed vendors on a portion of the piping work for the reactor feed pumps and motors modification.[304] The original design required a removing and rerouting over 290 feet of piping.[305] This was not reasonably constructible so we chose a new vendor with expertise in the area to produce a final design, removing and rerouting only 60 feet of piping.[306] This single change saved approximately $6.6 million in installation costs.[307] And there were other instances where management decisions saved money.[308]

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300 Ex. 4, Stall Direct at 61:18-64:15.

301 Ex. 4, Stall Direct at 63:18-27; Ex. 3, O'Connor Direct at 61:21-62:22.

302 Ex. 3, O'Connor Direct at 63:19-20.

303 Ex. 3, O'Connor Direct at 66:23-26.

304 Ex. 9, O'Connor Rebuttal at 62:22-63:8.

305 Ex. 9, O'Connor Rebuttal at 62:22-63:8.

306 Ex. 9, O'Connor Rebuttal at 62:22-63:8.

307 Ex. 9 O'Connor Rebuttal at 62:22-63:8.

308 Ex. 9, O'Connor Rebuttal 62:18-20.

e. 2011 Outage

The implementation efforts during the 2011 outage were more challenging than those undertaken during the 2009 outage.[309] Additionally, the Company was faced with as-found conditions related to the condensate demineralizer system once it began the 2011 outage that required additional design efforts and unplanned implementation efforts to be coordinated between General Electric and Day Zimmerman, during the outage.[310] Because of the high-radiological environments in the condensate demineralizer vessel vaults, special work plans were developed to protect installers, and although the Company and Day Zimmerman had worked together to develop proposed work plans, Day Zimmerman was unable to accurately predict the amount of time that this work would require, which was compounded by the as-found conditions during the outage.[311]

Beside the condensate demineralizer vessel vaults, a substantial and highly sensitive portion of the installation work was performed in confined, radiological spaces.[312] These areas are not only a difficult environment in which to perform work but also create risk in that they cannot be fully vetted prior to work commencing due to accessibility limitations. As-found conditions in the Plant required management to respond to circumstances discovered during installation, which necessitated field design changes.[313] Field design changes resulted from interferences discovered during installation that generally cannot be discovered in a detailed up-front engineering process.[314] This happened approximately 2,000 times during the Program due to

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309 Ex. 3, O'Connor Direct at 80:6-13.

310 Ex. 9, O'Connor Rebuttal at 58:21-27.

311 Ex. 3, O'Connor Direct at 80:15-81:10.

312 Ex. 3, O'Connor Direct at 5:16-17, 33:10-11.

313 Ex. 9, O'Connor Rebuttal at 75:9-14 and Schedule 27.

314 Ex. 9, O'Connor Rebuttal at 76:23-25 and Schedule 22 (9 of 9).

accessibility and installation complexities.[315] For instance, many Plant areas are not accessible during normal operation due to high levels of radiation, while some interferences like the location of rebar, piping and wiring inside of concrete walls are not apparent until the work begins.[316]

The complexity of the approximately 2,000 instances dictated the amount of time and effort of the Company's response.[317] Simple changes required only a few hours to address while the most complex changes required hundreds of hours of effort.[318] Field design changes often required reanalysis, preparation time, review time, and appropriate time for approval.[319] For the most complex changes, a change in one system impacted other nearby or related systems, thereby requiring reanalysis of a number of systems.[320] This analysis was highly iterative.[321] Each time a change was proposed and analyzed, the Company confirmed that the systems worked together in accordance with applicable standards.[322] This sometimes required multiple rounds of reanalysis, as the "ripple" effects of a particular change were addressed.[323]

In sum, the Company expended between $25-30 million to address field design changes as summarized below:[324]

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315 Ex. 9, O'Connor Rebuttal at 75:18-19 and Schedule 27 (1 of 8).

316 Ex. 9, O'Connor Rebuttal and Schedule 27 (2 of 8).

317 Ex. 9, O'Connor Rebuttal at Schedule 22 (8-9 of 9).

318 Ex. 9, O'Connor Rebuttal at Schedule 22 (9 of 9).

319 Ex. 9, O'Connor Rebuttal at Schedule 22 (of 9).

320 Ex. 9, O'Connor Rebuttal at Schedule 22 (9 of 9).

321 Ex. 9, O'Connor Rebuttal at Schedule 22 (9 of 9).

322 Ex. 9, O'Connor Rebuttal at Schedule 22 (9 of 9).

323 Ex. 9, O'Connor Rebuttal at Schedule 22 (9 of 9).

324 Ex. 9, O'Connor Rebuttal at 77.

Category of Change	Total Number	Sample Size Reviewed	Cost per Change	Total Associated Cost
Basic	Approx. 1,600	Approx. 5%	$1,000-$10,000	$8-13 million
Intermediate	Approx. 400	Approx. 5%	$10,000-$250,000	$12 million
Complex	2	2	$2 million and $3 million	$5 million

No witness challenged Company management's response to any of these changes, or contested that virtually all of them were unavoidable even with more preparation and planning in design. At most, no more than $1 million in field design changes could have been avoided.[325]

f. Bechtel Retention

After the conclusion of the 2011 outage, the Company reevaluated whether it should proceed with Day Zimmerman as the lead implementation vendor because the 2013 implementation required a "different kind of skill set" given that the work to be performed during that outage was beyond Day Zimmerman's "mechanical-related work" capabilities.[326] Additionally, from 2009 to 2011, the Company had experienced a trend of less experienced, or new, nuclear craft labor.[327] The Company retained Bechtel, to prepare for and oversee implementation for the 2013 outage, but required that Bechtel retain Day Zimmerman as its main mechanical subcontractor and to retain institutional knowledge and preserve implementation continuity.[328]

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325 Ex. 9, O'Connor Rebuttal at 78:9-11.

326 Tr. Vol. I (O'Connor) at 97:11-98:10.

327 Ex. 9, O'Connor Rebuttal at 69:14-15.

328 Ex. 9, O'Connor Rebuttal at 69:21-70:3.

Bechtel is a large and sophisticated multi-national company with deep expertise in the area of nuclear construction.[329] As described by Mr. Sieracki in response to the ALJ's question about use of a contractor such as Bechtel, a different organization may be needed to accomplish the more sophisticated work we needed to complete construction.[330] Bechtel was retained because the Company recognized that the final modifications scheduled for the 2013 outage would be the most challenging installations of the Program.[331] Bechtel had depth in the work to be performed in 2013, which included not only mechanical work but also "electrical -- huge electrical, a lot of instrumentation, and a lot of testing now in integrated operations on all of these systems."[332] It was logical to switch implementation contractors for the 2013 outage.

g. 2013 Outage

Despite our decision to bring in Bechtel and despite our bringing in new personnel to manage the 2013 outage,[333] the 2013 outage was the most challenging of all.[334] For instance, to install the 13.8 kV electrical distribution system, electric cable, more than two inches in diameter and in excess of 100 pounds per foot, required teams of 10 electricians to pull the cable through the conduit.[335] Overall, approximately 14 miles of new cable and raceway had to be installed in the Plant for the 13.8 kV system.[336] During the 2013 outage, the Company also faced lower than anticipated productivity,

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329 Ex. 3, O'Connor Direct at 84:1-2.

330 Tr. Vol. II (Sieracki) at 59:5-25.

331 Ex. 3, O'Connor Direct at 83:23-25.

332 Tr. Vol. I (O'Connor) at 98:2-12.

333 Tr. Vol. I (O'Connor) at 100:9-13 (describes individuals who left after 2011 outage and were replaced).

334 Ex. 3, O'Connor Direct at 83:24-26; Tr. Vol. I (O'Connor) 70:17-20.

335 Ex. 3, O'Connor Direct at 90:10-14.

336 Ex. 3, O'Connor Direct at 132:16-17. Although the Company decided to install a 13.8 kV system for the non-safety-related equipment, this magnitude of work would have been required if the Company had decided to install a second 4 kV system. Ex. 3, O'Connor Direct at 132:19-20; Ex. 9, O'Connor Direct at 96:27-97:1 and 98:3-13. No matter what voltage was installed, the installation would have been labor- and time-intensive and the $119 million would not have been avoidable absent the EPU. Ex. 9, O'Connor Rebuttal at 88:19-20.

which was beyond its control.[337] The final cost of the outage was $151 million and the duration was 138 days.[338] Six major modifications were installed.[339]

While the Department's criticisms focused more on the 2011 outage than the 2013 outage, management responded to the challenges with both outages appropriately.[340] The fact that outage cost per day remained the same for both outages indicates that the Company's management of both outages was steady and appropriate.[341]

	2011 Outage	**2013 Outage**
Outage Planning	$10.7 million	$32 million
Outage Costs	$135 million	$151 million
Actual Outage Days	87	138
Estimated cost per Outage Day	$0.91 million	$0.91 million

h. Conclusion of this Question

In summary as to this question, the Company's substantial and detailed presentation on this record establishes that we managed the LCM/EPU Program reasonably. While we do not claim that our performance was perfect, it was dedicated and proactive and designed to complete our work in a reasonable fashion under the circumstances. Our performance also reasonably evolved as we were faced with changing circumstances. As a result, the record would not support any general or specific finding of mismanagement under the circumstances.

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337 Ex. 3, O'Connor Direct at 90:20-21.

338 Ex. 9, O'Connor Direct at 71:1 and Table 6.

339 Ex. 9, O'Connor Direct at 88:11.

340 Ex. 9, O'Connor Rebuttal at 73:21-22.

341 Ex. 9, O'Connor Rebuttal at 74:16-22 and Table 7.

Management actions need only fall within a "zone of reasonableness" to be prudent.[342] And the zone of reasonableness requires flexibility and moderation such that a "determination that one course of conduct is reasonable is not a determination that any other course is unreasonable."[343] All determinations of management reasonableness or prudence are "judged according to whether a utility's actions were reasonable and prudent in light of circumstances at the time[.]"[344] Under these well established standards the Company's management of the Program was prudent.

More specifically throughout the Program, the Company (1) executed vendors contracts that included an orderly process for change orders, (2) required vendors to develop and implement recovery plans to overcome performance issues that arise during implementation, (3) implemented rigorous QA/QC procedures to ensure quality, and (4) employed internal project managers to lead the Company's Program team and to oversee key vendors.[345] That does not mean the Company did not adapt to changing Program circumstances.[346] Rather, the Company utilized its structure to adapt its actions, which is a sign of strong management and included all of circumstances described above.[347] The Company oversaw the efforts of numerous vendors that were selected based on their ability to do the work.

With a Program as large and complex as the one we undertook and the number of vendors we had to retain, some disputes between the Company and vendors about the work were inevitable.[348] Making vendors changes along the way implicates

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342 *See Fed. Power Comm'n.*, 426 U.S. at 278.

343 *Application of Peoples Natural Gas Co.*, 389 N.W.2d at 908.

344 *In re Citizens Communic'ns Co.*, 220 P.U.R.4th 280 (Vt.P.S.B. 2002).

345 Ex. 9, O'Connor Rebuttal at 66:16-25.

346 Tr. Vol. I (O'Connor) at 102:1-5.

347 Ex. 11, Sieracki Rebuttal at 28:5-6; Ex. 3, O'Connor Direct at 83:7-84:14.

348 Ex. 9, O'Connor Rebuttal at 80:5-15.

potential claims the Company may possess against certain vendors.[349] But the presence of potential claims the Company possesses does not indicate imprudence, rather it evidences good judgment exercised by management to promptly address any deficient vendor work by making a change in the vendor responsible for the work.[350] By so doing the Company avoided delays in the Program associated with contemporaneous dispute resolutions while preserving the ability to pursue claims at a more appropriate time in the future as warranted. The Company has committed to offset any claims or settlements it achieves to the cost of the Program so that ratepayers obtain the benefit of any such settlements.[351]

The largest management decisions focused on the outages during which the most difficult work was performed. After the 2009 outage, the Company assessed its performance and its management practices.[352] This is a process the nuclear industry calls "lessons learned," which was prudently followed by the Company.[353] Because the 2009 outage demonstrated reasonably good performance and productivity by Day Zimmerman, few changes were made headed into the 2011 outage.[354] The difficulties the Company encountered during the 2011 outage suggested that the remaining work for final implementation would be significant and that it was not sustainable to rely as heavily on internal resources.[355] The Company called upon Bechtel to manage the 2013 outage that, in the end, led to successful completion of the Program.

[349] Ex. 9, O'Connor Rebuttal at 80:5-15.

[350] Ex. 9, O'Connor Rebuttal at 80:5-15; Ex. 11, Sieracki Rebuttal at 7:4-9.

[351] Ex. 9, O'Connor Rebuttal at 80:13-15.

[352] Ex. 9, O'Connor Rebuttal at 67:15-24.

[353] Ex. 11, Sieracki Rebuttal at 5:15-20; Ex. 3, O'Connor Direct at 74:20-75:2.

[354] Ex. 9, O'Connor Rebuttal at 67:15-24.

[355] Ex. 9, O'Connor Rebuttal at 67:9-11.

Management should not be faulted just because Program costs rose. No witness challenged that (1) any of the amount we spent was not supported by the actual work performed or that (2) different management would have obviated the need to perform the work or lessened the man hours necessary to complete the work.[356] All management decisions were made to accomplish the Program as soon as reasonably possible while doing the right work for the Plant as changing circumstances justified. We hired and oversaw the efforts of some the best designers and constructors in the industry, who despite their expertise still faced significant challenges. No party has even alleged we should have selected others to do the work. We reacted responsibly to progressively difficult outages by adding internal resources and making changes in our vendors as the needs of Program developed along the way. Whether different management decisions could have perhaps been made, is irrelevant because the prudence inquiry does not focus on the propriety of one decision over another so long as both were reasonable under the circumstances. The Company has satisfied its burden to demonstrate the reasonableness of its management of the Program.

5. <u>Is an allocation of costs between the LCM and EPU functions relevant to this prudence review?</u>

a. *Uses of LCM/EPU Split*

The Commission's Order Approving Investigation and Notice and Order for Hearing in this proceeding directed the Parties to consider several issues, including "how these [Program] costs should be allocated between the Life Cycle Management and Extended Power Uprate parts of the Monticello project."[357] Stated differently, the Commission separately noted that the Parties should address in these proceedings

[356] For example, the 13.8 kV system alone required over 230,000 work hours to install. Ex. 3, O'Connor Direct at 134:14.

[357] Order Approving Investigation and Notice and Order for Hearing at p. 3, Docket No. E-002/CI-13-754 (Dec. 18, 2013).

"which cost increases are due to 1) solely the EPU, 2) solely the LCM and 3) both projects."[358] The Company respectfully submits that the total costs of the Program are attributable to the integrated Program, which is overwhelmingly cost-effective as a whole, and that an LCM/EPU split is no longer relevant to this proceeding.

The Company's position has always been that all costs incurred in furtherance of the LCM/EPU Program were incurred for the single integrated purpose of maximizing the value of Monticello by extending its life and increasing its capacity.[359] While the initial determination of a split between LCM and EPU had value in the Certificate of Need stage to model whether it was cost-effective to proceed with an EPU, no party has contested that the Company's 58.4/41.6 percent LCM/EPU split was appropriate at the time and this split was not contested at the Certificate of Need proceedings.

It is important to be clear that the Program has always been "overwhelmingly cost-effective as a whole."[360] There has been no dispute that if the Commission had required a Certificate of Need for LCM activities, and if LCM and EPU Certificates of Needs had been considered simultaneously – whether together or separately – the overall Program would not have been approved with significant benefits over the next best alternative. Indeed, the Company depicted these benefits – utilizing even the final Program costs the Company could not have predicted – in Table 5 from Mr. Alders' Direct Testimony:[361]

358 Order Approving Investigation and Notice and Order for Hearing at p. 4, Docket No. E-002/CI-13-754 (Dec. 18, 2013).

359 Ex. 3, O'Connor Direct at 3:3-7.

360 Ex. 309, Shaw Direct at 14:1-2.

361 Ex. 2, Alders Direct at 34.

2008 Hindsight (Total Plant) Value at $665 MM

Monticello Life Extension + EPU	PVSC Results $millions
Monti Decommissioning (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$893
Monti Total	$4,266

Monticello Retirement and Replacement	PVSC Results $millions
Monti Decommissioning (2011)	$423
Replacement Capacity	$1,615
Replacement Energy	$2,954
Incremental Emissions	$585
Total Retirement Costs	$5,577

Net PVSC (Benefit)/Costs	**($1,311)**

Finally, a split between LCM and EPU activities as applied to final Program costs represents a hindsight analysis, and does not address whether the Company's decisions and actions were prudent at the time.[362] The Company's decisions to replace certain equipment was not based on whether a certain percentage of the work would be attributable to LCM or EPU in the end, but on what work was needed to accomplish both tasks – with keeping the Plant running the priority.[363] This is especially true since much of the work the Company did would have been necessary to maintain the existing 600 MW at Monticello regardless of whether an additional 71 MW was added.[364] As a result, any final LCM/EPU split is based on the results of the Company's actions and not on the prudence or reasonableness of decisions made and actions undertaken along the way.

Nevertheless, the split of final project costs has been a topic of considerable debate in this proceeding. We believe this is largely because the ALJ and Commission utilized the LCM/EPU split from the Monticello EPU Certificate of Need proceedings

362 Ex. 425, Final Order Approving Nuclear Cost Recovery Amounts for Florida Power & Light Company and Duke Energy Florida, Inc., Docket No. 130009-EI, at 35-36 (Florida Public Utilities Commission, (Oct. 18, 2013).

363 Ex. 3, O'Connor Direct at 145:10-16.

364 Ex. 9, O'Connor Rebuttal at 12:17-21; 13:4-9.

because (1) Monticello did not yet have its uprate license; and (2) determining what portion of Program costs was associated with the increased capacity allowed a determination of the Program costs to be excluded from rate base until the EPU was "used and useful." While an LCM/EPU split may have been an attractive mechanism for that purpose, a determination of whether the Company was prudent does not depend on this mechanism.[365]

Finally, to the extent a cost-effectiveness test is used to determined whether Program costs were just and reasonable, no split is necessary because the Parties agree that the Program is cost-effective as a whole. Attempting to theoretically divide the Program into parts does not fairly represent the overall value of the Company's investments. Nor does such a theoretical split change that the need for and decision to proceed with the EPU and LCM was each previously evaluated, modeled, and vetted through contested case proceedings based on the information available at the time of those proceedings. The fact that those costs increased, or that a Party might now assign final Program costs differently between LCM and EPU activities, would only incorrectly have the prudent investment standard turn on the results of the Company's actions rather than the actions themselves.[366]

b. Certificate of Need

To the extent any split is applied is this proceeding over the Company's objection, the Company recommends the 58.4/41.6 percent LCM/EPU split used in the 2008 Certificate of Need is the only supportable option.[367] This split was derived by

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365 *See* Ex. 311, Shaw Surrebuttal at 7:2-8 (states that cost-effectiveness does not equate with prudence).

366 *Gulf States Utils. Co.*, 578 So. 2d at 85 ("[T]he focus in a prudence inquiry is not whether a decision produced a favorable or unfavorable result, but rather, whether the process leading to the decision was a logical one, and whether the utility company reasonably relied on information and planning techniques known or knowable at the time.").

367 To provide the information needed to assess the need for the uprate, the Company had to provide an estimate of the cost of the uprate. That proxy was developed as a good faith estimate using reasonable

looking at the total Program cost at the Certificate of Need stage and identifying the costs that were likely attributable to the LCM vs. EPU aspects of the Program. The EPU accounts for 41.6 percent, or $133 million, of anticipated total Program costs as of the 2008 EPU Certificate of Need.[368] There has been no dispute that the Company's 58.4/41.6 percent LCM/EPU split was reasonable at the time of the Monticello EPU Certificate of Need.

This 58.4/41.6 percent LCM/EPU split has the benefit of having actually been used in the relevant timeframe (2006-2008) to assess the alternatives that were available at the time we decided to pursue the uprate.[369] If the Commission applies this split to the facts of this case, it will be judging our performance based on facts and circumstances known at the time of our performance. Thus no impermissible hindsight will be injected into the analysis.

Moreover, the 58.4/41.6 percent LCM/EPU split is uncontested in this record. The Company provided the 58.4/41.6 percent LCM/EPU split allocation to estimate the costs associated with LCM versus the costs attributable to the incremental 71 MW.[370] In fact, this ratio was conservative based on the factors known at the time. Rather than use a ratio of six to one (LCM/EPU) as suggested by the 2003 presentation included with Mr. O'Connor's Rebuttal Testimony,[371] the Company used a ratio of

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engineering judgment at the time and was intended to be conservative. Ex. 9, O'Connor Rebuttal at 81:23-82:26.

368 In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at 15, ¶ 55, Docket E002/GR-12-961 (July 3, 2013) ("In its CON application, the Company estimated the total cost of the EPU and LCM activities at $320 million. Of that amount, the Company estimated that $133 million, or 41.6 percent, was attributable to the EPU alone. The estimate was not based on an incremental cost study. Instead, costs for activities that changed the output of the plant were assigned to the EPU and costs relating to aging equipment were assigned to the LCM.").

369 Minn. R. 7849.0120(B)(2); Ex. 15, Alders Surrebuttal at 13:14-16; Ex. 9, O'Connor Rebuttal at 81:11-14.

370 Tr. Vol. II (Alders) at 11:15-21.

371 Ex. 9, O'Connor Rebuttal at Schedule 4.

roughly six to four (58.4 LCM/41.6 EPU) for modeling purposes to ensure the EPU costs were not underrepresented.[372] Thus the 58.4/41.6 percent LCM/EPU split was not only the Company's initial good faith analysis of a conservative attribution of LCM/EPU costs, it was contemporaneous with our decision to proceed.[373]

If the Commission finds no imprudence occurred, there is no basis to utilize a cost-effectiveness test or LCM/EPU test to determine a proxy remedy. And if the 2008 split analysis is utilized, the actual costs of the Project are still cost-effective.[374] Under either circumstance, no further analysis is required.

c. After-the-Fact Split Not Relevant

Both the Company and Dr. Jacobs prepared an after-the-fact engineering analysis[375] of a likely LCM/EPU split based on final costs of the Program. While these splits (78 LCM/22 EPU Company; 14.3 LCM/85.7 EPU Department) each offer alternative hindsight views of the division between the twin aspects of the Program, the Parties' views are widely disparate and neither addresses whether the Company's decisions were initially prudent. Because such splits cannot replicate the reasonable conditions that existed at the time, they are generally inapplicable to this proceeding.

If the Commission determines that (i) imprudent actions occurred, (ii) an LCM/EPU split is appropriate to the final remedy determination, and (iii) the contemporaneous 58.4/41.6 percent LCM/EPU split should not be used, the Commission is left with

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372 Ex. 8, Alders Rebuttal at 10:22-27.

373 Ex. 2, Alders Direct at 22:15-23; Ex. 8, Alders Rebuttal at 10:18-27. Tr. Vol. II (Alders) at 9:21-10:1; Ex. 8, Alders Rebuttal at 21:13-22:15.

374 Ex. 8, Alders Rebuttal at 28:3-5.

375 Both Parties' engineers conducted these analyses – rather than the Parties' accountants – and Dr. Jacobs acknowledged that his split involved an engineering rather than an accounting exercise. Tr. Vol. III (Jacobs) at 99:4.

the Parties' after-the-fact LCM/EPU splits or its own to develop a hybrid split. The Company does not recommend using an after-the-fact split for assessing prudence.

a. Conclusion of this Question

In summary as to this question, in assessing our prudence we do not believe the LCM/EPU split concept should be used; rather, our performance should be judged as a whole. If, however, the Commission believes a split is necessary to assess the prudence of our decisions and actions implementing the Program, then the Commission should use the 58.4/41.6 percent LCM/EPU split that was developed and used in the 2008 Certificate of Need.

V. REPLY TO CRITICISMS

Despite our detailed explanations regarding the decisions we made for the LCM/EPU program, both the Department and the OAG responded with essentially four generalized criticisms to support their respective disallowances. They are:

- General criticisms about our failure to estimate costs accurately on the front end, despite the fact that inaccurate cost estimation and use of more "contingency" did not increase costs.[376]

- General observations about "good" project management while assuming our management was wanting, without tying our performance to specific facts or examples, relying primarily on the 2011 Cost History document that provides one employee's hindsight assessment of the development of the project.[377]

- Imposition of an after-the-fact remedy[378] that superimposes 2013 costs and Dr. Jacobs' 2013 hindsight LCM/EPU split on what we knew in 2008. Dr. Jacobs uses a single "contemporaneous" document – Enclosure 8 to Xcel Energy's

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376 Ex. 300, Crisp Direct at 15-23.

377 Ex. 301, Crisp Direct at 23-27.

378 Ex. 313, Campbell Direct at 27:21-18:1 (cost-effectiveness proxy); Ex. 200, Lindell Rebuttal at 26:19-28:2 (all costs over Certificate of Need estimate inherently suspect proxy).

EPU License Amendment Request[379] – to develop his after-the-fact split, while ignoring numerous other "contemporaneous" documents that contradict his conclusions. The Department recognizes that it results in no disallowance if the split is less than 73 percent EPU,[380] a level easily met on this record.

- Criticisms about the Plant generally, complaints about the complexity of the Program and our choice of accounting for it as an integrated initiative, neither of which are alleged to have resulted in higher costs, and the embedded assumption that higher costs require a remedy.[381]

As we will explain, neither the Department nor the OAG provide evidentiary support sufficient to overcome our *prima facie* case on the reasonableness of our costs.

A. <u>Our Decision to Proceed was Prudent</u>

The Department and OAG call into question the Company's initial decision to proceed with the Program. While it is not entirely clear that they conclude we should not have proceeded with the Program at all, the parties do criticize our initial decision on three grounds: (i) had parties understood in hindsight the final costs it calls into question our decision to move forward; (ii) moving ahead as an integrated effort was wrong, and (iii) our initial cost estimates were too low and should have been studied more prior to proceeding. In this Section, we respond to these criticisms.

We recognize that one decision here may overlap with our responses to the questions posed in the affirmative case. This is because the Company's decision to proceed is important and a finding that suggests our initial decision was imprudent has broad implications throughout this case.

379 Ex. 305, Jacobs Direct at Attachment B.

380 Ex. 309, Shaw Direct at 31:4-7.

381 Ex. 313, Campbell Direct at 34:5-23 ("The Monticello plant has issues . . . .").

1. Support for Decision to Proceed

2001 through 2008 was a time of tremendous change in State energy policy, increasing forecast resource needs, and unprecedented high natural gas prices. These factors greatly influenced the Company's decision to pursue the Program and the approach we took to multi-track our efforts. It is necessary to consider the Company's decision to (i) proceed with the Program; (ii) as an integrated effort; (iii) with high-level initial cost estimates; and (iv) attribution of costs to the LCM and EPU aspects of the Program, all in the context of the circumstances facing the Company at the time these decisions were made. As we will explain in greater detail in the sections that follow, the record establishes that the Company made reasoned, prudent decisions on each of these factors based on the information reasonably available at the relevant times.

The need for LCM work derived in part from the Plant's history. In the 1990s and very early 2000s the Monticello facility was managed with the expectation it would be shut down in 2010[382] due to the expiration of its operating license and Minnesota State law precluding nuclear units from operating beyond their initial NRC licenses.[383] And although the reactor was capable of longer operation and an increase in capacity, the balance of Plant systems were designed for an expected 40-year operating license,[384] using 1960s technology when the Plant was constructed.[385]

382 Ex. 3, O'Connor Direct at 43:12-22.

383 In 1994, the Minnesota Legislature placed a moratorium on additional dry cask storage in the State of Minnesota, effectively limiting the operation of Monticello to its original operating license. 1994 Minn. Laws c 641, art 1, s 2(d). As a result, the Company managed the plant to retirement until the statutory moratorium for additional dry cask storage was lifted. 2003 Minn. Laws 1st Spec. Sess. ch. 11, art. 1, § 2.

384 The overall initial design of Monticello was not conducive to replacing significant components or doing upgrades or replacements. It was assumed at the time of construction, that original equipment would last the duration of the license and then the plant would be shut down. Ex. 3, O'Connor Direct at 33:1-8. In many instances, mechanical and electrical equipment was installed, with associated piping, wiring, hangars, and support field-run, and then containment or support concrete was poured around these components. Ex. 3, O'Connor Direct at 33:6-11; Ex. 9, O'Connor Rebuttal at 18:19-20 ("Field-run" means that the supporting wiring, piping, hangars, and electrical conduit were run according to what could be accomplished during construction and final placement of these systems were not necessarily documented on as-builts.).

There has been no dispute in this record that this baseload need existed and was of serious concern to the Commission and other Company stakeholders. Nor is there any contention that the work we did was the wrong work. Combined with the Company's thorough benchmarking of other nuclear facilities' LCM/EPU activities and analysis conducted by the Company's experts (including General Electric), we had good reason to pursue the Program in the manner undertaken by the Company.

2. Integrated Effort was Reasonable

From 2003 to early 2006, the Company identified the possibility of an uprate, but focused on extending the life of the Plant and obtaining the approvals to continue operations at Monticello.[386] This was a logical approach, as the uprate would offer no benefits to customers if the Plant's operating license was not approved. Had the Company undertaken the work necessary to keep the Plant running without also considering EPU needs, we would have had to replace or modify the same equipment when it did undertake the EPU. Conversely, if ignored the old equipment, it is doubtful whether the Plant could still be operational.

We note a 20-year life is not long for a large generating asset and major repairs midway through that life would have to be spread over a much shorter period of time and may not be cost-effective.[387] It was far better to combine all of that work in a

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Additionally, the electrical distribution system installed in the 1960s, which supported safety- and non-safety-related equipment throughout the Plant, was sized to support Monticello as it was designed in the 1960s and according to the regulatory margin and regulatory expectations in place at that time. Ex. 3, O'Connor Direct at 33:13-16.

385 Ex. 3, O'Connor Direct at 32:24-33:14; Ex. 9, O'Connor Rebuttal at 4:22-5:22, 114:2-21; Ex. 8, Alders Rebuttal at 4, n.5 (citing NRC: Fact Sheet on Reactor License Renewal at http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/fs-reactor-license-renewal.html (last visited Aug. 8, 2014) ("Economic and antitrust considerations, not limitations of nuclear technology, determined the original 40-year term for reactor licenses. However, because of this selected time period, some systems, structures, and components may have been engineered on the basis of an expected 40-year service life.")).

386 Ex. 8, Alders Rebuttal at 7:21-8:4.

387 Ex. 3, O'Connor Direct at 8:16-18.

single initiative that maximized the value of the asset and also allowed for a longer depreciation schedule to lower customer costs.[388]

The Department argues that our decision to move forward with an integrated effort was wrong since the Company could have replaced only that work necessary for the EPU and delayed LCM work. Specifically, Dr. Jacobs speculates that if not for the integrated Program, the Company could have delayed certain LCM projects for some amount of time.[389] Dr. Jacobs' underlying logic is faulty. His assumption that the Company was in a hurry to do the EPU and could have delayed unspecified, LCM projects ignores that there would be no EPU if the Plant itself was not kept in an operational condition. Retaining the existing 600 MW was far more critical than adding an incremental 71 MW.[390] In light of these considerations and the efficiencies gained by an integrated approach, we appropriately managed the integrated effort to ensure the continued operation of the Plant first and its expanded capacity second.

The Company also questions the evidentiary weight that should be assigned to Dr. Jacobs opinions.[391] He admitted under cross-examination that he made this statement without having evaluated what projects could have been delayed,[392] without knowing what conditions were required by the NRC when it granted the life extension license amendment,[393] without determining how long the Plant could have operated at all absent completion of the life-cycle management work[394] and while acknowledging that

388 Ex. 9, O'Connor Rebuttal at 121:22-23

389 Ex. 307, Jacobs Surrebuttal at 12:2-13.

390 Ex. 10, O'Connor Rebuttal at 88:8-13 and Schedule 32.

391 *See Lee v. Crookston Coca-Cola Bottling Co.*, 290 Minn. 321, 326, 188 N.W.2d 426, 431 (Minn. 1971) (stating that opinion testimony that is without foundation is "purely speculative, immaterial and inadmissible").

392 Tr. Vol. IV (Jacobs) at 16:1-6.

393 Tr. Vol. IV (Jacobs) at 14:12-25.

394 Tr. Vol. IV (Jacobs) at 36:16-20.

the work was necessary "at some point" to continue operating the Plant.[395] Indeed, Mr. Crisp admitted that any work delayed to the future would likely be more costly due to inflation.[396]

3. Cost Estimate was Reasonable

Our cost estimate of $320-346 million ($2008$) was based on conceptual design plans.[397] The initial cost range was based on an estimated cost of $29-32 million for the steam dryer, $21 million for the 13.8 kV electrical distribution system, and $270-293 million ($2006$) for all other LCM/EPU costs.[398]

As a preliminary matter, we want to address a misunderstanding between the Company and the Department as to this range. The Department viewed the $346 million figure as $320 million in 2008 dollars escalated to present dollars.[399] The $346 million was included in the 2008 Certificate of Need was in 2008 dollars.[400] Without AFUDC, $346 million in 2008 dollars equates to $397.5 million in 2014 dollars.[401] With AFUDC added, the initial estimate in 2014 dollars is $453 million, which is an apples-to-apples comparison with the $748 million used by the Department.[402]

The Company's $346 million ($2008$) initial estimate was a high-level and good-faith estimate of the overall cost to complete the Program.[403] Not only was this a reasonable approach, but using conceptual design estimates was common practice for

395 Tr. Vol. IV (Jacobs) at 14:9-11.

396 Tr. Vol. III (Crisp) at 74:11.

397 Ex. 3, O'Connor Direct at 31:20-21.

398 Ex. 3, O'Connor Direct at 30 at Table 5.

399 Ex. 313, Campbell Direct at 19:6-7.

400 Ex. 15, Alders Surrebuttal at 15:9-11.

401 Ex. 15, Alders Surrebuttal at 15:14-15.

402 Ex. 15, Alders Surrebuttal at 15:12-15.

403 Ex. 9, O'Connor Rebuttal at 44:7-8.

Certificates of Need. At the Certificate of Need stage, detailed costs are not known sufficient to rely upon them for rate recovery:

> Moreover, a number of potentially significant costs are omitted, such as environmental mitigation expenses, which cannot be known until after the EQB's routing procedure is complete. While these estimates may be sufficient for purposes of making a decision regarding need, they cannot form the basis for determining eligibility for cost recovery.[404]

Additionally, our cost estimate was developed by General Electric, the original designer of Monticello, which is consistent with industry practice, and was benchmarked against the costs of other EPU projects undertaken at the time. We now explain each of these reasons in greater detail.

a. Reliance on General Electric

First, the Company relied on industry leader General Electric to help create the cost estimate.[405] General Electric designed the original Plant and held the proprietary designs to many of its systems, so was the most logical choice to design the Program for us. General Electric had already done this type of work at other BWR plants around the country. Mr. Crisp acknowledged that he was not criticizing the use of General Electric.[406] He admitted it was reasonable to rely on General Electric's "initial cost scoping assessment," to set the conceptual design and estimate.[407]

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[404] Ex. 15, Alders Surrebuttal at 17:7-13, *quoting, In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificates of Need for Four Large High Voltage Transmission Projects in Southwestern Minnesota*, REPLY TO XCEL ENERGY'S MOTION TO LIMIT THE SCOPE OF EVIDENCE OF THE MINNESOTA DEPARTMENT OF COMMERCE, at 2 (APR. 25, 2002).

[405] Ex. 11, Sieracki Rebuttal at 17:10-14.

[406] Tr. Vol. III (Crisp) at 17:12-15; Ex. 9, O'Connor Rebuttal, Schedule 1.

[407] Tr. Vol. II (Crisp) at 32:9-19 ("Q. And you also understand that GE developed an initial cost scoping assessment for the LCM/EPU program? A. Yes, I do. … Q. Do you think it is reasonable for [the Company]

b. Circumstances at the Time

Second, the Company's $320-346 million ($2008$) estimate was exactly that, an estimate, based on information known at the time.[408] While we made a good faith effort to provide accurate estimates, at the time, it was not possible to provide detailed or firm costs. Work at an operating nuclear plant is not like building a combined-cycle plant or wind farm. Those technologies make it is easier to estimate final costs. As design progresses more information becomes known:

> <u>It is normal for designs and scope to evolve as a project progresses through the complex and multi-level design process</u>. LCM/EPU Program work required the replacement of major components, often located in difficult and inaccessible areas, which makes complete design on all modifications before any implementation occurs infeasible. …. <u>Design would have to proceed to a relatively advanced level in order to lessen the risk of a cost estimate being inaccurate</u>. (Excerpted from "*The Engineering and Design Process, Xcel Energy Nuclear Department*".)[409]

It is necessary to implement projects like this through an iterative design process as articulated in "*The Engineering and Design Process, Xcel Energy Nuclear Department.*"[410] As a result, it is not unusual for actual costs to vary substantially from initial estimates as the engineering is completed and the magnitude of the work becomes clearer.[411]

While Mr. Crisp reviewed "*The Engineering and Design Process, Xcel Energy Nuclear Department*," he offered no criticisms to the processes described therein.[412]

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to rely on an outfit like GE? A. Absolutely, …"); Ex. 11, Sieracki Rebuttal at 19:12-16; Ex. 3, O'Connor Direct at 45:8-15.

408 Ex. 11, Sieracki Rebuttal at 17:8-10.

409 Ex. 9, O'Connor Rebuttal, Schedule 22 (5-6 of 9). (Emphasis added.)

410 Ex. 11, Sieracki Rebuttal at 20:3-7.

411 Ex. 11, Sieracki Rebuttal at 20:3-7.

412 Tr. Vol. III (Crisp) at 34:14-19.

Importantly, neither Mr. Crisp nor any other witness criticized the decision to proceed with Program and create a cost estimate before design work was complete. Mr. Crisp disclaimed that he was testifying as to whether the parallel approach was imprudent.[413] Instead, he indicated only that this approach contributed to cost increases.[414] But he acknowledged cost increases can happen without any imprudence whatsoever.[415] Our approach was sound and allowed us to proceed promptly under the circumstances.[416]

c. Benchmarking

Third, the Company benchmarked its initial cost estimate against other comparable projects in the industry. All industry data at the time supported the Company's initial cost estimate.[417]

Project	**Descrip-tion**	**Initial Cost Estimate**	**Latest Cost Estimate**	**Ratio of Final to Initial Cost**	**Estimate of Schedule Extension**	**Year Completed**
Ginna	EPU	$33 million	$44 million	1.33	n/a	2006
Brunswick	EPU	$145 million + $2.5 million contingency	$180* million	1.22* (including contingency)	n/a	2002
Vermont Yankee	EPU	$75 million	$100 million	1.35	n/a	2006

* Progress Energy reported that the project cost nearly $180 million.

We set our initial cost estimates much higher than the benchmarked projects to be conservative.[418] No circumstances existed to justify supporting costs significantly greater than we did, or that indicated final costs could approach $665 million.[419]

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413 Tr. Vol. III (Crisp) at 16:15-17:15.

414 Tr. Vol. III (Crisp) at 17:16-19.

415 Tr. Vol. III (Crisp) at 17:20-22.

416 Ex. 11, Sieracki Rebuttal at 11:11-21.

417 Ex. 9, O'Connor Rebuttal at 37:24-38:5 and Table 3.

d. *Additional Design*

There may be a belief that the LCM/EPU Program estimates could have been better had the Company done more detailed design before submitting the Certificate of Need, essentially, questioning the reliability of the Company's $320-346 million ($2008$) estimate. We respectfully disagree with such arguments.

The Company's cost range was based on information known at the time.[420] Had we taken the time to develop detailed design plans prior to proceeding with Certificate of Need and implementation, we would have delayed final implementation by as much as four years.[421] Under the resource planning context we faced at the time, such a delay would have been inconsistent with our efforts to bring new capacity to our customers to meet the forecast need at the time.

Mr. Crisp conceded that the Company's parallel approach was intended to complete the Program more expediently than with a tradition design it, then bid it, then build it, type of project. But he simply never addressed the factors that warranted expediency.[422] Neither Mr. Crisp nor any other witness criticized the decision to proceed with and create a cost estimate before design work was complete. Mr. Crisp in fact disclaimed that he was testifying in any manner as to whether the decision to begin project design in parallel with licensing and construction activities in 2006 was prudent or imprudent.[423] Instead, far from imprudence, he indicated only that in his

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418 Ex. 9, O'Connor Rebuttal at 39:21-23.

419 Ex. 9, O'Connor Rebuttal at 39:23-25.

420 Ex. 11, Sieracki Rebuttal at 17:9-10.

421 Ex. 9, O'Connor Rebuttal at 52:1-53:2 and Figure 2.

422 Tr. Vol. III (Crisp) at 30:3-8.

423 Tr. Vol. III (Crisp) at 16:15-17:15.

opinion the parallel approach contributed to cost increases.[424] And critically, he acknowledged that cost increases can happen without any imprudence whatsoever.[425]

e. Contingency

Mr. Crisp claims that our initial estimate was not reasonable because no contingency was used, or alternatively, the Company should have used a 100 percent contingency. Mr. Crisp is mistaken on both fronts. The Company utilized contingencies throughout the course of the Program in varying ways. The initial contingency in the \$320-346 million cost estimate was located within the initial \$273 million Nuclear Projects Authorization (NPA) in the amount of "\$15.431 million plus \$7 million in 2006 dollars for two different contingencies."[426] As Program costs changed over time, so too did the amount of contingency.[427] And, importantly, monetary contingencies are useful but do not change the overall cost of the Program or answer any questions concerning the propriety of dollars spent.[428]

Mr. Crisp testified, however, that no contingency whatsoever was used during the Program.[429] Mr. Crisp was mistaken. As the Company explained in response to inquiries about various contingency levels over time, a separate line item for contingency occurred during the January 2013 estimate because that was the only time it was considered a stand-alone item.[430] At all other times, the authorized contingency was allocated across the various sub-projects as opposed to the stand-alone line

[424] Tr. Vol. III (Crisp) at 17:16-19.

[425] Tr. Vol. III (Crisp) at 17:20-22.

[426] Ex. 9, O'Connor Rebuttal at Schedule 13 (2 of 5).

[427] Ex. 9, O'Connor Rebuttal at Schedule 13 (2 of 5).

[428] Ex. 11, Sieracki Rebuttal at 55:14-17; Tr. Vol. III (Crisp) at 40:21-25.

[429] Ex. 300, Crisp Direct at 30:9-11.

[430] Ex. 9, O'Connor Rebuttal at Schedule 13 (2 of 5); Ex. 3, O'Connor Direct at Schedule 8 (2 of 8).

item.[431] As a result, Mr. Crisp's reliance on the Schedule 8 to Mr. O'Connor's Direct Testimony (page 2 of 8), which shows only the stand-alone line item of contingency in the amount of $20 million used in connection with the January 2013 cost estimate, is not evidence that contingency was not used.[432]

In addition, Mr. Crisp's suggestion that the Company should have utilized a contingency of 100% or more[433] when it created the $320-346 million cost estimate is not supported by the document called "Cost Estimate Classification System"[434] upon which he relies for two primary reasons. First, as Mr. Crisp admitted, the document mentions no applicability to nuclear projects.[435] It applies to estimating for "production of chemical, petrochemicals, and hydrocarbon processing."[436]

Second, the document in no way suggests, even for the less complex industries to which it applies, that a contingency of 100% should be utilized in the conceptual phase of a project. Mr. Crisp is conflating the "<u>Expected Accuracy Range</u>" of an early project "Class 5" cost estimate with <u>contingency</u>. The two are not synonymous. Twice the document upon which Mr. Crisp relied confirms they are distinct:

- For a "Class 5" estimate the "Expected Accuracy Range" is up to 100% greater than an initial cost estimate but the document notes the accuracy range (which Mr. Crisp conflates with contingency) applies to a "cost estimate <u>after</u> application of contingency."[437]

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431 Ex. 9, O'Connor Rebuttal at Schedule 13 (2-3 of 5).

432 Tr. Vol. III (Crisp) at 83:20-84:25.

433 Tr. Vol. III (Crisp) 13:11-12; 41:1-6; Ex. 303, Crisp Surrebuttal at 23:16-18.

434 Ex. 303, Crisp Surrebuttal. at Schedule 1.

435 Tr. Vol. III (Crisp) at 46:19-22.

436 Ex. 303, Crisp Surrebuttal at Schedule 1 (2 of 11).

437 Ex. 303, Crisp Surrebuttal at Schedule 1 (3 of 11).

- The "Expected Accuracy Range" for a "Class 5" estimate is calculated "after inclusion of an appropriate contingency."[438]

Mr. Crisp testified that if the initial cost estimate contains contingency (which, in fact, was the case), then the expected accuracy of such estimate would be up to 100%, or even more for complex nuclear projects with added risk.[439] In sum, the Company's initial cost estimate of $320-346 million included appropriate contingency, and according to Mr. Crisp's testimony, a deviation of 100% would be in line with expectations. That is precisely where final Program costs landed in the end.

The Company's estimation accuracy is consistent with other recent major projects. In particular, FPL's experience is noteworthy. Their implementation at St. Lucie and Turkey Point were closely comparable to us. Indeed, as Dr. Jacobs acknowledged, "St. Lucie and Turkey Point were significantly more than the cost increases at Monticello, but they had the same -- similar challenges."[440] Despite all of the challenges encountered in Florida and despite Dr. Jacobs recommending significant disallowances, FPL was authorized to recover 100 percent of its costs.[441]

Grand Gulf experienced comparable cost increases doing similar work. And Susquehanna also experienced cost increases and delays, even though the scope of that project was substantially less than ours.[442] Mr. O'Connor's Direct Testimony, Table 3 summarizes:[443]

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[438] Ex. 303, Crisp Surrebuttal at Schedule 1 (6 of 11).

[439] Tr. Vol. III (Crisp) at 45:11-17, 46:7-47:1.

[440] Tr. Vol. III (Jacobs) at 105:2-5. Despite all of the challenges encountered in Florida and despite Dr. Jacobs recommending significant disallowances in the Florida proceedings, FPL was authorized to recover 100 percent of its costs. Tr. Vol. III (Jacobs) at 105:19.

[441] Tr. Vol. III (Jacobs) at 105:19.

[442] Ex. 3, O'Connor Direct at 25:3-10.

[443] Ex. 3, O'Connor Direct at 24:11 at Table 3.

Project	Description	Initial Cost Estimate	Latest Cost Estimate	Initial to Final Cost	Estimate of Schedule Extension	Year Completed
Grand Gulf	EPU	\$420-\$500 million	\$874 million	1.7-2.1	n/a	2012
Turkey Point and St. Lucie	4 EPUs	\$1,398 million	\$3,129 million	2.2	1 year	2011, 2012, 2013
Cooper	EPU	\$289 million	\$409 million	n/a	Suspended	n/a
Bruce A, Units 1 & 2	Refurbishment and Restart	C\$2.75 billion	C\$4.8 billion	1.7	2 years	2012
Point Lepreau	Refurbishment	C\$1.4 billion	C\$2.4 billion	1.7	3 years	2012
Susquehanna	EPU	\$217 million	\$345 million	1.6	2 years	2010, 2011
Monticello	LCM/EPU	\$320-\$346 million	\$665 million	1.9-2.1	2 years	2013

The Company acknowledges that a somewhat higher range than \$320-346 million could have been created in 2008. At most, using hindsight, the Company may have been able to estimate a range of \$360-420 million – but this would not have changed the cost-effectiveness of the overall Program.[444] Nor would it have changed that the benefits of the Program still would have far exceeded its costs based on what was known at the time.

f. Certificate of Need Modeling was Reasonable

The modeling done to support the CON demonstrated that moving ahead with the project was cost effective. First, even during the 2008 Certificate of Need, the Company viewed the LCM/EPU Program as an integrated initiative. However, under the Commission's rules, we recognized the need to impute cost information for the incremental 71 MW that were the subject of the Certificate of Need for purposes of modeling alternatives. As a result, the Company provided the 58.4/41.6 percent

[444] Ex. 9, O'Connor Rebuttal at 44:25-45:3.

LCM/EPU split allocation to provide a conservative estimate of the costs associated with LCM versus the costs attributable to the incremental 71 MW.

Despite the discussion in this record regarding the propriety of using an LCM/EPU split for purposes of the Department's cost-effectiveness test, there has been no dispute that the Company's 58.4/41.6 percent LCM/EPU split was reasonable at the time of the Monticello EPU Certificate of Need. In fact, this ratio was conservative based on the factors known at the time, as described on pages 76-77, *supra*. The 58.4 LCM/41.6 EPU split was not only the Company's good faith analysis of a reasonable attribution of costs, it was contemporaneous with our decision to proceed.[445]

4. <u>Conclusion</u>

Based on the facts and information described above regarding the Company's initial decisions to proceed with the LCM and EPU as an integrated program, initial cost estimates, and initial theoretical split between LCM and EPU activities for modeling purposes, the Company made the most reasonable choice by pursuing the Monticello LCM/EPU Program.

In his Direct Testimony, Mr. Shaw suggests that had the Department understood in 2008 that the Program would cost $665 million that the Department would have recommended against approval of the EPU Certificate of Need.[446] The Company pointed out in Rebuttal that imposing today's costs on a 2008 analysis is a classic

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[445] Ex. 2, Alders Direct at 22:15-23; Ex. 8, Alders Rebuttal at 10:18-27. Tr. Vol. II (Alders) at 9:21-10:1; Ex. 8, Alders Rebuttal at 21:13-22:15. If the Commission determines that imprudent actions occurred and that an LCM/EPU split is appropriate to the final remedy determination, then the Company's thoughtful 78 percent LCM/22 percent EPU analysis best reflects the additional, unexpected LCM work that had to be done to keep the plant operational. Because the topic of a possible LCM/EPU split has generated significant debate in this proceeding, we provide a detailed discussion below to illustrate why 78 percent LCM/22 percent EPU is the appropriate split (if any is used), that should be applied to final Program costs, and why Dr. Jacobs LCM/EPU split is neither reasonable nor supported in the record.

[446] Ex. 309, Shaw Direct at 32:6-11.

example of hindsight that must be avoided under the prudent investment standard.[447] While Mr. Shaw's Surrebuttal testimony continues to disagree with us on the application of hindsight, he did clarify his testimony to say that his cost-effectiveness adjustment is intended "to be used to determine an appropriate prudency adjustment based on the specific circumstances of this case."[448] We take this to mean that using cost-effectiveness as a remedy does not mean that the Department is recommending that the EPU Certificate of Need should never have been granted in the first place. Such an argument, if made, would clearly constitute classic second-guessing using after-acquired information we had no way of knowing in 2008.[449]

B. Management Prudence

The Company has always recognized that a significant focus of this case would be on our implementation effort and our performance managing this major multi-year construction project. Thus, we included in the record a significant amount of detailed factual data regarding our management of the implementation of the modifications. Primarily through the testimony of Mr. Crisp, the Department and the OAG (through adopting Mr. Crisp's testimony) criticize our implementation performance and generally accuse us of "mismanagement." This section will outline the arguments in the parties' testimony and summarize our responses.

1. Scope of the Initiative

The overarching Program scope never changed.[450] We always intended to undertake the work necessary to perform two separate but related functions: (1) allow for Monticello's continued safe and reliable operation to at least 2030, and (2) achieve

[447] Ex. 12, Sparby Rebuttal at 11:15-12:10; Ex. 8, Alders Rebuttal at 18:8-14; 23:20-25.

[448] Ex. 311, Shaw Surrebuttal at 6:19-21.

[449] Ex. 9, O'Connor Rebuttal at 45:16-17.

[450] Ex. 9, O'Connor Rebuttal at 57:7-8.

uprate operating conditions.[451] While Mr. Crisp was generally critical of our early Program scoping efforts, he testified that the Company complied with several initial steps that should be taken when setting the overarching scope of the Program.

For example, Mr. Crisp agreed the Company satisfied the "first step" in developing the Program's overall scope by defining the desired twin "final outcome[s]" at the beginning of the Program.[452] Mr. Crisp also agreed that the Company satisfied the next step by defining early the goal date for Program completion.[453] He further agreed that is was reasonable for the Company to rely on industry expert General Electric to help perform the third step when determining Program scope – assessing the existing condition of plant equipment and making judgments as to whether equipment has adequate capacity to be utilized in the Program.[454]

2. Program Development

Mr. Crisp generally criticized the Company's level of planning and preparation during the 2006-2008 timeframe and essentially contended that the Company should have performed more design early, even if that meant delaying the Program. But critically, Mr. Crisp never attempted to quantify the impact of his high-level criticisms on the cost growth of the Program.[455]

a. As-builts

Mr. Crisp suggested that the Company should have used as-builts from a prior uprate in 1998 (the 1998 Rerate) as the "starting point" for Program development.[456]

451 Ex. 9, O'Connor Rebuttal at 57:9-11.

452 Tr. Vol. III (Crisp) at 37:7-24.

453 Tr. Vol. III (Crisp) at 37:25-38:7.

454 Tr. Vol. III (Crisp) at 38:20-39:4.

455 Ex. 11, Sieracki Rebuttal at 9:5-7; Ex. 9, O'Connor Rebuttal at 73:2-4.

456 Ex. 300, Crisp Direct at 5:20-28.

According to him, as-builts from prior work would could have been assessed to improve on initial work scoping, and estimating.[457] However, these criticisms ignore the facts. The 1998 Rerate was primarily an analytical exercise and required only modest changes to Plant components.[458] There was no need or requirement to update Plant drawings.[459] Mr. Crisp conceded on the stand that the 1998 Rerate was only a "math exercise [with] possibly some tweaking."[460]

As-builts available to use for the majority of the systems associated with the Program were sometimes not accurate, which is common.[461] Older nuclear plants were not built with major upgrades in mind.[462] Because the power-plant side was originally anticipated to last 40 years and then be shut down, it was not thought necessary to develop detailed as-built drawings of all of those systems for use beyond 40 years.[463]

Consistent with construction practices in the 1960s, when Monticello was built, the power block (as distinguished from the nuclear island) used field run techniques.[464] In the 1980s, the Plant committed to document safety-related electrical systems and in 2008 began updating all mechanical, electrical, and civil as-built conditions when discrepancies are found.[465] But that effort did not allow us to avoid encountering numerous discrepancies as we did our installations.

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457 Ex. 300, Crisp Direct at 17:15-18:3.

458 Ex. 11, Sieracki Rebuttal at 32:19-22; Ex. 9, O'Connor Rebuttal at 17:7-19:9.

459 Ex. 11, Sieracki Rebuttal at 33:9-13; Ex. 9, O'Connor Rebuttal at 17:7-19:9.

460 Tr. Vol. III (Crisp) at 50:5-17.

461 Ex. 11, Sieracki Rebuttal at 32:24-33:7; Ex. 9, O'Connor Rebuttal at 17:7-19:9.

462 Ex. 11, Sieracki Rebuttal at 32:24-33:7; Ex. 9, O'Connor Rebuttal at 17:7-19:9.

463 Ex. 11, Sieracki Rebuttal at 32:24-33:7; Ex. 9, O'Connor Rebuttal at 17:7-19:9.

464 "Field-run" means that the supporting wiring, piping, hangars, and electrical conduit were run according to what could be accomplished during construction and final placement of these systems were not necessarily documented on as-builts. Ex. 9, O'Connor Rebuttal at 18:25-19:6.

465 Ex. 3, O'Connor Direct at 33:6-11; Ex. 9, O'Connor Rebuttal at 18:19-20 and 19:3-6.

b. Monticello's Modification Design Process

Mr. Crisp did not address the time consuming, iterative and complex design processes used at the Monticello plant,[466] and took no issues with those processes.[467] The Company explained how the work increased within most Program modifications as design progressed and the reasons why. Four major modifications accounted for $406 million,[468] which was more than half of the total Program costs of $665 and which contained the bulk of the cost growth.[469]

Mr. Crisp was asked about each of these modifications. He offered no testimony on the costs and had no opinion about the work scope on any of them.[470] Thus he did not criticize the reasonableness of adding any item of work within the "Final Scope" outlined in the Schedules to Mr. O'Connor's Direct Testimony. He also was in no way critical of (1) the cost necessary to complete any modification, or (2) the benefits the Company derived from each modification.[471] He simply ignored the benefits that the Program delivered. And the Department confirmed that it verified the total cost the Company claimed it incurred were actually incurred.[472] All such costs were reasonably incurred by the Company.[473]

The Department did not perform a technical or detailed analysis of the Program or of the many Company actions and decisions that were made for the Program modifications. Without such a foundation, their high-level criticisms lack foundation.

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466 Ex. 9, O'Connor Rebuttal at Schedules 21-22.

467 Tr. Vol. III (Crisp) at 34:14-19.

468 Ex. 3, O'Connor Direct at 5:1 at Table 1 and Schedules 23, 25, 26, 28.

469 Ex. 3, O'Connor Direct at 32:8-18.

470 Tr. Vol. III (Crisp) at 24:30-27:14.

471 Tr. Vol. III (Crisp) at 18:17-25, 19:23-20:3.

472 Tr. Vol. IV (Campbell) at 134:7-18.

473 Ex. 11, Sieracki Rebuttal at 59:9-14; Ex. 9, O'Connor Rebuttal at 81:11-19.

By not reviewing the history of any Program modifications, the inference that more work within the "Final Scope" should have been known earlier so as to create a higher initial cost estimate has no support. Because Mr. Crisp conducted no review of the reasons for additional work within each modification, his observation that "scope creep" occurred did not address whether the Company acted prudently. As Mr. Crisp acknowledged, scope creep can happen for "a whole host of reasons."[474] Yet Mr. Crisp did not address the "whole host of reasons" because he did not review whether the added work scope within Program modifications was reasonable.[475]

3. Regulatory Communications

Both the Department and OAG have argued that the Company's communications about costs were insufficient. Ms. Campbell noted in Surrebuttal that:

> [M]y communication concern, as correctly noted by Mr. Sparby, focused on the lack of meaningful communication of higher costs of the Monticello LCM and EPU projects (not just generally communications), and especially the expected higher costs of the EPU that resulted in the project not being cost-effective.[476]

To dispel this notion, it is important to detail the Company's communications regarding Project costs and other updates. First, the Company did not identify significant cost increases until it experienced the challenges of the 2011 outage – and once those cost increases were identified, the Company provided continual updates:

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[474] Tr. Vol. III (Crisp) at 33:19.

[475] Tr. Vol. III (Crisp) at 33:24-34:3.

[476] Ex. 315, Campbell Surrebuttal at 23:6-10. Relying on Ms. Campbell's testimony and the OAG's conclusion that Mr. Crisp and Ms. Campbell stated "NSP may have been aware of cost overruns as early as 2006," OAG witness Mr. Lindell also expressed a concern "that NSP failed to take reasonable steps to ensure that information was provided in a timely manner, or, even worse, that NSP was attempting to conceal the full impact of the cost overruns from the Commission and other interested parties." Ex. 200, Lindell Rebuttal at 25:3-7. Although Mr. Crisp may disagree with the Company's initial cost estimates for the Program, we have never read Mr. Crisp's testimony to suggest or establish that the Company intentionally underestimated costs. Nor would such a suggestion comport with the facts. Because the remainder of the OAG's allegations regarding regulatory communications rely on the Department's analysis, we address both OAG and Department concerns by speaking to the Department's concerns.

- *Nov. 3, 2010*: The Company's rate case is filed (Docket No. E002/GR-10-971) and includes updated costs for the Program of about $361 million through 2011.[477] At this point we had not experienced significant cost increases and had no basis to provide additional information.

- *March-May 2011*: The 2011 outage occurred, running longer and incurring substantially more costs than the Company predicted.[478]

- *May 4, 2011*: In rate case rebuttal testimony (and discovery responses), we further updated the estimate to $399.1 million for the LCM/EPU Program.[479]

- *Aug. 25, 2011*: We provided post-hearing Supplemental Testimony in the rate case, explaining that new information had come to light causing delays and cost increases, and Program costs would be in excess of $500 million.[480] The rate case procedural schedule was extended these cost issues.[481]

- *Nov. 4, 2011*: Our then-CNO testified at the re-opened rate case hearing that final costs were expected to be approximately $550 to $600 million.[482]

- *Nov. 14, 2011*: After lengthy negotiations, we entered into a Stipulation and Settlement committing to undergo this prudence review.[483]

- *Nov. 24, 2011*: The Company filed a Notice of Changed Circumstances in the Monticello EPU Certificate of Need proceedings.[484] Since the cost issue was well-known and we had stipulated to this prudence investigation, the Notice focused on the delay in implementation of the Program required by the rules.[485]

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477 Ex. 8, Alders Rebuttal at 16 n.27 (citing D. Koehl Direct in rate case at p. 31).

478 Ex. 3, O'Connor Direct at 78:15-80:2.

479 Ex. 8, Alders Rebuttal at 16 n.27 (citing D. Koehl Rebuttal in rate case at p. 15).

480 Ex. 8, Alders Rebuttal at 16 n.27; NSP Motion to Admit Post-Hearing Supplemental Testimony into the Record, Docket No. E002/GR-10-971 (Aug. 25, 2011); D. Koehl Post-Hearing Supplemental Testimony at pp. 1-9) (Aug. 25, 2011).

481 Ex. 8, Alders Rebuttal at Schedule 1 (3 of 3).

482 Ex. 8, Alders Rebuttal at 16 n.27.

483 Stipulation and Settlement Agreement at pp. 3-4 and 7, Docket No. E002/GR-10-971 (Nov. 14, 2011).

484 Notice of Changed Circumstances, Docket No. E002/CN-08-185 (Nov. 22, 2011).

485 ORDER, Docket No. E002/CN-08-185 (Jan. 6, 2012).

- *2012 Forward*: We continued to provide cost updates in our 2012 rate case,[486] and in this prudence proceeding and our 2013 rate case.[487]

Given this timeline, we respectfully disagree with the Department's contention that the Company's regulatory communications were insufficient.[488] Rather, record shows the Company provided regular updates regarding cost increases.

a. 2011 Cost History

The 2011 Cost History was referenced by the Department and OAG as alleged support for a material disallowance without quantification. That document lends no support to any finding of imprudence. Preliminarily, the Department misinterpreted the 2011 Cost History as evidencing recommendations that management disregarded.[489] All recommendations by the project team were approved.[490] And the 2011 Cost History is not a complete or accurate assessment of the Program.[491]

That document was created for the purpose of providing context and information to the CNO in 2011.[492] It was prepared years after decisions were had and at a time right after the difficult 2011 outage when the Program was under substantial pressure for missing cost and timing estimates.[493] During that period, tensions were running high

486 O'Connor Direct at 17, Docket No. E002/GR-12-961 (Nov. 2, 2012).

487 Ex. 12, Sparby Rebuttal at 30:2-5.

488 Specifically, Ms. Campbell criticizes that "it wasn't until the 2010 Rate Case (Docket No. E002/GR-10-971) in the post hearing supplemental testimony of Mr. Koehl on August 25, 2011 on page 7 that the Company indicated the Monticello LCM and EPU costs could exceed $500 million." Ex. 315, Campbell Surrebuttal at 23:11-14. However, as noted above, we provided significant information as soon as we became aware of it six months earlier.

489 Ex. 9, O'Connor Rebuttal, Schedule 24 (13 of 22).

490 Ex. 9, O'Connor Rebuttal, Schedule 24 (13 of 22).

491 Ex. 9, O'Connor Rebuttal at 65:4-5.

492 Ex. 9, O'Connor Rebuttal at 63:24-25.

493 Ex. 9, O'Connor Rebuttal at 64:19-20.

and some attempts to assign blame naturally occurred.[494] The apparent "disagreements" between Monticello site staff and the dedicated project team are normal large projects that balance the needs of operators and designers.[495]

The 2011 Cost History conveys the author's perspective that the Program should have been run by the site rather than a dedicated project team.[496] The Company appreciates the initiative of our Plant employees and the desire to be involved in major capital projects. However, from the broader corporate perspective, we recognize that Plant operations staff have a full-time job keeping the Plant running safely and that it would have been inadvisable to distract them also to run a major construction project.[497] We reasonably chose a dedicated project team that could work with Plant staff but also allow Plant staff to focus on their primary responsibility to ensure safe and reliable operations.[498] "Ownership" of the Program always resided with the project team, which reported through the projects organization.[499]

In any case, there certainly was no lack of site involvement and in the Program. This was critical given the size of the Program, but naturally created some tension.[500] Mr. O'Connor was the Monticello Site Vice President at the time and was directly responsible for key decisions such as the decision to retain Day Zimmerman after the 2009 outage.[501] Site personnel also played an important role in arguing for specific

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494 Ex. 9, O'Connor Rebuttal at 64:20-22.

495 Ex. 9, O'Connor Rebuttal at 49:18-19; Ex. 11, Sieracki Rebuttal at 42:20-22.

496 Ex. 9, O'Connor Rebuttal, Schedule 24 (20 of 22).

497 Ex. 11, Sieracki Rebuttal at 42:22-24; Ex. 9, O'Connor Rebuttal, Schedule 24 (17-18 of 22).

498 Ex. 9, O'Connor Rebuttal, Schedule 24 (20 of 22).

499 Ex. 9, O'Connor Rebuttal, Schedule 24 (14 of 22).

500 Ex. 9, O'Connor Rebuttal, Schedule 24 (14 of 22); Ex. 11, Sieracki Rebuttal at 42:17-22.

501 Ex. 3, O'Connor Direct at 76:1-2.

work to make the upgrades more user-friendly for our NRC-licensed operators,[502] and providing internal Plant resources to help complete the 2011 outage.[503]

While the 2011 Cost History reflects a recommendation for a delayed implementation schedule, we chose 2009/11 implementation to meet customer needs.[504] That implementation schedule was reasonable and allowed us to move forward promptly under the circumstances.[505] One employee's opinion does not override that rationale.

In sum, a single document created by one person from a single perspective is hardly a basis to criticize, and does not support a finding of imprudence. The prudence inquiry requires all circumstances be weighed when judging our actions. When placed in its proper context, the 2011 Cost History supports the Company's position that we made reasonable – albeit difficult – decisions based on the circumstances we faced.

4. Contractor Selection and Management

The thrust of the Company's contracting and management strategy to accomplish all the work within the Program centered on selecting the right contractor for the work at hand.[506] Mr. Crisp's characterization of a number of Company actions as being "disjointed" "stops and starts" has no support.[507] In response to Company inquires he confirmed that he was not testifying that the Company's actions, which included

502 Ex. 3, O'Connor Direct at 143:9-10.

503 Ex. 3, O'Connor Direct at 75:25.

504 Contrary to the Department's suggestion, the Company's Board of Directors never "overruled" a recommendation for the 2011 and 2013 implementation schedule. Ex. 9, O'Connor Rebuttal at Schedule 24 (13 of 22).

505 Ex. 11, Sieracki Rebuttal at 12:27-13:2 (quoting July 2006 order approving Xcel Energy's 2004 Resource Plan); Ex. 8, Alders Rebuttal at 8:17-19 n.17.

506 Tr. Vol. I (O'Connor) at 97:22-23.

507 Ex. 300, Crisp Direct at 20:7-21.

making contractor changes, were in any way imprudent.[508] The Company made well-considered changes in contractors as the Program developed to meet the challenges faced and to have the most suited entities do the work.

a. Design Contractors

Given General Electric's prior work on Monticello and their control over proprietary design information, it was an efficient choice to utilize their prior knowledge and experience.[509] Mr. Crisp agreed, testifying that the Company's reliance on General Electric for such work was "absolutely" reasonable.[510]

b. Installation Contractors

Mr. Crisp criticizes our use of installation contractors, although his testimony appears to fail to appreciate the difference between design and installation and appears to take a one-size-fits-all approach to "nuclear contractors."[511] Mr. Crisp also ignores the Company testimony on why we made installation contractor choices and simply criticizes one contractor rather than another.[512]

Day Zimmerman is a widely-used and respected implementation contractor in the nuclear power industry.[513] The OAG, who is critical of the Company's implementation effort, admitted that they did not know who Day Zimmerman is, beyond what was stated in the filing, and did not even know whether Day

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508 Ex. 9, O'Connor Rebuttal at Schedule 1 (stating he did not determine whether various Company actions contractor changes were imprudent).

509 Ex. 11, Sieracki Rebuttal at 45:14-17; Ex. 3, O'Connor Direct at 47:26-48:2.

510 Tr. Vol. III (Crisp) at 32:17-19.

511 Ex. 300, Crisp Direct at 20:12-13. Mr. Crisp criticizes us for hiring Day Zimmerman as construction contractor rather than General Electric, when it is well-known that General Electric is not in the construction business and would have hired someone like Day Zimmerman. Tr. Vol. I (O'Connor) at 107:15-23.

512 Ex. 3, O'Connor Direct at 49:16-50:26.

513 Ex. 3, O'Connor Direct at 50:14-17.

Zimmerman was a design contractor or an installation contractor, thereby discrediting any criticism they may have.[514]

Day Zimmerman was selected as the 2009 implementation contractor based on responses to a mid-2007 Request for Proposal (RFP).[515] There is nothing in the record to criticize or rebut the Company's selection. In fact, on the stand Mr. Crisp agreed "in general" with Mr. O'Connor's assessment that implementation work was not within General Electric's "wheelhouse" and was better suited to others.[516] And Mr. Crisp agreed that sometimes it is appropriate to change contractors.[517] Thus Mr. Crisp's characterization of the decision to select Day Zimmerman over General Electric as a "disjointed" "start and stop"[518] has no evidentiary support.

c. Work Transfers

Between the 2009 and 2011 outages, the Company identified issues with certain design proposals for the 2011 outage.[519] Mr. Crisp made the same "disjointed" "start and stop" characterization of the Company's action in 2010 to transfer some work scope to other contractors due to this.[520] This criticism similarly lacks factual support.

Making contractor changes over the course of the Program is common because design and contractor performance issues have become more frequent in a complex industry like nuclear power plant construction.[521] Nuclear vendor performance has

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514 Tr. Vol. IV (Lindell) at 96:1-15.

515 Ex. 3, O'Connor Direct at 49:24-50:10.

516 Tr. Vol. III (Crisp) at 36:14-37:2. Indeed, General Electric informed the Company that their expertise was not in implementation and recommended someone other than them take that role. Tr. Vol. I (O'Connor) at 107:15-23.

517 *See* Tr. Vol. IV (Lindell) at 95:24-25.

518 Ex. 300, Crisp Direct at 20:7-13.

519 Ex. 9, O'Connor Rebuttal at 62:25-63:8.

520 Ex. 300, Crisp Direct at 20:14-16.

521 Ex. 4, Stall Direct at 61:18-64:15; Ex. 3, O'Connor Direct at 63:19-20.

declined in recent years due to growing competition for talent in the nuclear industry, a shrinking skilled labor pool and high demand for skilled workers, general attrition related to retirements because of the aging nuclear workforce, the decrease in the number of U.S. nuclear engineering degree programs, and talent migration.[522]

As the Company moved through 2010, it faced design and performance challenges.[523] The Company responded to these challenges by occasionally moving some work to other contractors with more specialized expertise.[524] This comported with the Company's strategy of selecting the right contractor for the work at hand. This was hardly a disruptive or start and stop approach.

d. Bechtel Retention

Mr. Crisp made the same characterization once more with the Company's action to retain Bechtel in 2011 to help us complete implementation.[525] Again, Mr. Crisp's criticism lacks support. Bechtel was retained because the Company recognized that the final modifications scheduled for the 2013 outage would be the most challenging installations of the Program.[526] As Mr. O'Connor testified, the 2013 implementation required a "different kind of skill set" given that the work to be performed during that outage was beyond Day Zimmerman's "mechanical-related work" capabilities.[527] It was therefore logical to switch implementation contractors for the 2013 implementation. And Day Zimmerman's experience and mechanical expertise was not lost by the switch to Bechtel as Mr. Crisp implied.[528] Mr. Crisp is silent on the

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522 Ex. 4, Stall Direct at 63:18-27; Ex. 3, O'Connor Direct at 61:21-62:22.

523 Ex. 3, O'Connor Direct at 63:19-20.

524 Ex. 3, O'Connor Direct at 66:23-26.

525 Ex. 300, Crisp Direct at 20:17-18.

526 Ex. 3, O'Connor Direct at 83:23-25.

527 Tr. Vol. I (O'Connor) at 97:11-98:10.

528 Ex. 300, Crisp Direct at 21:1-22:5.

fact that Day Zimmerman remained on the job as the primary mechanical subcontractor for the 2013 outage.[529]

In the end, Mr. Crisp never attempted to address the Company's position that replacing contractors to better suit the work being performed is more efficient, and that it is a prudent project management practice to assess which contractor will provide the best overall value, especially as significant aspects of a project change. He also did not testify that the Company should not have changed contractors, nor did he allege that any contractor change under the specific circumstances actually encountered on the Program was unreasonable or imprudent. Instead, he merely noted that "very real justifications" for changing contractors can exist, without expressing any opinion on whether the changes the Company made along were reasonable based on the circumstances presented.[530] Whether or not such changes could add cost or involve delay, as Mr. Crisp suggests, is not relevant without addressing whether the changes were reasonable based on the circumstances.

In contrast, the Company provided facts and details explaining the reasonableness of Company actions during every phase of the Program, including (1) Program Start-Up, (2) the Installation Process, (3) the 2009 Outage, (4) 2009-11 Implementation Planning, (5), the 2011 Outage, (6) 2011-13 Implementation Planning, and (7) the 2013 Outage.[531] That testimony has not been credibly attacked.

5. <u>Reliance on Mr. Crisp Misplaced</u>

Mr. Crisp went so far as to state that he was not testifying about the prudence of imprudence of anything.[532] The Department's recommended disallowance, however,

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529 Ex. 11, Sieracki Rebuttal at 48:21-23; Ex. 9, O'Connor Rebuttal at 47:16-18.

530 Ex. 300, Crisp Direct at 21:2-4.

531 Ex. 3, O'Connor Direct at 58:9-92:22; *see generally* Ex. 9, O'Connor Rebuttal.

532 Tr. Vol. III (Crisp) at 15:11-17:15.

was premised largely on the allegation that it has "showed through its consultants that certain conduct, largely surrounding Xcel's management and execution of the LCM and EPU projects" was not up to the Department's expectations.[533] But Mr. Crisp disavows any opinion of imprudence.

Further, the OAG simply adopts Mr. Crisp's discussion and then assumes (incorrectly) that Mr. Crisp is opining about imprudence. In light of the limited nature of Mr. Crisp's testimony, which included a statement that he was not testifying that the Company was imprudent, it is unclear how the OAG concludes "the testimony of Mr. Crisp . . . demonstrates that NSP has incurred significant imprudent and unreasonable costs."[534]

The OAG also assumes that Company disputes with contractors indicate a lack of proper oversight and implicates NSP's poor management in general. Mr. Lindell concludes "To the extent that NSP's mismanagement of the project resulted in contractor disputes and increased the total cost to ratepayers, the costs were incurred unreasonably and should be disallowed," which is not supportable.[535]

Disputes with contractors on a project as large as Program are inevitable and commonplace. Far from being imprudent, the Company proactively addressed disputes as they arose. The Company appropriately preserved any claims it possesses against vendors and committed to offset any claims or settlements it achieves to the cost of the Program.[536] This was far more preferable to engaging in a dispute resolution process such as arbitration during the pendency of the Program, which

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[533] Tr. Vol. IV (Campbell) at 117:5-8; 123:11-23.

[534] Ex. 200, Lindell Rebuttal at 26:16-17.

[535] Ex. 200, Lindell Rebuttal at 21:7-9.

[536] Ex. 9, O'Connor Rebuttal at 80:13-15.

would have caused needless delay. The prudent investment standard compensates a utility "for all prudent investments at their actual cost[.]"[537]

By conducting no meaningful or in-depth review of the Program, Mr. Crisp glossed over the difficulties and complexities involved in nuclear plant design construction and essentially surmised poor management must exist because costs went up. The Company's detailed submissions describe the challenges and difficulties faced in the Program and why the Program cost more than originally estimated.

C. <u>LCM/EPU Cost Allocation</u>

The Department recommends that the Company be disallowed $71.42 million (Minnesota jurisdiction) based on the hindsight conclusion that the EPU megawatts were not cost-effective.[538] To achieve this conclusion, the Department superimposed Dr. Jacobs' after-the-fact (and incorrect) LCM/EPU split of 2013 costs on a 2008 cost-effectiveness test.[539] The Department reaffirmed at the hearing that this is the remedy that it is seeking to impose on the Company.[540]

For the reasons discussed earlier in this Brief, the Company does not believe an LCM/EPU split is appropriate to assess the Company's overall performance, and is not consistent with the merits the overall Program. The Company further explained that an after-the-fact LCM/EPU split injects hindsight into the prudence analysis, as it penalizes the Company even if it made reasonable decisions that nonetheless resulted in higher costs making the project not 'cost effective' in hindsight.

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[537] *Duquesne Light Co.*, 488 U.S. at 309.

[538] Ex. 313, Campbell Direct at 27 and 35.

[539] Ex. 8, Alders Rebuttal at 23:20-25.

[540] Tr. Vol. IV (Campbell) at 125:22-126-4.

Even if the Commission finds that the Company was imprudent, an after-the-fact LCM/EPU split does not aid the determination of the proper remedy. A hindsight LCM/EPU split, applied to final Program costs, does not address what damages flowed specifically from imprudent decisions and actions and artificially undermines the overwhelming benefits of the overall Program. If the Commission believes an LCM/EPU split is necessary as a proxy to determine damages for imprudence, the Company continues to believe that the 58.4/41.6 percent LCM/EPU split is the appropriate split to be used as it was developed contemporaneously with the Company's decision to proceed.

1. The Department's LCM/EPU Split

In addition to the above considerations, Dr. Jacobs' 85.5 EPU/14.5 EPU split is not supportable in this record. As the record evidence establishes, Dr. Jacobs' split is inconsistent with the prudent investment standard; simplistically relies on a single out-of-context document to the exclusion of the other facts; is at odds with the condition of the equipment that was replaced and the work that was done; and is at odds with the methodology he employed in prior sworn testimony. Each of these concerns is discussed in more detail below.

a. Inconsistent with Prudent Investment Standard

An LCM/EPU split used in a breakeven analysis based on current costs is based on hindsight, as it assumes the utility made prior decisions knowing what the final program cost and final LCM/EPU split would be. For this reason, an after-the-fact LCM/EPU split does not help determine whether the Company's decisions were reasonable based on the information available at the time. Overall, then, a final LCM/EPU split utilizing final Program costs is not consistent with the prudent investment standard.

Other state commissions have agreed. The Department's approach to a disallowance in this proceeding is essentially the same as the "breakeven" analysis Dr. Jacobs advocated for in Florida.[541] Just as in Florida, that position should be rejected here. That Commission stated:

> [W]e find witness Jacobs' recommendation shall not be adopted because there is no support regarding how, if at all, his use of a breakeven analysis does not apply hindsight analysis and distinguishes between prudent and imprudent utility management actions.[542]

The same is true in this proceeding.

b. LCM/EPU Split is Unsupported

Dr. Jacobs bases his analysis in reliance on a single document, a Company letter to the NRC signed by Mr. O'Connor on November 5, 2008 ("Enclosure 8"). Dr. Jacobs contends that there are two reasons why the Enclosure 8 is the "best source" to determine an accurate split.[543] First, it was submitted "under oath and under penalty of perjury" and second, it is a "contemporaneous document."[544]

(1) *Under Oath*

Dr. Jacobs contends that it is reasonable to rely on the Enclosure 8 because it was submitted under oath and under penalty of perjury. However, as Dr. Jacobs admitted, Company witness Mr. O'Connor's pre-filed and live testimony in this proceeding, which provided a vastly different LCM/EPU allocation using both the Enclosure 8

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541 Tr. Vol. III (Jacobs) at 106:20-21, 110:1-10 and 112:12 (agrees that Mr. Shaw's cost-effectiveness analysis is the same as his breakeven analysis that was rejected in Florida).

542 Ex. 425, Final Order Approving Nuclear Cost Recovery Amounts for Florida Power & Light Company and Duke Energy Florida, Inc., Docket No. 130009-EI, at 35-36.

543 Ex. 305, Jacobs Direct at 9:7-9.

544 Ex. 305, Jacobs Direct at 9:7-9.

and a broader array of contemporaneous documents, was also provided under oath.[545] Moreover, while Mr. O'Connor agrees that it is appropriate to look at the Enclosure 8 as one source, there is a substantial amount of other evidence that must be considered in determining whether a modification was LCM or EPU driven.

(2) *Single Document*

The fact that Dr. Jacobs' relied on a single document for the majority of his allocations for a highly complex nuclear initiative makes his conclusion suspect. As the Company pointed out, this letter was part of the Company's resubmitted License Amendment Request to the NRC.[546] Thus the purpose of the letter was to provide an overview of the work that the Company intended to complete as part of the LCM/EPU Program, not an attempt to classify modifications as LCM or EPU.

Given that the purpose of the document was not to classify modifications, the Company relied on short-hand throughout the document to note where a change in size of equipment was needed for "EPU conditions" when in actuality the broader scope of work was both LCM and EPU- related.[547] For example, in referring to the replacement of the 40-year old worn out existing main transformer, the Enclosure 8 states that the Company plans to "[r]eplace the existing main generator step-up transformer to provide increased operating margins under EPU conditions."[548] Dr. Jacobs uses this reference to "EPU conditions" as his justification to attribute the entire cost of this modification to the uprate despite the fact that the existing transformer was at the end of its service life. This modification is evidence of why

545 Tr. Vol. III (Jacobs) at 121:1-18.

546 Ex. 9, O'Connor Rebuttal at 86:15-19.

547 Ex. 8, O'Connor Rebuttal at 81: 17-19.

548 Ex. 305, Jacobs Direct at Attachment B at 10.

these shorthand notations should not be taken out of context to assign costs to LCM or EPU categories as Dr. Jacobs has done.

Interestingly, while Dr. Jacobs states that this Enclosure 8 is the primary basis of his opinion, he ignores the plain language of the document for a key modification, the 13.8 kV distribution system. The Enclosure 8 unequivocally states that "[t]his modification is an LCM modification to increase margin in the on-site distribution system."[549]

(3) *Failure to Assess Age and Condition of Equipment*

Dr. Jacobs' simplistic analysis ignores the age and condition of the Plant equipment prior to replacement. He freely admits that he did not assess the age and condition of the equipment prior to replacement; nor did he assess whether the NRC would have allowed the Company to continue to operate based on the condition of the existing equipment.[550] He also acknowledges that before the LCM/EPU Program, the Company "had a policy of deferring capital projects, expecting that Monticello would be shut down and decommissioned in 2010."[551] Thus, Dr. Jacobs was aware that many components in the Plant were in need of replacement or repair to support continued operation over the extended life of the Plant.[552] Nevertheless under Dr. Jacobs' cost allocation, only $95.4 million of the total project costs of $664.9 million are attributed to improvements necessary to extend the life of the aging Plant.[553]

Nor did Dr. Jacobs assess whether the existing equipment had performance-related issues prior to the uprate. In fact, Dr. Jacobs agreed during cross-examination that

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549 Ex. 305, Jacobs Direct at Attachment B (13 of 14).

550 Tr. Vol. IV (Jacobs) at 36:11-15.

551 Ex. 305, Jacobs Direct at 3:24-4:1.

552 Ex. 9, O'Connor Rebuttal at 86:6-8.

553 Ex. 9, O'Connor Rebuttal at 86:8-10.

undervoltage alarms in the distribution system indicated that the system needed to be upgraded regardless of the uprate.[554] Dr. Jacobs also never took into account the age and condition issues thoroughly documented by the Company related to the other major modifications.[555] Dr. Jacobs also did not take into account the conditions the Company discovered when it began implementing the Program.[556]

The reason Dr. Jacobs failed to account for the age, condition, and performance-related issues associated with the existing equipment is because his analysis is based solely on the 2008 Enclosure 8. But this single letter is not the only contemporaneous document produced by the Company. As Dr. Jacobs noted, the Company produced over 3,000 documents.[557] Many of these documents provide tremendous insight into the state of the Plant prior to the Program. They show the existing system condition assessments related to the Plant and long-range plans outlining needed future improvements dated prior to or contemporaneous with the 2008 Certificate of Need.[558] An examination of these documents demonstrates the unreasonableness of Dr. Jacobs' allocation.

(4) *Mismatch of Split and Final Costs*

Even if use of a single 2008 document out of context were valid on its face, Dr. Jacobs' application of the 2008 Enclosure 8 to final costs does not account for the as-found work and other conditions that were identified after the 2008 Certificate of

554 Tr. Vol. IV (Jacobs) at 34:22-35:7.

555 The Company agrees that two of the ten major modifications, the steam dryer and the 1AR transformer should be considered LCM only costs. Ex. 305, Jacobs Direct at 11:4-6 and Attachment WRJ-3; Ex. 9, O'Connor Rebuttal at 114:2-5.

556 Tr. Vol. IV (Jacobs) at 38:21-25 ("Q: And you did not specifically assess what conditions the company found at the plant when it began opening walls and working on systems during program implementation? A: I did not.").

557 Tr. Vol. III (Jacobs) at 100:15-18.

558 Tr. Vol. III (Jacobs) at 100:25-101:7.

Need and that drove Program cost increases. By undertaking a current analysis applying a 2008 document to final Program costs, there is a mismatch between the overall costs Dr. Jacobs is analyzing and the earlier document he uses for that analysis. He did not assess, for example, that the increased costs for the condensate demineralizer cost estimates were largely driven by as-found conditions, meaning that additional work was necessary for LCM reasons regardless of the EPU.[559] Nor does he acknowledge the field change orders driven by as-found conditions that could not have been known at the initial engineering phase.[560] To the extent the Commission wishes to use an after-the-fact cost-effectiveness test as applied to final costs, the Company's approach appropriately factors the specific drivers of the Program cost increases into its 78/22 percent LCM/EPU split analysis, as discussed in more detail below.

c. "Like-for-Like" Replacement

Dr. Jacobs defends his meager allocation of costs to the LCM by contending that the Company could have replaced aging equipment on a "like-for-like" approach that would have been less costly.[561] However, the Company explained that "like-for-like" replacement of nearly 40-year old components "would require extensive reverse engineering, which is simply not cost-effective, efficient, or smart."[562] For example, the existing condensate demineralizer system was an antiquated analog system that required multiple manipulations to be performed manually and required two operators to clean two vessels each week for approximately six to eight hours.[563] After the Company pointed out the flaw in continuing use of such an inefficient system, Dr.

559 Ex. 3, O'Connor Direct at Schedule 23 at 1.

560 Ex. 9, O'Connor Rebuttal at 75:9-14 and Schedule 27.

561 Ex. 305, Jacobs Direct at 14:19-21.

562 Ex. 13, Stall Rebuttal at 15:3-5; Ex. 9, O'Connor Rebuttal at 117:4-12.

563 Ex. 9, O'Connor Rebuttal at 117:14-18.

Jacobs attempted to redefine "like-for-like" replacements as "replacing equipment with new equipment with similar performance specifications and physical characteristics."[564] But Dr. Jacobs' definition is inconsistent with the NRC's long-standing definition of these terms as "replacement of an item with an item that is identical" that "was purchased at the same time from the same vendor."[565] Given the age and condition of the existing equipment, a like-for-like replacements suggested by Dr. Jacobs would not have been practical or wise.

In addition, even if "like-for-like" replacement could be achieved, there is no evidence that such an approach would have resulted in any substantial cost savings. This is because the installation and removal costs would have been similar.[566] Replacement of the Plant's existing 4 kV distribution system under a "like-for-like" construct would not have eliminated the major costs of this upgrade which included a separate room to install the new bus work and installing 14 miles of new cable and raceway.[567]

d. Inconsistency with Prior Testimony

Finally, the bright-line methodology employed by Dr. Jacobs does not reflect the prudent investment standard and is the precise opposite of the approach that he employed in an earlier Florida proceeding as a consultant for the Florida Office of Public Counsel[568] related to the St. Lucie and Turkey Point EPUs.[569] As previously noted, in that case Dr. Jacobs employed a breakeven analysis like that used by Department witness Mr. Shaw in this proceeding, but developed a split between LCM

564 Ex. 307, Jacobs Surrebuttal at 6:6-11.

565 Ex. 429, NRC – Licensee Commercial-Grade Procurement and Dedication Programs (Generic Letter 91-05) at 3.

566 Ex. 9, O'Connor Rebuttal at 118:10-12.

567 Ex. 9, O'Connor Rebuttal at 118:10-20.

568 Florida's Office of Public Counsel is similar to Minnesota's Office of the Attorney General.

569 Ex. 305, Jacobs Direct at 3:1-6; *see generally In re Nuclear Cost Recovery Clause*, Docket No. 08009-EI (Fla. Pub. Serv. Comm'n).

and EPU costs that supports the Company's approach here and is opposite Dr. Jacobs' own approach in this case.

Although Dr. Jacobs had testified in prior proceedings that certain modifications are "typically required to ensure reliable operations beyond the original 40 year operating life of the plant" such as "replacement of main transformers" and "feedwater heaters,"[570] Dr. Jacobs attributed the incremental cost of the increased size of the components to the EPU.[571] In this way, Dr. Jacobs' approach was opposite his approach in this proceeding, where he has attributed all costs to the EPU so long as he believed any increment of the overall cost was attributable to the Monticello uprate:[572]

> Q. In other words, regardless of what other needs the plant might have had for those projects, so long as some portion of that need was attributable to the EPU, you put 100 percent of work order in the EPU, is that right? . . . .
>
> A. That's correct.[573]

Dr. Jacobs' opposite approach in the St. Lucie and Turkey Point proceedings was driven by Florida's unique Nuclear Plant Cost Recovery requirement.[574] Florida permits a utility to annually recover costs related to an uprate but those costs related to normal maintenance or replacement, *i.e.*, unrelated LCM modifications, must be recovered through normal base rate cost recovery mechanisms.[575] Thus, in Florida

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570 Tr. Vol. IV (Jacobs) 30:6-10.

571 Ex. 428, Jacobs Excerpt at 9-10, Docket No. 080009-EI (Fla. Pub. Serv. Comm.) (July 30, 2008).

572 Ex. 305, Jacobs Direct at 7:9-11 ("My analysis indentifies costs specifically needed to support the EPU project."); Tr. Vol. III (Jacobs) at 115:15-116:13 ("irrespective of other needs, without these projects, the EPU could not proceed; and therefore, I consider them to be EPU projects.").

573 Tr. Vol. III (Jacobs) at 115:25-116:10.

574 Fla. Admin. Code R. 25-6.0423.

575 Fla. Admin. Code R. 25-6.0423; *see also* Ex. 428, Excerpt of Revised Direct Testimony of William Jacobs, Jr., before the Florida Public Service Commission in Docket No. 080009-EI, filed on July 30, 2008 at 10 ("if

Dr. Jacobs had an incentive to minimize costs attributed to the EPU to minimize the utilities' cost recovery. In contrast, he appears to have maximized costs attributable to the EPU to support a disallowance utilizing the Department's breakeven analysis.

In sum, Dr. Jacobs' LCM/EPU split was unsupported in the record, inconsistent with the prudent investment standard, and inconsistent with NRC guidance and his prior testimony. For each of these reasons, alone or in the aggregate, the record will not support use of Dr. Jacobs' proposed split for assessing prudence in this case.

2. Company's LCM/EPU Split Represents Final Costs

The Company also prepared an after-the-fact split, which we continue to believe should also not be used to assess our prudence but provided useful data points for analyzing our costs.[576] In this "avoided cost" analysis, we categorized the costs for specific modifications in one of three ways: (1) *LCM-only costs*: costs that were solely related to LCM activities; (2) *EPU-only costs*: costs that were solely related to EPU activities, including licensing costs; (3) *combination LCM and EPU costs*: LCM activities that were sized to accommodate the uprate (a category Dr. Jacobs did not use).[577]

Based on evaluation of these factors for each item of work we did, the Company carefully exercised engineering judgment to attribute costs to unavoidable LCM or avoidable EPU.[578] Using this analysis, the Company determined that 78.0 percent of

replacement of the steam generators had been modified specifically to support the EPU project, then I believe that only the incremental cost of the modification to support the EPU project would have qualified for recovery through the cost recovery clause, and the remainder of the costs would have been recovered through normal base rate mechanisms.")

576 Ex. 3, O'Connor Direct at Schedule 29.

577 Ex. 9, O'Connor Rebuttal at 83:7-12.

578 Ex. 9, O'Connor Rebuttal at Schedule 30 at 4. The Company allocated common costs for the Project on a pro rata basis to the LCM and EPU.

the work was unavoidable LCM that was necessary for the long-term health of the Plant, and 22.0 percent of the work was avoidable EPU.[579]

If the Commission determines that imprudent actions occurred and that an LCM/EPU split is appropriate to the final remedy determination, then the Company's thoughtful 78 percent LCM/22 percent EPU analysis best reflects the additional, unexpected LCM work that had to be done to keep the Plant operational. To further illustrate the reasonableness of the Company's approach – should the Commission decide an after-the-fact split is useful – we provide the following detailed discussion of each of the ten major modifications[580] based on all contemporaneous records and analysis of the actual work we did. This discussion begins with the modifications that are plainly LCM-related modifications, and then moves to those modifications where there is room for disagreement as to the proper allocation.

a. 1AR Transformers, PRNM, and Steam Dryer

Both Dr. Jacobs and the Company classify replacement of the 1AR transformer, the PRNM System, and the steam dryer as LCM modifications. Contemporaneous documents support these allocations.[581] The PRNM System was a 1960s vintage analog system with many aging components that required constant replacement or repair and another obvious LCM choice.[582] Replacement of the existing steam dryer is another modification that was undoubtedly related to LCM.[583]

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579 Ex. 3, O'Connor Direct at 146:17-20.

580 These ten modifications are (i) 1AR Transformers; (2) PRNM; (3) Steam Dryer; (4) Main Transformer; (5) 13.8 kV System; (6) Feedwater Heaters; (7) Condensate Demineralizer; (8) Condensate Pumps and Motors; (9) Reactor Feed Pumps; and (10) Motors and High-Pressure Turbine. Due to the similar considerations relating to certain of these modifications, some of them are discussed in combination with each other, below.

581 Ex. 9, O'Connor Rebuttal at 114:9-13 and Schedules 33, 34.

582 Ex. 9, O'Connor Rebuttal at 113:3-23.

583 Ex. 9, O'Connor Rebuttal at 114:5-115:7.

b. Main Transformer

Replacement of the 40-year old generator step-up ("GSU") main transformer is a modification that plainly belongs to LCM. Dr. Jacobs, however, classifies this modification as 100 percent EPU given that the Enclosure 8 notes that the new transformer will "provide increased operating margins under EPU conditions."[584] The Company took a more measured approach and allocated 10 percent of the cost of this modification to EPU to account for the increased size of this transformer to support uprate conditions.[585] The contemporaneous documents support the Company's mostly LCM allocation. The Company provided a 2003 "Capital Project Summary Sheet" that noted that "replacement of the main transformer and 1AR transformers to support operation for 20 more years."[586]

The Company documented performance issues with the main transformer. We identified a gassing problem that was resulting in transformer degradation and that could have lead to in-service failure if the main transformer as not replaced.[587] While the Company agrees that the main transformer was replaced with a slightly larger one to account for uprate conditions, the age and condition of the existing transformer warranted replacement even absent the EPU. Thus, the Company's allocation of 90 percent of the costs to LCM is more accurate based on the facts in the record.

c. 13.8 kV System

Despite the Enclosure 8's unequivocal statement that the 13.8 kV upgrade is "an LCM modification to increase margin in the on-site distribution system,"[588] Dr.

584 Ex. 305, Jacobs Direct at Attachment B (10 of 14).

585 Ex. 9, O'Connor Direct at 90:13-15.

586 Ex. 10, O'Connor Rebuttal at Schedule 32 at Attachment G.

587 Ex. 10, O'Connor Rebuttal at Schedule 32.

588 Ex. 305, Jacobs Direct at Attachment B (13 of 14).

Jacobs attributes 100 percent of the 13.8 kV system to EPU. The Company, on the other hand, allocated this modification as LCM consistent with the Enclosure 8.[589] Other contemporaneous documents and Dr. Jacobs' admissions on cross-examination confirm the need for distribution capacity irrespective of the uprate.

The Company's "Monticello License Renewal Plan" dated July 31, 2001, indentifies 4 kV breaker replacement as a necessary LCM related project.[590] A 2003 "Capital Summary Sheet" notes the need to replace 4 kV breakers due to "aging and wear" as these were original Plant equipment.[591] Another 2003 "Capital Summary Sheet" also identified "power cable replacement" as necessary for LCM due to age and the need to improve reliability.[592] These contemporaneous documents show the Company recognized the need to both replace aging components of the existing 4 kV electrical system to support long-term operation of the Plant.

Prior to the 13.8 kV upgrade, the Plant was operating at less than a 1 percent margin, which increases the vulnerability of the Plant and limits operators' ability to respond to events.[593] In addition, the Plant experienced under-voltage conditions when starting motors and pumps and had to sequence these large loads.[594] The existing 4 kV buses were also very close to maximum fault ratings prior to the LCM/EPU Program. Notably, bus #11 was at 99% of its maximum rating.[595] Dr. Jacobs admitted that these types of problems indicated a need to upgrade the system.[596]

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589 Ex. 9, O'Connor Rebuttal at 92:24-25.

590 Ex. 9, O'Connor Rebuttal at Schedule 33.

591 Ex. 10, O'Connor Rebuttal at Schedule 32 at Attachment D.

592 Ex. 10, O'Connor Rebuttal at Schedule 32 at Attachment K.

593 Ex. 9, O'Connor Rebuttal at 95:8-11.

594 Ex. 9, O'Connor Rebuttal at 19-21.

595 Ex. 9, O'Connor Rebuttal at 95:25-96:1.

596 Tr. Vol. IV (Jacobs) at 34:22-35:7.

Dr. Jacobs attempts to counter the Company's allocation of the 13.8 kV system to LCM based on the fact that the Company could have stayed at a 4 kV voltage absent the uprate. But the decision to utilize a 13.8 kV voltage was not a driver of the costs for this modification. As Mr. O'Connor explained "it is highly likely that the costs of a comparable 4 kV upgrade would have been substantially similar to what we incurred."[597] Regardless of the voltage, the Company would have selected an upgrade that: (1) split the safety system from the non-safety system; (2) required construction of new switchgear at the site of the old hotshop or a comparable remote location which would have required similar amounts of raceway and cable; and (3) would have required replacement of the 1R and 2R transformers and the 4 kV horizontal magnablaster breakers as these were original Plant equipment.[598]

d. Feedwater Heaters

Dr. Jacobs classifies 88 percent of the feedwater heater modification (13A/B, 14A/B, and 15 A/B feedwater heaters, cross-around relief valves, main steam drain tank, feedwater flow transmitters, and feedwater dumps, drains, valves, and piping) to EPU. The Company attributed 90 percent of this modification to LCM. While the Enclosure 8 simply states that replacement of the "existing 13, 14, 15 feedwater heaters with new ones sized for EPU conditions," other contemporaneous documents demonstrate that much of this equipment had reached the end of its useful life.

As early as 2001, the Company had identified the need to replace the feedwater heaters due to age and condition.[599] Four of the six heaters were original equipment and the other two were 30 years old. Also, feedwater heaters 15A/B were operating

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597 Ex. 9, O'Connor Rebuttal at 99:13-14.

598 Ex. 9, O'Connor Rebuttal at 99:15-21.

599 Ex. 9, O'Connor Rebuttal at 104:17-21.

"well beyond their original size rating" prior to replacement.[600] All six heaters also experienced service-related degradation, with tube wall thinning and plugging. In fact, a tube failure on feedwater heater 15B caused a Plant shutdown in 2005.[601]

Moreover, the Company evaluated the condition of the six feedwater heaters in 2006 and found that "replacement is an LCM item since the existing units could be justified for use under EPU conditions . . . ."[602] Likewise in 2003 the Company noted that the "[s]ervice life of feedwater heaters requires they be replaced to support the extended period of operation."[603] And Dr. Jacobs acknowledged that in prior testimony he has stated feedwater heaters typically require replacement at the end of a nuclear plant's initial operating license.[604] Dr. Jacobs allocation to the EPU is untenable.

e. Condensate Demineralizer System

Dr. Jacobs attributed 100 percent of the costs for the condensate demineralizer system to the EPU. We attributed 25 percent of the costs for replacement of the vessels and piping to EPU given that these components were larger to support the uprate. The Company's allocation of the majority of the costs to LCM is supported by the obsolescence and age-related deterioration of the existing system.

Evidence of age-related deterioration was found in the vessels and filters for this system. By 2010, documents demonstrate that the vessels and filter elements supported resin for only six months before needing to be recharged.[605] In addition, the old analog control system for the existing system was obsolete, out of date, and

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600 Ex. 9, O'Connor Rebuttal at 105:19-25.

601 Ex. 9, O'Connor Rebuttal at 105:19-25.

602 Ex. 9, O'Connor Rebuttal at Schedule 36.

603 Ex. 9, O'Connor Rebuttal at Schedule 34.

604 Tr. Vol. IV (Jacobs) at 30:6-10.

605 Ex. 9, O'Connor Rebuttal at 107:16-22.

challenging from an operational perspective because it required multiple manual manipulations.[606] Replacement parts for this aging system were also becoming harder to procure. For instance, replacements of the pneumatic flow controllers and the stepping switch controller were no longer available.[607] In fact, even in 2000 the Company recognized the need to replace this system for long-term operations and had placed this system on the Long Range Plan.[608] And the system wiring was degraded to a point where it required immediate replacement.[609] Given well-documented age-related deterioration, obsolescence, and replacement parts issues, the Company's allocation of this modification to 75 percent LCM is well-supported.

f. Condensate Pumps and Motors, Reactor Feed Pumps and Motors and High-Pressure Turbine

The Company acknowledges that the allocations for the condensate pumps and motors, the reactor feed pumps and motors and the high pressure turbine modifications are less clear based on the record as a whole, as the timing of replacement of these pieces of equipment could have possibly been delayed. However, given the duration of the Company's extended license, delaying replacement would have increased costs and would not have maximized the depreciation schedule for these substantial investments.[610] Thus the Company's allocation of these costs to life-cycle management is warranted.

Condensate Pumps and Motors: The Company allocated 25 percent of this modification to LCM while Dr. Jacobs attributed the entire cost to the uprate. The condensate pumps were original Plant equipment and their performance was

[606] Ex. 9, O'Connor Rebuttal at 108:3-5.

[607] Ex. 9, O'Connor Rebuttal at 108:1-2.

[608] Ex. 10, O'Connor Rebuttal at Schedule 32.

[609] Ex. 9, O'Connor Rebuttal at 108:11-13.

[610] Tr. Vol. IV (Jacobs) at 15:8-9.

degrading such that it was approaching a point with adequate suction flow/pressure could not be provided to the reactor feed pumps.[611] But the Company acknowledged that without the uprate it is likely that these issues could have been resolved through maintenance or replacement of the internal components. As a result, the Company's allocation of 75 percent of this modification to EPU is reasonable.

Reactor Feed Pumps and Motors: The Company allocated 93 percent of this modification to LCM while Dr. Jacobs attributed the entire cost to EPU. The Company's allocation of 7 percent of the costs to the uprate is an acknowledgment that these components were sized to support the uprate. Replacement of the reactor feed pumps and motors was primarily driven, however by performance, service-life, and design issues. In fact, replacement of this system was identified in the Company's 2001 Long Range Plan as necessary for Plant reliability. The existing pumps and motors experienced chronic performance issues that could be addressed by replacement.[612] The Company could have delayed addressing these issues but anticipated that the pumps would need replacement within approximately six years even absent the uprate.[613] Thus, it was reasonable to accelerate replacement. Such acceleration is appropriate as even Dr. Jacobs acknowledged that this acceleration has the benefit of minimizing costs and maximizing the depreciation schedule.[614]

While timing of this replacement is open to debate, there is no debate that the unique design of the feedwater pumps benefitted from immediate replacement. The original

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[611] Ex. 9, O'Connor Rebuttal at 111:12-19.

[612] Ex. 9, O'Connor Rebuttal at 109: 17-21.

[613] Examining the service-life of the equipment, given the age of the motors prior to replacement, they were not designed or expected to remain in-service until 2030 which would have assumed a 60-year service life as opposed to the typical 40-year life for this type of equipment. Ex. 9, O'Connor Rebuttal at 110:4-7. In addition, while the rotating assemblies had been replaced, the stators were original and had never been rewound.

[614] Tr. Vol. IV (Jacobs) at 15:8-19.

feedwater pumps were a custom redesign of a 3-stage fire pump and were the only feedwater pumps that employed this design.[615] This unique design was less than ideal and the reactor feedwater pumps often required frequent overhauls to keep them operational.[616] In fact, in 2005, the casing of the pumps required substantial repair to address joint leakage issues.[617]

High-Pressure Turbine: The high pressure turbine replacement is the most debatable modification for purposes of the LCM/EPU cost allocation. The Company allocated 94 percent of this modification to LCM and 6 percent to EPU to account for the larger sized turbine needed to support the uprate. Dr. Jacobs labeled this modification entirely EPU. The existing turbine was put in place during the 1996/98 rerate. The turbine that was in place prior to the rerate had lasted 25 years. As a result, it is technically possibly that the 1996 turbine could have lasted 35 years until the expiration of the extended license.[618] We believe replacement during the LCM/EPU Program was a prudent life-cycle management decision because it enabled the Company to maximize the depreciation schedule for this significant, nearly $60 million investment.[619] Nevertheless we recognize the record could support a debate over whether the original turbine could have lasted to 2030 absent the uprate.[620]

3. Conclusion

The Company does not support allocating costs between the twin purposes of the integrated effort and urges the ALJ and the Commission to view our effort as a whole, consistent with the decisions made for the Program and its overall benefits to

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615 Ex. 9, O'Connor Rebuttal at 109: 23-25.

616 Ex. 9, O'Connor Rebuttal at 109:23-110:3.

617 Ex. 9, O'Connor Rebuttal at 110:1-2.

618 Ex. 9, O'Connor Rebuttal at 103:5-6.

619 Ex. 3, O'Connor Direct at 93.

620 Tr. Vol. IV (Jacobs) at 15:8-19.

customers. However, the Parties have provided various analysis of a potential allocation to be used in the event it is decided that an allocation is important. In that circumstance, the Company believes that the 58.4/41.6 percent LCM/EPU split used in the 2008 EPU Certificate of Need is the only existing split in the record that complies with the legal prudent investment standard and does not inject hindsight into the split analysis. If the Commission concludes that an after-the-fact LCM/EPU split should be applied to final costs, Dr. Jacobs' split does not accurately reflect either the needs of the Plant, the meaning of the document he relied upon, or the post-2008 conditions that drove the actual cost-increases. The Company's 78/22 percent LCM/EPU analysis most appropriately considers all the available information available when the final costs were known, and therefore is the more appropriate after-the-fact split analysis on this record.

D. <u>Remedies</u>

The final section of this Initial Brief discusses the topics of causation as a necessary element to a prudence claim, as well as the appropriate remedies that could be imposed if a finding of imprudence is made. This primarily calls for a discussion of causation and damages, both essential elements to a prudence claim.

1. <u>Causation</u>

Department and OAG assume that a remedy can be imposed simply because costs went up and without tying it to specific ratepayer harm. This approach overlooks the essential causation element of a prudence review.[621] Under the applicable test, even if imprudence is found (which cannot be, based on the Department's testimony), a

[621] *See State ex. rel. Associated Nat. Gas Co. v. Pub. Serv. Comm'n of the State of Mo.*, 954 S.W.2d 520, 530 (Mo. Ct. App. 1997) (citing *Bus. & Prof. People v. Ill. Commerce Comm'n*, 525 N.E.2d 1053, 1059 (Ill. App. Ct. 1988) & *New England Power Co.*, 31 FERC 61,047 at 61,089 n.38 (noting that the issue of the utility's prudence was relevant only if it caused harm to the utility's consumers)) (stating that to disallow a utility's recovery costs from its ratepayers, a regulatory agency must find that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers).

disallowance is permitted only if it caused ratepayer injury.[622] If the cost would have been incurred anyway, no disallowance is warranted.

This causation requirement has been borne out in commission prudence investigations and court appeals around the country. In *Violet v. Fed. Energy Regulatory Comm'n*, for example, the United States Court of Appeals for the First Circuit affirmed a FERC decision finding New England Power Company's decision to enter into a joint operating agreement, which allowed Boston Edison Company to take charge of the Pilgrim II nuclear project, was prudent.[623] The Court also noted the importance of "tangible evidence of a causal link between the allegedly imprudent contract and the costs [the utility] now seeks to recover …."[624] And in *Re San Diego Gas and Elec. Co.*, the California Public Utilities Commission (CPUC) applied the test to its review of a utility contract.[625] The CPUC noted the complainant was:

> like a plaintiff in a personal injury action who has proved liability but has presented no evidence on damages. Although the general burden of proof remains on the applicant, . . . [the complainant] bear[s] some responsibility for establishing some baseline measure of the results of the prudent behavior they advocate.[626]

There can be no disallowance "without some indication of what sort of success a utility who had negotiated more creatively would have achieved."[627]

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622 *Pa. Pub. Util. Comm'n v. Duquesne Light Co.*, 63 Pa. P.U.C. 337, 352 (1987); *In re GPU, Inc.*, 96 Pa. P.U.C. at 91-92 ("Even if imprudence is found, a cost disallowance cannot be justified unless the utility's imprudent conduct was the real and proximate cause of some injury to customers."); *Pa. Pub. Util. Comm'n v. Philadelphia Elec. Co.*, 71 Pa. P.U.C. 42, 45-46 (Pa. P.U.C. 1989).

623 800 F.2d 280, 282 (1st Cir. 1986).

624 800 F.2d at 283.

625 31 C.P.U.C.2d 236 (Cal.P.U.C. 1989).

626 31 C.P.U.C.2d 236 (Cal.P.U.C. 1989).

627 31 C.P.U.C.2d 236 (Cal.P.U.C. 1989).

We appreciate that the parties have found it difficult to isolate specific imprudence that caused ratepayer harm. We disagree that this difficulty is because of the Company's accounting or the Company's documentation. Higher costs are not a reason to impose a remedy without factual support or establishing causation.[628]

a. Causation of Cost Increases

Costs increased because the Company undertook all of the work necessary to ensure the long-term viability of the Plant and to position it for operating at uprate conditions. It was the following factors, and not imprudence, that caused our costs:

- The need to undertake additional and expanded projects to ensure overall success of the Program;[629]
- Evolving NRC requirements and expectations that required us to do additional work and made the work we did much harder;[630]
- Increased licensing costs arising from the unexpected five-year licensing process;[631]
- Installation challenges in working on a 40-year-old operating nuclear Plant that was not designed to facilitate major equipment replacements;[632]
- As-found conditions at the Plant showing more equipment degradation and other problems than we anticipated;[633]
- Specific installation issues we encountered on the feedwater heater and 13.8 kV system installations;[634]

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[628] Ex. 16, O'Connor Surrebuttal at 23:4-12; Tr. Vol. IV (Jacobs) at 31:3-15.

[629] Ex. 3, O'Connor Direct at 31:23-32:4.

[630] Ex. 3, O'Connor Direct at 34:4-35:2; 35:7-36:3; 36:20-38:4; Ex. 9, O'Connor Rebuttal at 24:9-15.

[631] Ex. 9, O'Connor Rebuttal at 23:23-24:4.

[632] Ex. 3, O'Connor Direct at 32:26-33:11.

[633] Ex. 3, O'Connor Direct at 39:4-26.

[634] Ex. 16, O'Connor Surrebuttal at 13:19-15:22 (feedwater heaters); 10:6-12:24 (13.8 kV system).

- Declining nuclear experience in the labor pool, which, coupled with the increasing complexity of the installations severely impacted installations;[635]

- Significant labor productivity issues arising out of the challenging physical layout of the Plant and the need to install equipment around existing systems;[636]

- Vendor issues that we encountered and resolved along the way;[637]

- Application of the NRC's worker fatigue rule that went into effect after our estimates and made it more difficult to attract and retain qualified craft labor.[638]

b. No Causation On this Record

The parties' criticisms do not support a finding of causation or ratepayer harm from these cost increases. These criticisms revolve around (i) low cost estimates; (ii) the need for "better" project management; and (iii) a number of extraneous and unrelated criticisms that do not relate to the costs we incurred in the Program.

c. No Causation From Low Cost Estimates

More detailed cost estimates would not have reduced costs and did not cause higher costs,[639] but rather would have identified costs earlier.[640] At most, we might have provided an initial estimate in the $420 million range but that would have made no difference. And identifying a higher estimate earlier would not have lowered the cost of the Program because it would not have accounted for as-found conditions, interferences, and degraded wiring discovered during installations.[641] Mr. Crisp agrees

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635 Ex. 9, O'Connor Rebuttal at 69:14-19.

636 Ex. 3, O'Connor Direct at 40:3-12.

637 Ex. 3, O'Connor Direct at 40:17-41:25.

638 Ex. 3, O'Connor Direct at 40:10-12; 91:5-6; 92:3-22; Ex. 16, O'Connor Surrebuttal at 7:14; 17:10-12.

639 Ex. 16, O'Connor Surrebuttal at 7:6-7.

640 Ex. 16, O'Connor Surrebuttal at 4:18-22.

641 Ex. 16, O'Connor Surrebuttal at 7:15-16.

cost increases can happen without imprudence[642] and he admits "that the amounts the Company actually spent for each modification could be justified."[643]

Our testimony fully describes the reasons for our low cost estimates[644] and the resource planning context[645] that called for us to proceed with the Program on the basis of high-level conceptual estimates. Further, the record supports a finding that all of the work we did was necessary to ensure Program success.[646] Thus, even if we had done a better job of predicting costs, it did not cause ratepayer harm.

d. No Causation From General Management Prudence Criticisms

The Department and the OAG rely almost exclusively on the testimony of Mr. Crisp to support any claim that the Company "mismanaged" implementation. Mr. Crisp, in turn, relies on sound-bites and generalities about "good" project management and assumes that the Company could have done a better job without providing specifics or even rendering an opinion about the Company's prudence.[647]

Without finding imprudence, however, Mr. Crisp states that costs would have been lower than $665 million if the Company had done a better job of managing the Program,[648] yet he admits that he did no analysis that quantified the financial impact of his criticisms.[649] Because Mr. Crisp made no effort to quantify costs and does not opine on prudence, his opinion cannot support a finding of causation. The OAG

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642 Tr. Vol. III (Crisp) at 17:20-22.

643 Tr. Vol. III (Crisp) at 18:17-20.

644 *E.g.*, Ex. 9, O'Connor Rebuttal at 36:16-46:10 and Table 3

645 *See generally* Ex. 2, Alders Direct at 6-24; Ex. 8, Alders Rebuttal at 3-17.

646 Ex. 9, O'Connor Rebuttal at 42:4-7.

647 Tr. Vol III (Crisp) at 15:22-24 and 17:7 (acknowledges that he rendered no opinion of prudence or imprudence); Ex. 9, O'Connor Rebuttal at 2:10 and Schedule 1.

648 Tr. Vol. III (Crisp) at 67:5.

649 Tr. Vol. III (Crisp at 59:9-12.

tries to expand upon Mr. Crisp's testimony by assuming imprudence without tying the criticisms to specific costs. The OAG relies on Mr. Crisp for the notion that "complexity" of the job should not have increased costs.[650] However, Mr. Crisp's criticism is not so much that we should not have incurred those costs, but rather that we should have foreseen them better. And nowhere in his testimony does Mr. Crisp suggest that costs due to added complexity equate to imprudence.[651]

The OAG repeats Mr. Crisp's criticism of "starts and stops" with contractors and assumes (unlike Mr. Crisp) that this equates to imprudence. Again, however, the record establishes that our contracting strategy was appropriate and evolved to meet changing circumstances.[652] There is nothing about this allegation that can be said to have caused ratepayer harm. Both Mr. Crisp and the OAG rely on the 2011 Cost History for the proposition that the Company's project management was not perfect. But again, Mr. Crisp does not suggest that this document demonstrates imprudence that caused ratepayer harm. This is like the *San Diego Gas and Electric Co.* case,[653] where the mere claim of higher costs does not establish imprudence or causation.[654]

e. Other Issues Not Tied to Program Costs

Finally, the Department raises a series of other concerns and criticisms about the Company, Monticello and our nuclear program generally. None of these concerns, however, can be said to have caused the costs of the LCM/EPU Program to have increased and, indeed, most of these issues are unrelated to the costs we incurred and some of them are unrelated to the Program entirely. These issues are: (i) the

650 Ex. 16, O'Connor Surrebuttal at 16:7-10.

651 Ex. 16, O'Connor Surrebuttal at 16:21-25. Tr. Vol. III (Crisp) at 17:20-22.

652 Ex. 16, O'Connor Surrebuttal at 18:14-19:16.

653 31 C.P.U.C.2d 236 (Cal.P.U.C. 1989).

654 31 C.P.U.C.2d 236 (Cal.P.U.C. 1989).

Company's choice to account for the LCM and EPU aspects of the initiative as an integrated whole rather than accounting for the LCM and EPU aspects separately; (ii) concerns over the Company's regulatory communications relating to the Program; (iii) issues pertaining to the ascension of the Plant from 600 MW to 671 MW; and (iv) a series of other issues wholly unrelated to the Program and the costs we incurred implementing it.

(1) *Accounting*

While the Department is unhappy with the way the Company accounted for the effort, there is no suggestion that our accounting methods resulted in spending more money than necessary. There is no dispute that the Company's accounting for the initiative followed the FERC uniform system of accounts, which has been adopted by the Commission and governs our accounting practices. This accounting mechanism requires that we account for costs based on work orders that correspond to specific units of property. It does not call for accounting based on functionality or allocation between two separate but related purposes such as LCM and EPU.

> Costs for capital projects such as the LCM/EPU Program are tracked and accounted for based on work orders. Work orders are generally established at a level needed to record costs in the Company's accounting records. For capital projects such as Monticello 1 LCM/EPU, this would be at the Federal Energy Regulatory Commission ("FERC") account level – buildings, equipment, etc. by function – with additional detail to ensure specific components of plant, property and equipment could be identified for unitization, depreciation and ultimately retirement. Work orders for related items can be grouped using "parent" work orders to roll-up and group "child" subproject work orders for subproject elements.[655]

[655] Ex. 5, Weatherby Direct at 2:25-3:7.

The Department's dissatisfaction with our accounting appears to be that it made development of their LCM/EPU split more difficult.[656] However, Dr. Jacobs developed his LCM/EPU split as an engineering exercise not an accounting exercise.[657] It was an engineering-based attribution of costs to divide those costs between two functions (for Certificate of Need purposes) not to comport with project management principles or FERC accounting requirements.[658] It would have been inconsistent with FERC accounting requirements to account by separate functions.

And, due to the integrated nature of the effort, attributing a portion of costs for certain equipment to LCM and a portion of costs for the same equipment to EPU would always have required the same allocation exercise the parties conducted here. Even if the Company had attempted to account for the Program as separate EPU and LCM, that attribution of costs would have to be assessed and re-assessed along the way to ensure accuracy as the need for additional work evolved, and the Department may still have disagreed with the Company's attribution of costs. Overall, the Company's accounting for Program costs was consistent with FERC and consistent with the integrated nature of the Program, and there is nothing about the accounting that can be said to have caused increased costs.

(2) *Regulatory Communications were Reasonable*

As described earlier in this Brief, the Company provided significant information at several intervals in our rate cases as we came to realize that costs were increasing

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656 Ex. 313, Campbell Direct at 20:19-21 ("Xcel's choice in tracking these costs resulted in needlessly higher costs for this prudence review since it was necessary for the Department to hire a consultant to split apart what Xcel never should have put together.").

657 Tr. Vol. III (Jacobs) at 99:1-4.

658 Ex. 3, O'Connor Direct at Schedule 29 (page 2 of 6) ("[W]e relied on the judgment of the Monticello engineering to apportion the costs between unavoidable LCM and avoidable EPU based on the nature of the vendor services necessary to complete each modification.")

rapidly.[659] While we agree that it is important to keep our stakeholders informed, and did so, even if our communications were less than ideal, there is no suggestion that our communications caused our Program costs to increase.

(3) *Ascension Issues*

The Department and the OAG raise concerns over the timing of when Monticello will be able to ascend to the 671 MW (rather than its historic 600 MW) level. As Mr. O'Connor points out:

> This is not an indication of problems with the plant or the equipment we installed nor an indication of imprudence. The equipment is working. We are working closely with the NRC to validate the Power Ascension Performance information collected before ascending to new EPU levels.[660]

All construction costs for which we seek recovery in this proceeding were complete when ascension began and the current calculation confirmation process is unrelated to our capital expenditures. Once again, there is no record support for the notion that the timing of ascension or the need to obtain NRC concurrence with our calculations caused our costs to increase.

(4) *Other Issues at the Plant*

Finally, the Department notes a series of unrelated "issues" at Monticello.[661] These issues are (i) an NRC "yellow" finding associated with the need to satisfy applicable flood protection requirements that is wholly unrelated to the LCM/EPU Program;[662]

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[659] *See* Ex. 8, Alders Rebuttal at 15:15-17:12; Stipulation and Settlement Agreement at pp. 3-4 and 7, Docket No. E002/GR-10-971 (Nov. 14, 2011).

[660] Ex. 407, O'Connor Opening Statement at 4.

[661] Ex. 313, Campbell Direct at 34:5-7.

[662] Ex. 16, O'Connor Surrebuttal at 33:17-34:26; Ex. 313, Campbell Direct at 3:22-23.

(ii) a weld inspection issue at the Plant pertaining to one of our dry casks that is wholly unrelated to the LCM/EPU Program;[663] (iii) an NRC finding of "human performance" issues at the Plant that did not relate to the implementation of the LCM/EPU Program;[664] and (iv) a malfunction in an unrelated circulating water pump that has caused the Plant to be derated at the present time.[665] We have taken all of these issues seriously and are working to address the concerns.

But these issues are not relevant to our prudence in implementing the LCM/EPU Program and there is no record evidence to suggest that any of these issues caused the costs of the Program to increase. It is not sufficient to raise a series of "issues" and then merely suppose that our performance was inadequate, particularly for those issues that are wholly unrelated to the LCM/EPU Program.[666]

2. Remedy Must be Supported and Proportionate

Finally, any remedy must be supported on the record,[667] tied to imprudence,[668] and proportionate.[669] It is not appropriate simply to impose a proxy remedy that applies

663 Ex. 16, O'Connor Surrebuttal at 35:1-16; Ex. 313, Campbell Direct at 3:23; Ex. 436, Campbell Opening Statement at 1.

664 Ex. 16, O'Connor Surrebuttal at 35:18-36:11; Ex. 313, Campbell Direct at 3:23-24; Ex. 436, Campbell Opening Statement at 1.

665 Ex. 407, O'Connor Opening Statement at 4.

666 Reliance on issues of this sort amount to nothing more than speculation. *See Hinz v. Neuroscience, Inc.*, 538 F.3d 979, 984 (8th Cir. 2008) ("[T]here can be no recovery for damages which are remote, conjectural, or speculative.") (quoting *Jensen v. Duluth Area YMCA*, 688 N.W.2d 574, 579 (Minn. Ct. App. 2004)); *Leoni v. Bemis Co.*, 255 N.W.2d 824, 826 (Minn. 1977) ("The controlling principle governing actions for damages is that 'damages which are speculative, remote, or conjectural are not recoverable.'") (quoting *Hornblower & Weeks-Hemphill Noyes v. Lazere*, 301 Minn. 462, 467, 222 N.W.2d 799, 803 (1974)); *Carpenter v. Nelson*, 257 Minn. 424, 427-28, 101 N.W.2d 918, 921 (1960).

667 *See* Minn. Stat. § 14.69 (stating that agency decisions must be supported by substantial evidence); *LaFavor v. Am. Nat. Ins. Co.*, 279 Minn. 5, 12, 155 N.W.2d 286, 291 (1967) ("[w]hile the evidence in proof of a crucial fact may be circumstantial, it must not leave it in the field of conjecture").

668 *Violet,* 800 F.2d at 283; *In re GPU, Inc.*, 96 Pa. P.U.C. at 91-92 ("Even if imprudence is found, a cost disallowance cannot be justified unless the utility's imprudent conduct was the real and proximate cause of some injury to customers.").

(i) a hindsight cost-effectiveness test (Department), or (ii) a disallowance of simply because our costs exceeded our initial estimates (OAG).

And in structuring any remedy that is found, it is important from both an analytical and a policy perspective not to overcorrect.[670] The Commission should review the history of our implementation and take this into account in fashioning a remedy.[671]

3. Department's Remedy Not Tied to Prudence

The Department recommends that the Company be disallowed \$71.42 million (Minnesota jurisdiction), or approximately a \$10.713 million revenue requirement reduction based on the hindsight conclusion that the EPU megawatts were not cost-effective,[672] by superimposing 2013 costs and Dr. Jacobs' after-the-fact (and incorrect) LCM/EPU split on a 2008 cost-effectiveness test.[673] The Department reaffirmed at the hearing that this is the remedy that it is seeking to impose on the Company.[674]

The Department's approach to a disallowance is essentially the same as the "breakeven" analysis Dr. Jacobs advocated for in Florida.[675] Just as in Florida, that

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669 *Covington & L. Tpk. Rd. Co. v. Sandford*, 164 U.S. 578, 597 (1896); *Duquesne Light Co.*, 488 U.S. at 307-08 ("The guiding principle has been that the Constitution protects public utilities from being limited to a charge for their property serving the public which is so 'unjust' as to be confiscatory. . . . If the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation and so violated the Fifth and Fourteenth Amendments.").

670 We are concerned about the impact of a general disallowance without specific facts supporting imprudence or harm. This could send a signal to our investors that our nuclear programs do not have strong regulatory support in Minnesota. Ex. 12, Sparby Rebuttal at 33:11-15.

671 Ex. 12, Sparby Rebuttal at 17:23-26.

672 Ex. 313, Campbell Direct at 27; 31:6-10; and 35.

673 Ex. 8, Alders Rebuttal at 23:20-25.

674 Tr. Vol. IV (Campbell) at 125:22-126-4.

675 Tr. Vol. III (Jacobs) at 106:20-21; 110:1-10; 112:12 (agrees that Mr. Shaw's cost-effectiveness analysis is the same as his breakeven analysis that was rejected in Florida).

position should be rejected here. When Dr. Jacobs tried to inject a hindsight cost-effectiveness test in Florida, that Commission stated:

> [W]e find witness Jacobs' recommendation shall not be adopted because there is no support regarding how, if at all, his use of a breakeven analysis does not apply hindsight analysis and distinguishes between prudent and imprudent utility management actions.[676]

However, if the Commission feels it must consider cost-effectiveness retroactively, then any consideration of cost-effectiveness should exclude the $97 million in sunk costs that we had spent in furtherance of the Program prior to issuance of the Certificate of Need.[677] The Department disagreed and argued excluding sunk costs would create a perverse inventive for utilities to spend as much capital upfront as possible,[678] and provide biased results.[679]

The Department's argument conflates the purpose of a cost-effectiveness analysis with the purpose of this prudency investigation. A utility retains recovery risk for imprudent expenditures regardless of whether those expenditures occurred before or after a certificate of need is granted.[680]

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676 Ex. 425, Final Order Approving Nuclear Cost Recovery Amounts for Florida Power & Light Company and Duke Energy Florida, Inc., Docket No. 130009-EI, at 35-36.

677 *See Appeal of Conservation Law Found. of New England, Inc.*, 507 A.2d 652, 661-62 (N.H. 1986) (upholding the New Hampshire Public Utilities Commission's use of incremental cost analysis that ignored sunk costs); *Energy Efficiency and Conservation Program*, Nos. M-2012-2289411 and M-2008-2069887, 2014 WL 769433, FINAL ORDER at *24-25 (Pa.P.U.C. Feb. 20, 2014) (sunk costs are not included in cost-effectiveness of program); *In re: Petition to Determine Need for Hines Unit 3 in Polk Cnty. by Fla. Power Corp.*, No. 020953-EI, 2003 WL 271937, ORDER GRANTING DETERMINATION OF NEED (Fla.P.S.C. Feb. 4, 2003) (finding Hines Unit 3 the least-cost alternative when compared to the RFP proposals over objections that the analysis improperly excluded sunk costs).

678 Ex. 309, Shaw Direct at 19:18-20:3.

679 Ex. 311, Shaw Surrebuttal at 8:25-28.

680 Ex. 8, Alders Rebuttal at 28:15-19.

In contrast, a cost-effectiveness analysis demonstrates whether the going forward cost of continued construction or operation of a power plant is more cost-effective than the costs associated with replacement power.[681] The cost-effectiveness analysis should not include sunk costs, that is, the costs already spent on a project. For the purpose of economic analysis, "[s]unk costs are bygones."[682] Sunk costs should not be included in cost-effective analysis because the utility cannot avoid the expense by adopting a different course of action.[683] This understanding of cost-analysis is consistent with Commission precedent.[684] And the Department does not dispute the Company's rationale for spending money prior to receiving the Certificate of Need.

Further, the parties agree that the Program remains cost-effective as a whole.[685] Consistent with the purpose of cost-effectiveness analyses, the Company performed internal management reviews in 2010 and 2011, to confirm that it would still be prudent to pursue the Program.[686] The Company also conducted hindsight analyses using the final $665 cost level under 2008 conditions. The modeling all showed the work we did at Monticello was appropriate.[687]

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681 Ex. 8, Alders Rebuttal at 29:9-15.

682 *In the Matter of the Petition by N. States Power Co. for Auth. to Change Certain of its Natural Gas Rates for Retail Customers in the State of Minn.*, No. G-002/GR-78-1052, 1979 WL 461804, ORDER (Minn. P.U.C. Sept. 21, 1979).

683 Ex. 8, Alders Rebuttal at 29:12-13.

684 *E.g.*, *In re Interstate Power & Light Co.*, Docket No. E-001/GR-10-276, ALJ FINDINGS OF FACTS ¶¶ 149-51 (Apr. 27, 2011) (cost-effectiveness analysis comparing costs of repairing coal plant with replacement power costs, does not include sunk costs) (*aff'd* Findings of Fact, Conclusions and Order (Aug. 12, 2011)); *In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Elec. Serv. Rates in Minn.*, Docket No. E-017/GR-10-239, ALJ FINDINGS OF FACT ¶¶ 9-24 (Feb. 14, 2011) (recognizing that the Commission originally found the Big Stone II project to be "more cost-effective than other alternatives" but that change circumstances rendered the project much more costly and no longer reasonable).

685 Tr. Vol. IV (Shaw) at 106:18-21.

686 Ex. 3, Alders Direct at 51:2-21.

687 Ex. 3, Alders Direct at 32:23-34:8.

Under Mr. Shaw's model, the EPU aspect is not cost effective by about $84 million, using his 2008 model, $665 million, and Dr. Jacobs' 14.3/85.7 percent LCM/EPU split.[688] Removing the $97 million in sunk costs would shift Mr. Shaw's cost-effectiveness analysis enough to show that the EPU aspect is virtually cost-effective using Mr. Shaw's test.[689]

4. <u>OAG's Remedy Disproportionate</u>

The OAG's proposed remedy also is infected with hindsight by disregarding the reasons for our cost increases and merely focusing on cost caps and assumptions that higher costs must be wrongful. This could not withstand scrutiny and the OAG's proposed remedy is wholly disproportionate to any harm done.

First, in making its proposed disallowance the OAG assumes that any costs over the amount estimated in the Certificate of Need proceeding are not appropriate and a disallowance is justified. As described in detail in Mr. Alders' Rebuttal[690] and Surrebuttal[691] testimonies, we do not agree that costs can be lawfully capped at the Certificate of Need level under these circumstances.

Based on its incorrect premise, the OAG advocates a direct disallowance of 75% of all costs in excess of $320 million. This disallowance is not sustainable.[692] It is not sufficient to assume imprudence and assess an arbitrary percentage penalty.[693] Rather, the prudent investment standard calls for (i) specific findings of imprudence, not just

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688 Ex. 309, Shaw Direct at 31-32 and Table 20.

689 Using Dr. Jacobs' split results in about $82.5 million of costs he attributes to the EPU ($97 million multiplied by 85.7 percent), which virtually cancels out the $84.4 million cost-effectiveness disallowance.

690 Ex. 8, Alders Rebuttal at 14:15-25.

691 Ex. 15, Alders Surrebuttal at 15-24.

692 Ex. 15, Alders Surrebuttal at 24:15-16.

693 Ex. 15, Alders Surrebuttal at 24:16-17.

cost increases, and (ii) quantified harm arising caused by the imprudence. As Mr. Alders testified:

> At $321 million, the OAG's proposed disallowance is disproportionate to any conceivable harm in this situation. The Company reasonably spent $665 million to obtain 671 MW of reliable baseload capacity for 20 years at about $1,000/kW installed. This compares very favorably with the cost of alternative forms of new baseload generation, even if new coal plants could have been feasible under the circumstances. While our actual costs were higher than initially projected, preserving Monticello as a carbon-free resource is overwhelmingly cost effective as a whole based on 2008 assumptions. As Mr. Sparby stated in his Rebuttal Testimony, disallowance approaching $100 million (as proposed by the Department) would unduly impair this asset and should not be imposed.[694]

Second, the OAG states that any recovery over $320 million should be without any return on the investment. The OAG provides no rationale for this recommendation. In short, if we incurred costs prudently, they should be recoverable with a return. Any other outcome, including those proposed by both the Department and OAG, would unfairly penalize the Company despite its prudent actions.[695]

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[694] Ex. 15, Alders Surrebuttal at 24:22-25:5.

[695] "[T]he disallowance suggested by the OAG ($323 million disallowed outright and no return on $107 million) would result in an effective reduction in the Company's Minnesota jurisdiction overall recovery by more than $271 million over the life of the investment on a net present value basis, and an approximately $38.4 million decrease in the Company's proposed revenue requirement in its current rate case, Docket No. E002/GR-13-861. Such an outcome would be confiscatory and could not be sustained on any reasonable reading of the facts or record. Ex. 15, Alders Surrebuttal at 27:24-28:4.

VI. CONCLUSION

Xcel Energy appreciates the opportunity to explain the LCM/EPU Program. This major initiative allowed us to provide 20 more years of reliable baseload power for our system and positions us to increase the capacity of Monticello to 671 MW for the remainder of our existing operating license and potentially beyond. While we acknowledge that the costs were higher than we estimated, higher costs do not equal imprudence. Rather, the record supports a recommendation to the Commission that our implementation of the Program was, overall, reasonable under the circumstances. This record would not support a material disallowance.

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Respectfully submitted,

By /s/

Aakash H. Chandarana
Alison C. Archer
Assistant General Counsel
NORTHERN STATES POWER COMPANY, a Minnesota corporation
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401
Telephone: (612) 215-4662

Michael C. Krikava
Elizabeth M. Brama
Paul J. Hemming
Briggs and Morgan
2200 IDS Center
Minneapolis, MN 55401
Telephone: (612) 977-8566

ATTORNEYS FOR NORTHERN STATES POWER COMPANY