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February 12, 2015

<u>ELECTRONIC FILING</u>

Mr. Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 Seventh Place East
St. Paul, MN 55101

Re: *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

Dear Mr. Wolf:

Enclosed for filing in the above-referenced proceeding, please find Xcel Energy's Exceptions and Clarifications to the ALJ Report.

Please contact me if you have any questions regarding this filing.

Sincerely,

/s/ Alison C. Archer

Alison C. Archer

Enclosure
cc: Attached Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Betsy Wergin	Vice Chair
Nancy Lange	Commissioner
Dan Lipshultz	Commissioner
John Tuma	Commissioner

IN THE MATTER OF A COMMISSION INVESTIGATION INTO XCEL ENERGY'S MONTICELLO LIFE CYCLE MANAGEMENT/ EXTENDED POWER UPRATE PROJECT AND REQUEST FOR RECOVERY OF COST OVERRUNS

Docket No. E002/CI-13-754
OAH Docket No. 48-2500-31139

XCEL ENERGY EXCEPTIONS AND CLARIFICATIONS TO ALJ REPORT

February 12, 2015

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I. INTRODUCTION AND SUMMARY

Northern States Power Company d/b/a Xcel Energy respectfully takes Exception to the Administrative Law Judge's Report. We begin by noting the parties' and the ALJ's efforts to develop the record for the Commission's consideration. The record was lengthy and complex, and resulted in vastly different perspectives. These divergent views make the Commission's deliberations and decision particularly challenging.

Perhaps even more challenging, however, is that a significant amount of relevant and probative record evidence is missing from the Report. There is no discussion of the context in which this situation arose, no discussion of the overall industry influence, and no recognition of the Company's commitment to nuclear safety and the importance of keeping Monticello a viable part of our fleet for the long term. Without this material, the Report reads as though the only question remaining is whether the recommended remedy is appropriate.

With all due respect, we are disappointed in the Report and its failure to address the whole record. While we recognize that substantial cost increases would engender frustration with the Company, we do not think this view fairly reflects the changing and more challenging environment in the nuclear industry that evolved during the course of this project, causing impacts not just for us, but for others as well. Despite the comprehensive record, the linchpins of the ALJ's prudence determination are essentially a 2011 document representing the opinions of one Company employee and Department witness, Mr. Crisp's reliance on this document. In order to make a reasonable decision, it is critical for the Commission to consider a complete picture of the entire record.

In contrast, the Company provided substantive and substantial explanations of why and how the LCM/EPU Program unfolded as it did, including multiple rounds of pre-filed testimony from six witnesses amounting to several hundred pages and dozens of supporting Schedules. We responded to nearly 200 information requests, provided the Department with over 3,000 documents about the Program, and provided access to our entire accounting database. All of this information provided a thorough discussion of the Company's management of the highly complex Program.

Throughout these Exceptions, we examine both the critical swaths of the record overlooked by the ALJ and the specific reasons the Company's decisions and actions were prudent. We explain the alternatives we considered and rejected – several of which were referenced by the ALJ as preferable even though the Report does not include examination of the downsides of those paths. We submit that the record reflects our prudence and does not support a disallowance.

A. The Value of the Program

Although the Report recommends disallowance of a significant portion of our costs, the ALJ does not examine what customers actually got for the money. The answer is that while the costs of the Program increased significantly beyond initial estimates, the final cost provided substantial and commensurate benefits for customers in a very challenging nuclear industry. This outcome is missing from the ALJ's Report.

First, carbon-free nuclear power has long been a critically important baseload resource for the Company. Preserving and expanding generation at Monticello provides an additional 20 years of more than 600 MW of baseload nuclear generation at about \$1,000/kW installed – a cost no party disputes is "overwhelmingly cost-effective as a whole."[1] At the same time, this resource provides carbon-free power in an increasingly-challenging CO_2 reduction expectations.[2] Maintaining generation at

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

[2] Ex. 9, O'Connor Rebuttal at 3:17-24. In 2007 the legislature passed the Next Generation Act that called on the state's utilities to achieve 30% carbon dioxide reductions. The importance of maximizing carbon-free

Monticello maximizes the use of existing infrastructure and the robust transmission system that has developed in the region, while also reducing our reliance on historically volatile natural gas and market energy.[3] The fuel diversity that nuclear power offers was a key driver in our decision to pursue a license extension that would preserve Monticello's 600 MW of baseload generation, and also contributed to our subsequent decision to add an additional 71 MW through the uprate.

Second, despite the challenges we faced, the Company achieved a well-designed power plant built to last through at least 2030. To date all equipment installed for the 10 major modifications of the Program is performing well and the plant has operated within its normal parameters in its first full year of operations after completion of the effort. The Company preserved the 600 MW of baseload power and it is nearly 80 percent of the way to full uprate conditions. This is no small achievement in today's nuclear world, where two nuclear plants undergoing major construction were permanently shut down as a result of seemingly reasonable decisions that led to devastating consequences. Again, none of this is discussed in the Report.

The project we built also regained critical safety margin that had eroded after forty years of operations. Margin improvement both in equipment performance and design is required in today's NRC regulatory climate. Because the Company made increasing safety margin its primary focus, the project upgrades were the right ones to assure compliance in today's world.[4] In fact, the Department's construction management

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generation was recently reinforced in our 2015 Resource Plan (Docket E-002/RP-15-21), which describes the Company's increasing CO_2 reduction obligations and commitments. Maintaining and increasing carbon-free generation such as nuclear is key to meeting those obligations and having Monticello available through at least 2030 is a benefit to our customers and the State.

[3] Ex. 2, Alders Direct at 3:14-19.

[4] For example, the 13.8 kV electrical distribution system allowed the Company to stop the practice of sequencing the start of motors and avoid triggering alarms. Tr. Vol. IV (Jacobs) at 34:22-35:7. The new condensate demineralizer system avoided taking operators away from their positions to conduct manual backwashes every few days. Ex. 3, O'Connor Direct at 106:9-12. And replacing original equipment, such as some of the feedwater heaters, transformers and pumps and motors, was integral to satisfying the NRC's

witness, Mr. Crisp, admitted that he takes no issue with the work the Company did.[5] He admits "that the amounts the Company actually spent for each modification could be justified."[6] The Report includes none of this context.

It is important to be clear that the benefits derived from the Program are the result of consideration of alternatives by the Company each step of the way. As a macro level example, although the ALJ accepted the suggestion by Department witness Mr. Crisp that the Company could have reduced cost by delaying the Program,[7] the Report does not examine the benefits of the Company's approach and the negative anticipated outcomes of Mr. Crisp's alternative.[8] The Report ignores that no Party rebutted the Company's assessment that absent parallel tracking, Program implementation would have been delayed until at least 2017,[9] thus failing to address the identified need. It also overlooks the need to start upgrading very aged equipment sooner rather than later, and that this same equipment would need to touched again if we later pursued the uprate. In short, the Report overlooks that the timeframe for making the uprate decision was a limited window. At a time when natural gas traded at historic highs (with long-range forecasts in the $8-10/mcf range), the decision to add 71 MW made sense. Likewise, the Report overlooks that when Mr. Crisp was cross-examined, he admitted that the Company's parallel-track decision did not in and of itself increase

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rules on proper maintenance and managing an aging nuclear plant. Ex. 4, Stall Direct at 17:4-18:24; *see* Ex. 9, O'Connor Rebuttal at Schedule 11 at 8-9 (Company Response to Department IRs 59, 60, and 62 explaining impact of changes in NRC rules).

[5] Tr. Vol. III (Crisp) at 24:10-27:14.

[6] Tr. Vol. III (Crisp) at 18:17-20.

[7] Report at Conclusions of Law ¶ 10.

[8] "Multi-track" refers to working on various aspects of the Program simultaneously. For example, the Company planned for the 2009 outage while the 2008 EPU Certificate of Need proceedings were pending, thereby allowing the Company to begin the outage within weeks of obtaining the Certificate of Need. This put significant Company investment at risk if a Certificate of Need was not issued, but also highlights the importance at the time of pursuing the Program immediately.

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

Program costs[10] and that he had no opinion regarding Mr. O'Connor's conclusion that a different approach was unlikely to reduce costs.[11] And Dr. Jacobs acknowledged that delaying work likely would have increased costs and reduced benefits.[12] As such, the Report overlooks the evidence that the Company would not have met our customers' needs, would have increased construction costs, and very likely would have foregone the option of an uprate by adopting the approach Mr. Crisp advocates in this proceeding.

With respect to more specific scoping questions, the Company examined a multitude of alternatives to maximize the benefits to customers of the modifications we implemented. The Report fails to examine or reflect the Company's robust analysis of alternatives to equipment planning and design, including decisions whether to repair or replace equipment. The Company found that much of the original plant equipment, including the steam dryer,[13] feedwater heaters,[14] condensate demineralizer system,[15] main power transformer and 1AR emergency transformer,[16] reactor feed pumps and motors,[17] condensate pumps and motors,[18] and PRNM system,[19] was at

[10] Tr. Vol. III (Crisp) at 28:18-21.

[11] Tr. Vol. III (Crisp) at 15:11-17, 18:17-25, 22:7-14, 22:21-23; Ex. 9, O'Connor Rebuttal at 53:14-54:6 and Schedule 22 (The Engineering and Design Process, Xcel Energy Nuclear Department). And while Mr. Crisp reviewed Mr. O'Connor's explanation, he declined to state an opinion on the propriety of it. Tr. Vol. III (Crisp) at 34:13-19.

[12] Tr. Vol. IV (Jacobs) at 15:8-12, 36:6-37:19.

[13] Ex. 3, O'Connor Direct at 103:4-104:4 and Schedule 5 at 1 (LCM/EPU Modification In-Service Table); Ex. 9, O'Connor Rebuttal at Schedule 32 at 18 (Company Response to Department IR 124 including contemporaneous documents detailing the conditions of the existing equipment) (Attachment C of these Exceptions).

[14] Ex. 9, O'Connor Rebuttal at Schedule 32 at 7 (Attachment C of these Exceptions) and 34 (Monticello Nuclear Generating Plant Potential Capital Expenditures Strategy, May 22, 2003).

[15] Ex. 9, O'Connor Rebuttal at Schedule 32 at 5 (Attachment C of these Exceptions).

[16] Ex. 3, O'Connor Direct at 114:23-115:9; Ex. 9, O'Connor Rebuttal at 90:17-21; 114:7-15 and Schedules 32 at 19-20 and 42 (Attachment C of these Exceptions); 33 at 13 (2001 Long Range Plan), and 34 at 10 (Monticello Nuclear Generating Plant Potential Capital Expenditures Strategy, May 22, 2003).

[17] Ex. 9, O'Connor Rebuttal at Schedule 32 at 8-10 (Attachment C of these Exceptions).

the end of its operating life and required replacement.[20] These conclusions were the result of detailed analysis not discussed in the Report.

A prime example of our alternatives' analysis was with the Reactor Feed Pumps and Motors modification. The main two options evaluated by the Company were whether to replace the original two pumps with two larger pumps or replace the originals and add a third supplemental pump.[21] These aging pumps and motors needed replacement anyway to sustain long-term operation, so implementing the two-pump solution allowed us to combine that work with the uprate. Both options had recognized challenges, and the Company determined the two pump solution provided greater operating continuity without the need to develop new protocols and training for our licensed operators.[22] Similarly, another key example is the process by which we decided to undertake the 13.8 kV modification. In analyzing options, we convened the 2007 Electrical Summit at which the Company narrowed the options. This analytical approach allowed us to reach a consensus on the optimal outcome for the plant. The cost estimate for the less robust solution was equivalent to the solution that created greater reliability margin.[23] Again, the Report does not consider or assess this prudent weighing of alternatives to meet the needs of the plant and ultimately our customers.

Third, like Monticello, major upgrade work at plants in Florida and elsewhere also experienced a doubling effect on their costs. As Department witness Dr. Jacobs

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[18] Ex. 9, O'Connor Rebuttal at Schedule 32 at 10-11 (Attachment C of these Exceptions).

[19] Ex. 3, O'Connor Direct at 99:24-100:6; Ex. 9, O'Connor Rebuttal at 112:21-23.

[20] Ex. 9, O'Connor Rebuttal at 87:19-22 and Schedule 32 (Attachment C of these Exceptions).

[21] Ex. 4, Stall Direct at 48:12-14.

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

[23] Ex. 9, O'Connor Rebuttal at Schedule 35 at 6 (Company Response to Department IR 83 describing the 2007 Electrical Summit).

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 challenges."[24] Despite a prudence challenge in which Dr. Jacobs participated, the Florida commission authorized 100 percent recovery of the costs.[25]

B. Why Costs Escalated

Even if the final costs of the Program are commensurate with their value to customers, it is valid to ask whether any Program costs should have been avoided. The Report appears to conclude overall that early scoping and project management decisions caused cost increases. However, the Report glosses over detail regarding the circumstances the Company faced when embarking on the Program or why we believed it was necessary to proceed as we did in light of the energy markets and customer resource needs at that time.

During the 2003-2008 timeframe, market conditions created a strong incentive on behalf of customers to preserve Monticello's base capacity and then also increase that capacity. In that pre-fracking, pre-Great Recession world, moving expeditiously to reduce dependence on high-priced natural gas was a cost-effective means of meeting customers' growing demand for energy.[26] In that same timeframe our resource plan showed a need for up to 1,125 MW of incremental baseload generation.[27] We recognize that the environment has changed dramatically, with $3-4/mcf natural gas

[24] Tr. Vol. III (Jacobs) at 105:2-5 (emphasis added).

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

[26] In that timeframe, natural gas prices were at historic highs, including post-Katrina highs of $14/mcf and levelized forecast prices in the $8-10/mcf range over the license period. Ex. 8, Alders Rebuttal at 11:3-5.

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

and a period of capacity surplus, but all agree that the fracking revolution and the Great Recession that brought on those changes were unforeseeable.[28]

The Report does not describe the short timeframe we had available under these circumstances to (i) obtain the 2005 life-extension Certificate of Need, (ii) obtain an extended operating license from the NRC, (iii) study, develop and design the equipment upgrades necessary to support the license extension, and (iv) design and implement the uprate. Equipment upgrades identified from as early as 2001 that would be needed to extend the life of the plant were pressing, and involved much of the same equipment that needed slightly different sizes and designs if we were going to capture the additional carbon-free baseload, output from the uprate. To preserve nuclear generation at Monticello we needed to move forward with a single project – not two different projects – to achieve maximum value for our customers.[29] These factors, along with the record evidence that we utilized our contractors' expertise to establish the planned timeline for the Program, are critical to understand why we pursued a multi-tracking approach to the Program and sought a Certificate of Need utilizing a high-level cost estimate.

The Report further ignores that we pursued the Program based on a review of the information available at the time. The record establishes our detailed design review process;[30] why we made key scope and implementation timing decisions; our

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[28] Department Initial Br. at 70.

[29] As a result, the LCM/EPU split issue should not be applied in the prudence context. It has relevance only as an artificial allocation of costs between the twin purposes of this integrated project. And even if the Commission were to enter the hypothetical world of splits, the thought that 85 percent of the project cost should have been allocated to the uprate is inconsistent with common sense (it means the LCM work we identified in our 2005 CON proceeding for License Extension, which like our 2008 CON represented high-level conceptual estimates with no detailed design, could have been built for 25 percent less than we had projected). Ex. 9, O'Connor Rebuttal at 82.

[30] *See* Ex. 9, O'Connor Rebuttal at Schedules 21 (Company Response to Department IR 19 explaining appropriateness of initial design) and 22 (The Engineering and Design Process, Xcel Energy Nuclear Department).

willingness to reject designs that were inadequate or too expensive;[31] and that we documented all of the design changes in our response to discovery (and summarized in our exhibits).[32] Not one of these items was challenged.[33] Nor does the Report acknowledge that key witnesses affirmed our scope. The record supports finding that our decisions over the course of the Program did lead to higher costs, but they were necessary to assure safe operations of the plant and the appropriate scope of the Program as new information emerged.

The Report also overlooks the record evidence on how evolving NRC requirements and an increasing lack of skilled craft labor throughout the industry contributed to cost increases. Beginning in 2008 and escalating throughout the LCM/EPU Program, complying with the NRC's expectations became increasingly more difficult and expensive. The expected 12-to 18-month EPU license process took five years and cost $60 million. The NRC instituted new rules such as the worker "fatigue rule" that made working in a nuclear environment much more expensive. The NRC also heightened its enforcement of aspects of the EPU and pushed utilities to design robust solutions to enhance nuclear safety, at a significant cost in terms of both time and money. Combined with labor issues and the construction issues that emerge in any complicated construction project – let alone nuclear construction on a 40-year old generation plant – cost increases were ultimately unavoidable.

The best evidence of the evolving regulatory and nuclear construction world is a comparison of the costs of nuclear projects that occurred prior to 2008 with those, like Monticello, that occurred later. Plants worked on prior to 2008 were completed

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[31] Ex. 9, O'Connor Rebuttal at 42:19-21; 62:25-63:12.

[32] *E.g.,* Ex. 3, O'Connor Direct at 131:3-14 and 132:11-7; Ex. 9, O'Connor Rebuttal at 75:9-14, 99:16-17, and Schedule 27 (Company Response to Department IR 28 identifying required field design changes); Tr. Vol. III (Jacobs) at 100:15-102:25 (discussing some of the 3,000 documents produced in discovery).

[33] *See* Ex. 9, O'Connor Rebuttal at Schedule 19 at 6-8 (Company Response to Department IR 106 identifying major projects during outages).

with modest cost increases and delays. This was the frame of reference we had when we developed both the LCM and EPU. But costs went way up thereafter – not just for the Company, but also for all of the utilities undertaking this type of work. Our experience is summed up by Mr. O'Connor:

> In retrospect, it seems apparent the Program was going to cost much more than we had forecast, but at the time we began the Program, the final costs were not evident. We were looking backward for others' experience, while the world ahead of us was changing rapidly.[34]

The fact that the world was about to change in ways no utility running nuclear plants could foresee is not, as the ALJ essentially concluded, evidence of imprudence. Rather, we urge the Commission to consider the full circumstances we faced and judge our decisions and actions accordingly.

C. Specific Criticisms

Despite the outcome we achieved at Monticello and our explanations about the issues we encountered, we recognize that we needed to fully and transparently explain why the parties' criticisms should not result in a material disallowance. While there were many issues reviewed on this record, the Report focuses on two: (i) accuracy of the Company's initial cost estimate; and (ii) the criticisms of one Company employee in the 2011 Cost History document. The Company welcomes a discussion on these and other issues.

Cost Estimate: The record contains a complete description of the basis for our initial estimate of $320-346 million without AFUDC, including independent input and specific assessments that the Report does not mention. While these estimates turned out to be too low, the record does not support a finding that we would have believed

[34] Ex. 3, O'Connor Direct at 7:18-21.

in 2008 that the costs could rise to the $665 million level. Nor does the record support a finding that we would have attributed more costs to the EPU than the LCM when planning the Program. As a result, even under the Department's cost-effectiveness test, there is no basis to say that a different cost estimate would have changed the decision to proceed with the Program.

Further, better estimates do not change the ultimate cost level or the necessity of incurring those costs for the long-term betterment of the plant. We provided significant evidence that our cost increases were driven by the need to implement equipment replacements necessary to achieve operational success, not because of a low initial estimate, undue speed, or lack of care. In fact, the record contains no criticism of the scope of work we did. To the extent the Commission has concerns about whether we built the right project, we encourage the Commission to read more about the plant conditions described in the record.[35] To enable that review, we have included the Company's Response to Department IR 124 as Attachment C to these Exceptions.

Overall, the unanticipated cost increases were due principally to two factors: (i) increased scope to ensure we got the job done right; and (ii) higher labor expenses. While a higher initial estimate might have reduced the difference between the initial cost estimate and the final cost, increased scoping needs and craft labor issues cannot be eliminated with more rigorous project oversight. Other criticisms raised in the Report are not tied to avoidable cost increases. For example, we were criticized for changing contractors after the 2011 outage and the ALJ implies that this might have increased costs.[36] Yet no one criticizes our 2013 outage implementation. While there is an implication that had we started with Bechtel our costs would have been lower,

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[35] *See* Ex. 9, O'Connor Rebuttal at Schedule 32 (Attachment C of these Exceptions).

[36] Report at Findings of Fact ¶ 80.

this ignores that Bechtel declined to bid for the Program work initially.[37] And the parties and the ALJ do not address that the daily outage costs (the Project's most significant cost driver) for the 2011 and 2013 outages were virtually equal.[38]

2011 Cost History Criticisms: We disagree with Findings 52-55 of the Report, which characterize the 2011 Cost History document as an admission of imprudence by the Company. Because of the importance placed on that document by the ALJ, we have provided a copy of it as Attachment D to these Exceptions for the Commission's convenience.

Fundamentally, the 2011 Cost History provides one plant engineer's strong views about how he would have wanted the project implemented. The Company encourages this kind of frank discourse and expects employees to provide candid feedback as part of our nuclear safety-conscious culture.[39] Indeed, industry rules require that we encourage frank discussion and ensure that employees can air their views candidly. This encourages a hindsight approach that is valid for purposes of assessing possible future changes, but does not mean that all opinions provided are accurate or would have warranted different decisions when they were made.[40]

Unfortunately, the 2011 Cost History memo lacks the same sort of context that is missing from the Report. The perspective of the memo is of a plant engineer defending a point of view about the plant.[41] This site employee had no involvement with resource planning, natural gas pricing, or our CO_2 reduction requirements. Nor

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

[38] Ex. 9, O'Connor Rebuttal at 74:16 at Table 7.

[39] Ex. 4, Stall Direct at 16.

[40] "The focus on safety and reliability demands that a utility adapt, evolve and continually strive to get better. Far from a sign of imprudence, it is expected that utility managers review recently completed work efforts and probe how they can perform better in the future." Ex. 4, Stall Direct at 26:7-10.

[41] Ex. 9, O'Connor Rebuttal at 63:24.

did this employee have the information presented by management or access to the discussions that occurred after receiving site input.[42]

The memo suggests the Company could have used a higher starting point cost estimate and perhaps should have. However, the memo's suggested starting estimate was also far too low in hindsight. Further, the memo does not recognize that the estimate we used was prepared for us by General Electric (a contractor that Department witness Crisp agreed was an "absolutely" reasonable choice for the design work[43]) or that, rather than being overlooked, the higher estimate in the memo did represent the high end of the range that was provided to management for consideration.[44]

The memo criticizes the scope and design of the Program. Key scope decisions were driven primarily by reliability needs. We followed the same design review process as we did for all nuclear projects.[45] We have included the Company's Design Review process as Attachment B to these Exceptions, to reassure the Commission that the Company has and uses strong processes to ensure quality designs.

The memo incorrectly suggests that the Company "accelerated" implementation. The Company considered two implementation schedules and knowingly chose the earlier one based on all of the circumstances.[46] That was a reasonable choice based on feasibility and the economic conditions we faced at the time. The record does not support the imputation that we unduly rushed because of the implementation

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[42] Ex. 9, O'Connor Rebuttal at 64:10-12.

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

[44] Ex. 9, O'Connor Rebuttal at Schedule 24 at 5 (Company Response to Department IRs 77, 78 and 80).

[45] Ex. 9, O'Connor Rebuttal at Schedule 22 (The Engineering and Design Process, Xcel Energy Nuclear Department).

[46] Ex. 9, O'Connor Rebuttal at Schedule 20 (Company Response to Department IR 41 regarding implementation schedule choices).

schedule. As described later in these Exceptions, the Company rejected designs and equipment that did not meet specifications and delayed implementation when necessary. And there is no factual support in the Cost History memo or the record that indicates additional time would have improved our vendor outcomes.

D. Record Support

The Company respectfully suggests that the Commission should be reluctant to find imprudence when no expert witness testified that any particular decision was imprudent.[47] Mr. Crisp candidly acknowledged that his and Dr. Jacobs' engagement did not include rendering opinions on the prudence of the Company's decisions and actions. It is not supportable to find imprudence based on their testimony when it does not itself delve into that ultimate question.

Further, the Company's evidence provided ample support to satisfy our burden of proving prudence and reasonable costs. Mr. O'Connor's credibility was not impeached in any way. He was with the project in a leadership capacity from 2007 through today, which spans all but the first year of the project. He was on-site and hands-on when critical scope and implementation decisions were made.

The Report further criticizes Mr. Alders because he sponsored modeling testimony but was not himself the modeler. Of course, as the Commission knows, it is common to sponsor technical testimony prepared by others. And Mr. Alders has provided modeling testimony many times during his 40-plus year career.

Finally, it is true that our retained experts – Mr. Stall and Mr. Sieracki – were paid for their work (as were Dr. Jacobs and Mr. Crisp for the Department). But there was no substantive criticism of their testimony or work. Mr. Stall has been in the industry for well over 30 years and he went through the trenches with the EPU projects in Florida.

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

The fact that he faced similar challenges as the Company does not make him less credible; it reinforces that the difficulties faced in the industry were very real, especially given that the Florida commission found no imprudence with respect to similar cost increases. Mr. Sieracki's pre-filed testimony and 40 years of experience with construction management (including multiple nuclear power plants) were also largely unrebutted, and he was asked only a very few questions on the stand.

On the other side of the equation, Dr. Jacobs admitted he testified here in direct contradiction to his Florida testimony on how to attribute costs.[48] He also admitted he did not assess Monticello's need for the work to continue plant operations regardless of an uprate.[49] He admitted he ignored contemporaneous documents that expressly illustrated the Company's need for LCM work before the EPU was contemplated.[50] And Mr. Crisp admitted that he takes no issue with the work the Company did.[51] He agreed cost increases can happen without imprudence[52] and "that the amounts the Company actually spent for each modification could be justified."[53]

Based on the record, we do not believe that this case presents the Commission with a challenging legal question. The Company has satisfied its burden of proving that the decisions and actions we took were prudent. The Company provided evidence sufficient to make its *prima facie* case. Other parties raised challenges to that evidence and we provided additional evidence overcoming them.

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48 Tr. Vol. IV (Jacobs) at 30:11-31:2.

49 Tr. Vol. IV (Jacobs) at 36:11-15.

50 *E.g.*, Tr. Vol. III (Jacobs) at 128-140 (referencing 2003 Capital Project Summaries).

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

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

53 Tr. Vol. III (Crisp) at 18:17-20.

The remainder of these Exceptions will focus on the detailed record evidence that was omitted or ignored that demonstrates the prudence of our actions and decisions. Last, we discuss the Parties' proposed remedies for imprudence. While our performance was not perfect, the decisions we made were in the best interests of the plant and our customers, resulting in an overwhelmingly cost-effective project. The Company was prudent and the Program costs should be recoverable.

II. THE ALJ DID NOT CONSIDER THE ENTIRE RECORD ESTABLISHING PRUDENCE

In this prudence investigation, the key question is whether the Company established that its decisions and actions with respect to the Program were prudent. The prudent investment standard considers whether the utility's decisions or actions were reasonable under the circumstances that were known or reasonably should have been known at the time.[54] The standard does not require perfection, allow for second-guessing based on facts the utility could not have known at the time decisions were made, or allow a finding of imprudence simply because a party disagrees with a decision in hindsight, as these approaches would create due process concerns.[55]

The utility's conduct must only fall within a "zone of reasonableness" to justify recovery.[56] As the Minnesota Supreme Court has noted:

> Reasonableness is a concept of some flexibility and moderation, not exclusivity; a determination that one course of conduct is

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[54] Department Initial Br. at 1; OAG Initial Br. at 7; XLI Initial Br. at 3-4.

[55] *In re GPU, Inc.*, 96 Pa. P.U.C. 1, 91-92 (Pa. PUC 2001); *In re Long Island Lighting Co.*, 24 N.Y.P.S.C. 4921 at *6 (Aug. 19, 1981); *Pa. Pub. Util. Comm'n v. Philadelphia Elec. Co.*, 71 Pa. P.U.C. 42 (Pa. PUC 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.").

[56] *See Fed. Power Comm'n v. Conway Corp.,* 426 U.S. 276, 271, 278 (1976).

> reasonable is not a determination that any other course is unreasonable.[57]

Thus the prudence standard requires a fact finder to consider both the reasons the Company made its decisions as well as the reasons we rejected available alternatives.[58] While the Company carries the burden of proof, no disallowance is appropriate if the Company incurred costs prudently. We believe that a fair analysis of our decisions, when informed by the circumstances that were known at the time, indicates they were prudent. This Commission has consistently allowed recovery of prudently incurred costs as part of its application of the just reasonable rate standard discussed in the 1987 *Northern States Power Company* decision cited in the Report.[59]

As a result, we do not believe this case presents any novel or problematic legal issues. Prudently incurred investment costs are reasonable. The Company bears the burden of showing that its costs were prudent by describing that the actions it took fell within the range of reasonable decisions available to it. The Company has met its burden by producing substantial, qualitative evidence that our actions and decisions throughout the Program were prudent. At times we had to make difficult decisions, but each was supported by appropriate reasoning and valid judgments. The parties challenged some of our decisions, and we provided additional substantial evidence to address those challenges.

Nonetheless, in many instances the Report relies on a party's opinion that in hindsight a different approach would have been preferable and ignores record evidence that each of the Company's decisions was the product of both considerable research and

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

58 *Gulf States Utils. Co. v. La. Pub. Serv. Comm'n,* 578 So. 2d 71, 85 (La. 1991) (citing *Metzenbaum v. Columbia Gas Transmission Corp.,* Opinion No. 25, 4 FERC 61,277, 26 P.U.R.4th 144 (1978)).

59 Report at pages 34-35 (citing *In the Matter of the Petition of Northern States Power Co. for Authority to Change is Schedule of Rates for Elec. Serv. in Minn.*, 416 N.W.2d 719, 723 (Minn. 1987)).

examination of alternatives available at the time. In addition, the Report rarely assesses whether a decision, if imprudent, caused harm. Overall, the Report fails to consider all evidence on the record and apply both aspects of the prudent investment standard to arrive at a balanced, sustainable outcome.

A. The Overlooked Record on Industry Context

The Report is largely silent with respect to considerable record evidence that provided critical support and context for the Company's decisions throughout the Monticello LCM/EPU Program, including: (i) the physical condition of plant equipment and the benefits of keeping it in good working order for the renewed license period; (ii) the Company's identified need for additional baseload generation coupled with historically high natural gas prices; and (iii) the evolving NRC regulatory circumstances and changes in the industry that impacted our implementation.

1. The Benefits of Keeping the Plant Running

A key gap in the Report is the absence of meaningful discussion regarding the outmoded condition of the equipment at Monticello and how this ultimately drove the plant's LCM/EPU Program needs. From 1994 to 2003, an extension of nuclear licenses with the NRC was not possible for Minnesota nuclear generating plants due to Minnesota legislation that prevented these plants from constructing any new on-site dry cask storage.[60] This effectively required nuclear plants in Minnesota to make investments only where necessary to operate the facilities to the expiration of the original operating license. Put differently, as a result of Minnesota laws Monticello did not undertake any major life cycle management or replacement programs from 1994 to 2003.[61] While other nuclear generating plants around the country were undertaking modernization efforts to meet changing industry codes and standards

[60] 2003 Minn. Laws 1st Spec. Sess. ch. 11, art. 1, § 2.

[61] O'Connor Rebuttal at 4:7-11.

during this timeframe, the cost of such efforts would not have been appropriate at Monticello given its expected retirement in 2010.[62] From the mid-1990s through 2002, the capital budget for Monticello was kept to around $5 million per year for non-regulatory capital projects and the book value of the plant had depreciated to $153 million.[63]

The Report does not acknowledge that this necessary approach meant that much of the power block side equipment was near the end of its expected life and, in some cases, had become obsolete once license extension became a viable option.[64] Equipment in the plant experienced increased wear rates, which reduced equipment operating margins.[65] Much of the equipment on the power block side was original plant equipment that would have been safe for operations through the planned 2010 retirement but was otherwise reaching, or had reached, the end of its useful life.[66]

For example, the Report overlooks that when the moratorium on nuclear was lifted in 2003, Monticello was still operating on analog (rather than modern digital) systems that were both out of date and making it increasingly difficult to meet industry regulations.[67] This included highly technical and integral systems such as the condensate demineralizer control system, which was an inefficient and pneumatic system that increased the likelihood of transients, or operations disruptions, during plant operation as the water chemistry had to be adjusted manually.[68] Further, the plant was operating under an undesirable sequencing start-up scheme – meaning a

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[62] O'Connor Rebuttal at 4:9-16.

[63] O'Connor Rebuttal at 4:13-16.

[64] O'Connor Rebuttal at 4:20-21.

[65] O'Connor Rebuttal at 4:21-22.

[66] O'Connor Rebuttal at 4:22-24.

[67] O'Connor Rebuttal at 5:11-12.

[68] O'Connor Direct at 11:18-20; O'Connor Rebuttal at 107:23-24, 108:3-9; Report at Findings of Fact ¶ 104.

tiered start-up of large pumps and motors – because major improvements to the electrical distribution system had not been made.[69] Sequencing was necessary because the operating margins of the electrical distribution system had degraded over time and when any of this equipment was started, even when not brought online concurrent with another large piece of equipment, the electrical distribution system experienced under-voltage conditions.[70] These types of issues facing the plant are not fully evaluated in the Report.

Instead, the Report relies on general themes that the plant had depreciated and that a moratorium on extending the life of nuclear had been in place without illustrating the record evidence of the impact of these factors. Such detail provides crucial context for:

- The ultimate scope of the work that the Company partially identified up front and partially became known as construction progressed;
- The short lead times the Company was facing to keep the plant running, which necessitated the multi-track approach;
- Why there was only one integrated project – not separate LCM and EPU projects for either implementation or accounting purposes;
- Why the costs of the Program increased significantly as construction got underway; and
- The reasons the Program was LCM-driven – not EPU-driven as the Department's LCM/EPU split indicates.

2. *Existing Energy Markets*

The Report also misses that the critical energy market issues the Company was facing in the early 2000s were much different than today, and drove the timeframe for early

[69] O'Connor Rebuttal at 5:16-22.

[70] O'Connor Rebuttal at 95:19-22.

project decisions. In light of planned retirements of baseload coal under MERP and growing demand throughout the first decade of 2000, the Company and the Commission saw a critical need for new baseload power. At the same time, natural gas was a volatile resource and the retirement of baseload plants would increase our customers' exposure to this volatility. The Prairie Island, Sherco, and Monticello uprates were all considered critical to address dynamics that were different from today's capacity stability and low natural gas prices.

Much of the hindsight analysis in this proceeding appears to be driven by the very different luxury of time and flat demand in the marketplace today. This approach missed important history related not only to Minnesota's law precluding a life extension for Monticello before 2003[71] – meaning that once the law changed, significant work was needed in a relatively narrow window just to keep the plant running[72] – but also to forecasted demand needs over the short planning horizon (through 2015).[73] This important context explains why the Company evaluated both a multi-track and alternate approaches,[74] why reasonable minds might differ about the preferred approach, and why the Company ultimately decided to proceed in parallel with design, licensing and construction to meet forecast customer needs.[75]

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[71] 2003 Minn. Laws 1st Spec. Sess. ch. 11, art. 1, § 2.

[72] Tr. Vol. I (Sparby) at 30:17-21 (discussing that Company had enough time but not a "generous" amount of time to complete its work).

[73] *In the Matter of N. States Power Co. d/b/a Xcel Energy's Application for Approval of its 2005-2019 Res. Plan*, No. E002/RP-04-1752, INITIAL FILING at 1-1 (Nov. 1, 2004). At the time the initial 2004 resource plan filing was prepared, extending the life of Monticello was the only consideration. Increasing the capacity of Monticello came later in the 2004 resource plan docket.

[74] Ex. 9, O'Connor Rebuttal at Schedule 24 at 13 (Company Response to Department IR 78 explaining reasoning for recommendation of 2009 and 2011 refueling outage schedule).

[75] This was based on (1) Commission directives to submit a plan for additional baseload resources including nuclear uprates; (2) forecasted baseload need; (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.

It is important to recognize that in the 2004-06 timeframe, Company demand forecasts showed a near-term need for 1,125 MW of incremental new baseload capacity.[76] This need was in fact the impetus for the 2003 law change that allowed us to preserve Monticello as a resource on the system and avoided a Company capacity deficit that would have been 600 MW larger.[77] The Company took this demand seriously and moved expeditiously to retain Monticello's 600 MW of capacity consistent with our obligation "to keep the lights on."[78] The record confirmed the need to proceed with planning in line with the Company's demand forecast:

> The development of a complete design for a program of this magnitude would have taken years and cost many millions of dollars, and if Xcel Energy had waited for the design to be complete, the LCM/EPU Program would not have met Xcel Energy's needs according to the forecasted demand in its resource plan.[79]

At the time these key evaluations were undertaken and decisions made, natural gas prices in the $8-10/MMBtu range emphasized the importance of retaining the nuclear resource and evaluating the possibility of an uprate.[80] At that time, hydraulic fracturing had not been proven economical and natural gas prices were forecasted to increase even further over the evaluated planning horizon.[81] It was not until 2011, four years into the LCM/EPU Program implementation effort, that the domestic hydraulic fracturing economy had a material impact on natural gas prices.[82] To meet

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

[77] Ex. 2, Alders Direct at 18:17-18; Ex. 9, O'Connor Direct at 2:25-3:3.

[78] *In the Matter of N. States Power Co. d/b/a Xcel Energy's Application for Approval of its 2005-2019 Res. 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).

[79] Ex. 11, Sieracki Rebuttal at 12:4-8.

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

[81] Ex. 8, Alders Rebuttal at 11-12.

[82] Ex. 2, Alders Direct at 51 n.18; Ex. 11, Sieracki Rebuttal at 13:11-14.

this need, the multi-tracking approach was intended to complete the Program faster than an approach where all design was completed up front.[83]

The high level reference to demand in the Report does not adequately capture the urgency of our customers' demand needs nor the Company's process of evaluating implementation schedules. It does not fully make clear that the Company's experienced nuclear project expert at the time – General Electric – assessed the situation and determined that either a 2009/2011 outage or a 2011/2013 outage schedule was feasible.[84]

The Report also fails to capture the long lead times necessary to order equipment and plan designs for an outage. Given the energy markets and demand we were facing at the outset of the Program, we had to make the best decisions possible and move forward. And once equipment was ordered as sized for the EPU and manufacturing got underway, we would have lost time and increased cost by changing paths.[85] As we discuss later in these Exceptions (but the Report does not acknowledge), a different path would have been the wrong decision for customers from both economic and practical implementation standpoints.

Based on this data, the scope of work, and the customer harm if the Company chose an alternate path, the information available at the time made clear that moving forward with parallel implementation and high-level early cost estimates was a reasonable decision, and in fact the most appropriate decision under the circumstances.

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[83] Ex. 1, Initial Filing, Prudence Report at 6; Ex. 3, O'Connor Direct at 59:16-60:19; Ex. 11, Sieracki Rebuttal at 10:21-12:12; Ex. 12, Sparby Rebuttal at 19:15-10:15.

[84] Ex. 3, O'Connor Direct at 49:7-11.

[85] Ex. 9, O'Connor Rebuttal at 52:8-11 and Schedule 24 at 22 (Company Response to Department IR 80 explaining impact of long lead times on initial proposal).

3. The Evolving Nuclear Industry During the Course of the Program

The Report also effectively overlooks that while the Monticello LCM/EPU Program was underway, industry changes affected both Monticello and other nuclear projects and utilities. The context of these changes is important in this case, as it underscores both the need for the total expenditures on the Program and the reasonableness of the Company's decisions.

a. Evolving NRC Requirements

Over the course of the Program, there were two ways in which NRC regulations affected the cost of the Program: 1) the NRC's changing methodology for the evaluation of a license amendment request, and 2) the NRC and industry's continued development of regulations to ensure the safe operation of nuclear generating plants when large scale construction is undertaken. The first affected the length of time for processing and the cost of processing the license amendment request for the EPU. However, the specific licensing costs of the Program do not appear to be in dispute.

The second regulatory evolution at the NRC significantly affected Program costs, as they resulted in additional work due to "as-found" conditions that were not capable of evaluation and identification without large components removed from the plant, and the creation of certain inefficiencies in labor. The Report recognizes that the NRC's fatigue rule went into effect after the 2011 outage, and notes that it impacted the hiring and retention of experienced craft labor for the 2013 outage by requiring more time for certain tasks than previously estimated because of the work day and hour limitations.[86] However, when noting that costs increased beyond those identified in

[86] Report at Findings of Fact ¶¶ 66 and 67.

the EPU Certificate of Need, the Report includes no allowance for the impacts of the fatigue rule or inexperienced craft labor.[87]

The Report also does not address the additional series of NRC rules that affected the work to be to be done at the plant to both operate it through the license extension to 2030 and to support the uprate. These rules include the maintenance rule, the aging management rule, and the back-fit and forward-fit rules.[88]

For example, the ALJ does not acknowledge that as equipment was removed during Program implementation, components were exposed that had not been available for detailed inspection since the plant was constructed. NRC regulations then had significantly more effect than initially anticipated, requiring the Company to make modifications to, or replace, any equipment discovered during implementation of the Program that did not meet the NRC's relevant design criteria or applicable safety requirements.[89] Application of these rules often drives the replacement of older and obsolete equipment or equipment for which spare parts are no longer available, instead of just repairing the equipment as-is.[90] Additionally, the NRC regulations require that if during implementation of a project a nuclear plant encounters degraded systems that impact safety, then those systems must be corrected.[91] During the Program, the Company encountered these issues, such as the wiring associated with the condensate demineralizer system and the feedwater heater piping, both of which

[87] *See* Report at Conclusion of Law ¶ 8.

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

[89] Ex. 3, O'Connor Direct at 18:12-15. Other examples include the condensate pumps and motors, condensate demineralizer, 1AR feeder cable, Off Gas Dilution Fan Cable, reactor feedwater pumps and motors, drain cooler piping, and 1AR transformer, which were all required changes for aging management concerns. Ex. 3, O'Connor Direct at Schedule 5 at 5, 8, 15, 20. 27-28, and 32 (LCM/EPU Modifications In-Service Table); Ex. 9, O'Connor Rebuttal at Schedule 24 at 16 (Company Response to Department IR 78 identifying additional items added by Site due to age or condition), and Schedule 31 at 4 (Company Response to Department IR 58 categorizing work orders).

[90] Ex. 4, Stall Direct at 18:14-16.

[91] Ex. 4, Stall Direct at 17:16-18.

added substantial man hours and cost during the Program over what had been initially planned.[92] The impact of the need to complete this work to comply with these rules was not disputed by the Department's witnesses but was not addressed in the Report.

b. Craft Labor Skill and Availability

The Report also does not address the challenges faced by the Company in hiring and retaining qualified craft labor. Mr. Stall explained that as the Project progressed there was "growing competition for talent in the nuclear industry, which is being driven by a shrinking labor pool and high demand for skilled workers."[93] NRC restrictions such as the fatigue rule, combined with demand in other industries (including the booming hydraulic fracturing industry) that did not impose such restrictions, made it especially difficult to attract qualified craft labor. As a result, approximately 90 percent of the craft supervision and labor employed by the Company was nuclear-experienced during the 2009 outage, but that number declined dramatically to approximately 45 percent in 2011.[94] The Report does not acknowledge that these challenges impacted productivity and therefore overall costs of the Project, particularly with respect to especially complex modifications.[95]

c. Impacts on Nuclear Projects Industry-Wide

Finally, the Report does not address the extent to which the experience of other nuclear facilities engaging in similar projects in the same timeframe demonstrated that the final cost of the Monticello Program was largely the result of increasing NRC regulation and industry-wide change rather than imprudence. The implementation of these rules and industry-wide standards were affected by start-up and post-

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[92] Ex. 3, O'Connor Direct at 39:4-26, 118:25-119:3, and 119:21-120:11.

[93] Ex. 4, Stall Direct at 63:21-23.

[94] Ex. 9, O'Connor Rebuttal at 69:15-17.

[95] *See* Ex. 9, O'Connor Rebuttal at 45:10-17.

modification issues that were encountered at Dresden and Quad Cities in Illinois prior to Program initiation.[96] Testimony by Company witnesses Mr. O'Connor and Mr. Stall, which was expressly underscored by Department witness Dr. Jacobs, illustrated that the cost increase experience at Monticello was consistent with that of nuclear plants around the country that were likewise managing complex projects under very challenging regulatory and construction circumstances.[97] For example, Mr. Stall testified that:

> The final installed cost of the Florida EPUs was approximately $3.129 billion or an average of $782.25 million per unit. This was more than double the initial estimates. The primary drivers for those increased costs were: (i) expanded scope as a result of detailed design engineering, (ii) unexpected construction challenges, (iii) difficult and time-consuming implementation of modifications within the confines of the existing power plant, and (iv) nuclear regulatory issues.[98]

Likewise, Dr. Jacobs contended that the increase in cost from estimates to final at "St. Lucie and Turkey Point were significantly more than the cost increases at Monticello, but they had the same -- similar challenges."[99] In Florida, as here, "no evidence was presented to show that . . . [the utility had the] opportunity to reduce EPU Project costs" or was otherwise imprudent.[100] Here, the Company was able to complete the extensive Monticello LCM/EPU Program at a lower per-unit cost than the nuclear programs implemented by FPL that the Florida commission found to be prudent.

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96 Ex. 4, Stall Direct at 9-10.

97 Ex. 3, O'Connor Direct at 24 and Table 3.

98 Ex. 4, Stall Direct at 8-9.

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

100 Ex. 425, *In re Nuclear Cost Recovery Clause*, Fla. Pub. Serv. Comm'n No. 130009-EI, FINAL ORDER APPROVING NUCLEAR COST RECOVERY AMOUNTS FOR FLORIDA POWER & LIGHT COMPANY AND DUKE ENERGY FLORIDA, INC. at 34 (Oct. 18, 2013).

Nor were the impacts of industry and NRC changes abstract in the record. The following tables from the record graphically demonstrate how the changes in the industry fundamentally changed the cost profile of projects like the Monticello LCM/EPU.[101] The key difference in these tables is the timing of the effort. Construction after 2008 became much more expensive:

EPU Cost Comparisons for Early to Mid 2000s

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.

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

[101] Ex. 9, O'Connor Rebuttal at 38:4 at Table 3; Ex. 3, O'Connor Direct at 24:11 at Table 3.

In addition to the costs of the Monticello LCM/EPU Program being in line with other, similar programs completed during the same timeframe, the Monticello LCM/EPU Program had considerably more success than some. Proper Program development and the work performed during the outages allowed the Company to restart and operate the plant after each outage without issue.[102] The absence of start-up and operations issues after Program implementation speak to the quality of design, implementation, and post-installation testing.[103] This is in stark contrast to the issues experienced at other nuclear generating plants with similar programs, such as San Onofre and Crystal River 3, where the facilities had to shut down because of construction issues or because the replaced equipment was not operating as required.[104]

Company witness Mr. Stall further underscored that "proposed uprate programs at three nuclear stations – La Salle, Limerick, and Cooper – were [recently] cancelled due to changing market conditions and the cost and schedule risks. Regarding Cooper Station, the Nebraska Public Power District acknowledged the difficulties other utilities were having in completing these projects on time and within original budget as important factors, particularly as the regulatory environment at the NRC has become more difficult and the market for nuclear generation has softened in the past couple of years."[105] Finally, Mr. Stall summarized these experiences at the evidentiary hearing:

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[102] Ex. 4, Stall Direct at 60:16-22. Mr. Stall continued that in his experience "the types of major modifications that went into this initiative could readily be expected to result in relatively more difficulties than were encountered here." Ex. 4, Stall Direct at 60:24-26.

[103] Ex. 4, Stall Direct at 60:26-27.

[104] And in 2012, the NRC granted a license amendment to uprate the Nine Mile Point station in New York – but only after the application was pending for an extended period of time and encountered increasing licensing challenges.[104] Ex. 4, Stall Direct at 9:27-10:3.

[105] Ex.4, Stall Direct at 10:5-12.

> The reality of the nuclear industry today is that all of these considerations have become much more complex and 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.[106]

We provided this critical context on the record to be clear that many of the factors driving cost increases have been unavoidable industry-wide, and are in large part outside the utilities' control. We recognize that other utilities' increases in nuclear project costs do not absolve the Company of responsibility for managing our own projects and cost increases. However, the absence of any consideration of most of these industry-wide concerns in the Report, even though most coincided with Monticello LCM/EPU mid-licensing and mid-construction challenges, establishes an incomplete review of the record and results in over-attribution of "fault" to the Company.

B. The Record Establishes the Company's Prudence

The ALJ's imprudence finding was largely focused on his conclusion that the Company's "principal failure" was in "initial scoping and early Project management up until beginning installation during the 2009 refueling outage."[107] The Report's conclusions are largely silent about the Company's actions after outage work commenced in 2009 and instead conclude that post-2009 issues were attributable to initial scoping and early Project management. The ALJ based the perceived pre-2009 shortcomings on (1) the testimony of Department expert witness Mr. Crisp; and (2)

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

[107] Report at Conclusions of Law ¶ 7.

the 2011 Cost History document described earlier.[108] We address each of these principal bases for the Report below.

1. *Mr. Crisp's Key Admissions*

The Report relies primarily on Mr. Crisp for a finding of imprudence.[109] The Department suggested and the ALJ essentially concluded that Mr. Crisp "identified many decisions and actions including poor project management by Xcel that were not reasonable at the time."[110] However, Mr. Crisp expressly declined to find any of the Company's costs or actions were prudent or imprudent.[111] He also admitted "that the amounts the Company actually spent for each modification could be justified."[112] He did not address amounts actually spent in any manner.[113] Thus, Mr. Crisp had no basis to suggest that costs should have been lower.

In light of these contradictions and the limited bases for Mr. Crisp's testimony,[114] it was critical for the ALJ to consider the testimony of other experts. For example, based on his 40 years of experience, including prudence reviews of six different

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108 Report at Findings of Fact ¶¶ 72-81 and Conclusions of Law ¶¶ 7-10.

109 Report at Conclusions of Law ¶¶ 7, 9-10. The ALJ also made several findings referencing Mr. Crisp's testimony in paragraphs 72-90 of the Report's Findings of Fact, but it is not clear whether these sections are simply stating the Department's views subject to later conclusions by the ALJ.

110 Department Initial Br. at 9; Report at Conclusions of Law ¶¶ 7, 9-10.

111 Tr. Vol. III (Crisp) at 15:11-20 (**Q.** You're not testifying in your pre-filed testimony as to the prudence or imprudence of Xcel Energy's decisions on the LCM/EPU program; correct? **A.** On the prudence of the costs? **Q.** Yes. **A.** That's correct. **Q.** And the prudence of various decisions as well; isn't that right? **A.** Not on the prudence, that's correct."); Tr. Vol. III (Crisp) at 15:11-17:15.

112 Tr. Vol. III (Crisp) at 18:17-20. Likewise, the Department acknowledged that Mr. Crisp did not "opin[e] as to the reasonableness at the time of any particular event." Department Initial Br. at 39.

113 *See, e.g.*, Tr. Vol. III (Crisp) at 18:17-25, 22:21-23; 25:15-21.

114 Mr. Crisp relies heavily on the 2011 Cost History Memo. Ex. 300, Crisp Direct at 23:8-29:18.

nuclear power plants,[115] Company witness Mr. Sieracki reviewed the Program in detail[116] and concluded that "[t]he cost growth is not due to poor management."[117]

Likewise, Company witness Mr. Stall experienced many of the same challenges at other nuclear facilities where he was directly involved in project management, and provided detailed explanation of their causes.[118] And Company witness Mr. O'Connor provided extensive testimony regarding all aspects of the Company's Program management.

Rather than examining the specific records, documents, and evidence for each witness's conclusions, the Report relies largely on generalized credibility assessments. The Report also largely ignores the admissions and specific information gleaned during cross-examination, including Mr. Crisp's. Below we address the specific facts underlying the ALJ's key conclusions to illustrate our concerns with the outcome of the Report.

2. *Initial Planning Based on Assessment of Alternatives*

As described above, to meet its needs in a timely manner, the Company had to accommodate the long lead times required to order equipment to implement the Program.[119] We needed to move forward with a project – not two different projects in which we replaced equipment once for LCM purposes and then replaced it again later at EPU-capacity. The same equipment that was identified for replacement in the 2003 timeframe was also identified for replacement in our 2005 Certificate of Need

[115] Ex. 11, Sieracki Rebuttal at 1:19, 3:3-4.

[116] Ex. 11, Sieracki Rebuttal at 5:15-17; 5:24-6:5; 7:5-8; 13:15-18; 29:15-18; 30:5-7; 31:18-20; 45:16-17;47:9-11 and 47:22-23.

[117] Ex. 11, Sieracki Rebuttal at 60:2-6.

[118] Ex. 4, Stall Direct at 61:16-65:3.

[119] Ex. 8, Alders Rebuttal at 30:1-2.

filing, and was the same equipment that would need to be replaced at slightly different sizes and designs to capture the additional baseload, carbon-free output. In general, we had one opportunity to order equipment based on the unqualified decision at the time that an EPU was not only prudent but needed. For instance, to obtain a block of steel to construct the new turbine for Monticello – regardless of size – required the Company to place an order 30 months in advance to preserve a place in the queue.[120] This context underscores the importance of not using hindsight or unsupported criticism of final choice to evaluate the Company's prudence.

a. Initial Cost Estimate

The Report found that (1) the Company's initial cost estimate for the Program was too low;[121] and (2) the Company should have utilized a contingency of 100 percent (rather than 10 percent) when estimating Program costs for the Certificate of Need.[122]

With respect to the first issue, there is no doubt that our initial estimate was too low. Candidly, we wish it would have been possible at the outset to foresee all of the challenges Monticello ultimately faced.

However, as we have examined our initial estimation in hindsight, the evidence continues to underscore that it was based on a reasoned assessment of the information available at the time. Changes in overall cost for a complicated nuclear program can and do occur without imprudence.[123] For this reason, it was critical for the ALJ to carefully assess the evidence of the information the Company considered when developing the initial Program cost estimate.

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120 Ex. 9, O'Connor Rebuttal at 52:8-11.

121 Report at Findings of Fact ¶ 40 and Conclusions of Law ¶ 5.

122 Report at Findings of Fact ¶ 42.

123 Tr. Vol. III (Crisp) at 17:20-22; Tr. Vol. IV (Jacobs) at 31:3-15.

The Report's conclusions that the Company should have included additional design and project planning factors and a higher contingency in our initial cost estimates[124] pass over most of the record evidence of the specific facts, expert information, and detailed investigation of plant needs that the Company utilized to develop the Program's initial cost estimate. None of these bases supported higher contingency or conducting more detailed design up front. As a result, the record does not support the ALJ's conclusory findings that in hindsight the Company should have looked at the available information differently.

(1) Setting the Initial Cost Estimate

The Company's $320-346 million ($2008$) initial cost estimate was based on information known at the time[125] and on conceptual design plans.[126] These included (1) information and advice received from General Electric as the Program's lead designer, as well as General Electric's broad industry experience; (2) our formal and informal benchmarking of prior projects; and (3) our own internal review of the needs of Monticello.[127] Of these factors, the Report references only the Company's benchmarking efforts, and even in that respect misapprehends the nature of the Company's initial cost estimate.

First, the Report overlooks that General Electric provided overall cost information in addition to recommendations about Program implementation timing.[128] The Report also overlooks that Mr. Crisp acknowledged he was not criticizing the use of General Electric,[129] but rather admitted it was "absolutely" reasonable to rely on General

[124] Report at Findings of Fact ¶¶ 74 and 76.

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

[126] Ex. 3, O'Connor Direct at 31:20-21.

[127] Ex. 9, O'Connor Rebuttal at 38 at Table 3.

[128] Ex. 3, O'Connor Direct at 47:18-49:3.

[129] Tr. Vol. III (Crisp) at 17:12-15.

Electric's "initial cost scoping assessment" to set the conceptual design and estimate.[130]

The Report does recognize that the Company undertook benchmarking to develop our initial Program cost estimates of $320-346 million. Although the ALJ notes that the Company's initial cost estimate was intentionally 75 percent higher than the highest benchmarked project costs, the Report concludes that the Company's 10 percent initial contingency[131] was too small because the benchmarked projects each went over budget by 22 – 35 percent.[132] In doing so, the Report misapprehends the Company's approach.

The three benchmarked projects (Ginna, Brunswick, and Vermont Yankee) referenced in Finding of Fact No. 28 had initial cost estimates ranging between $33 million and $145 million and later cost ranges, after increases, ranging between $44 million and $180 million.[133] The only apparent contingency utilized in these project estimates was a $2.5 million contingency on the $145 million Brunswick project (less than 2 percent).[134] By comparison, the Monticello Program cost included a 10 percent contingency *and* was set 75 percent higher than the final cost of the most expensive benchmarked plant.[135] This was an intentional effort to be conservative, and the Company had no basis to estimate initial costs even higher. In other words, the

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130 Tr. Vol. III (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] 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.

131 Ex. 9, O'Connor Rebuttal at Schedule 13 at 2 (Company Response to Department IRs 52 and 54 detailing the level of contingency included in the original LCM and EPU project budget). The initial contingency in the $320-346 million cost estimate was "$15.431 million plus $7 million in 2006 dollars for two different contingencies." Ten percent is a rough approximation of the total contingency.

132 Report at Findings of Fact ¶ 28.

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

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

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

Monticello Program did account for cost increases at the benchmarked projects – simply in a different, equally reasonable manner the Report does not illustrate.[136]

Third, the Company's testimony fully described the specific plant needs underlying our cost estimates,[137] as well as the resource planning context that called for us to proceed with the Program utilizing high-level conceptual estimates and a multi-tracked approach (as discussed in more detail below) rather than delaying the project by several years to develop more detailed initial estimates.[138] This detail comprises many pages of testimony and schedules in Mr. O'Connor's Direct and Rebuttal Testimony,[139] and will not be repeated extensively here. It is important to be clear, however, that the Report does not address this detailed evidence in any depth, and therefore arrives at conclusions that are inconsistent with the overall record.

Finding of Fact No. 52 references the 2011 Cost History as primary support for the ALJ's conclusion that the Company's cost estimate was too low. 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 merely provides another opinion that was also too low and would not have changed the final cost of Program.[140] Further, the 2011 Cost History does not suggest that the Company did not consider this cost amount; rather, it indicates the Company chose another number. Given the additional information available to the Company – namely, the General Electric cost

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[136] Conversely, the ALJ's statement that "[a] straight line projection of the benchmarks' historical overrun rates would take the rate to 50 percent in five years"[136] is new and not in the underlying record. Rather, it is based on the ALJ's independent assumption that, as time passes each year, any attempt to estimate a project budget will be 3 percent more unreliable. Report at Findings of Fact ¶ 28 and n.65. We can find no support for this assumption, nor for the logic of the ALJ's conclusion.

[137] *E.g.*, Ex. 9, O'Connor Rebuttal at 36:16-46:10 and Table 3.

[138] *See generally* Ex. 2, Alders Direct at 6-24; Ex. 8, Alders Rebuttal at 3-17.

[139] *E.g.,* Ex. 3, O'Connor Direct at 45:26-46:12; Ex. 9, O'Connor Rebuttal at 36:16-46:10 and Table 3, 65:6-8 and Schedule 24 at 5-6 and 13 (Company Response to Department IR 78 identifying reasoning for deviations from proposed estimates).

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

information and benchmarking – the Company's estimate appeared to be the more reasonable estimate at the time.

Even if the Commission accepted the ALJ's conclusion that the 2011 Cost History document means we should have adopted the author's views in 2008, the result would have been providing a marginally higher initial estimate ($362.5 million vs. $346 million)[141] that would have made no difference to the cost-effectiveness of the EPU or the overall Program at the time. No party disputes that at the time of the EPU Certificate of Need all parties and the Company expected the LCM needs of the plant to exceed the EPU effort. Certainly no party contested the Company's EPU split in the 2008 EPU Certificate of Need proceeding; rather, the Department first used the 2008 NRC Letter in this proceeding to develop an after-the-fact LCM/EPU split for the Department's cost-effectiveness remedy. Even an initial estimate of $665 million – let alone an estimate of $362.5 million – would not have changed the outcome of a cost-effectiveness test at the Certificate of Need stage. As such, any error in early estimation did not affect the decision to proceed or that the Program is ultimately overwhelmingly cost-effective for our customers.

(2) <u>Contingency</u>

Relying on a new opinion in Mr. Crisp's Surrebuttal Testimony,[142] the Report goes on to suggest that the Company should have added a 100 percent contingency to the $320-346 million initial cost estimate. Mr. Crisp's opinion was in turn based on his Surrebuttal attachment entitled "Cost Estimate Classification System" (the Cost

141 Ex. 301, Crisp Direct at 24:11-13.

142 Report at Findings of Fact ¶ 42 (citing Ex. 303, Crisp Surrebuttal at 23-24 and Tr. Vol. III (Crisp) at 73).

Estimate System).[143] There are several errors with Mr. Crisp's reliance on the Cost Estimate System, and therefore the ALJ's conclusions and use of this document.

First, the Report does not reference Mr. Crisp's admission (and the text of the Cost Estimate System itself) that the document is not applicable to nuclear projects.[144] Instead, it applies to estimating for "production of chemical, petrochemicals, and hydrocarbon processing."[145]

Second, the document does not suggest that a contingency of 100 percent should be utilized, but rather states that an <u>accuracy range</u> of *minus 50 percent to plus 100* percent is to be expected for early phase project cost estimates.[146] Mr. Crisp, and in turn the ALJ, confused the "Expected Accuracy Range" (how accurate a project cost estimate is expected to be) with contingency (the amount of contingency included within the cost estimate). The two are not synonymous, as confirmed by the express language in two separate parts of the document:

- For the very early phases of a project, the estimated "Expected Accuracy Range" is minus 50 to plus 100 percent greater than the initial estimate.[147] This accuracy range (which Mr. Crisp confuses with contingency) expressly applies to a "cost estimate after application of contingency."[148]

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143 Ex. 303, Crisp Surrebuttal at 23-24 and Attachment MWC-S-1 (Cost Estimate Classification System).

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

145 Ex. 303, Crisp Surrebuttal at Attachment MWC-S-1 at 2 (Cost Estimate Classification System).

146 Ex. 303, Crisp Surrebuttal at Attachment MWC-S-1 at 2-3 (Cost Estimate Classification System).

147 Ex. 303, Crisp Surrebuttal at Attachment MWC-S-1 at 2-3 (Cost Estimate Classification System).

148 Ex. 303, Crisp Surrebuttal at Attachment MWC-S-1 at 3 (Cost Estimate Classification System).

- The "Expected Accuracy Range" for an early phase estimate is calculated "after inclusion of an appropriate contingency."[149]

Put differently, this document merely illustrates the common understanding regarding the variability of cost estimates at the very early stages of a project, and does not speak to whether the Company's contingency was too high or too low.

Third, the Report does not address Mr. Crisp's admissions on cross-examination that the Company's understanding of the Cost Estimate System document was correct and Mr. Crisp's characterization was wrong:[150]

> Q. And that's a range that's determined after the inclusion of a total project cost with a contingency built into it?
>
> A. If a contingency is built into it, yes.
>
> . . .
>
> Q. Okay. So the accuracy range we were talking about earlier, that's the range to use after a contingency is -- if there's a contingency built into the initial estimate. I think that's your testimony; right?
>
> A. That's correct. And it's also -- I think if you read further on, the range could be even greater, depending on the amount of risk in that particular project.

To put Mr. Crisp's Surrebuttal in context, in Rebuttal Testimony the Company had indicated that although we underestimated initial costs, the highest potential estimation we could have reasonably accepted in 2008 was approximately $420 million. This amount would not have supported the Department's disallowance under its cost-effectiveness test, would have been double any of the benchmarked projects, and would have accounted for the high end of the bounding exercise range

[149] Ex. 303, Crisp Surrebuttal at Attachment MWC-S-1 at 6 (Cost Estimate Classification System).

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

provided by the 2011 Cost History memo. Use of any number higher than $420 million – let alone the final Program cost – would not have been logical given the costs of other recently completed projects and that future challenges facing the industry and regulatory changes were not yet known. Mr. Crisp's belated contingency argument was therefore an attempt to avoid our argument that he applied hindsight to criticize our initial cost estimates.

Finally, Mr. Crisp's hearing testimony regarding a 100 percent contingency is not only an inaccurate rendering of the Cost Estimate System, but also inconsistent with regulatory history in Minnesota. The Company has never provided such a wide range of potential outcomes, as it has typically been considered more reasonable to provide a range of potential costs that is more targeted to the outcome the Company believes to be likely. From a planning perspective, cost sensitivities of this magnitude would render any analysis of the potential economic costs and benefits meaningless.

Similarly, other utilities embarking on uprates provided cost estimate ranges similar to the Company's estimate for Monticello. Grand Gulf, for example, provided a cost estimate ranging from $420 to $470 million based on preliminary conceptual design work.[151] Florida Power & Light provided even more targeted initial estimates of approximately $750 million and approximately $651 million for the Turkey Point and St. Lucie uprates, respectively.[152] Overall, the Report's high level findings that the

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[151] *In re Joint Petition of Sys. Energy Resources Inc., and S. Miss. Elec. Power Ass'n for a Certificate of Pub. Convenience and Necessity to Construct, Own, Operate, and Maintain an Extended Power Uprate Modification and Related Facilities at the Grand Gulf Nuclear Station in Claiborne Cnty., Miss.*, Miss. Pub. Serv. Comm'n No. 2009-UA-260, JOINT PETITION FOR FACILITIES CERTIFICATE AND MOTION FOR WAIVER at 5 (May 22, 2009). Grand Gulf also noted that their estimates did not include any costs associated with constraints that may be identified during the detailed analysis phase of the project. *In re Joint Petition of Sys. Energy Resources Inc., and S. Miss. Elec. Power Ass'n for a Certificate of Pub. Convenience and Necessity to Construct, Own, Operate, and Maintain an Extended Power Uprate Modification and Related Facilities at the Grand Gulf Nuclear Station in Claiborne Cnty., Miss.*, Miss. Pub. Serv. Comm'n No. 2009-UA-260, at DIRECT TESTIMONY OF C. JEFFREY RICHARDSON at 27:6-11 (May 22, 2009).

[152] *In re Fla. Power & Light Co.'s Petition to Determine Need for Expansion of Elec. Power Plants*, Fla. Pub. Serv. Comm'n No. 070602-EI, DIRECT TESTIMONY & EXHIBITS OF STEPHEN T. HALE at 13:7-10 (Sept. 17, 2007).

Company should have included a 100 percent contingency or identified a higher initial cost are not supported by the record or the regulatory process in Minnesota.

(3) Additional Considerations

The Report identifies other issues raised by the Department with respect to the Company's initial cost estimate, but it is not clear what weight (if any) the ALJ gives these issues in arriving at his Conclusions and Recommendations. We address them here to further illustrate the Company's prudence.

As-Builts: Finding of Fact No. 75 faulted the Company for not having "up-to-date" drawings of the plant "as-built," which the Department believes would have reduced the number of as-found conditions the Company encountered during construction and which would have resulted in a more accurate initial cost estimate. The Report does not discuss Mr. O'Connor's explanation (with additional analysis not repeated here) that such updated as-builts were not available:

> During the timeframe that first generation nuclear plants were constructed, it was not unusual that the "as built" configuration of non-safety related secondary plant systems were not fully documented on plant drawings, as many of the mechanical systems were "field run" (skilled craft labor determine the installation routing) to facilitate ease of installation.[153]

The Company agrees that as-builts would have been helpful, but it cannot be said the Company was imprudent because as-builts were frequently not developed during the era of Monticello's construction.

Also underlying the ALJ finding was Mr. Crisp's testimony that the Company should have used as-builts from a prior uprate in 1998 (the 1998 Rerate) as the "starting

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[153] Ex. 9, O'Connor Rebuttal at Schedule 9 (Company Response to Department IR 27 explaining why drawing discrepancies are unsurprising).

point" for Program development.[154] As-builts were not available from the 1998 Rerate because that minor uprate was primarily an analytical exercise that required only modest changes to plant components.[155] Mr. Crisp conceded on the stand that the 1998 Rerate was only a "math exercise [with] possibly some tweaking."

Work in Tight Spaces: Findings of Fact Nos. 76-77 and Conclusion of Law No. 9 conclude that the Company should have better anticipated work challenges associated with construction in the confined spaces present at a vintage nuclear plant in order to create a more accurate initial cost estimate. However, the record illustrates that the Company planned for and addressed "controlling factors" such as the small footprint of the plant.[156] The issue was that the full scope of the limitations could not be fully assessed until modification design was advanced to the point where engineers and contractors could compare designs against the physical limitations imposed. This could not be fully assessed until modification design was advanced to the point where engineers and contractors could compare design against the physical limitations imposed by "controlling factors."[157] This is common in the nuclear industry:

> In my opinion it is not feasible to discover all of the "controlling factors" earlier in time because design needs to progress to a sufficiently detailed stage from which the team compares the design to existing plant conditions and, then make assessments about interferences.[158]

Further, while the Report attributes the issues with feedwater heater installation to the "much larger" size of new heaters, in fact the new feedwater heaters were less than

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154 Ex. 300, Crisp Direct at 5:20-28.

155 Ex. 11, Sieracki Rebuttal at 32:19-22; Ex. 9, O'Connor Rebuttal at 17:7-19:9.

156 Ex. 9, O'Connor Rebuttal at 34:16-35:8.

157 Ex. 11, Sieracki Rebuttal at 5:22-6:5; 34:16-24.

158 Ex. 11, Sieracki Rebuttal at 34:26-35:8.

five inches larger than those being replaced.[159] An accurate review of the evidence would establish that the challenges the Company faced had more to do with the final design of the heaters and the craft labor issues the Company encountered than with the size of the replacements. The Report does not address these critical facts.

b. "Fast-Tracking"

A common theme of the Department's position and the Report was that the Company undertook an "aggressive, fast-track schedule by using a parallel process" and that this approach "contained unreasonable risks" that led to "costs that were imprudently incurred."[160] "Fast tracking" is Mr. Crisp's terminology; it is described by the Company as multi- or parallel-tracking and references the Company's decision to undertake design phases while other aspects of the Program were underway rather than completing all of the Program design up front. For example, initial design for the 2009 outage occurred while the EPU Certificate of Need process was underway, allowing the Company to initiate that outage very shortly after the Certificate of Need was issued. Likewise, the Company began planning for the 2011 outage shortly after the 2009 outage ended.

The ALJ's conclusions regarding this approach are again based on Mr. Crisp's testimony that the Company simply appeared to proceed too quickly.[161] Despite the pre-filed testimony the ALJ references, at the evidentiary hearings Mr. Crisp admitted that he was not testifying that the Company's decision to employ a parallel track

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159 Ex. 16, O'Connor Surrebuttal at 14:1-4 (The new "feedwater heaters are the same length as the old ones and are less than five inches wider than the old ones. Given the historic concerns with the access hatch size and the 13A/B feedwater heater replacement rigging, however, we likely would have had to make the access hatch larger even absent the uprate.")

160 Report at Conclusions of Law ¶ 10.

161 Report at Findings of Fact ¶¶ 78 and 79.

approach was imprudent.[162] Instead, he indicated only that this approach contributed to cost increases.[163] When asked on the stand, Mr. Crisp admitted that (1) his testimony was not addressing any specific costs;[164] (2) the Company's parallel-track decision did not "in and of itself" increase Program costs;[165] and (3) he disavowed providing any opinion regarding Mr. O'Connor's conclusion that avoiding a multi-track approach was unlikely to reduce costs.[166]

Mr. Crisp conceded that the Company's parallel approach was intended to complete the Program more expediently than with a traditional design it, then bid it, then build it, type of project.[167] He further acknowledged that reliance on the General Electric Scoping Assessment, which concluded that either 2009 and 2011 or 2011 and 2013 outages were feasible,[168] was reasonable.[169] And Mr. Crisp did not address the factors that warranted expediency,[170] particularly with respect to anticipated baseload

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[162] Tr. Vol. III (Crisp) at 16:8-17:22; *see* Ex. 9, O'Connor Rebuttal at Schedule 1 (Mr. Crisp's response to Company IR 8 stating that he did not determine that the Company's parallel approach was imprudent).

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

[164] *See, e.g.*, Tr. Vol. III (Crisp) at 18:17-25; 22:21-23; 25:15-21.

[165] Tr. Vol. III (Crisp) at 28:18-21.

[166] Tr. Vol. III (Crisp) at 15:11-17, 18:17-25, 22:7-14, 22:21-23. When asked whether completing more upfront design would have lessened Program cost, Mr. O'Connor referenced a comprehensive explanation of Monticello's design process from a document entitled *The Engineering and Design Process, Xcel Energy Nuclear Department*, and concluded: "I seriously doubt it." Ex. 9, O'Connor Rebuttal at 53:14-54:16 and Schedule 22 (The Engineering and Design Process, Xcel Energy Nuclear Department). And while Mr. Crisp reviewed Mr. O'Connor's explanation, he declined to state an opinion on the propriety of it. Tr. Vol. III (Crisp) at 34:13-19 ("I reviewed it. I'm not certain that I actually opined upon this document.").

[167] Tr. Vol. III (Crisp) at 30:3-8.

[168] Report at Findings of Fact ¶ 24.

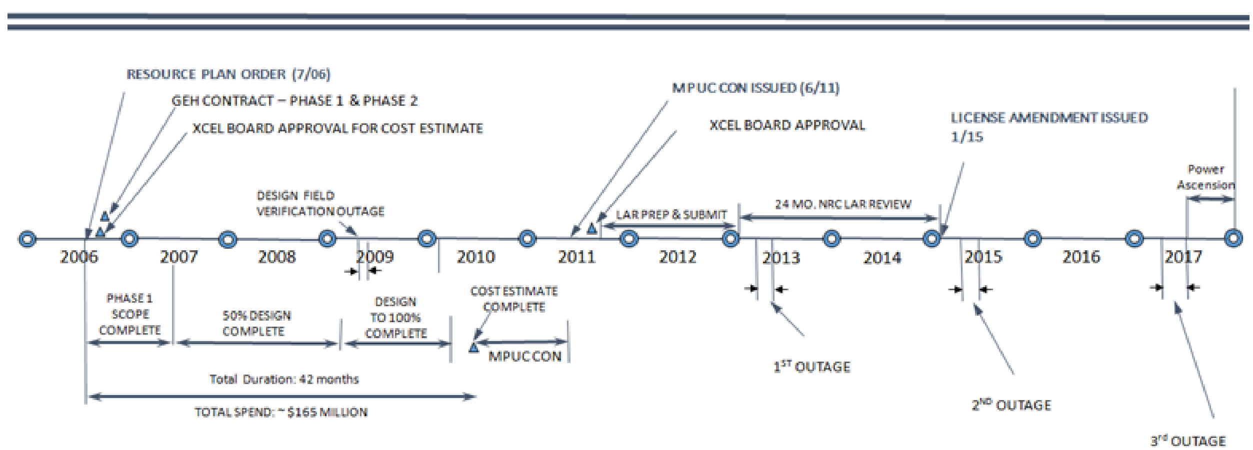
[169] Tr. Vol. III (Crisp) at 32:9-19.

[170] Tr. Vol. III (Crisp) at 30:9-18.

demand.[171] The Report similarly does not conduct any balancing of these factors against the likely outcome if the Company had delayed implementation.[172]

Moreover, the Report does not address the record evidence illustrating that if the Company completed most design work before proceeding, our initial cost estimate might have been more accurate (although, as described above, it would not have changed the decision to proceed with the Program), but the Program would have been delayed approximately four years and this itself would have led to higher costs. Figure 2 in Mr. O'Connor's Rebuttal Testimony provides a graphic depiction of what would have happened had the Company fully designed the initiative prior to proceeding, illustrating that the Program would not have been placed in service until 2017 – two years after the significant need we forecasted and seven years into the 20-year life extension of the plant:[173]

LCM/EPU Project Timeline – Detailed Cost Study Before CON Application



[171] Tr. Vol. III (Crisp) at 30:9-18; Ex. 9, O'Connor Rebuttal at Schedule 1 (Mr. Crisp's response to Company IR 8 stating that he did not determine that the Company's parallel approach was imprudent).

[172] The resource planning and energy market context of that timeframe shows the Company needed to proceed in parallel with design, licensing and construction to meet forecast customer needs. 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.

[173] Ex. 9, O'Connor Rebuttal at 52:17-54:5 and Figure 2.

This was not feasible given the forecast at the time.[174] We further do not believe the Commission would have found such a drawn-out approach to be reasonable at the time we undertook the Program.

In addition to the testimony of Company witness Mr. O'Connor, Mr. Sieracki confirmed not only the time demands of the Program but also the cost of proceeding with the Program in the manner Mr. Crisp suggests:

> The development of a complete design for a program of this magnitude would have taken years and cost many millions of dollars, and if Xcel Energy had waited for the design to be complete, the LCM/EPU Program would not have met Xcel Energy's needs according to the forecasted demand in its resource plan.[175]

Department witness Dr. Jacobs also conceded that Program costs likely would have been higher if implementation had been delayed.[176]

Finally, the Company provided uncontested evidence that a multi-track approach is common and often necessary in the industry:

> In addition, it has been my experience that major capital projects in the nuclear power industry often proceed to implementation with only preliminary designs completed. In light of the evolving Nuclear Regulatory Commission ("NRC") regulations and the complexities of working inside an operating nuclear plant, it is very difficult to complete reliable, detailed designs ahead of time. Thus, the concurrent permitting, design, and implementation (i.e., construction) planning approach Xcel Energy took was consistent with many other utilities' experience.[177]

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174 Ex. 9, O'Connor Rebuttal at 52:17-54:5; Ex. 11, Sieracki Rebuttal at 12:4-12.

175 Ex. 11, Sieracki Rebuttal at 12:4-8.

176 Tr. Vol. IV. (Jacobs) at 15:8-12.

177 Ex. 11, Sieracki Rebuttal at 13:20-14:2.

The Report did not address any of this testimony, nor the Company's balancing of interests when deciding to proceed with multi-track implementation, and therefore is an incomplete and ultimately incorrect assessment of prudence.

c. Project Scoping and Alternatives Considered

In Findings 53 and 74 the Report criticizes the Company's efforts to set the scope of work at the beginning of the Program. This issue largely overlaps with multi-tracking, which anticipated additional design as the Program got underway. Again, the Report does not address unrebutted testimony that proceeding with the Program based on a high-level scope was "particularly" common for projects in the nuclear industry.[178] "[M]ajor capital projects in the nuclear power industry often proceed to implementation with only preliminary designs completed."[179] The Company's response to Department Information No. 19 addressed this in detail but was not considered in the Report.[180]

The Report also does not consider the Company's evidence that "[g]iven the tight time frame needed to deploy additional baseload generation, Xcel Energy did not have sufficient time to have GE fully design the then-identified modifications, [and] develop a detailed scope of all the required modifications[.]"[181] Rather, the high-level scope was established based on then-known LCM needs and the major modifications identified in the 2006 General Electric Scoping Assessment, which identifies most of the Program modifications without purporting to offer detailed design or detailed work scopes associated with each modification.[182] This assessment properly identified the 10 major modifications necessary to complete the Program and the requirements

[178] Ex. 11, Sieracki Rebuttal at 14:25-15:9.

[179] Ex. 11, Sieracki Rebuttal at 13:20-22.

[180] Ex. 9, O'Connor Rebuttal at Schedule 21.

[181] Ex. 11, Sieracki Rebuttal at 19:4-7.

[182] Ex. 9, O'Connor Rebuttal at 58:2-3.

for several did not change, including the turbine, PRNM system, and main and 1AR transformers.[183]

Subsequently, the Company made necessary scope changes within various modifications when circumstances called for additional considerations.[184] The Report did not fault the Company's selection of the modifications that were used to create the overall scope of the Program,[185] and does not address the Company's evidence on how the work was refined as design progressed.

Overall, there is considerable data in the record that describes the options and alternatives the Company considered in designing the 10 major modifications.[186] Schedule 32 of Mr. O'Connor's Rebuttal Testimony (Attachment C to these Exceptions) provides a 57-page detailed discussion of its decision to replace and upgrade systems at the plant and the alternatives that were explored during that process.[187] We provide a summary of some of the options we considered here:

- *Generator Rewind*: The existing generator was original plant equipment. We compared replacement with rewinding the generator and concluded rewinding was sufficient.[188]

- *Rotating or Static Exciter*: The existing exciter was original plant equipment. The Company considered replacing the exciter with a static excitation system, but

183 Ex. 9, O'Connor Rebuttal at 58:4-6.

184 Ex. 9, O'Connor Rebuttal at 57:7-17.

185 Report at Findings of Fact ¶ 32.

186 *See generally* Ex. 3, O'Connor Direct at 93-146 and Schedules 17 (Summary of licensing activities and incurred costs), 19 (Summary of turbine replacement modification), 21-28 (Summaries of PRNM, steam dryer, condensate demineralizer, main transformer, feedwater heaters, reactor feed pump, condensate pumps and motors, and 13.8 kV distribution system modifications).

187 Ex. 9, O'Connor Rebuttal at Schedule 32 at 1 (Attachment C of these Exceptions).

188 Ex. 9, O'Connor Rebuttal at Schedule 32 at 21-22 (Attachment C of these Exceptions).

found that the static exciter would be much more expensive and challenging to install than a rotating exciter.[189]

- *Turbine Replacement*: We determined the existing high-pressure turbine required replacement or major maintenance to operate until 2030.[190] Replacing rather than repairing was appropriate because partial repairs can lead to vibration and imbalance issues.[191] And turbine technology had greatly improved and the existing turbine had vibration issues.[192]

- *Reactor Feed Pumps and Motors*: Our main consideration was whether to replace the existing two pumps with larger ones or add a third supplemental pump.[193] Both options had challenges, and the Company determined the two pump solution presented fewer challenges and provided greater operating continuity for our licensed operators.[194]

- *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.[195] We concluded that even with the challenges, proceeding with the replacement was preferable.[196]

- *Internal Distribution System Options*: We knew we needed to do significant work on the internal distribution system.[197] 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.[198] Many components of the

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189 Ex. 9, O'Connor Rebuttal at Schedule 32 at 22-23 and 57(Attachment C of these Exceptions).

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

191 Ex. 9, O'Connor Rebuttal at Schedule 32 at 16 (Attachment C of these Exceptions).

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

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

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

195 Ex. 9, O'Connor Rebuttal at Schedule 32 at 5-6 (Attachment C of these Exceptions).

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

197 Ex. 4, Stall Direct at 55:12-21; Ex. 3, O'Connor Direct at 131: 8-14 and Schedule 28 (Summary of 13.8 kV System modification).

198 Ex. 9, O'Connor Rebuttal at Schedule 35 at 6 (Company's Response to Department IR 83 regarding 13.8 kV distribution system).

> 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.[199] 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.[200] 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.[201]

The testimony of Mr. Stall confirms that our choices among alternatives were reasonable:

> 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.[202]

The Report does not address this data nor Mr. Crisp's acknowledgement that he did not contest the scope of the work that was ultimately done.

Finally, the Commission may question whether the Company considered the alternative to abandon the EPU effort. The record reflects that the Company did revisit the project several times to ensure it made sense to proceed. The first checkpoint was at the end of the 2009 outage (only a few months after receiving the Certificate of Need), as Mr. Alders summarized:

> By the end of the 2009 outage, we had already spent about $200 million on engineering, licensing and construction, including

[199] Ex. 9, O'Connor Rebuttal at Schedule 32 at 11-13, 28, and 42 (Attachment C of these Exceptions).

[200] Ex. 9, O'Connor Rebuttal at Schedule 32 at 11 (Attachment C of these Exceptions).

[201] Ex. 9, O'Connor Rebuttal at Schedule 35 at 6 (Company's Response to Department IR 83 regarding 13.8 kV distribution system).

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

> about $75 million that had been spent in the 2009 outage itself. At that point the Program was roughly on track and had exceeded our forecasts by a relatively small amount. Seeking to withdraw the certificate of need at that time would have been inconsistent with our experience to that point and would have been inconsistent with our desire to upgrade the plant and add incremental capacity. We had no evidence at the time that would contradict the Commissions certificate of need Order.[203]

In May 2010, the Company conducted an internal analysis to determine whether the costs associated with the EPU remained cost effective and found that adding an additional $50 million to the EPU side of the equation was still cost effective.[204] These conclusions did not change prior to the 2011 outage:

> Prior to the 2011 implementation outage, we had already expended $280 million in furtherance of the Program. Once again, at this point we had no basis to think that we should change course. Further, stopping at that point would have resulted in significant stranded costs. By the end of the 2011 implementation outage, when it became apparent that final costs were going to substantially exceed the original estimates, we had spent $430 million.[205]

We conducted another internal analysis in May 2011 as the 2011 outage came to a conclusion, using "the original model used to evaluate the EPU Program in 2008. At the time we had identified an additional $79 million in capital above our original estimate. The analysis indicated that even if the entire $79 million was attributed to the EPU Program, it would have still been prudent to pursue the Program."[206] In light of the investments we had already started, coupled with internal modeling and the plant's need for us to complete the upgrades (e.g., feedwater heaters, additional

[203] Ex. 2, Alders Direct at 60:11-18.

[204] Ex. 2, Alders Direct at 51:5-10.

[205] Ex. 2, Alders Direct at 60:20-25.

[206] Ex. 2, Alders Direct at 51:17-21.

distribution capacity, new pumps and motors) to support 20 years of operation regardless of whether we continued with an uprate, we concluded, appropriately, that the most practical and economical approach was to stay the course to preserve the future of Monticello.

3. *The Company's Program Management Was Prudent*

a. <u>The 2011 Cost History does not support a finding of imprudence.</u>

In Findings 52 through 55 of the Report, the ALJ relies heavily on the 2011 Cost History for his conclusions regarding imprudence. We believe the value and accuracy of this document, in which one site employee criticizes the Company in hindsight, has been significantly overstated in this record. We have provided a copy of that memo as Attachment D with our Exceptions for the Commission's convenience. As discussed in more detail in our testimony,[207] the 2011 Cost History offers one individual's summary of how he would have preferred a different approach in several respects. While we encourage our employees to be frank and candid with their opinions, we do not agree that the memo should be viewed as an indictment of our effort or a basis to justify a material disallowance.

The prudent investment standard requires that management actions need only fall within a "zone of reasonableness" to be prudent.[208] 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."[209]

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[207] *E.g.,* Ex. 9, O'Connor Rebuttal at 63-66 and Schedule 24 (Company Responses to DOC IRs 77, 78 and 80).

[208] *See Fed. Power Comm'n.*, 426 U.S. at 278.

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

Reasonableness or prudence is "judged according to whether a utility's actions were reasonable and prudent in light of circumstances at the time[.]"[210]

Because the memo was a linchpin to the ALJ's decision, we provide below key statements from the Findings and our response to dispel any lingering concerns:

> *"[T]he Company's initial cost estimate 'had high uncertainty since little engineering was done on the design concepts suggested,' and the 'EPU project team position was that each project should have a more detailed review to define the final scope and cost.' Instead, the Board approved the Nuclear Projects Team's recommendation for a two year earlier start with a cost estimate of $90 million below the EPU Project team's cost estimate."*[211]

This after-the-fact view mischaracterizes several points. First, the additional $90 million represented the high end of a range of costs provided to management.[212] Second, it was reasonable to retain and rely on General Electric to design this work and to develop cost estimates.[213] Third, the Company added substantial dollars to the General Electric estimate, which allowed room for a more substantial scope than the General Electric initial scoping study. In any case, the memo's estimate was also much lower than what we actually experienced, suggesting that even the author did not appreciate the magnitude of the effort that would be required in light of the evolving industry. That estimate cannot support a finding of imprudence.

Further, the Company carefully reviewed whether it was feasible to complete the work in the 2009 and 2011 timeframe and, based on the facts available at the time, believed

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

211 Report at Findings of Fact ¶ 52.

212 Ex. 9, O'Connor Rebuttal at Schedule 24 at 5 (Company Response to Department IRs 77, 78 and 80).

213 Tr. Vol. III (Crisp) at 32:17-19.

it was reasonable[214] and in fact the best choice versus delaying implementation until 2011/2013.[215]

> *"[T]he EPU Project team had little input in scoping the Project and no ability to ensure that the scope included any detailed engineering. When the Project Team did provide input, they were ignored; this led to "the need for the site to create many modifications around the base scope in the GE contract."*[216]

There was only one team responsible for the overall implementation of the Program. This assertion highlights the author's questioning of whether the Program should have been run by the site or by the dedicated project staff that were specifically tasked with the job. We explained why the Company chose to use a dedicated team to ensure the site personnel were not distracted from their primary duties to safely operate the plant.[217] The Company described the thought process behind this decision in greater detail in response to Department Information Requests Nos. 78[218] and 107.[219] All of this was ignored by the ALJ.

Further, it is undisputed on the record that the site had considerable influence in the development and design of the Program. The ALJ attempted to dismiss Mr. O'Connor's testimony because he did not become Chief Nuclear Officer until later, but the ALJ and the 2011 Cost History author ignore that in 2007 Mr. O' Connor led the site group as the Monticello Site VP. No one individual had more responsibility for what was happening at the plant. He was personally involved in the selection and

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214 Ex. 9, O'Connor Rebuttal at Schedule 24 at 13 (Company Response to Department IRs 77, 78 and 80); s*ee generally*, Ex. 3, O'Connor Direct at 49:7-13, 58:10-59:12; Ex. 9, O'Connor Rebuttal at 49:15-51:2 and Schedule 20 (Company Response to Department IR 41 regarding implementation schedule choices).

215 Ex. 9, O'Connor Rebuttal at Schedule 20 (Company Response to Department IR 41 regarding implementation schedule choices).

216 Report at Findings of Fact ¶ 53.

217 Ex. 9, O'Connor Rebuttal at Schedule 24 at 20 (Company Response to Department IRs 77, 78 and 80).

218 Ex. 9, O'Connor Rebuttal at Schedule 24 at 3-18.

219 Ex. 9, O'Connor Rebuttal at Schedule 23 at 1-6.

retention of the installation contractor and oversaw the decision whether to move to a different contractor.[220] Further, the site was instrumental in selecting the 13.8 kV modification and actively participated in the "Electrical Summit" that was convened to assess alternatives and select the best choice for the plant.[221]

In any case, an engineer on the site wanting more control over the Program does not make the Company's choice to hire dedicated professionals for a major construction project imprudent.[222] The Company properly balanced the considerations and came to a reasoned conclusion with which the memo's author simply disagreed.[223]

> *"In order to work around the GE contract, the Company had to add 'significant design engineering and project management resources beyond original project staffing.'"*[224]

We did add project management resources as would be expected to implement the project and keep it on track, and considered this a smart choice. Vendor performance was problematic throughout all aspects of the Project. This required additional management and oversight than was originally anticipated. But the Company's internal costs were commensurate with the size and complexity of the effort.[225] And

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220 Ex. 3, O'Connor Direct at 76:1-5 and Ex. 3, O'Connor Direct at 83:23-84:3.

221 Ex. 3, O'Connor Direct at 131 (describes electrical summit); Ex. 9, O'Connor Rebuttal at Schedule 35 (Xcel Energy Response to DOC IR-83 which describes the Electrical Summit in detail).

222 Ex. 9, O'Connor Rebuttal at 49:18-21; Ex. 11, Sieracki Rebuttal at 42:20-22.

223 Ex. 9, O'Connor Rebuttal at Schedule 24 at 20-21 (Company Response to Department IR 80 explaining the decision to have Projects group rather than Site manage the Project).

224 Report at Findings of Fact ¶ 53.

225 Ex. 3, O'Connor Direct at 27:19; *see* Ex. 5, Weatherby Direct at Schedule 6 (Results of the Company's Cost Classification Study).

the additional design costs were $13 million, which was comparatively a small piece of a project of this size.[226]

> *"[T]he Project team was also unable to 'obtain scope change decisions that balanced scope and cost.' The most significant scope changes 'did not appear to be approved by management in any detail.' When the scope had to be changed, it was done without 'an appropriate consideration of cost' because of the fast-track schedule The 'expected cost impact was not reviewed by appropriate management,' even when the costs were large. When management did give approval to increase the scope of the Project, it was done 'without the cost impact of the changes being known.' Those approvals ended up being very expensive, because 'schedule restraints forced parallel work and required significant cost commitments to be made to achieve goals.'"*[227]

The overarching Program scope never changed.[228] We always intended to undertake the work necessary to both allow for Monticello's continued safe and reliable operation to at least 2030, and achieve uprate operating conditions.[229] However, we have readily acknowledged throughout this process (and without regard to the 2011 Cost History) that the amount of work we needed to complete increased significantly from our initial estimates. We appropriately made design choices that were important to safety and reliability.

We followed the same design review process as we did for all nuclear projects.[230] That design and review process includes multiple steps and many checks and balances to ensure safety and quality. Design proceeded into seven district Phases detailed in

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226 Ex. 9, O'Connor Rebuttal at 79:7-16, 79:18 at Table 9; Ex. 10, O'Connor Rebuttal at Schedule 28 at 3-5 (Non-Public) (Company Response to OAG IR 6 identifying approximate amounts paid to contractors for scoping and design costs).

227 Report at Findings of Fact ¶ 54.

228 Ex. 9, O'Connor Rebuttal at 57:7-8.

229 Ex. 9, O'Connor Rebuttal at 57:9-11.

230 Ex. 9, O'Connor Rebuttal at Schedule 22 at 5-6 (The Engineering and Design Process, Xcel Energy Nuclear Department) (Emphasis added).

Mr. O'Connor's Rebuttal testimony, including (summarized here but detailed in testimony) the Study Stage, Design Stage, Design Review Meetings, Challenge Boards, Design Review Boards, Plant Operating Review Committee, and Design Approval.[231] Key scope decisions that arose out of this multi-level (30/60/90/100%) process[232] were primarily driven by reliability and design needs to recapture safety margin and operate the plant safely for another twenty years or more. We explored viable alternatives where they were available. We priced an alternative to the 13.8 kV system and the estimated price tag was the same.[233] We debated the two vs. three pump design, and site concerns about current equipment and operations moved us to a two pump solution.[234] We rejected General Electric designs that we believed added too much to our costs.[235] This was the prudent course of action and likely saved millions of dollars by not proceeding with suboptimal designs.[236] The Project team did focus on developing a resilient design that would last. In today's world, this was a smart approach.

> *"The Company's review process was 'insufficient to allow early identification of cost issues,' and this resulted in 'a challenge to project managers to be able to control and forecast cost.'"*[237]

The review process is the same process we used on every other capital project. Mr. Weatherby's Direct Testimony provides a detailed discussion of the accounting for

[231] Ex. 9, O'Connor Rebuttal at Schedule 22 at 4-5 (The Engineering and Design Process, Xcel Energy Nuclear Department).

[232] Ex. 11, Sieracki Rebuttal at 35:2-4; Ex. 9, O'Connor Rebuttal at Schedule 22 (The Engineering and Design Process, Xcel Energy Nuclear Department).

[233] Ex. 9, O'Connor Rebuttal at Schedule 35 at 6 (Company Response to Department IR 83 describing the 2007 Electrical Summit).

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

[235] Ex. 9, O'Connor Rebuttal at 42:14-21.

[236] Ex. 9, O'Connor Rebuttal at 42:18-21.

[237] Report at Findings of Fact ¶ 54.

the effort and the detailed cost records that were maintained.[238] Likewise, Mr. Sieracki provides an expert assessment of the Company's implementation of the Program,[239] which led him to the overall conclusion that "the cost growth is not due to poor management. As previously discussed, Xcel Energy management decisions that affected cost were reasonable and prudent."[240]

As previously discussed, after the 2009 outage, the Company assessed its performance and its management practices.[241] This is a process the nuclear industry calls "lessons learned," which was prudently followed by the Company.[242] We have acknowledged that we were surprised by the difficulty and cost arising in the 2011 outage. The difficulties the Company encountered during the 2011 outage suggested that the remaining work for final implementation would be significant.[243] We revised the implementation approach for the 2013 outage that, in the end, led to successful completion of the Program.

These outage costs are driven by the work needed and could not be avoided by the project managers. Perhaps these managers were more optimistic than we all would have preferred, but this is not mismanagement. The forecast of costs for the project explains why the cost deviation is large, not that the costs themselves are imprudent.[244]

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238 Ex. 5, Weatherby Direct; Ex. 6, Weatherby Direct (Non-Public).

239 Ex. 11, Sieracki Rebuttal at 50:15-54:11.

240 Ex. 11, Sieracki Rebuttal at 60:2-6.

241 Ex. 9, O'Connor Rebuttal at 67:15-24.

242 Ex. 11, Sieracki Rebuttal at 5:15-20; Ex. 3, O'Connor Direct at 74:20-75:2; Ex. 9, O'Connor Rebuttal at 71:17-72:23.

243 Ex. 9, O'Connor Rebuttal at 67:9-11.

244 Ex. 9, O'Connor Rebuttal at 44:25-45:3.

b. Mr. Crisp on Early Project Management

Besides the previously discussed specific items, the ALJ appears to have generally relied on the testimony of Mr. Crisp to support Conclusion of Law No. 10 that the Company's project management leading up to the 2009 outage was poor.

Almost all of Mr. Crisp's criticisms focus on what he, and in turn the ALJ, characterized as a haphazard early planning and design process. The primary problem with that characterization is that it is based on Mr. Crisp's high-level hindsight conclusion that a design-then-bid-then-build approach would have been preferable to avoid changes and allowed development of a more accurate initial cost estimate and work-scope. As described previously, the Company had critical reasons to implement what ALJ referred to as a "fast-track" approach. Mr. Sieracki noted that Mr. Crisp's criticisms would be "more appropriate if the LCM/EPU Program were a traditional design/bid/build project, in which a more detailed plan is completed prior to the start of construction."[245] In short, Mr. Crisp, and in turn the ALJ, are holding the Company to standards imposed by a fundamentally different and lengthier project delivery system that was not used on the Program for good reason.

Overall, Mr. Crisp did not address the time-consuming, iterative and complex design processes used at the Monticello plant as described in the Company's Nuclear Department's *The Engineering and Design Process*,[246] and took no issues with those processes.[247] The Company explained how the work increased within most Program modifications as design progressed and the reasons why. Mr. Crisp largely reiterated his fundamental conclusion that virtually all problems the Company encountered

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[245] Ex. 11, Sieracki Rebuttal at 10:24-26.

[246] Ex. 9, O'Connor Rebuttal at Schedules 21 (Company Response to Department IR 19 explaining appropriateness of initial design) and Schedule 22 (The Engineering and Design Process, Xcel Energy Nuclear Department).

[247] Tr. Vol. III (Crisp) at 34:14-19.

could have been avoided by delaying the Program at the outset. This conclusion is unrealistic given the complexity of any nuclear construction project, is unrelated to the reasons for undertaking the Program as we did and the benefits obtained, and ignores the significant problems with Mr. Crisp's preferred approach.

Just as importantly, Mr. Crisp did not object to the scope of the Company's work or the final product.[248] It is important to be clear that four major Program modifications accounted for $406 million,[249] which was more than half of the total Program costs of $665 and which contained the bulk of the cost growth.[250] 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.[251] 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.[252] Rather, he ignored the benefits that the Program delivered.[253]

Finally, 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 when the scope of modifications occurred. As Mr. Crisp acknowledged, scope creep can happen for "a whole host of reasons."[254]

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248 Tr. Vol. III (Crisp) at 24:20-25:4, 26:4-27:14.

249 Ex. 3, O'Connor Direct at 5:1 at Table 1 and Schedules 23 (detailed summary of the condensate demineralizer modification), 25 (detailed summary of feedwater heater modification), 26 (detailed summary of the reactor feed pumps and motors modification), 28 (detailed summary of the 13.8 kV modification).

250 Ex. 3, O'Connor Direct at 32:8-18.

251 Tr. Vol. III (Crisp) at 24:20-27:14.

252 Tr. Vol. III (Crisp) at 18:17-25, 19:23-20:3.

253 Tr. Vol. III (Crisp) at 19:23-20:3.

254 Tr. Vol. III (Crisp) at 33:12-19.

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.[255] As such, Mr. Crisp does little more than blame management for cost increases without fully assessing the reasons for or benefits of the Company's approach.

The ALJ Report's single Project management criticism that is based on decisions made after implementation was underway, relying again on Mr. Crisp, was that changes in contractors caused improper Program delays.[256] However, Mr. Crisp did not provide testimony that the Company should not have changed contractors, or that an individual contractor change in the Program was unreasonable or imprudent. Rather, Mr. Crisp simply stated that changing contractors creates risk management issues the Company must address, without offering an opinion as to whether the Company appropriately addressed those issues.[257] Moreover, the Report is silent on the robust systems the Company had in place to effectively manage contractors performing the work.[258] We urge the Commission to reject the implication that there is a "Catch-22" by which the Company would be imprudent either by changing contractors or by retaining a non-performing contractor.

4. *Proper Accounting Did Not Require an Advance LCM/EPU Split*

There is no dispute that the Program cost the $665 million at issue in this case[259] and that the Company's accounting records were sufficient to enable the Parties to identify

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[255] Tr. Vol. III (Crisp) at 33:24-34:3.

[256] Report at Findings of Fact ¶ 80.

[257] Report at Findings of Fact ¶ 80 ("replacement of contractors creates 'serious risk management issues that must be addressed by not only the Company but also by the new contractor.'").

[258] *See* Xcel Energy Initial Br. at 69-73.

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

how and where the Company incurred costs for the Monticello Program.[260] However, in Conclusion of Law 11, the ALJ states that our accounting practices made it difficult to separate LCM costs from EPU costs and, as a result, our "costs were not transparent as required." This finding is incorrect and unsupported by the record.

First, the Report recognizes that the Company provided evidence of its accounting for the LCM/EPU Program consistent with the FERC Uniform System of Accounts, "correctly accounting for the work by unit of property modified or installed, rather than by function."[261] The ALJ makes no finding that the Uniform System of Accounts required a separate accounting of costs by LCM and EPU work (by function) in order for costs to be transparent. As a result, the ALJ's conclusion that costs were not "transparent" because they were not sorted by LCM and EPU costs is based on mixing proper accounting (which must follow FERC) with allocation of costs among various purposes.

We did not maintain separate accounting for the LCM work and for the EPU work because it was one integrated project, with the same "units of property installed or modified" for both EPU and LCM purposes.[262] In other words, the same feedwater heaters, feedwater reactor pumps, and condensate demineralizer that had to be replaced for LCM purposes were also somewhat increased in capacity for EPU purposes. As such, there is no clear manner in which to definitively distinguish between the LCM and EPU portion of costs for a single component. Nor would it necessarily make sense to do so. As a result, accounting for the Program in

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260 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.

261 Report at Findings of Fact ¶ 29; *see* Ex. 5, Weatherby Direct at 2:25-3:7.

262 As Mr. Sparby testified, the accounting should follow the project and not visa-versa. Ex. 12, Sparby Rebuttal at 8:25-9:8.

accordance with FERC and with the nature of the Program is not indicative of imprudence.

It is also important to keep in mind that the Commission's first directive to identify a distinction between LCM and EPU costs arose from the ALJ's recommendations in our 2012 rate case, where an LCM/EPU split was utilized to determine what portion of Monticello costs were "used and useful." The fact that we had separate Certificates of Need for the license extension portion of the ISFSI application and the EPU does not mean we have been required historically to keep two sets of books. Rather, because a Certificate of Need is essentially a construction permit,[263] it does not override FERC accounting nor dictate the way utilities account for their costs. An analogous situation is where a utility receives a Certificate of Need for a single transmission line with the dual purposes of serving immediate reliability needs and potential future expansion. The Company would account for that line as a single unit of property regardless of efforts to support expansion potential.

Further, an allocation by functionality (LCM v. EPU) is not an accounting effort,[264] but rather an engineering effort.[265] Since the major modifications all served both purposes and such an allocation effort requires judgment, early allocations would have been subject to adjustment as new costs emerged and would need to be continually

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[263] The Minnesota Court of Appeals adopted this view in *In re Excelsior Energy, Inc.*, 782 N.W.2d 282 (Minn. St. App. 2010). The Court stated:

> The certificate-of-need evaluation applies only to *proposals* to construct large energy facilities. Minn. Stat. § 216B.243, subd. 2 ("No large energy facility shall be *sited or constructed* in Minnesota without the issuance of a certificate of need."). . . . . The certificate of need has no bearing on a large energy facility's contractual agreements.

In re Excelsior Energy, Inc., 782 N.W.2d at 295 (emphasis in original).

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

[265] *See* Tr. Vol. III (Jacobs) at 99:1-4; Ex. 3, O'Connor Direct at Schedule 29 at 2-3 (Unavoidable LCM and Avoidable EPU Costs) ("[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.").

revised until the Program was completed. It is highly unlikely such a process would have saved costs.

Finally, had the Company allocated costs between the LCM and EPU components during construction it would not have changed this proceeding in any material way. Regardless of whether completed contemporaneously or at the conclusion of the project, the applied engineering judgment would have been subject to disagreement as the parties have different points of view on the proper allocation of the costs between LCM and EPU.

III. THE RECORD DOES NOT SUPPORT THE DEPARTMENT'S LCM/EPU SPLIT

The ALJ's proposed disallowance is centered on the Department's cost-effectiveness test, which is in turn dependent on Dr. Jacobs' allocation of Program costs between the LCM and EPU aspects of the Program. The Report accepts Dr. Jacobs' proposal that in hindsight 85 percent of the final costs of the integrated Program should be attributed to the EPU because any work order that had even a small EPU component should be assigned 100 percent to the EPU. In arriving at this conclusion, however, the Report addresses neither the illogical principle of Dr. Jacobs' approach, nor the underlying facts that require a different outcome.

First, the Report does not make clear that it is an undisputed conclusion of all parties[266] that the Program is "overwhelmingly cost-effective as a whole."[267] Because the Program was constructed as single project – which was critical given that the same equipment was replaced for the LCM and EPU simultaneously – considering the

[266] The Report stated that "Xcel argued first that an allocation of costs between LCM and EPU is inappropriate because it considered the Project an integrated effort that is overwhelmingly cost-effective as a whole." Report at Findings of Fact ¶ 92 (citing solely to Xcel Energy's Initial Brief at 76). In fact, it was Department witness Mr. Christopher Shaw who presented Direct Testimony that the Program was "overwhelmingly cost-effective as a whole." Ex. 309, Shaw Direct at 14:1-2.

[267] Ex. 309, Shaw Direct at 14:1-2.

integrated value of the Program is necessary to a reasonable assessment of Program value.

Second, the ALJ fundamentally concludes that the LCM portion of the Program was roughly $100 million total ($665 million * .15%), which is $35 million *less* than the estimated LCM costs stated in 2006 dollars in our ISFSI Certificate of Need.[268] When paired with the lack of information in the Report regarding the plant's long term maintenance needs regardless of an EPU, this outcome cannot be reconciled with the objective evidence on the record.

Ultimately, the ALJ's conclusions regarding the appropriate LCM/EPU split overlook four critical issues:

- The Report does not acknowledge the significant record evidence indicating the Program was LCM-driven, regardless of any specific numerical split of costs between the LCM and EPU;
- The ALJ disagreed with the Company's proposed attribution of costs to the LCM and EPU because he (erroneously) believes the Company defaulted to LCM; but does not acknowledge that Dr. Jacobs also used this approach – he just defaulted to the EPU;
- The Report deemed Dr. Jacobs credible without examining the documentation on which the ALJ acknowledges that Dr. Jacobs' opinion is dependent; and
- A cost-effectiveness test is a hindsight-based remedy for perceived imprudence that cannot withstand the prudent investment standard.

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268 Ex. 9, O'Connor Rebuttal at 12:17-13:9. The estimated LCM costs for Monticello in 2006 were approximately $135 million.

We address each of the first three concerns in turn below, and address the infirmities of the cost-effectiveness test as a prudence remedy later in these Exceptions.

A. The Program was LCM-Driven

Relying entirely on Dr. Jacobs, the Report adopts the Department's LCM/EPU split without examining the underlying records that illustrate the LCM needs of the plant were the driver of the Monticello Program from the Program's initiation before an EPU was considered to its conclusion. The Report does not include any discussion of the significant historical records illustrating that many of the plant's components needed to be addressed regardless of the uprate or a change in equipment size,[269] including the steam dryer,[270] feedwater heaters,[271] condensate demineralizer system,[272] main power transformer and 1AR emergency transformer,[273] reactor feed pumps and motors,[274] condensate pumps and motors,[275] and PRNM system.[276] As previously discussed, much of the equipment was deteriorated, obsolete, and/or no longer available for component replacement, and included 1960s-era analog equipment that needed attention regardless of the EPU.[277]

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269 Ex. 3, O'Connor Direct at 93:1-136:11 and Schedules 29 (Unavoidable LCM and Avoidable EPU Costs) and 30 (Table showing how each plant modification was categorized between LCM-only and EPU-only work); Ex. 9, O'Connor Rebuttal at 81:1-123:18 and Schedule 32 (Attachment C of these Exceptions).

270 Ex. 3, O'Connor Direct at 103:4-104:4 and Schedule 5 at 1 (LCM/EPU Modification In-Service Table); Ex. 9, O'Connor Rebuttal at Schedule 32 at 18-19 and 43 (Attachment C of these Exceptions).

271 Ex. 9, O'Connor Rebuttal at Schedule 32 at 7-8 and 25; Schedule 34 at 14 (Monticello Nuclear Generating Plant Potential Capital Expenditures Strategy, May 22, 2003).

272 Ex. 9, O'Connor Rebuttal at Schedule 32 at 5-7 (Attachment C of these Exceptions).

273 Ex. 3, O'Connor Direct at 114:23-115:9; Ex. 9, O'Connor Rebuttal at 90:17-21; 114:7-15 and Schedules 32 at 19-20 and 42 (Attachment C of these Exceptions); Schedule 33 at 13 (2001 Long Range Plan), and 34 at 10 (Monticello Nuclear Generating Plant Potential Capital Expenditures Strategy, May 22, 2003).

274 Ex. 9, O'Connor Rebuttal at Schedule 32 at 8-10 (Attachment C of these Exceptions).

275 Ex. 9, O'Connor Rebuttal at Schedule 32 at 10-11 (Attachment C of these Exceptions).

276 Ex. 3, O'Connor Direct at 99:24-100:6; Ex. 9, O'Connor Rebuttal at 112:21-113:27.

277 Ex. 9, O'Connor Rebuttal at 87:19-22 and Schedule 32 (Attachment C of these Exceptions).

In particular, the Report says virtually nothing about the many contemporaneous documents from 2001 through 2008 that illustrate the need for LCM work regardless of any EPU.[278] The contemporaneous evidence provided by the Company shows that the purpose of the EPU was "integration with Life Cycle Management projects for the Monticello Nuclear Generating Plant."[279] Many of the components we replaced had been identified as early as our 2001 Long Range Plan as being necessary for plant reliability.[280] And by our 2003 Long Range Plan, a significant proportion of the LCM work that we did had been identified, including replacing the feedwater heaters, addressing the shortcomings in the internal electric distribution system, replacing pumps and motors, work on the generator, and replacing transformers.[281] For example, a May 2003 *Nuclear Capital Expenditures Strategy* document, which is attached as Schedule 34 to Mr. O'Connor's Rebuttal Testimony, contains numerous references to work that was identified to be necessary for life extension without regard to a potential uprate:

- Transformers (page 10 of 32):
- Generator Exciter (page 11 of 32);
- Feedwater Heaters (page 14 of 32):
- Feedwater Piping (page 15 of 32);

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278 *E.g.*, Ex. 9, O'Connor Rebuttal at Schedule 6 (Certificate of Need Application for Independent Spent Fuel Storage Installation (ISFSI) from January 2005 showing a representative list of necessary LCM modifications) and 32 (Attachment C of these Exceptions).

279 Ex. 16, O'Connor Surrebuttal at Schedule 6 at 4 (July 24, 2006 Investments in Life Cycle Management and Power Uprate for Monticello Presentation).

280 Ex. 9, O'Connor Rebuttal at 109:9-13. Examining the service-life of the equipment, given the age and condition was an important and prudent consideration. Generally, the plant's components 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.

281 Ex. 9, O'Connor Rebuttal at Schedule 34 at 15 (Monticello Nuclear Generating Plant Potential Capital Expenditures Strategy, May 22, 2003).

- Cabling (page 18 of 32);
- Electric Distribution Work (page 20 of 32);
- Feedwater Pumps and Motors (page 29 of 32).

For each of these upgrades, the stated reason for undertaking the project was to "[i]ncrease plant reliability and safety for the extended period of operation."[282] And the rationale for including them was that "[n]ot replacing these components could potentially lead to an extended shutdown."[283] Additional documents in the 2005-06 timeframe show that before embarking on the uprate, the Company identified multiple projects that were needed to support long-term plant viability, including the feedwater heaters, the main steam feedwater piping, and the main and 1AR transformers.[284] The Report discusses none of these upgrade needs.

While the Report concludes that our work on the feedwater heaters was excessive, the record is undisputed that they were a long-standing concern for the Company. By at least 2001 we had identified the need to replace the plant's six feedwater heaters if we extended the operating license, and this work needed to be done regardless of the uprate.[285] Consistent with this identified need, Dr. Jacobs admitted that items such as feedwater heaters and main transformers are "typically required to ensure reliable operations beyond the original 40 year operating life of the plant."[286] Dr. Jacobs

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282 *See* Ex. 9, O'Connor Rebuttal at Schedule 34 at 12 (Monticello Nuclear Generating Plant Potential Capital Expenditures Strategy, May 22, 2003).

283 *See* Ex. 9, O'Connor Rebuttal at Schedule 34 at 12 (Monticello Nuclear Generating Plant Potential Capital Expenditures Strategy, May 22, 2003).

284 Ex. 16, O'Connor Surrebuttal at 24:1-20 and Schedules 3 (Spreadsheet of 10-year Capital Projects as of November 11, 2005), 4 (Spreadsheet of 10-year Long Range Plan as of June 26, 2006) and 5 (Spreadsheet of 10-year Long Range Plan as of August 7, 2006).

285 Ex. 9, O'Connor Rebuttal at 103:18-106:9 and Schedule 32 at 7-8 (Attachment C of these Exceptions).

286 Tr. Vol. IV (Jacobs) at 26:24-27:6, 30:6-10; Ex. 428, *In re Nuclear Cost Recovery Clause*, Fla. Pub. Serv. Comm'n No. 080009-EI, REVISED DIRECT TESTIMONY AND EXHIBITS OF WILLIAM R. JACOBS, JR., PH.D. at 9:5-16 (July 30, 2008).

nonetheless assigned 100 percent of these costs at Monticello to the EPU.[287] None of this was addressed in the Report. For these reasons alone, a generalized acceptance of an outcome that defaults 85 percent of Program costs to the EPU is inconsistent with both the record and the plant's real needs.

B. The Company's Approach was Thoughtful and Reflects Plant Needs

The ALJ concluded that the Company fundamentally defaulted to attributing work to the LCM aspect of the Program.[288] This finding is unsupported in the record. Schedule 31 to Mr. O'Connor's Rebuttal Testimony provides a detailed analysis of the LCM and EPU needs and cost drivers for each individual modification. The Company took a hard look at plant equipment, which was built with the expectation it would only be used for the duration of a 40-year operating license, and estimated (to the extent possible) what work had to be done regardless of the EPU and what work could have been avoided if an EPU was not completed.[289] It would be correct to say that the Company attributed costs to LCM if such costs would have been needed absent the EPU, as this approach is consistent with the primary need to keep Monticello's 600 MW operating with or without the additional 71 MW.[290] However, we realized that certain costs were additive as a result of the EPU. Based on the totality of the evidence in the record, an LCM/EPU split that attributes a greater portion of costs to the EPU than to LCM needs is not consistent with the fundamental nature of the project or the needs of the plant.

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287 Ex. 305, Jacobs Direct at Attachment WRJ-3 (Dr. Jacobs's Allocation of EPU/LCM Costs).

288 Report at Conclusions of Law ¶ 12.

289 Ex. 3, O'Connor Direct at 145:3-147:4 and Schedules 29 (Unavoidable LCM and Avoidable EPU Costs), 30 (Table showing how each plant modification was categorized between LCM-only and EPU-only work), and 31 (Company's supplemental Response to OAG IR 48 from rate case); Ex. 9, O'Connor Rebuttal at 81:6-84:11 and Schedules 30 (Company Response to Department IR 123 explaining cost assignments in LCM/EPU Split Table in Ex. 3, O'Connor Direct at Schedule 29) and 31 (Company Response to Department IR 58 with expanded explanation of unavoidable LCM work for various modifications).

290 Conversely, the EPU could not have functioned if the Plant ceased to operate.

Although an LCM/EPU split has been of some interest to the parties and the Commission since the Commission first sought to determine what portion of the Program was "used and useful" for ratemaking purposes, ultimately no split is appropriate given the integrated nature of the Program. If the Commission disagrees and utilizes a split for purposes of determining whether the Company's decision to proceed with the Program was reasonable at the time of the EPU Certificate of Need, the 51.4/41.6 percent LCM/EPU split used in the 2008 Monticello EPU Certificate of Need proceedings is the best option because it is the only approach that does not inject further hindsight into the cost-effectiveness test. No party disagrees that this split was made in good faith, was based on the information known in 2008, and is not derived from applying a 2014 recast of information to the decisions the Company was making in 2006-2008. This should lead to a finding that the decision to move forward was prudent and no cost-effectiveness remedy applies.

C. ALJ's Adopted LCM/EPU Split Defaults Costs to EPU

Perhaps even more troubling than the Report's rejection of the Company's LCM/EPU split analysis is the ALJ's acceptance of Dr. Jacobs' analysis without analysis of the fundamental principles he utilized to reach his conclusion. As acknowledged by Dr. Jacobs at the evidentiary hearings, he assumed that if any changes to Monticello equipment completed via the Program were needed to accommodate the EPU, all charges for that equipment were EPU-related regardless of LCM needs:

> 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.[291]

Therefore, if any portion of a modification had EPU benefits, then Dr. Jacobs assigned the entire modification cost to the EPU regardless of LCM needs.

It is virtually impossible to reconcile the ALJ's acceptance of Dr. Jacobs' approach with other findings in the Report, the overall needs of the plant, and Dr. Jacobs' contradictory approach in other proceedings. First, the ALJ concluded that the Company's allocation of 78 percent of Program costs to LCM "is not reasonable because it improperly assumes that all costs are LCM costs until proven otherwise, which causes many items to be classified as LCM costs inappropriately."[292] While we disagree with this characterization of the Company's approach, this Finding appears to generally condemn a split based on default assumptions. Yet the Report accepts Dr. Jacobs' approach without examining his methods, and without acknowledging that Dr. Jacobs admitted defaulting to assigning all of a modification's costs to the EPU regardless of whether the greater driver of modification costs was LCM or the EPU.

The ALJ's acceptance of Dr. Jacobs' approach is further undermined by Dr. Jacobs' willingness to adjust his methods depending on his ultimate goal. The Report does not address the record evidence that the bright-line methodology employed by Dr. Jacobs is fundamentally contradicted by the approach he employed in trying to obtain a disallowance of costs associated with FPL's Turkey Point and St. Lucie EPU programs.[293] In Florida, he utilized the same type of breakeven analysis used by Department witness Mr. Shaw in this proceeding, but developed a split by attributing

[291] Tr. Vol. III (Jacobs) at 115:25-116:10.

[292] Report at Conclusions of Law ¶ 12.

[293] Tr. Vol. IV (Jacobs) at 30:11-31:2.

only the incremental cost of the increased size of components to the EPU.[294] In contrast, Dr. Jacobs attributed all modification costs to the EPU portion of the Monticello program so long as he believed any increment of the cost related to the uprate. Notably, Dr. Jacobs had an incentive to minimize costs attributed to the EPU in the Florida proceedings as a result of the way statutory cost recovery was structured. Here, he maximized costs attributable to the EPU to support a disallowance utilizing the Department's breakeven analysis. The Report finds Dr. Jacobs to be credible without examining this key piece of evidence.

D. Dr. Jacobs' Documents Do Not Reconcile With ALJ Conclusion

The Report characterizes Dr. Jacobs' analysis as based on review of multiple sources.[295] However, Dr. Jacobs' testimony makes clear that he relied almost exclusively[296] on an enclosure to a 2008 letter from the Company to the NRC (2008 NRC Letter) identifying work at the plant that would be affected by the EPU.[297] The Report does not actually look at the letter Dr. Jacobs relied upon, and does not analyze whether the letter supported Dr. Jacobs' conclusions. In addition, in his Surrebuttal Testimony Dr. Jacobs contended that only one document existed to identify work the Company needed to do for LCM purposes if not for the EPU.[298] This is plainly incorrect and misleading, and illustrates that Dr. Jacobs did not review key documents that were provided to him. These are only two of the fatal flaws the ALJ failed to address, and represent critical deficiencies in the ALJ's acceptance of Dr. Jacobs' LCM/EPU split.

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294 Ex. 428, *In re Nuclear Cost Recovery Clause*, Fla. Pub. Serv. Comm'n No. 080009-EI, REVISED DIRECT TESTIMONY AND EXHIBITS OF WILLIAM R. JACOBS, JR., PH.D. at 9:13-10:6 (July 30, 2008).

295 Report at Findings of Fact ¶ 97.

296 Ex. 305, Jacobs Direct at 8:11-29.

297 Ex. 305, Jacobs Direct at Attachment WRJ-2 (Nov. 5, 2008 Letter from Xcel Energy to the NRC Document Control Desk re: License Amendment Request [hereinafter NRC Letter]).

298 Ex. 307, Jacobs Surrebuttal at 12:8-11.

1. NRC Enclosure 8

To support attributing 100 percent of many major Program modifications to the EPU, Dr. Jacobs relied on an Enclosure 8 to the 2008 NRC Letter, which described specific modifications that would be affected or changed by the EPU.[299] As described above, Dr. Jacobs then concluded (in light of his EPU-centric approach) that to the extent the Company described modifications as being in any way related to the EPU, 100 percent of that modification's costs should be attributed to the EPU. There are several problems with Dr. Jacobs' approach.

First, the Report does not address how Dr. Jacobs' approach misunderstands the NRC letter on which he relies. The cover letter accompanying the NRC Enclosure 8 notes that approval for an uprate is requested "[p]ursuant to 10 CFR 50.90."[300] 10 CFR 50.90 specifies that:

> Whenever a holder of a license . . . desires to amend the license or permit, application for an amendment must be filed with the Commission, as specified in §§ 50.4 or 52.3 of this chapter, as applicable, **fully describing the changes desired**, and following as far as applicable, the form prescribed for original applications.[301]

Moreover, the Company states in the NRC letter that:[302]

Enclosure 8 includes a list of modifications planned for EPU implementation. The modifications listed in Enclosure 8 are planned actions which do not constitute regulatory commitments by NSPM. Modifications listed in Enclosure 8 are being implemented in accordance with the requirements of 10 CFR 50.59.

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[299] Ex. 305, Jacobs Direct at Attachment WRJ-2 (NRC Letter).

[300] Ex. 305, Jacobs Direct at Attachment WRJ-2 at 1 (NRC Letter) (emphasis added).

[301] 10 CFR 50.90 (2014).

[302] Ex. 305, Jacobs Direct at Attachment WRJ-2 at 3 (NRC Letter). Although the Company does not dispute that this document was provided under oath and represents the information known at the time, this language made it clear that Enclosure 8 was never intended to be a definitive list of work to be done in support of the EPU, let alone work to be done at the plant overall.

10 CFR 50.59(a)(1) in turn describes the "changes" that must be identified in an application under 10 CFR 50.90:

> Change means a modification or addition to, or removal from, the facility or procedures that affects a design function, method of performing or controlling the function, or an evaluation that demonstrates that intended functions will be accomplished.[303]

Tying the Company's 2008 NRC letter together with the governing federal regulations clarifies the fallacy of Dr. Jacobs' reliance on this document and the proper purpose of Enclosure 8: As required by federal regulation, Enclosure 8 identified any instance in which a change to equipment could be needed to implement the EPU – not any instance in which the entire need for the work was driven by the EPU.[304] As such, it is no basis for assigning 100 percent of any particular modification's costs to the EPU.

Second, Dr. Jacobs utilized the letter inconsistently, in a manner that favored attributing costs to the EPU. Although Dr. Jacobs characterized the letter as dictating whether a modification was EPU-driven because it was provided to the NRC under oath, he explicitly assigned modifications to the EPU even where the letter expressly stated the work was ***not*** related to the EPU. (Conversely, Dr. Jacobs did not assign any modifications that referenced the EPU to LCM work.) For example, Dr. Jacobs attributed 100 percent of the 13.8 kV system costs to the EPU although the NRC Letter states that the 13.8 system is "an LCM modification to increase margin in the on site [sic] distribution system."[305] He further attributed 100 percent of condensate demineralizer costs to the EPU even though the NRC Letter says nothing about the

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303 10 CFR 50.59(a)(1) (2014).

304 Ex. 305, Jacobs Direct at Attachment WRJ-2 at 3 (NRC Letter).

305 Ex. 305, Jacobs Direct at Attachment WRJ-2 at 13 (NRC Letter) and WRJ-3 (Dr. Jacobs's Allocation of EPU/LCM Costs).

EPU with respect to the need to replace the 1960s' analog control panel with a digital model.[306]

Third, Dr. Jacobs also did not consider earlier and contemporaneous documentation illustrating the need to replace the 4 kV breakers regardless of the EPU.[307] He testified that he was not familiar with plants that had 13.8 kV upgrades for EPU purposes, even though he attributed the Company's upgrade entire to the EPU.[308] Dr. Jacobs further agreed that an upgrade to the system was necessary regardless of the EPU, and unlike Mr. O'Connor[309] never evaluated the costs of replacing the 4 kV system with a 13.8 kV system vs. a system of some other voltage.[310]

In fact, Dr. Jacobs acknowledged that under voltage alarms occurring at the plant prior to the EPU indicated the need for distribution work absent the EPU:

> Q. Were you aware that the plant was receiving 4 kV undervoltage alarms when starting large motors even before EPU work was being done?
>
> A. I am aware of that, yes. I'm not sure at what point in time I became aware of that.
>
> Q. And do you have any opinion about whether that indicated the need for distribution system work independent of the EPU?

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306 Ex. 305, Jacobs Direct at Attachments WRJ-2 at 12 (NRC Letter) and WRJ-3 (Dr. Jacob's Allocation of EPU/LCM Costs).

307 Ex. 9, O'Connor Rebuttal at Schedule 33 at 13 (2001 Long Range Plan); Ex. 10, O'Connor Rebuttal at Schedule 32 at 28-41 (Non-Public) (Company Response to Department IR 124 including contemporaneous documents detailing the conditions of the existing equipment).

308 Tr. Vol. IV (Jacobs) at 18:13-20:11. Importantly, Dr. Jacobs wasn't aware that the Palo Verde nuclear facility where he worked has a 13.8 kV system, or that Monticello's sister plant in Spain had difficulties taking a piecemeal approach to upgrading their 4 kV system.

309 Ex. 9, O'Connor Rebuttal at 99:9-21.

310 Tr. Vol. IV (Jacobs) at 23:14-25.

A. I believe it would, yes.[311]

None of this testimony is addressed in the Report.

Fourth, while Dr. Jacobs said he relied on NRC Enclosure 8 because it was provided under oath, he acknowledged during cross-examination that all of the Company's testimony submitted in this proceeding and in our 2008 EPU Certificate of Need proceeding, where we presented the 41.6/58.2 LCM/EPU split as a conservative estimate, was also submitted under oath.[312] This does not necessarily make such testimony more important than the NRC Enclosure, but rather underscores that multiple additional documents providing more direct and relevant context for an LCM/EPU split are equally reliable.

Finally, Dr. Jacobs' manner of applying the 2008 NRC letter to final Program costs assumes either that the Company knew the final cost would be $665 million and drafted the Enclosure 8 in accordance with that knowledge, or that the increases in costs the Company experienced after the 2008 NRC letter was submitted were driven solely by EPU considerations. However, Dr. Jacobs never examined the drivers of cost increases. Even if the 2008 EPU Certificate of Need 41.6/58.4 percent split was applied to the $320 million cost estimate in the Certificate of Need, with Dr. Jacobs' split applied to the cost increases, the total costs attributed to the EPU would be $85 million less than Dr. Jacobs' EPU-centric method. In sum, Dr. Jacobs fundamentally misused the 2008 NRC Letter and declined to consider other evidence.

2. Additional Contemporaneous LCM Documents

Dr. Jacobs' conclusions that the EPU drove many of the modifications, and therefore the LCM/EPU split adopted in the Report, are further undermined by additional

311 Tr. Vol. IV (Jacobs) at 34:23-35:7.

312 Tr. Vol. III (Jacobs) at 121:1-18.

record evidence the Report largely ignores. For example, as Dr. Jacobs acknowledged on cross-examination,[313] the following work was all identified in the ISFSI Certificate of Need as representative work needed for LCM – regardless of the EPU – and was completed as part of the LCM/EPU Program:

- Steam Dryer;
- Electrical breaker replacement;
- Cable replacement;
- Replacement of main steam and feedwater piping;
- Replacement of feedwater heaters; and
- Replacement of static exciters.[314]

Although he failed to do so in pre-filed testimony, at hearings Dr. Jacobs acknowledged that these modifications, though in many respects sized to support the EPU, "were also needed regardless of the EPU for life extension."[315] Dr. Jacobs was also asked on cross-examination to review the Company's 2001 and 2003 long range plans, and admitted that much of the work was needed regardless of the EPU.[316] Furthermore, 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

[313] Tr. Vol. IV (Jacobs) at 11:11-23. In his testimony, Dr. Jacobs characterized this list as the only information about work the Company might have needed for LCM purposes without being clear that the Company provided this list as "representative" of maintenance needs or that there were additional contemporaneous documents available. Ex. 307, Jacobs Surrebuttal at 12:8-13; Ex. 9, O'Connor Rebuttal at 87:17-88:17.

[314] Tr. Vol. IV (Jacobs) at 13:8-14:11.

[315] Tr. Vol. IV (Jacobs) at 14:9-10.

[316] Tr. Vol. IV (Jacobs) at 6:14-9:25.

"feedwater heaters,"[317] Dr. Jacobs attributed these costs to the Monticello EPU.[318] These admissions, which are not addressed in the Report, further contradict Dr. Jacobs' conclusions.

3. ALJ Overlooks Dr. Jacobs' Misunderstanding of NRC Requirements

Finally, Dr. Jacobs defended his inadequate allocation of costs to the LCM by contending that if not for the EPU, the Company could have replaced aging equipment on a "like-for-like" approach that would have been less costly.[319] The ALJ likewise appears to have adopted this theory, but does not address the multiple documents in the record confirming that it was inconsistent with NRC requirements and infeasible.

Dr. Jacobs attempted to define "like-for-like" replacements in Surrebuttal as "replacing equipment with new equipment with similar performance specifications and physical characteristics" and criticized Mr. Stall for taking the term "like-for-like" "in a literal sense."[320] At the evidentiary hearing, however, the Company demonstrated that Mr. Stall's "literal" definition was in fact the definition mandated by the NRC. The NRC's long-standing definition of "like-for-like" specifically requires "replacement of an item with an item that is identical" that "was purchased at the same time from the same vendor."[321] Although Dr. Jacobs attempted to characterize his approach as simply defaulting to a "layperson's" definition, he admitted the Company is not allowed to rely on an individual's "lay" definition of such a term and

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317 Tr. Vol. IV (Jacobs) 30:6-10; Ex. 428, *In re Nuclear Cost Recovery Clause*, Fla. Pub. Serv. Comm'n No. 080009-EI, REVISED DIRECT TESTIMONY AND EXHIBITS OF WILLIAM R. JACOBS, JR., PH.D. at 9:5-16 (July 30, 2008).

318 Ex. 305, Jacobs Direct at Attachment WRJ-3 (Dr. Jacobs's Allocation of EPU/LCM Costs).

319 Ex. 305, Jacobs Direct at 14:19-21.

320 Ex. 307, Jacobs Surrebuttal at 6:6-11.

321 Ex. 429, NRC – Licensee Commercial-Grade Procurement and Dedication Programs (Generic Letter 91-05) at 3 (providing NRC definition of "like-for-like").

could not plan any Program work around a lay definition.[322] Put simply, Dr. Jacobs did not understand the long-standing meaning of "like-for-like" in nuclear industry terminology, thereby underscoring his lack of nuclear operational experience (he has not worked in a nuclear plant since approximately 1985 – 13 years before the first nuclear uprate was conducted in the United States.)[323]

In comparison, Mr. O'Connor explained in detail 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."[324] 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.[325] Similarly, replacement of the reactor feed pumps on a "like-for-like" basis would have been ill-advised. The original reactor feed pumps were a custom design of a 3-stage fire pump into a 2-stage reactor feed pump.[326] This customized design was the source of substantial maintenance issues during refueling outages; thus, it made sense to replace this original equipment with an improved design rather than on a "like-for-like" basis.[327]

In summary, the documents on which Dr. Jacobs premised his LCM/EPU split do not support attributing more costs to the EPU than to the LCM – let alone the attribution of 85 percent of Program costs to the EPU. While the Company disagrees that any LCM/EPU "split" of costs is necessary given the overall cost-effectiveness of

322 Tr. Vol. IV (Jacobs) at 78:9-17.

323 Tr. Vol. III (Jacobs) at 92:23-93:14.

324 Ex. 9, O'Connor Rebuttal at 117:4-12; *see*, Ex. 13, Stall Rebuttal at 24:24-15:11.

325 Ex. 9, O'Connor Rebuttal at 117:14-18.

326 Ex. 9, O'Connor Rebuttal at 109:23-24.

327 Ex. 9, O'Connor Rebuttal at 109:25-110:1.

the Program, the ALJ's adoption of Dr. Jacobs' outcome-focused analysis is not defensible under a complete review of the record.

IV. THE PARTIES' REMEDIES ARE UNWARRANTED

The Report provides a discussion of the parties' recommended remedies (Findings of Fact 107-123) and concludes that the Department's proposed cost-effectiveness remedy is "a balanced and fair approach designed to ensure that Xcel will have sufficient funds to operate the plant safely, but not be allowed more than the maximum amount of the EPU costs at which the EPU is cost-effective."[328] The ALJ then concludes that a disallowance of $71.42 million or a $10.237 million revenue requirement downward adjustment for 2015 is appropriate.[329]

A. Remedy Must be Supported

The Company appreciates the ALJ's effort to be fair and balanced and his recommended outcome is consistent with his conclusion that "[e]ither a total allowance or total disallowance would be unreasonable and unfair."[330] However, we are concerned that the disallowance he proposes is unsupported by this record. Certainly any disallowance greater than that recommended by the Department would be disproportionate and unfair.[331]

Any remedy imposed by the Commission must be supported on the record,[332] caused by the imprudence,[333] and proportionate.[334] The record supports findings that costs

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328 Report at Findings of Fact ¶ 124.

329 Report at Conclusions of Law ¶ 16.

330 Report at Conclusions of Law ¶ 15.

331 A substantial general disallowance of the type recommended by the OAG or blanket denial of a return on our investment recommended by XLI could send a signal to our investors that our nuclear programs do not have strong regulatory support in Minnesota. *See* Ex. 12, Sparby Rebuttal at 33:5-7.

332 *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").

increased because the work at Monticello was necessary to ensure both the long-term viability of the plant and position it for operating at uprate conditions.

We do not think that Minn. Stat. § 216B.03 or the *NSP* case[335] change this analysis. This legal authority stands for the proposition that the Company bears the burden of proving its rates are just and reasonable and doubts should be resolved in favor of ratepayers. The Company agrees but does not believe that these authorities were intended to set a burden that is impossible to meet. Rather, if the Company has established that its actions and decisions were prudent and the costs incurred were necessary then those costs were necessarily just and reasonable and recoverable.[336]

In addition, if the Commission disagrees with us, we believe the importance of Monticello and the impacts of disallowance caution against overcorrecting for concerns that the final costs were much higher than we predicted. Under these circumstances, in the event the Commission finds any imprudence it is critical to implement a remedy that is proportionate and reasonable without impairing a critical asset needed to serve customers.[337] An overly detrimental outcome would send the

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333 *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.").

334 *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.").

335 *Northern States Power Co. for Authority to Change its Schedule of Rates*, 416 N.W.2d 719, 723 (Minn. 1987).

336 The Commission's obligation in considering whether rates are just and reasonable is "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers." *In re Request of Interstate Power Co. for Auth. to Change Its Rates For Gas Serv.*, 574 N.W.2d 408, 411 (Minn. 1998).

337 The Company has already foregone or delayed recovery of millions of dollars and we face the risk that this number may increase based on recommendations pending in our 2013 rate case. The under recovery could range from $35 to $65 million or even more depending upon the outcome of the current rate case determination of the "used and useful" issue. Ex. 12, Sparby Rebuttal at Schedule 1 (Summary Monticello Annual Base Rate Recovery Compared to Annual Revenue Requirement Through 2014).

wrong signals to the financial markets, which could be harmful to all Xcel Energy stakeholders, including employees and customers particularly in light of the changes in the industry.[338]

B. Parties' Proposed Remedies

1. *Department's Cost-Effectiveness Remedy*

The remedy proposed by the Department and adopted by the ALJ is not supported by the record in this proceeding. This remedy applies hindsight by superimposing (a) 2013 actual costs ($748 million with AFUDC) and (b) Dr. Jacobs' 14.3/85.7 percent LCM/EPU split on 2008 assumptions. This approach is inconsistent with the prudent investment standard and disallows costs because they went up, not because of imprudence. Monticello remains "overwhelmingly cost-effective as a whole,"[339] and on that basis the cost-effectiveness remedy should result in no disallowance.

In addition, the Department's cost-effectiveness test is precisely the same "breakeven analysis" the Florida Public Service Commission rejected when Dr. Jacobs attempted to apply it to the Turkey Point and St. Lucie LCM/EPU projects.[340] The Florida Commission rejected this analysis "because there is no support regarding how, if at all, [Dr. Jacobs'] use of a breakeven analysis does not apply hindsight analysis and distinguishes between prudent and imprudent utility management actions."[341] Dr. Jacobs never explained how his analysis in this proceeding would not apply hindsight. The same fundamental flaws exist here, although they are not addressed in the Report.

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338 Ex. 12, Sparby Rebuttal at 33:3-7.

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

340 Tr. Vol. III (Jacobs) at 110:4-16.

341 Ex. 425, *Final Order Approving Nuclear Cost Recovery Amounts for Fla. Power & Light Co. and Duke Energy Fla., Inc.*, Fla. Pub. Serv. Comm'n No. 130009-EI at 36.

In recommending the Department's cost-effective analysis, the ALJ relies on a Commission decision in Xcel Energy's 2008 rate case that "it was necessary to accept the Department's proxy recommendation because 'setting rates that overcharge ratepayers,' in the absence of detailed information, '[was] not an acceptable alternative.'"[342] The "proxy remedies" approved by the Commission in that case were implemented because the disallowance had "a reasonable factual basis" in that the "work order on which it is based clearly misallocated costs" and "the Company acknowledged this and made three adjustments to the initial allocation."[343] Those factors do not exist here, and the Company offered alternatives in the event the Commission believes a remedy is needed. The Commission should again place this case and the remedy proposed into context. This is not a minor rate case dispute. If the Commission acts to impair the Monticello asset, there is no opportunity to correct this in a future case or to cut costs during the year to adjust to the disallowance. The investment has been made and the consequences of a disallowance are both significant and permanent in attributing harm other than through a proxy remedy. A proxy is not the most appropriate remedy when evaluating the Company's prudence.

2. *XLI's Denial of Return Remedy Disproportionate*

XLI proposed a proxy remedy based on the conclusion that because costs went up, all of those costs should not earn a return on the investment. XLI proposes that the Company be denied any return on the $402.1 million costs over the Company's initial Certificate of Need estimate.[344] Denying a return on this amount results in a $25.796

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[342] Report at 36 (quoting *In the Matter of the Application of N. States Power Co. d/b/a Xcel Energy for Auth. To Increase Rates for Elec. Serv. in Minn.*, PUC Docket No. E002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 21 (Oct. 23, 2009)).

[343] *In the Matter of the Application of N. States Power Co. d/b/a Xcel Energy for Auth. To Increase Rates for Elec. Serv. in Minn.*, PUC Docket No. E002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 21 (Oct. 23, 2009).

[344] Report at Findings of Fact ¶ 117.

million revenue requirement reduction (Minnesota Jurisdictional basis) beginning in 2015. This revenue requirement reduction is roughly 250 percent greater than that proposed by the Department and recommended by the ALJ, and would likely translate into a capital cost disallowance of approximately $200 million. Such an extreme remedy would be unduly detrimental and is unsupported by the record or applicable law.

This recommendation assumes it is appropriate to limit recovery for any costs in excess of those estimated in the 2008 EPU Certificate of Need. But no party suggests that the Company's Certificate of Need cost estimate was intended to be exact, as the Company has always been clear that it was an early, high level estimate. Further, while parties can and do debate the Company's actions, no party suggests that 100 percent of the conditions found in a nuclear construction project of this size, on a 40-year old plant, could have been predicted.

In addition, capping costs at the Certificate of Need-level information fundamentally shifts the regulatory framework that has guided traditional prudence review under the prudent investment standard.[345] While the Company recognizes that there has been considerable debate in recent years over the quality of cost estimates at the Certificate of Need stage, that debate substantially post-dates the 2008 EPU Certificate of Need proceeding and there was no discussion in that record about whether our costs should be capped.[346] Alternatively, imposing a form of a cost cap here would be a retroactive action and overly punitive, in addition to being inconsistent with the standard

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[345] Ex. 12, Sparby Rebuttal at 12:21-24.

[346] At the Certificate of Need stage at the time, 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." Ex. 15, Alders Surrebuttal at 17:8-13 (quoting *In the Matter of the Application of N. States Power Co. d/b/a Xcel Energy for Certificates of Need for Four Large High Voltage Transmission Projects in Sw. Minn.*, No. E002/CN-01-1958, REPLY TO XCEL ENERGY'S MOTION TO LIMIT THE SCOPE OF EVIDENCE OF THE MINNESOTA DEPARTMENT OF COMMERCE at 4 (Apr. 25, 2002)).

regulatory practice at the time we developed our Certificate of Need estimate. Cost disallowances of this type are not supported by Minnesota law.[347]

Finally, as the ALJ concluded, a $25.796 million revenue requirement adjustment would be inconsistent with the principle of crafting a fair and balanced remedy that ensures the Company has sufficient revenue to continue operating the plant safely.[348]

3. OAG's Remedy Unreasonable

The OAG suggested denying 75 percent or $321 million of all costs over the initial Certificate of Need estimate and denying any return on any amount authorized in excess of that estimate ($107.1 million). The Department provided a rough estimate that the OAG's recommendation amounts to approximately a downward revenue requirement adjustment of $58 million for 2015.[349] This remedy is more than 500 percent higher than the Department's proposed remedy and is confiscatory.

The OAG urges a similar effective cost cap with an even more detrimental outcome. There is no record support that the Program could have ultimately been built for $320 million. Further, there is no record support that we could have avoided all of the substantial costs simply by avoiding the uprate. It is not sufficient to assume imprudence and assess an arbitrary percentage penalty.[350] This proposed remedy also is infected with hindsight because it disregards the reasons Program costs increased and focuses on assumptions that higher costs must be wrongful. The OAG's

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347 "Indeed, the Public Utility Act expressly prohibits retroactive ratemaking." *Peoples Natural Gas Co. v. Minn. Pub. Utils. Comm'n*, 369 N.W.2d 530, 533 (Minn. 1985) (citing Minn. Stat. § 216B.23, subd. 1 (1984)); *see* Minn. Stat. § 216B.23, subd. 1 (2014) ("Whenever upon an investigation . . . the commission shall find rates, tolls, charges, schedules or joint rates to be . . . unreasonable or unlawful, the commission shall determine and by order fix reasonable rates, tolls, charges, schedules, or joint rates to be imposed, observed, and followed *in the future*.") (emphasis added)).

348 Report at Findings of Fact ¶ 124.

349 Ex. 315, Campbell Surrebuttal at 37:7-12.

350 Ex. 15, Alders Surrebuttal at 24:16-17.

approach could not withstand scrutiny, and the OAG's outcome is disproportionate to any findings of ratepayer harm.

Finally, the OAG's rough-cut remedy ignores that our experience was fully consistent with the evolution of the nuclear industry, and that other regulatory commissions allowed 100 percent recovery of significant cost increases in light of circumstances presently facing major nuclear projects.[351] Under these conditions, which the Company not only faced during the Program but also will continue to face going forward, a general disallowance of this magnitude would signal the investment community that our nuclear programs do not have strong regulatory support in Minnesota.[352] We urge rejection of this outcome.

C. Alternative Considerations

The Company respectfully submits that our performance, while not perfect, involved concrete assessments, decisions, and actions each step of the way to prudently manage a very challenging project. As a result, we have not proposed a specific remedy. However, we provide additional discussion here on alternatives in the event the Commission chooses to craft a remedy that is consistent with the prudent investment standard.

First, in our Reply Brief we provided a Table identifying categories of specific additional costs that the OAG identified as being suspect. We reproduce that here:

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[351] Tr. Vol. III (Jacobs) at 105:2-5; *see* Ex. 12, Sparby Rebuttal at 33:10-13.

[352] Ex. 12, Sparby Rebuttal at 33:5-7.

Potential Avoidable Costs

Cost	Description	Potential Additional Costs	OAG Proposed Imprudence Disallowance
Potentially Duplicative Designs	Reasonably moved work to alternative designer to keep work on track and maximize skill and that about $13 million of that was overlapping other vendors' scope.[353]	$13 million	$6.5 million
Abandoned Work	The Company identified work totaling about $11 million was not fit for the intended purpose for various reasons.[354]	$11 million	$5.5 million
Field Change Orders	Field changes of about $25-30 million were unavoidable and mostly could not have been found ahead of time[355]	$1 million	$7.5 million
Total		**$25 million**	**$19.5 million**

While we believe these costs are justified on this record, we acknowledge that a disallowance of $25 million could be crafted if the Commission takes a different view. Further, if the Commission were to find that all of the field change orders were imprudent (a conclusion with which the Company does not agree), a total disallowance of around $50-55 million could be justified.

The ALJ appears to have found the Company's use of contractors wanting and seems to have concluded that the existence of contractor difficulties is a sign of vicarious mismanagement on our part.[356] The Company disagrees because, as noted earlier in these Exceptions, vendor disputes are unavoidable in a major construction project, particularly in the highly complex, safety-conscious nuclear industry at a time when

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353 Ex. 9, O'Connor Rebuttal at 79:7-16, 79:18 at Table 9; Ex. 10, O'Connor Rebuttal at Schedule 28 at 3-5 (Non-Public) (Company Response to OAG IR 6 identifying approximate amounts paid to contractors for scoping and design costs).

354 Ex. 9, O'Connor Rebuttal at 80:17-26 and Schedule 29 (Company Response to OAG IR 48 identifying abandoned work).

355 Ex. 9, O'Connor Rebuttal at 75:7-77:15, 77:17 at Table 8 and Schedule 27 (Company Response to Department IR 28 identifying required field design changes).

356 Report at Findings of Fact ¶ 80. This is another finding where it is unclear whether the ALJ is adopting the Department's position or merely stating that it is the position of the Department.

skilled craft labor was at a premium. In addition, replacing a vendor who fails to perform is not merely acceptable, but prudent and necessary.

Nevertheless, we recognize that the existence of vendor claims results in some uncertainty. The disputes, the amounts in issue, and a description of the pending and settled claims are identified in our response to OAG IR-5.[357] That information has been marked "Trade Secret," but leads to development of the range provided.[358]

Overall, we submit that no remedy is warranted. If the Commission disagrees, any applied remedy should not derive from a non-specific proxy that involves hindsight, caps or modified caps based on early estimates, but rather should be fashioned in a manner that is consistent with the record evidence, the prudent investment standard, and with the balancing of interests necessary to arrive at a just and reasonable rate.

V. CONCLUSION

The Company respectfully recommends that the Commission adopt the Report with the changes described above and in Attachment A to these Exceptions.

[357] Ex. 203, Schedule JJL-2.

[358] Previously, we preserved, pursued and resolved claims recognizing that any value received should be an offset to the cost of the Program. Claims that have already been settled have been accounted in this way. We are willing to treat future claims and settlements in the same way or have them be removed from this case for the Company to pursue independently.

Dated: February 12, 2015

Respectfully submitted,

By */s/Alison C. Archer*

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

1. Xcel's handling of the Monticello LCM/EPU Project was ~~not~~ prudent.

2. The Company's request for recovery of all Monticello LCM/EPU Project costs ~~overruns~~ is ~~not~~ reasonable.

3. All costs incurred by the Company were in furtherance of the LCM/EPU Project which was a single, integrated project. While a split between LCM and EPU costs had value in the 2008 Certificate of Need proceeding to determine whether to proceed with the EPU and in prior rate cases for the purposes of a "used and useful" determination, this allocation is irrelevant in a prudence investigation. If the Commission finds it necessary to allocate costs between LCM and EPU to determine the prudence of the Company's decision to proceed with the LCM/EPU Project in 2008 or for purposes of making a "used and useful" determination, c~~C~~osts should be allocated between the LCM and EPU portions of the Project in a ratio of 58.4 percent to 41.6 percent, respectively, that was used in the 2008 Certificate of Need proceeding. This is the only split developed contemporaneously with the decision to proceed with the LCM/EPU Project and does not require hindsight analysis.

4. The record does not support a finding of imprudence in the Company's decisions and actions in the implementation of the LCM/EPU Project and does not support a disallowance. ~~The Department's preferred disallowance remedy should be adopted, as follows. The Commission should disallow $71.42 million on a Minnesota jurisdictional basis with related Allowance for funds Used During Construction (AFUDC) costs, which reflects the portion of the Monticello EPU overrun that was not cost effective, as calculated by the Department, for a resulting revenue requirement adjustment of $10.237 million for 2015 on a Minnesota jurisdictional basis and ongoing over the remaining life of the plant, stepped down each year due to accumulated depreciation.[1]~~

FINDINGS OF FACT

Factual and Procedural Background

3. Between 1994 and 2003, Minnesota law effectively prohibited ~~made it very difficult to~~ extending a nuclear power plant's operating license due to State statutory restrictions against reliance on on-site storage of spent nuclear fuel.[2] Xcel had a policy of deferring capital projects, expecting that the Plant would be shut down and decommissioned in 2010.[3] Monticello's net plant in rate base had depreciated to $153 million by 2007, thus limiting the amount that could be earned on the ~~a potentially risky nuclear~~ plant.[4]

7. In 2006 Xcel decided to combine its LCM program for the life extension of the Plant with an effort to seek an EPU to add 71 MW of capacity.[5] Xcel's Prudence Report describes the Company's LCM/EPU Project implementation approach~~the reason for the decision~~ as follows:

~~[1] At the close of the record, Xcel had not received its operating license for EPU. Adjustments may be necessary when that occurs.~~

[2] Ex. 305 at 3 (Jacobs Direct); Ex. 2 at 14:2-4 (Alders Direct).

[3] *Id.*

[4] Ex. 305 at 4 (Jacobs Direct).

[5] ~~Initial Filing – Prudence Report at 6 (October 18, 2013) (eDocket No. 201310-92719-02)~~ Ex. 1 at 6 (Prudence

> We chose to multi-track the initiative to meet the Company's forecast need for additional baseload capacity. Thus, we proceeded with the licensing, design, engineering and implementation project phases concurrently. This approach, while accepting some risk, was beneficial to our customers' interest in that we expected to provide the benefits of the LCM/EPU [Project] as soon as possible.[6]

7a. In 2006, in Xcel Energy's 2004 Resource Plan docket, the Commission concluded that "[s]ince the need to keep the lights on ultimately trumps other interests, delays along the way favor unilateral action by Xcel . . . must step in and build, buy, or otherwise secure the generating capacity required to fulfill its duty to serve."[7] As a result, the Commission directed the Company to file Certificate of Need applications for a total of 375 MW, including the 71 MW EPU at Monticello, to meet the critical need for baseload capacity by 2015.[8]

9. In order to perform an EPU, Xcel also had to get regulatory approval from the NRC in the form of a license amendment. Xcel filed a license amendment request for the EPU with the NRC on March 31, 2008 but withdrew that submission based on NRC staff concerns about whether the submission satisfied the NRC's completeness review because of new Advisory Committee on Reactor Safeguards request for increased scrutiny for steam dryer structural analysis.[9] Department witness Mr. Crisp claimed that the reason for withdrawal was because Xcel Energy included a "statement that contradicted the statements" made by Xcel Energy in the license extension application for Monticello filed in 2005 with the NRC because the 2007 license extension did not mention the EPU.~~Action on the license amendment request was delayed because the Company had given the NRC incomplete information about its plans for the Monticello Plant~~.[10] ~~Xcel was unable to file an updated request until November 5, 2008.~~ Mr. O'Connor explained that the statement Mr. Crisp believed was contradictory, in fact, was not because the NRC only processes one application at a time, the Company did not have internal authorization to proceed with the EPU at the time of the license extension, and any mention of an EPU in the license extension would have been inconsistent with the status of the Company's evaluations at that time.[11] Xcel Energy resubmitted its uprate license amendment request to the NRC on November ~~8, 2006~~5, 2008.[12] After this ~~delayed~~ filing, the NRC staff concluded the application met the completeness requirements and NRC staff began its review of the license amendment request.[13] Xcel did not receive approval for the NRC EPU license until December, 2013.[14]

13. In November 2011, as part of its 2010 rate case, the Company entered into a Stipulation and Settlement committing to undergo this prudence review and to forego recovery of the

Report).

6 *Id.* The term "multi-track" refers to the Company's approach to its implementation of the LCM/EPU Project and not the Company's decision to combine the LCM and EPU work into a single initiative.

7 *In the Matter of N. States Power Co. d/b/a Xcel Energy's Application for Approval of its 2005-2008 Res. Plan*, PUC Docket 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).

8 *Id.;* Ex. 2 at 18:20-21 (Alders Direct).

9 Ex. 3 at 52:25-26, 53:2-4, and Schedule 17 at 1 (O'Connor Direct).

10 Ex. 300 at 13 (Crisp Direct).

11 Ex. 9 at 21:1-9 (O'Connor Rebuttal).

12 Ex. 3 at 51:24-25, 52:25-26, 53:2-7 and Schedule 17 at 1 (O'Connor Direct); Ex. 300, MWC-~~2~~3 at 1 (Crisp Direct).

13 Ex. 3 at 53:7-10 (O'Connor Direct).

14 Ex. 305 at 6 (Jacobs Direct).

NRC licensing costs for that rate case.[15] In its 2012 rate case, Xcel requested full recovery of the LCM/EPU Project costs.[16] On September 2, 2013, the Minnesota Public Utilities Commission issued its Findings of Fact, Conclusions, and Order in Xcel's 2012 rate case.[17] In that Order, the Commission determined that only the LCM was in service and that the EPU was not yet used and useful because the additional 71 MW were not operating.[18]

Initial Planning for the EPU (2006-2007)

28. In ~~light of~~ developing the initial estimate for the Program, Xcel~~'s~~ evaluated similar programs at other nuclear facilities that they referred to as "benchmarks~~,~~" ~~the 10 percent contingency was extremely small~~.[19] The plants that had just been completed had cost overruns of 33 percent and 35 percent.[20] The most comparably sized plant completed four years earlier had a cost overrun of 22 percent.[21] Xcel's LCM\EPU Project was projected to be completed in 2011, five years away. Additionally, Monticello had a smaller footprint than some of the plants that were benchmarked.[22] In light of that information, Xcel Energy developed an initial estimate 75 percent higher than the most expensive program it had been able to benchmark.[23] ~~A straight line projection of the benchmarks' historical overrun rates would take the rate to 50 percent in five years.~~[~~24~~] That estimate included about 10 percent for contingency.[25]

EPU Certificate of Need (2008-2009)

39. The OAG argued that: "When Xcel filed the CON for the Monticello EPU, the Company outlined all of the major modifications it believed would be necessary to finish the Project.[26] In that filing, Xcel told the Commission that it had '~~"~~comprehensively evaluated the effects of the extended power uprate at Monticello,'~~"~~[27] and that only '~~"~~smaller scope modifications [would] be identified during the detailed engineering phase of the project.'[28]"~~[25]~~[29] The two quotes cited by OAG are from two, non-sequential pages of the uprate Certificate of Need application.[30] The comprehensive

[15] *In the Matter of the Application of N. States Power Co. for Auth. To Increase Rates for Elec. Serv. in the State of Minn.*, PUC Docket No. E002/GR-10-971, STIPULATION AND SETTLEMENT AGREEMENT at 3-4 and 7 (Nov. 14, 2011).

[16] *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, PUC Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 17–22 (Sept. 3, 2013).

[17] *the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, PUC Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46 (Sept. 3, 2013).

[18] *Id.*

[19] Ex. 3 at 24:2-10 (O'Connor Direct); Ex. 9 at 37:9-18, 38:4 and Table 3, 39:9-25 (O'Connor Rebuttal); *see also* Ex. 3 at 54:19-20 (O'Connor Direct).

[20] Ex. 9 at 38:4 and Table 3, 39:2-5 (O'Connor Rebuttal).

[21] *Id.*

[22] Ex. 9 at 39:13-17 (O'Connor Rebuttal).

[23] *Id.*; Ex. 17 at 8:11-16 (O'Connor Surrebuttal).

~~[24] Average of 34 percent – 22 percent = 12 percent increase over 4 years = 3 percent per year. 34 percent + 15 percent over 5 years = 50 percent.~~

[25] Ex. 9 at 40:1-10 and Schedule 13 at 2 (O'Connor Rebuttal) ("$15.431 million plus $7 million in 2006 dollars for two different contingencies" in the initial estimate).

[26] *In the Matter of the Application of N. States Power Co. for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate*, PUC Docket No. E-002/CN-08-185, APPLICATION at 3-16 (Feb. 14, 2008).

[27] *Id.*

[28] *Id.*

[29] OAG Br. at 26.

[30] *In the Matter of the Application of N. States Power Co. for a Certificate of Need for the Monticello Nuclear*

evaluation done at Monticello refers to the evaluation by General Electric to ensure that the Plant could handle a power uprate and that the NRC would be able to conclude that "sufficient safety and design margins exist" to support the uprate.[31] This statement does not mean that the design of modifications for the LCM/EPU Project was complete or nearly complete.[32] The reference in the application to "smaller scope" modifications does not take into account that the Company's application also stated that "the balance-of-plant systems that convert the steam produced in the reactor to electricity however will need significant modifications."[33] The Company identified these "significant modifications" with some detail in paragraphs A-J on pages 3-16 to 3-19 of the application but noted that the design was not complete.[34]

42. Department witness Mr. Crisp testified in his surrebuttal testimony that a ~~If Xcel had included a reasonable contingency factor, the total estimated LCM/EPU cost would have been at least $665 million (excluding AFUDC), calculated as follows. A~~ reasonable contingency factor as indicated by industry standards and the degree of due diligence Xcel had done to that time would have been 100 percent.[35] Applying 100 percent to Xcel's number of $346 million results in a total of $692 million. However, Mr. Crisp testified that the document he relied upon to support his 100 percent contingency does not state it applies to nuclear projects.[36] Second, the document does not recommend a contingency but rather discusses the ranges of accuracy for cost estimates after contingency, based on this level of design.[37]

43. ~~Because 665million is greater than the Department-calculated breakeven point of $485M, the EPU would not have been cost effective compared to the alternatives modeled in the 2008 EPU CON proceeding.[38] Therefore, the Department would not have recommended approval of the CON in that proceeding if a reasonable contingency factor had been included.[39]~~ Even if the Company had applied a 100 percent contingency to the 2008 LCM/EPU Project cost estimate, making the total initial estimate $692 million, the Department has testified that the Project would have still been

Generating Plant Extended Power Uprate, PUC Docket No. E002/CN-08-185, Application at 3-13 ("NMC, in conjunction with the designer of Monticello, GE, has comprehensively evaluated the effects of the extended power uprate at the Monticello. Based on NRC action at similar plants, it is expected that the NRC evaluation will conclude that sufficient safety and design margins exist such that the rated core thermal power can be increased from 1775 to 2004 megawatts") and 3-16 ("The major modifications and a short description of the work to be completed on each during the two refueling outages are listed below. Additional smaller scope modifications will be identified during the detailed engineering phase of the project.) (Feb. 14, 2008).

31 *Id.* at 3-13 and 3-14.

32 Xcel Reply Br. at 30.

33 *In the Matter of the Application of N. States Power Co. for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate*, PUC Docket No. E002/CN-08-185, APPLICATION at 3-15 (Feb. 14, 2008).

34 *Id.* at 3-16 to 3-19.

35 Ex. 303 at 23-24 (Crisp Surrebuttal); Evidentiary Hr'g Tr. Vol. 3 at 73 (Crisp).

36 Evidentiary Hr'g Tr. Vol 3 at 46:19-22 (Crisp).

37 Ex. 303 at Schedule 1 (Crisp Surrebuttal).

~~38 Ex. 309 at 32 (Shaw Direct); Ex. 311 at 5 (Shaw Surrebuttal).~~

~~39 Ex. 309 at 32 (Shaw Direct); Ex. 435 at 1-2 (Shaw Opening Statement). Mr. Shaw testified that the Commission did not order Xcel in 2006 (for the 2004 resource plan) to pursue an EPU, and that the 2008 CON modeling used assumptions in Xcel's 2007 resource plan, not the 2004 resource plan. Ex. 311 at 15-17 (Shaw Surrebuttal). Mr. Shaw also testified that the 2008 CON modeling focused entirely on the incremental value of the EPU, not the LCM and EPU together. Id.~~

overwhelmingly cost-effective if less than 73 percent of the Project costs were attributed to EPU.[40] There is no reason to believe that any party would attribute more to the EPU than the LCM based on the information known about the LCM/EPU Project in 2008, when the Commission evaluated whether the Company should proceed with implementation, because the LCM/EPU Project was considered LCM-driven at all times.[41]

Activity Before and During the 2011 Outage

52. The Department's criticisms of the LCM/EPU Project relied heavily on the EPU Cost History document.[42] In 2011, the Company's then-Chief Nuclear Officer Dennis Koehl requested that an internal document be prepared to provide input on the Project structure and opinions on the best way to proceed to completion of the installation.[43] The resulting EPU Cost History document was one employee's critical review of the LCM/EPU Project to date~~indicated that problems began as early as the Board's initial decision to begin the project~~.[44] The EPU Cost History ~~indicated that~~ memo criticized the Company's initial cost estimate because the author believed it "had high uncertainty since little engineering was done on the design concepts suggested," and claimed that the "EPU project team position was that each project should have a more detailed review to define final scope and cost."[45] Instead, the Board approved the Nuclear Projects Team's recommendation for a two year earlier start with a cost estimate $90 million below the EPU Project team's cost estimate.[46] The estimate in the 2011 Cost History document is somewhat higher than the estimate used in the 2008 Certificate of Need docket but would not have changed the cost-effectiveness of the overall LCM/EPU Project as discerned in 2008.[47]

53. The EPU Cost History document author felt ~~also indicated~~ that the LCM/EPU Project T~~t~~eam had little input in scoping the Project and no ability to ensure that the scope included any detailed engineering.[48] The author also believed that during the LCM/EPU Project there was ~~When the Project Team did provide input, they were ignored; this led to~~ "the need for the site to create many modifications around the base scope in the GE contract."[49] He also stated that ~~In order to work around the GE contract,~~ the Company ~~had to~~ added "significant design engineering and project management resources beyond original project staffing~~.~~" because "additional scope could be completed more cost effectively" by the Company than using General Electric.[50] Although the author intended this as a critique, this is actually an example of how the Company used existing resources at the site to ensure the LCM/EPU Project could be safely implemented by making use of the on-site expertise of the engineers and resources

[40] Ex. 309 at 14:1-2 (Shaw Direct).
[41] Ex. 3, O'Connor Direct at 93:1-136:11 and Schedules 29, 30; Ex. 9, O'Connor Rebuttal at 81:1-123:18 and Schedule 32.
[42] Ex. 300 at 15-31 (Crisp Direct).
[43] Ex. 300 at 24 (Crisp Direct); Evidentiary Hr'g Tr. Vol. 3 at 65–66 (Crisp). Mr. Koehl and the employee who prepared the EPU Cost History did not provide testimony in this case.
[44] Ex. 300, M~~CW~~WC-~~2~~3 at 3 (Crisp Direct); see also Ex. 302, MWC-3 (Crisp Direct) (trade secret EPU Cost History). The ALJ Report mistakenly cites to this exhibit as "MWC-2". The EPU Cost History is referred to in Mr. Crisp's testimony as "MWC-3" as MWC-2 is a different document. *See* Ex. 300 at 34:2-5 (Crisp Direct).
[45] Ex. 300, M~~CW~~WC-~~2~~3 at 3 (Crisp Direct).
[46] *Id.*
[47] Ex. 9 at 45:1-3 (O'Connor Rebuttal).
[48] Ex. 300, M~~CW~~WC-~~2~~3 at 3 (Crisp Direct).
[49] *Id.*
[50] Ex. 300, M~~CW~~WC-~~2~~3 at 3-4 (Crisp Direct).

familiar with the fire protection, logic, and structural systems that would need modification for implementation to proceed.[51] Further, additional design resources that were deployed when the Company identified design issues with vendors only cost approximately $13 million, a small portion of overall costs.[52]

53a. To fully understand some of the criticisms of the EPU Cost History document, it is important to understand the organization of the Nuclear capital projects group and the resources deployed for the LCM/EPU Project.[53] For projects with a larger scope and complexity than those normally handled by on-site resources, the Company relies on the Nuclear Projects Team to provide leadership in obtaining and deploying the requisite additional resources.[54] For the LCM/EPU Project, there were a couple key teams that reported up to the Company's Nuclear Projects Team leadership: 1) the Monticello on-site projects team that had primary responsibilities to ensure safe and reliable ongoing operations and maintenance at Monticello and provide some expertise to support the 2) LCM/EPU Projects Team with primary responsibilities for design, engineering, procurement, implementation, licensing, and management of the LCM/EPU Project.[55] While the LCM/EPU Project Team reported to the core Nuclear Projects Team, it was not the group responsible for final recommendations to the Board of Directors.[56] Ultimately, the EPU Cost History document author was critical of the Company's decision to have the LCM/EPU Project Team and not the site team responsible for lead implementation of the Program.[57] The Company does not believe that had the site managed the LCM/EPU Project it would have been more cost-effective than the Projects Group.[58] Employees at Monticello, on site, were responsible and engaged in performing their normal duties to ensure the safe and reliable operation of Monticello.[59] This dedication of employee resources led to the decision to develop an LCM/EPU Project Team reporting to the Nuclear Projects Team, responsible for the LCM/EPU Project to allow the site to focus, primarily, on the continued operation of Monticello.[60]

54. The EPU Cost History document author expressed several criticisms of the LCM/EPU Project:

- The EPU Cost History document author also ~~indicated~~ felt that there "was very limited capability for the [LCM/EPU P]roject [T]~~t~~eam ~~was also unable~~ to ~~"~~obtain a scope change decision~~s~~ that balanced scope and cost."[61] The author believed that "[r]eviews during Site Steering Committee and design review meetings often led to increased scope."[62] Mr. O'Connor supported that while changes to the scope for the LCM/EPU Project were

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[51] Ex. 9 at Schedule 23 (O'Connor Rebuttal); Ex. 300, MWC-3 at 304 (Crisp Direct).
[52] Ex. 9 at 79:7-16 and 79:18 at Table 9 (O'Connor Rebuttal); Ex. 10 at Schedule 28 at 3-5 (O'Connor Rebuttal, Non-Public).
[53] Ex. 9 at Schedule 23 (O'Connor Rebuttal).
[54] Ex. 9 at Schedule 23 at 2 (O'Connor Rebuttal).
[55] Ex. 9 at Schedule 23 at 3-6 (O'Connor Rebuttal).
[56] *See* Ex. 9 at 64:4-12 (O'Connor Rebuttal).
[57] Ex. 300, MWC-3 (Crisp Direct).
[58] Ex. 9 at Schedule 24 at 20 (O'Connor Rebuttal).
[59] *Id.*
[60] *Id.*
[61] ~~*Id.*~~ Ex. 300, MWC-3 at 4 (Crisp Direct).
[62] *Id.*

both necessary and appropriate for the continued and safe operation of Monticello.[63] This was consistent with the Company's approach to iterative design evaluations used throughout the LCM/EPU Project.[64] The Site Steering Review Committee was tasked with approval of recommendations for scope changes and worked with the LCM/EPU Project Team to ensure that changes proposed would be properly designed and that a condition assessment of existing equipment was completed.[65]

- According to the author t~~T~~he most significant scope changes "did not appear to be approved by management in any detail."[66] This is contrary to the detailed design process for each Project modification that ensured modifications were designed safely and all levels of engineering and management were included in the development and analysis of those designs.[67]
- ~~When the scope had to be changed, it was done without~~The author also wrote that "[c]hanges to scope with an appropriate consideration of cost were challenged by [sic] 'fast track' schedule." ~~because of the fast-track schedule.~~[68] The author felt that the "expected cost impact was not reviewed by appropriate management," even when the costs were large.[69] He also felt that the "large cost changes [associated with the reactor feed pump replacement that led to the electrical distribution upgrade] did not appear to be approved by management in any detail." However, the record reflects that the Site Steering Committee reviewed all scope changes and, in some instances where equipment was proposed to be replaced but found in good working order, proposed scope changes were not accepted.[70] ~~When management did give approval to increase the scope of the Project, it was done "without the cost impact of the changes being known."[71] Those approvals ended up being very expensive, because "schedule restraints forced parallel work and required significant cost commitments to be made to achieve goals."[72] Because projects did not have separate cost tracking, it was difficult for regulators to determine whether the Company acted prudently.[73]~~
- The author felt that "[n]ot having a budget by project resulted in ~~Company's review process was "insufficient to allow early identification of cost issues," and this resulted in "~~a challenge to project managers to be able to control and forecast cost."[74] Projects were, however, given their own work orders according to the systems and areas of the Plant that were being worked on during the LCM/EPU Project.[75] This is consistent with FERC accounting requirements.[76]

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[63] Ex. 9 at Schedule 24 at 15 (O'Connor Rebuttal).
[64] *Id.*; Ex. 9 at Schedule 22 (O'Connor Rebuttal).
[65] Ex. 9 at Schedule 24 at 15 (O'Connor Rebuttal).
[66] ~~*Id.*~~Ex. 300 at MWC-3 at 4 (Crisp Direct).
[67] Ex. 9 at Schedule 22 and Schedule 24 at 15 (O'Connor Rebuttal).
[68] ~~*Id.*~~Ex. 300 at MWC-3 at 4 (Crisp Direct).
[69] Ex. 300, M~~CW~~WC-~~2~~3 at 5 (Crisp Direct).
[70] Ex. 9 at Schedule 24 at 18 (O'Connor Rebuttal).
~~[71] *Id.*~~
~~[72] *Id.*~~
~~[73] *Id.*~~
[74] ~~*Id.*~~Ex. 300, MWC-3 at 5 (Crisp Direct).
[75] *See* Ex. 3 at Schedule 7 (O'Connor Direct) (list of all modification child work orders under the LCM/EPU Project parent work order.) Establishing this methodology allowed for common costs such as additional site security or temporary restroom facilities, that were not specific to one modification, to be accounted for and then allocated to

55. The EPU Cost History document was written by a ~~Project team member with a great deal of knowledge of the LCM/EPU Project. He was a~~ long-time employee in the Nuclear Department of Monticello and a member of the LCM/EPU Project T~~t~~eam throughout.[77] ~~He accurately described the sources of the escalating costs and tied them largely to early failures of high level management. According to Xcel, t~~The employee was not personally aware of what information was presented by its "Nuclear Projects Team" leadership to the Board of Directors,[78] and did not know that the "Nuclear Projects Team" leadership also consulted with other business units within the Company before making its recommendation.[79] Xcel ~~did not~~ explained that before making its recommendation to the Board of Directors, the Nuclear Projects Team leadership considered the information presented in the General Electric Scoping Assessment and by the LCM/EPU Project Team that they reasonably believed the work could be accomplished in the 2009 and 2011 outages.[80] The Nuclear Projects Team leadership also gathered information from the Resource Planning and Regulatory business units on the Company's resource needs.[81] Based on this information, the Nuclear Projects Team leadership presented a $274 million budget for implementation during the 2009 and 2011 refueling outages to the Board of Directors for its consideration and approval.[82] ~~what information was discussed with the Board or other business units or how such information might be relevant to the delays and cost overruns or to getting the Project completed. The EPU Cost History is a well-informed and believable description of Xcel's management of the Project.~~

NRC License Amendment Process 2008-2013

71. Department expert, Mr. Crisp, testified that Xcel should have been aware that moving in an expedited manner without full NRC approvals was likely to generate delays and cost increases.[83] But at hearing, Mr. Crisp agreed that the Company's multi-track approach did not "in and of itself" increase the LCM/EPU Project costs.[84]

Department's Criticisms of Xcel's Management of the LCM/EPU Project.

74. The Department claims that Xcel did not take these steps to ensure that costs would be controlled. Instead, according to the Department, Xcel began the Project on the basis of a "preliminary level of detail" that "failed to capture the true costs necessary to implement the overall [Project]."[85] According to Mr. Crisp, Xcel's decision to proceed without a fully defined scope for the Project "almost guarantee[d] schedule delays and cost overruns during the actual process of constructing the Project."[86] Mr. Crisp's testimony does not address Mr. O'Connor's testimony that had the Company developed a fully defined scope for the Project before proceeding, implementation of the LCM/EPU Project would have still required three outages and final implementation would have been

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child work orders after outages on a pro-rata basis according to the expenses that had been incurred for that modification for that outage. Ex. 5 at 8:17-10:16 (Weatherby Direct).

[76] Ex. 5 at 8:12-24 (Weatherby Direct).

[77] Ex. 9, Schedule 24 a 2 (O'Connor Rebuttal).

[78] Ex. 9 at 64, Schedule 24 at 4 (O'Connor Rebuttal).

[79] Ex. 9 at 49 (O'Connor Rebuttal).

[80] Ex. 9 at 64:16-13 and Schedule 24 at 13-14 (O'Connor Rebuttal).

[81] Ex. 9 at 49:15-21 (O'Connor Rebuttal).

[82] Ex. 9 at 64:16-13 and Schedule 24 at 13-14 (O'Connor Rebuttal).

[83] Ex. 303 at 18-19 (Crisp Surrebuttal).

[84] Evidentiary Hr'g Tr. Vol. 3 at 17:16-19 (Crisp).

[85] Ex. 3 at 30 (O'Connor Direct).

[86] Ex. 300 at 8 (Crisp Direct).

delayed until 2017, two years after the time when the baseload need had been identified and seven years into the 20-year license extension for the Plant.[87] Mr. O'Connor further testified that had the Company developed a fully developed scope as recommended by Mr. Crisp, it was unlikely that implementation of the LCM/EPU Program would have cost any less than it did.[88] As such, Mr. Crisp's criticism does not weigh the impacts of the alternative approaches.

75. The as-built drawings of the Monticello plant that were used to perform the design work were not up to date and therefore "did not completely match the actual as-found conditions."[89] Mr. Stall testified that "[w]ith a 40-year old plant it is unsurprising that the as-built drawings did not completely match the actual as found conditions."[90] In "many instances" field design changes were required as a result of these discrepancies between the as-built drawings and actual conditions.[91] But designing upgrades for an operating nuclear plant is necessarily an iterative process.[92] It is generally expected that significant field design work is necessary to adjust to as-found conditions.[93]

76. Mr. Crisp also noted Xcel's failure to anticipate the "very small footprint" of the existing Plant and the resulting difficulties that the small space created for dismantling and removing existing equipment as well as for installing the new larger equipment such as the feedwater heater.[94] Mr. Crisp testified that "Xcel knew the dimensions of the containment "room" for the feedwater heater. However, Xcel's estimated cost of installing the new, much larger feedwater heater did not take into account the significant difficulty in removing the former feedwater heater, modifying the size of the then-existing concrete "room" and installing the new, larger feedwater heater."[95] In response to Mr. Crisp's conclusions, the Company clarified that the new 13A/B feedwater heaters, which were located under the turbine floor, not in a "room", were not "much larger" but were, instead, the same length as the old ones and less than five inches wider than the old ones.[96]

77. Xcel knew that Monticello had a small footprint and knew about the layout of Monticello. Mr. Crisp concluded: "Taking that knowledge into account with proper scoping of the equipment needed and logistics of installing the equipment would have anticipated many of the difficulties Xcel has pointed to as causing the cost overruns."[97]

78. In addition, Mr. Crisp identified several other decisions and actions indicating poor project management by Xcel that were not reasonable at the time, based on what Xcel knew or should have known. Mr. Crisp claimed that t~~T~~hese decisions likely resulted in costs being higher than they would have been if reasonable decisions and actions had occurred.[98] Mr. Crisp provided e~~E~~xamples of ~~such~~ decisions that he believed were not shown by Xcel to be reasonable when made or performed included:

[87] Ex. 9 at Figure 2 (O'Connor Rebuttal).
[88] Ex. 9 at 54:7-16 (O'Connor Rebuttal).
[89] Ex. 4 at 62 (Stall Direct).
[90] Ex. 4 at 2 (Stall Direct).
[91] ~~*Id.*~~Ex. 4 at 62 (Stall Direct).
[92] Ex. 4 at 2 (Stall Direct).
[93] Ex. 4 at 2 (Stall Direct).
[94] Ex. 300 at 18-19 (Crisp Direct); Ex. 303 at 13 (Crisp Surrebuttal).
[95] Ex. 300 at 19 (Crisp Direct).
[96] Ex. 17 at 14:18-15:4 (O'Connor Surrebuttal).
[97] Ex. 3030 at 13 (Crisp Surrebuttal).
[98] Ex. 419 (Crisp Opening).

> …pursuit of a "fast-track" approach, the lack of separate cost tracking for the LCM and the EPU projects, lack of effective cost controls, …, and the lack of reasonable use of contingencies in the budgeting process and economic justification for the EPU.[99]

80. Mr. Crisp testified that the Company's ~~The~~ changes in contractors also created delays because replacement of contractors creates "serious risk management issues that must be addressed by not only the Company but also by the new contractor."[100] Mr. Crisp further alleged that ~~T~~the new contractor must review a significant amount of work or be "at extreme risk of liability claims throughout the life of the project."[101] Mr. Crisp concluded that ~~S~~ "such changes and process take considerable time, which impacts the overall project schedule."[102] However, the Company's lead designer was, and remained, General Electric throughout the Program.[103] Mr. Crisp testified that the Company's reliance on General Electric for the lead design work was "absolutely" reasonable.[104] Mr. Crisp raised "questions" about the Company's contracting practices and suggested that some decisions "likely" led to cost increases but did not conclude that the Company was imprudent in its management of contractors or that increases were avoidable.[105]

82. In response to the Department's criticism of Xcel's decision to proceed in parallel with design, licensing, and implementation of the LCM/EPU Project, ~~put the combined LCM/EPU Project on a fast track,~~ Xcel explained that the decision was necessary 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; (4) the General Electric Scoping Assessment supported proceeding with a 2009 and 2011 outage schedule; and (5~~4~~) the need to upgrade certain Monticello systems to support the Plant's continued operation during the license extension.[106]

Proposed Allocations of Costs

97. Dr. Jacobs focused on identifying modifications and work during the Project that were needed to support the EPU and assigned~~ing~~ costs to the EPU if the work associated with that system had any EPU component, not just the portion of that system that was related to EPU.[107] ~~those EPU-related modifications and work.~~ He ~~used several methods of identifying EPU-only projects, but~~ relied to a considerable extent on Xcel's 2008 sworn, contemporaneous letter to the NRC that expressly identified particular modifications intended for the EPU and other modifications planned for the LCM.[108] Dr. Jacobs disregarded the Company's testimony in this case and in the Certificate of Need proceedings, which was also under oath, about what components required replacement because of LCM regardless of the EPU.[109] He ~~also~~ considered discussions he had with Xcel employees and applied his basic criterion that if Monticello could not operate at the higher EPU power level without the particular work or project being evaluated, he considered that particular work or project to be an EPU project.[110] But Dr. Jacobs

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[99] Ex. 419 at 1-2 (Crisp Opening Statement).
[100] Ex. 300 at 21 (Crisp Direct).
[101] *Id.*
[102] Ex. 300 at 22 (Crisp Direct).
[103] Ex. 9 at 66:24-25, 78:23-26, 80:8-9, and Schedule 28 (O'Connor Rebuttal).
[104] Evidentiary Hr'g Tr. Vol. 3 at 32:17-19 (Crisp).
[105] Department Initial Br. at 23 and 25.
[106] Xcel Initial Br. at 36 at n. 125; Ex. 3 at 49:7-13 (O'Connor Direct).
[107] Ex. 9 at 84-87 (O'Connor Rebuttal).
[108] Ex. 421 at 1-2 (Jacobs Opening Statement); Ex. 305 , Att. B. at 3 (Jacobs Direct).
[109] *See* Ex. 9 at 84:18-86:12 (O'Connor Rebuttal).
[110] Ex. 421 at 1-2 (Jacobs Opening Statement).

did not document the actual discussions and the record reflects that the plant personnel with whom Dr. Jacobs spoke about the electrical distribution system did not have the same recollection as Dr. Jacobs of those discussions.[111]

~~100. Xcel's initial estimated ratio of EPU-related costs to LCM-related costs of 41.6 percent to 58.4 percent, respectively, is not supported by the record as a reasonable split of final total costs~~. ~~Allocating only 41.6 percent of final total costs to the EPU was not reasonable because Xcel's initial estimate of the cost split in 2008 was based on its flawed initial estimate of final costs.[112] Its allocation did not reflect two important facts: (1) Xcel's initial cost split estimate was based on a much lower total cost estimate, and (2) it does not consider the impact of the final cost of major EPU components such as the $121 million 13.8 kV distribution system modification which greatly shifted the cost ratio to the EPU Project.[113]~~

104. Xcel also disagreed with Dr. Jacobs' statement that it could have saved costs, absent the uprate, by replacing aging equipment on a "like-for-like" basis.[114] However, the NRC definition of "like-for-like" means the replacement of an item with an item that is identical.[115] Xcel 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."[116] 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.[117]

106. The LCM/EPU split is not relevant to the determination of prudence in this proceeding. The LCM/EPU Program was an integrated project affecting largely the same equipment and the work completed at the plant serves to both allow the continued operation of the Plant and to allow the Plant to achieve an uprated capacity. Based on the record, ~~Dr. Jacob's expertise, the relevant facts he collected, the logic of his methods, and his ability to respond to Xcel's criticisms, the ALJ finds that~~ Dr. Jacob's allocation of the LCM/EPU Project costs is incorrect, not supportable by the full record, and should not be adopted by the Commission.

Disallowance Recommendations

Recommendation of the Administrative Law Judge

124. The Department's proposed disallowance remedy based on a cost-effectiveness analysis is not appropriate given that no imprudence on the Company's part has been demonstrated. Because Xcel Energy met its burden by explaining how it spent the money for the LCM/EPU Program and no imprudence has been demonstrated, Xcel Energy should be allowed to recover the costs it incurred implementing the LCM/EPU Project.~~the most reasonable methodology under the evidence presented in this matter. It is a balanced and fair approach designed to ensure that Xcel will have sufficient funds to operate the Plant safely, but not be allowed more than the maximum amount of the EPU costs at which~~

[111] Ex. 9 at 88:19-89:20 (O'Connor Rebuttal).
[112] Xcel has not offered to be bound for cost recovery by its initial cost estimate for the LCM/EPU project, although it demands that its initial cost split estimate must be used by the Commission.
[113] Ex. 307 at 16 (Jacobs Surrebuttal).
[114] Xcel Initial Br. at 116.
[115] Ex. 429 (NRC Letter 91-05).
[116] Ex. 13 at 15 (Stall Rebuttal); Ex. 9 at 117 (O'Connor Rebuttal).
[117] Ex. 9 at 117 (O'Connor Rebuttal).

~~the EPU is cost-effective. It fairly compensates Xcel for reasonable costs incurred for the LCM/EPU Project and fairly requires ratepayers to pay a reasonable price for the energy produced by the LCM/EPU Project.~~

CONCLUSIONS OF LAW

6. Xcel has ~~failed to~~ demonstrated that the costs ~~overruns~~ it seeks to recover for the LCM/EPU Project were prudently incurred and are reasonable.

7. While Xcel could have made different decisions in its project management and initial scope development, the Company proceeded with the 2009/2011 outage based on several informing factors and its decision to proceed in this way is supported by the information they had available to them at the time the decision was made. Additionally, the Company managed its contractors appropriately and implemented appropriate monitoring and mitigation measures when it identified issues with engineering, design, or implementation. These are all prudent actions.~~Xcel's principal failure was that it did a very poor job managing the initial scoping and early Project management up until beginning installation during the 2009 refueling outage. The Company's decision to proceed with the combined LCM/EPU Project in 2009 rather than 2011 created an extremely difficult task that Xcel was not able to manage. From that point forward, additional issues arose that compounded Xcel's difficulties and required unreasonable amounts of time and money to resolve. It was a failure of management and was not prudent. As a result, significantly increased unreasonable costs occurred until the Project was completed.~~

8. The ~~cost overruns~~ additional costs for the feedwater heater, the 13.8 kV distribution system, and the installation costs totaling at least $261 million, cannot be attributed to ~~were caused by~~ Xcel's imprudent management~~. They are unreasonable~~ and, therefore, cannot be summarily ~~should be~~ denied, as requested by the OAG.

9. During the engineering and design phase of each modification, t~~T~~he Company~~'s failure to recognize problems~~ identified potential issues with spacing, clearances, access, high-dose areas, and physical arrangements of the Plant.[118] ~~was a direct failure of its LCM/EPU Project management.~~~~[119]~~ ~~Nothing related to the characteristics of the Plant, including its size, should have surprised Xcel or led to cost overruns.~~ The Company worked with implementation vendors and craft laborers to estimate the number of work hours necessary to complete the requisite work given these conditions.[120] The Company's awareness of these conditions, however, did not obviate the difficulties that a space-constrained and high-dose environment presented.

10. Xcel's decision to proceed with a multi-track approach to the LCM/EPU Project, which included concurrent permitting, design, and construction planning and activities, is common in the nuclear power industry.[121] In addition, given the resource planning context, where the Company faced significant baseload needs in 2015 and high natural gas prices, it was appropriate to multi-track the LCM/EPU Project. The Department's expert witness agreed that the Company's multi-track approach

[118] Ex. 9 at 46:17-19 (O'Connor Rebuttal).
~~[119] Ex. 300 at 17-19 (Crisp Direct).~~
[120] Ex. 9 at 46:19-23 (O'Connor Rebuttal).
[121] Ex. 11 at 3:20-14:4 (Sieracki Rebuttal).

did not "in and of itself" increase the LCM/EPU Project costs.[122] The Company's decision to proceed with a multi-track approach was reasonable. ~~on an aggressive, fast-track schedule by using a parallel process contained unreasonable risks. The fast track schedule required the Company to rely on preliminary scoping, rather than performing the full scoping effort necessary to have a thorough understanding of what needed to be done to finish the Project. The result was dramatically increased Project costs that were imprudently incurred by Xcel.~~

11. Xcel~~'s~~ provided all of its accounting records for the entire LCM/EPU Project, comprising over 40,000 separate transactions for over 40 separate subject work orders.[123] This data was provided in searchable electronic format.[124] ~~practices made it difficult to separately review the actual costs of the EPU from the costs of the LCM.[125] The costs were not transparent as required. Identifying these costs for this prudency review was a needless expense.~~ The Company's approach is consistent with the FERC Uniform System of Accounts by tracking costs according to the systems that were being worked on as part of the LCM/EPU Project, and were sufficient to enable the Parties to identify how and where the Company incurred costs.[126] Xcel's approach to accounting for the LCM/EPU Program was reasonable and prudent.

12. ~~Xcel failed to demonstrate that either of its proposed allocations between LCM costs and EPU costs is reasonable. Xcel's initial allocation was based upon a "rough estimate" of projected costs of the EPU. It did not include some of the very expensive machines and work that were planned and installed later that were clearly related to the EPU. The second allocation, 78 percent to the EPU and 22 percent to the LCM, is not reasonable because it improperly assumes that all costs are LCM costs until proven otherwise, which causes many items to be classified as LCM costs inappropriately.~~ All costs incurred by the Company were in furtherance of the LCM/EPU Project which was a single project. While a split between LCM and EPU costs had value in the 2008 Certificate of Need proceeding to determine whether it was cost-effective to proceed with the EPU and in prior rate cases for the Commission's "used and useful" determinations, this allocation is irrelevant in a prudence investigation. If the Commission finds it necessary to allocate costs between LCM and EPU to determine the prudence of the Company's decision to proceed with the LCM/EPU Project in 2008 or for purposes of making a "used and useful" determination, c~~C~~osts should be allocated between the LCM and EPU portions of the Project in a ratio of 58.4–percent to 41.6–percent, respectively, that was used in the 2008 Certificate of Need proceeding. This is the only split developed contemporaneously with the decision to proceed with the LCM/EPU Project and does not require a hindsight analysis.

13. Dr. Jacobs' review and analysis of the LCM/EPU Project split is not a proper split to use for the LCM/EPU Project as it required hindsight analysis and results in the LCM work totaling approximately $100 million (2013$) of the incurred $665 million (2013$). This is $33 million less than what the Company contemporaneously estimated the LCM work to cost in both the ISFSI Certificate of Need and the uprate Certificate of Need. This result is not logical or consistent with the record evidence regarding the nature of the LCM/EPU Project. ~~was more thorough and more consistent with the actual cost incurred for the EPU. Dr. Jacobs demonstrated that the appropriate allocation of costs between the LCM and EPU is 15 percent and 85 percent, respectively.~~

[122] Evidentiary Hr'g Tr. Vol. 3 at 17:16-19 (Crisp).
[123] *See* Ex. 6, Weatherby Direct at Schedule 2; Ex. 16, O'Connor Surrebuttal at Schedule 1.
[124] Xcel Initial Br. at 17-18.
~~[125] Ex. 313 at 20 (Campbell Direct).~~
[126] Ex. 5, Weatherby Direct at 2:25-3:7.

14. The facts in the record support ~~a substantial disallowance~~ recovery of the costs ~~overruns~~ incurred by the Company to implement the LCM/EPU Project.

~~15. Because of the failure of Xcel to demonstrate a reasonable figure for a disallowance and the difficulty determining the specific amount for a disallowance, it is most appropriate to order disallowance of that portion of EPU-related costs that render the Monticello Plant not cost-effective as of the present, as recommended by the Department. Such a calculation gives Xcel credit for its investment in the EPU to the extent that it will produce benefit to ratepayers, but does not reward it for its actions that were imprudent and unreasonable. Either a total allowance or total disallowance would be unreasonable and unfair.~~

~~16. Specifically, the disallowance should be a $71.42 million reduction to the capital costs of the Monticello EPU resulting in a $10.237 million revenue requirement downward adjustment for 2015 on a Minnesota jurisdictional basis, and ongoing adjustment for the life of the Plant stepped down for accumulated depreciation.~~

Xcel Energy also disagrees with ALJ Recommendations 1 through 6 but has not provided redline revisions as these items are the ALJ's Recommendations rather than adoptable findings or conclusions.

The Engineering And Design Process

Xcel Energy Nuclear Department

This Schedule was prepared at the request of and under the direction of Timothy J. O'Connor for his use in the normal course of his duties. It provides a narrative description of the engineering and design process used for the Monticello LCM/EPU Program. Design work on nuclear projects is complex and costly, particularly when performed within the confines of an older nuclear facility such as Monticello. The purpose of this Schedule is to illustrate that (1) the modifications on the LCM/EPU Program were carefully planned and followed standard procedures in the nuclear industry, and (2) even with the methodical roll-out of modification design, it was difficult to estimate Program costs in the early stages of design.

A. Detailed Description of Design Process

The initial designs developed to conceptually evaluate the LCM/EPU Program emanated from: (1) a review of the systems and equipment identified on the Long Range Plan ("LRP") as required to be addressed prior to or during the period of extended operation, and (2) identified pinch points that limited the ability of the plant to operate at uprated capacity levels. The process then created solutions to address these pinch points.

Once solutions were identified, the required physical changes were integrated with the LRP items, including those items for which earlier than planned installation made sense. The principle objective of this effort was to prepare the station for an additional 20 years of safe, reliable operation and support the license amendment request for the NRC to operate at the EPU power level. Accordingly, the design process for the LCM/EPU Program integrated the needs of modernizing the plant with the ability to increase output. The design process for physical modifications ensured that the desired level of quality was achieved and the needs of the station were addressed.

1. Evolving process

Design in the nuclear power business is an evolving process that moves the design from conceptual to final. Engineering design development requires an evolutionary approach for two reasons:

- First, initial engineering designs are intended to establish the high level functional criteria. From this functional criteria, performance criteria at a component or system level can be identified through design and licensing bases reviews and impact reviews from station and engineering programs. Once performance criteria are established at the system and component level, required design standards, specifications, calculations and plant specific information are synthesized into a more detailed design. Initial design outputs such as equipment specifications, conceptual layout and routing drawings and calculations are created. Input from field walkdowns, equipment vendors and detail component configurations are necessary to finalize the design for installation.

- Second, new information is frequently identified during the course of the design process that must be addressed in order for the design to perform its function. In the case of the LCM/EPU Program, for example, the large number of simultaneous modifications and the complexity of the plant's systems led to interactions, interferences, and dependencies among the modifications. While reasonable in a Program such as this, these interactions, interferences and dependencies were difficult to foresee until the Company completed a design for each modification. The need for iterative engineering analyses can lead to cost and schedule challenges. The LCM/EPU Program required close coordination between each of the modifications to ensure interactive design efforts did not result in substantial rework.

2. Required procedures

All design work at a nuclear plant is controlled by specific procedures. Safety related designs include all of the following controls, as applicable:

- Determine Design Control Requirements
- Design Interface Control
- Identification and Control of Design Inputs
- Plant Impact
- Design Description, Installation Plan and Test Plan
- Design Reviews (Constructability Review)
- 10 CFR 50.59/10 CFR 72.48 Screenings and/or Evaluation
- Independent Verification/Review
- Design Approval (DRB, PORC & Design Authority)
- Installation and Testing Instructions (Planning)
- Installation Design Support (ECNs & CCNs)
- Turnover (Partial and Final)
- Closeout

If the design is not safety related, some of these controls may not fully apply. Nevertheless, because of the complexity of the design, and the degree of regulatory, industrial safety or economic risk involved, it is generally considered best practices to account for all of these controls.

The engineering and design process at Monticello was designed to accommodate all the modifications in the LCM/EPU Program. It is customary for nuclear projects to be commenced using preliminary designs rather than definitive engineering prior to commencement of the project. The cost and time commitment necessary to prepare the detailed engineering designs and cost estimates is significant. Such assessments and planning can be cost prohibitive and it is exceptionally difficult to accurately estimate costs when all of the scope of a modification is not firm and detailed design work has not progressed.

The design and engineering process followed prescriptive procedures in developing final designs. This is an evolutionary process from conceptual to final design. This process began with a review of basic licensing requirements to identify aging equipment that needed replacement and pinch points that limited the ability of the plant to operate at uprated capacity levels. The process then created solutions to address these issues.

3. Design phases

Engineering and design are completed in various phases, essentially consisting of six stages that the Company was required to follow to ensure nuclear safety and so that designs were the best quality designs possible for the plant.

- *Study Stage*. The study stage provides the preliminary understanding of the Program and allows the Company to understand whether the Program is technically possible. Most nuclear capital projects are commenced during this phase because of the timing and regulatory requirements involved. While this contributes to changes in design as the job is more fully developed, it also allows the Company to move forward with iterative designs and adapt to evolving circumstances.

- *Design Stage*. The design process is initiated by a kick-off meeting for each modification. Each kick-off meeting is generally followed by periodic meetings through the process from conceptual to final design. In this stage, design control requirements are identified, design interface control is established, design inputs are identified and design description is prepared. Supporting design output documents, including calculation analysis and drawings, are prepared to support the process.

- *Design Review Meetings ("DRM") (30/60/90 percent levels)*. The first DRM (30 percent) is generally conducted once the scope of the modification is well defined, alternate design solutions are evaluated, and the designer is ready to recommend a design approach for the modification. As the design elements are finalized, most major nuclear projects will proceed to implementation long before achieving an overall 30 percent design for the modification. Further detail is developed at the 60 percent level and greater certainty in the overall design is established. Finally, DRM review to the 90 percent DRM level is intended to thoroughly evaluate the modification, including constructability, installation, and testing.

- *Challenge Boards*. For modifications that are determined to be high risk, a Challenge Board is conducted after the final DRM and prior to the Design Review Board. Challenge Boards are made up of key stakeholders, third party individuals and subject matter experts.

- *Design Review Boards ("DRB")*. Once all DRMs, independent design verifications, and, if required, third party reviews on open design issues are completed, the Design Review Board review is conducted. The DRB provides comprehensive review of the modification to ensure that all facets of design, construction, maintenance, testing, and operations are considered during development of the modification package.

- *Plant Operating Review Committee ("PORC")*. Finally, senior members of Monticello's plant staff, including the plant manager, are required to provide final sign-off on all designs. The Chair and the Vice-Chair that serve on the PORC are appointed by the plant Site Vice President.

- *Final Design Approval*. After all reviews are complete, the final design approval is completed by the Design Engineering Supervisor/Design Authority.

B. The Design Level Required for an Accurate Cost Estimate

In the context of working in an operating nuclear plant, it is uncommon for projects to be undertaken with up-front detailed analysis. It is normal for designs and scope to evolve as a project progresses through the complex and multi-level design process. 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. Each of these replacements or modifications must be completed in an operating nuclear power plant with limited space for large components. In effect, this requires the custom design of new components to fit in the current plant facilities and the removal and rerouting of large amounts of piping and wiring to access and accommodate the changes. In the boiling water reactor environment, there are many areas of the plant that cannot be accessed at all while the plant is in operation, making it even more challenging. Temperature and radiological dose are generally the reasons areas are not accessible. In addition, vital areas such as critical switchgear rooms are not accessible in any mode of operation (even shutdown) due to the potential to impact safety adversely. Special controls and protections must be in place before work in these rooms is allowed.

Design would have to proceed to a relatively advanced level in order to lessen the risk of a cost estimate being inaccurate. The first step in reaching such a level would be to determine specific design controls to be applied to the modification. In the case of the major modifications for the LCM/EPU Program, independent design review or independent design verification is required. At the commencement of this level of design work, the Responsible Engineer or Project Manager notifies potentially impacted departments that design work is started. The notification normally includes the following:

- Training Center
- Operations
- Maintenance
- System Engineering
- Supply Chain
- Procedures Group
- Configuration Management
- Management Sponsor (if not already listed above)
- Manager, Fleet Simulator Training
- Program Engineering

The design starts once the quality classification and applicable design controls are established. Design inputs are identified and routed to the organization for impact reviews. Applicable codes, standards and specifications that were used in the licensed

Plant design are identified and made available to the External Design Organizations. Design reviews and field walkdowns, where available, are completed as required by procedure. The design requirements are assembled, controlled, and maintained to provide a basis for verifying that the implemented design meets design requirements. Calculations required to support the modification are performed; and design output documents, such as drawings, specifications, and requirements for installation, inspection, and testing, are prepared.

Next, design reviews are performed to ensure that the design accomplishes its intended function and meets the established design requirements. Independent verification is performed before design output documents are released. When an outside engineering firm is contracted to perform design activities, responsibilities and interfaces are clearly defined. These responsibilities can be defined in specifications, the project plan, or both. Responsibilities, interfaces, and hold points are approved by the Company and agreed to by the contracted engineering management. The Company design engineering organization, as the Design Authority, retains responsibility for safe and reliable plant design.

As the design process proceeds, all necessary design output documents as follows are created:

- Design drawings
- Associated calculations
- Design Description
- Affected Document List (ADL)
- Affected Equipment List (AEL)

When the design is sufficiently developed any long-lead material/equipment is ordered. Material/equipment is not to be ordered during the design phase unless the expenditure was authorized by the project review group for major modifications or the Engineering Supervisor for minor modifications. The Responsible Engineer ("RE") has the Design Description, and associated design output documents reviewed or verified. All Preparer, Reviewer, and Approved signatures, as required, are affixed to each document or document cover sheets.

The RE may have the Modification Package reviewed by a knowledgeable individual (i.e., Peer) or a team of knowledgeable individuals named by the Design Authority. Multiple Design Review Meeting ("DRM") reviews are performed during the design phase and ultimately management review and approval is required. Design has to advance to at least a point where many DRM reviews have been conducted in order to develop cost estimates that have substantially less risk of being inaccurate as compared to cost estimates created at the beginning of design process.

C. Completion of Design

At the time the design is essentially complete, Issued-For-Construction ("IFC") drawings are prepared. This should typically occur 9 to 12 months before implementation. These IFC drawings form the basis for the installation planning. At this time a more accurate estimate of project costs can be made because reliable material takeoffs can be generated and used to determine installation labor. Equipment and material costs can also be reliably determined. To get to the IFC stage for an entire Program with the complexity of the LCM/EPU requires 4 to 6 years, which is why the design work is done in parallel with field work.

Even after IFC drawings are completed, construction often reveals that design needs to be modified to accommodate as-found conditions. While the Company attempts to minimize this, in efforts as large and complex as the LCM/EPU Program this is inevitable. Changes at this stage are called field design changes or just field changes. They are primarily driven by accessibility, interferences and installation complexities. The complexity of any particular change dictates the amount of time and effort required to resolve it. Simple changes may require only a few hours to address while the most complex changes required hundreds of hours of effort. Field design changes often require reanalysis, preparation time, review time, and appropriate time for approval.

In general, throughout the LCM/EPU Program, the Company used the same process to identify and implement necessary field changes, which can be broken down into three categories: basic, intermediate and complex. For the most complex changes, a change in one system impacted other nearby or related systems, thereby requiring reanalysis of a number of systems. This analysis was highly iterative. Each time a change was proposed and analyzed, the Company confirmed that the systems worked together in accordance with applicable standards. This sometimes required multiple rounds of reanalysis, as the "ripple" effects of a particular change were addressed.

For example, when the condensate demineralizer vaults were accessed, it was discovered that the wiring was substantially degraded and not able to be re-used as originally planned. Another example was the interference in moving the new equipment through the access hatch. The 3" ESW line had to be re-routed to provide adequate clearance for the new equipment. The 13.8 kV switchgear was not able to be installed close to the Feedwater Pumps due to space limitations and had to be relocated. After evaluating multiple options, the switchgear was relocated to the Hot Machine Shop location. This in turn required the Hot Machine Shop to be relocated to the Radwaste Building. None of these could have been discovered in a detailed up-front engineering process.

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☐ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	124
Requestor:	Nancy Campbell/Chris Shaw		
Date Received:	May 5, 2014		

Question:

Referring to the LCM/EPU Split table shown on Exhibit TJO-1, Schedule 29, page 4 of 6 through 6 of 6, please provide:

a) the detailed analysis Xcel used to develop the split between Unavoidable LCM Cost and Avoidable EPU cost for each modification;

b) the basis for the conclusion for each piece of equipment that Xcel determined would need replacement to ensure continued operation through the operating license term; and

c) explain what alternatives to replacement Xcel considered. For example, did Xcel consider recoating the condensate demineralizer tanks rather than replacement?

Response:

a) Our ongoing effort to maintain the original equipment at Monticello during its initial 40-year operating license meant that much of that equipment was worn and in some cases obsolete as we approached the decision to seek a license extension. When the Company was granted an extension of its operating license, we recognized that there were significant capital projects that needed to be done to ensure continued safe and reliable operations through the extended license period. Replacement of worn and obsolete systems was required regardless of whether we pursued the uprate.

As described in our October 18, 2013 filing, the Company decided to design and implement the LCM and EPU upgrades to the plant at the same time, so we

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combined these activities into a single Program. *See* Timothy J. O'Connor Direct Testimony, pp. 8, 145. As a result of this combined approach, the Company did not maintain separate accounting or records during implementation for potentially avoidable EPU upgrades as distinct from unavoidable LCM replacements.

When the Company decided to pursue the uprate we also recognized that there would be overlap in the work needed to accommodate the uprate and to support the long-term viability of the plant as a whole. By completing the EPU and LCM efforts simultaneously, the Company hoped to achieve economies of scale and to make the installation effort more seamless as combining the work reduced the expected aggregate duration of outages. While this approach may have resulted in replacing a number of components somewhat ahead of schedule, in the long-term this was a more efficient way to proceed overall. The combination of activities also allowed us to maximize the depreciation schedule and phase in the significant LCM expenses on a schedule that maximized our depreciation of costs over a longer period while minimizing the risk of needing to make major investments or face premature shutdown later in the plant's extended life. As such we continue to view the Project as an integrated effort that is not easily separable.

Because parties had expressed concerns with the lack of any quantifiable EPU amount in prior cases, in preparation for our filing in this case, the Company undertook an analysis to estimate the amount of costs that could have been avoided but for the EPU (avoidable EPU) and those that were necessary to support long-term operations of the plant regardless of whether the Company pursued the uprate (unavoidable LCM). *See* Timothy J. O'Connor Direct Testimony, Schedules 29 and 30.[1] As described in Schedule 29, the analysis we conducted was undertaken after the work was completed and was based on information we knew following completion of the work, including the condition of components found during the Program. Schedule 29 (as updated in Information Response DOC-123) describes the process we went through to analyze the modifications to assess the difference between the avoidable EPU and unavoidable LCM work.[2]

[1] We supplemented that analysis in response to DOC IR-58 and provided an updated Schedule 29 in response to DOC IR-123.

[2] We began by reviewing the cost incurred for each modification. With the total cost for each work order, we then undertook an analysis of how the cost could reasonably be allocated between necessary LCM work and avoidable EPU work. Once that allocation was made, we then allocated the common costs attributable to each modification on a pro rata basis to the LCM and EPU categories.

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For each modification, Company engineers analyzed: (i) the need for the work to support long-term operations; (ii) the need to increase the size or capacity of the modification to support the uprate; (iii) the actual work performed on the modifications, and (iv) the cost of components installed at the plant. Our engineers then assessed whether each modification would have been needed without the uprate. They applied their collective engineering judgment in classifying the work.

- Unavoidable LCM: Some of the modifications (*i.e.*, lines 1-17 of O'Connor Schedule 30, as supplemented in response to Information Request DOC-58) constitute LCM costs as these modifications were ultimately unavoidable, regardless whether we pursued the uprate. These projects were initially determined through analysis of equipment condition and our determination whether the equipment would support operations through 2030. If it was or would no longer be safe or economical to maintain the equipment for the duration of the extended license, the Company's decision to replace it was classified as unavoidable LCM.

- Avoidable EPU: Some of the modifications (*i.e.*, lines 18-25 of O'Connor Schedule 30, as supplemented in response to DOC-58) were determined to be undertaken exclusively for the EPU. In other words, these modifications would not have been done without the uprate. Generally, those costs relate to licensing and a number of modifications, such as the acoustic monitoring, that would not have been needed without the uprate.

- LCM/EPU Combination: Some of the modifications (*i.e.*, lines 26-36 of O'Connor Schedule 30, as supplemented in response to DOC-58), were made for a combination of reasons. Essentially, these modifications needed to be replaced because of age or condition for LCM purposes but required larger systems to accommodate the higher capacity from the uprate. Our engineers reviewed each such modification and made a reasonable engineering judgment of how to apportion the overall cost of the modification between the LCM and EPU aspects. Some of these modifications required up-sized equipment to support higher flows and temperatures associated with the uprate. If we could not determine an independent basis for the cost of the equipment, we attributed 12.1% of the equipment cost to the EPU. Our responses to Information Request

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DOC-74 and DOC-111 provide additional discussion on the reason for apportioning the cost of larger equipment.

b) One or more of the following four considerations influenced our decision whether a piece of equipment/modification: (1) should be replaced or repaired; and (2) should be categorized as unavoidable LCM, avoidable EPU, or a combination of the two.

1. End-of-Life – Was the component/equipment at the end of its design life and would continued operation challenge safe and reliable plant operation? Equipment that is at or near the end of its useful life will need to be addressed to support operations through 2030.

2. Service-Related Degradation – Was the component/equipment showing signs of performance degradation to the extent that a maintenance solution was no longer viable for the long term? If equipment showed signs of degradation, through testing or reduction in performance, that equipment would need to be addressed. While repair can be appropriate, replacement is generally preferable to support extended operations for approximately 20 years.

3. Obsolescence/Modernization – Was the component/equipment no longer supported by its vendor/OEM and/or spare parts sufficiently available to ensure reliable operation? We also considered industry modernization that was taking place to assess whether or not it would have been reasonable to attempt an additional 20 years of operations with outdated equipment. These considerations helped us assess whether repair was feasible or would require custom fabrication and other expensive workarounds, or whether improvements in technology warranted replacement.

4. Design/Operating Margin – Was either the design or operating margin such that the component/equipment represented a threat to safe, reliable operation going forward and for the long-term? We found this factor to be helpful in assessing whether a modification could have been avoided through maintenance.

Our analysis and assessment of these four factors, and the answers stemming from asking ourselves the questions presented above for each of the modifications significantly influenced whether the modification was considered unavoidable LCM work, avoidable EPU work, or a combination

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of the two. As requested, we provide the following additional discussion about our decision-making process as it pertains to the modifications identified on pages 4-6 of Schedule 29 to the Direct Testimony of Mr. O'Connor (as updated by the Company's response to Information Request DOC-123). Please also see our responses to DOC-58 and DOC-123 for additional discussion on this topic.

Condensate Demineralizer

The main criteria driving our decision to replace the condensate demineralizer system were (1) obsolescence, and (2) improving the design to increase reliability by automating the function. The condensate demineralizer system work required replacement of the old analog control system to automate the functions for long-term operations. The old controllers were obsolete and needed to be modernized for the long-term benefit of the plant. The need to upgrade and replace the controller was part of our long-range plan and was a project that had been identified as necessary, separate from the EPU.

Many parts on the old control system were obsolete. The flow controllers were pneumatic and no longer available. The control for the system was a stepping switch, and that was also no longer available. The plant was able to keep the system running, but spare parts for some items were no longer available. The aggregate issues with the system would have led to replacement of the majority of the system and major maintenance to recoat the tanks, if determined feasible, at some point in the period of extended operations, most likely sooner than later.

Once we decided to replace the controllers, this necessitated replacing all of the wiring, piping and associated systems. Similar to the PRNM system (discussed below), any decision to replace part of an analog system with a digital system requires a complete system replacement due to the difficulty in interfacing an analog component to a digital component.[3] We further discovered that the wiring had substantially degraded and needed to be replaced regardless of the other circumstances.

[3] This necessitated the following LCM work to complete the new Siemens/Moore APACS system:

1. Remove numerous instruments and controls (electrical and pneumatic) from panel C-80 and in each of the demineralizer vaults. Controllers, switches, and indication will be replaced with 2 redundant graphical operator display consoles, consistent with installation at many other nuclear plants.
2. Install ~ 40 new electronic flow, pressure, and dp transmitters as inputs to the new system.
3. Design, fabricate, and test the complete waterworks system.
4. As part of the panel replacement, a portion of the wiring was going to be re-used, but was found to be too deteriorated and was also replaced.
5. Other components that were becoming obsolete with parts no longer available were the ball valves, pneumatic valve positioners, and holding pumps.

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As part of our desire to enhance reliability, we also considered the need to modernize and upgrade the design of the system to automate the demineralization process to minimize the risk of human error. The old system required multiple valve manipulations to be performed manually while the new system automated and repositioned the system components to reduce the potential for error. Part of the new system was a different backwash process that improved reliability of operations of the plant. The automation of this system required replacement the existing piping and installation of new vessels.[4] All of this work was LCM in character and needed to be completed to support operations to 2030 regardless whether we pursued the uprate.

The only aspect of this project that was related to the EPU was the need to install larger vessels to accommodate the higher flows associated with the increased capacity from the uprate. We considered whether we could repair the existing system by relining the vessels but determined that this would not be sufficient to address all of the issues we encountered with this existing system. Replacing the vessels was much less labor intensive and minimized the amount of radiation dose we encountered compared to what would have occurred had we repaired the existing vessels.[5] Project E-99R000-11 PLC based Condensate Demineralizer System was originally placed on the Long Range Plan in 2000.[6]

This new system is consistent with DFCS design platform. It results in reduced training, spare inventory, and utilizes experience of plant staff. The new system will consist of ~350 digital and ~50 analog inputs and outputs. It also creates

[4] The existing air operator for the condensate demineralizer bypass valve AO-1740 was not large enough to open the valve on high system differential pressure of 52 psid. A new operator and control arrangement was installed to ensure opening of the valve during high system dP conditions. The CDM bypass valve is required to open in the event of closure of the CDM outlet valves, such as due to loss of instrument air. This ensures a supply of condensate/feedwater to the reactor vessel and reduces reliance on emergency injection systems for some transients.

[5] This is because repairing them would have required working within the existing vessels (an area of higher dose than in the vaults). Also, the liners and components are highly radioactive and it is difficult to contain contamination. Also, access to the area to conduct the repairs is limited and would have required expensive tooling to be developed for this specific application.

[6] The project was re-estimated in 2002 to include replacing the pneumatic flow balance control system, with installation during the 2003 re-fuel outage. The scope of the project was to replace the existing condensate demineralizer backwash and pre-coat system with a PLC based system. The new system would replace obsolescent and more than 30 year-old equipment including: timers, relays, and pnuematic instruments used for flow balance control and in automating the CDM backwash and precoat process. The original system required significant attention of plant staff to regenerate elements and in system maintenance and repair. There was an ever increasing failure rate of these components and this system's continued reliability and availability is critical to daily plant operations.

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substantial saving in element replacement costs and resin costs, particularly if it had not been done in order to match EPU flow conditions. Also, the upgrade improved water quality, which will reduce radiation dose for plant maintenance. The use of the programmable logic controller (PLC) has resulted in reduced operator time to backwash and precoat CDM vessels as well as reduced isolation and testing time associated with less maintenance.

Consideration of the age of the existing condensate demineralizer and the need to modernize this equipment led us to replace rather than repair this existing system for the long-term benefit of the plant. However, the new system also included larger vessels to accommodate greater flow that will be encountered under uprate conditions. As a result, we allocated an appropriate amount of the overall cost of this modification to the EPU as reflected in O'Connor Schedule 30, as supplemented in response to DOC-58, line 28.

Feedwater Heaters

Service-related degradation was the primary consideration in our decision to replace rather than repair the six feedwater heaters that were part of the Program. In addition, four of the six replaced feedwater heaters were original plant equipment and the other two were 30 years old. They had all reached the end of their realistic useful life.

We conducted tests on the feedwater heaters and determined that the tubes within the heat exchangers were experiencing plugging. This phenomenon is normal in the life-cycle of heat exchanges and becomes a problem only if a sufficient amount of the tubes have become plugged that it degrades performance. The 14 A/B and 15 A/B feedwater heaters were original 40-year-old equipment and the 13 A/B feedwater heaters were 30-year-old equipment. Our testing showed that they had degraded to the point where further tube plugging was not a viable long-term option. As a result, it they needed to be replaced to support extended operations if an extended operating license was obtained.

A related consideration supporting our decision is the end-of-life criterion because of the age of the feedwater heaters that we replaced. The feedwater heaters and associated equipment were recognized to be older equipment that would need to be replaced to support extended operations in our 2003 capital projects summary sheet. We provide a copy of the 2003 capital projects summary sheet as Attachment A to this response that addresses this need. As described in Mr. O'Connor's Direct Testimony (p. 38) our experience was that

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we had maintained the existing feedwater heaters well and made them last longer than experienced in the industry. Ironically, the good job we did in maintaining these heaters longer than our peers meant that they were quickly reaching the end of their useful life, as demonstrated by the testing that showed excessive tube plugging. Thus, it is clear that we would need to replace this equipment to support operations to 2030, regardless of the uprate.

Moreover, the Company recognized that further repair of this system would not be sufficient and that replacement was in the best interest of the plant. Substantial maintenance requiring longer refueling outages to re-tube the heat exchangers was not desirable even without EPU required capacity change.

Nevertheless, the feedwater heater work required installation of larger equipment to accommodate increased flows associated with the uprate. Thus, we took that allocation into account and attributed costs to the EPU. See O'Connor Schedule 30, as supplemented in response to DOC-58, lines 5, 13, 28, 29, 32, 34, and 36.

Reactor Feed Pumps and Motors
The decision, to replace the reactor feed pumps and motors, was driven by service-related degradation issues and obsolescence.

The main criterion supporting replacement of these pumps and motors (regardless of the uprate) is that they had experienced chronic performance problems that could be addressed by replacing them with modern equipment. The original reactor feedwater pumps were a custom redesign of a 3-stage fire pump into a 2-stage feedwater pump. Our experience with these pumps was that they required frequent overhauls during refueling outages.[7] Maintenance on the original pumps was overdue at the time the decision to replace was made so an overhaul was avoided.

While pumps can and are repaired, the number of times that you can weld and machine the casing without replacing the casing is limited. If the pump casing is at the end of its service life, the most cost-effective option is to replace the pump

[7] The major issue with pump maintenance was that the high differential pressure joint between the pump casing and the impeller barrel assembly has had a problem with cutting by water leaking by the joint. This leakage can occur over time between maintenance cycles. Repair has required machining of the pump casing to remove the cuts since weld repair is not feasible. This repair also requires obtaining a barrel assembly that is increased in length to accommodate the material removed from the casing by machining. This repair is difficult to accomplish in the time frame of a refueling outage and can lead to challenging outage length which supported pump replacement. Maintenance on the original pumps was overdue at the time the decision to replace was made so an overhaul was avoided.

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assembly. We believed that we would face that situation in the next several cycles (approximately six years) and as a result determined it was prudent to accelerate and integrate replacement of the pumps into the EPU design.

A second criterion supporting replacement was obsolescence, as the pumps age, the pumps became harder and took longer to repair and we became concerned that these performance issues would result in longer outages as we tried to obtain hard-to-find spare parts.

With respect to the pump motors, these were original equipment that was experiencing performance degradation that required replacement. While the rotating assemblies had been replaced the stators, were still original. Given their age, the motors were not designed or expected to remain in-service until 2030, approximately 60 years on a nominally 40-year life. Service life is defined based on motor insulations class within the industry standard NEMA MG-1 Motors and Generators. We had evaluated the acceptability of these motors beyond 40 years using NEMA MG-1 standard, and determined that there was a need to replace the motors as part of LCM. This is consistent with the 2003 capital project summary sheet (Attachments B and C to this response), which included replacement for LCM prior to the LCM/EPU Program based on limited remaining operational life of these motors. Note: Attachment B also includes other LCM projects.

Based on these two factors, we would have had to replace these pumps and motors regardless of whether we proceeded with the EPU. We had identified in our 2003 long-range plan that this system was one that was going to need to be replaced to increase plant reliability for the license extension period and that not replacing this component could potentially lead to an extended shutdown, which was an unacceptable risk if the Company was going to seek to extend the license. By the time the EPU began to be considered, we were already in the process of evaluating these pumps and motors to determine what we needed to do to support the life extension. We recognized that they were going to need to be replaced and we anticipated that the replacement would have had to occur in roughly the same timeframe as they were replaced as part of the Program.[8]

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[8] As part of the EPU evaluation, we reviewed the recommendation to add a smaller capacity supplemental reactor feed pump and motor. This proposed design presented significant installation and operational challenges as described on pages 124-126 of Mr. O'Connor's Direct Testimony. We also determined that even if we added a supplemental reactor feed pump, the two existing pumps and motors would still require replacement in the near future to support long-term operations. Replacement of the two pumps and motors with two larger ones allowed the plant configuration and operations to remain consistent during the extended life. Reliability has improved by addressing and eliminating wear

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Because the reactor feed pumps and motors replacement was necessary to support long-term operations but also needed to be sized to support uprate conditions, we allocated costs for this modification to both as shown on O'Connor Schedule 30, as supplemented in response to DOC-58, line 31. This is one of the systems where the Company increased the size of the pumps and motors to accommodate the uprate. As a result, we allocated 12.1% of the equipment cost to the EPU to reflect the higher capacity requirements to increase generation by 12.1%.

Condensate Pump and Motor
This project was similar to the reactor feed pumps and motors project described above. It included the replacement of two condensate pumps and two motors, replacement of condensate pump and motor auxiliaries, modification of area cooling for the condensate pump motors, an increase in the condenser hotwell level, and completion of the required testing protocol. The decision to replace the existing condensate pump and motor were driven primarily by service-related degradation issues and obsolescence considerations.

Regarding service-related degradation, the condensate pump motors were supplied by GE as part of original plant equipment.[9] Performance of the pump/motor combination was degrading and was approaching the point where adequate suction flow/pressure could not be provided to the reactor feedwater pumps. Performance degradation indicated that the pumps needed to be replaced before reaching the end of the period of extended life of the plant.

Regarding obsolescence, the condensate motors were in somewhat better shape and immediate replacement of them was less critical. However, we were concerned about their long-term viability, particularly since we knew we had to replace the related condensate pumps. Because we were already working on the pumps, the addition of motors to assure continued reliable operations was not viewed as being a significant additional cost and was appropriate to uprgrade at that time to assure performance over the extended license life. Further, retaining

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conditions that necessitated preventative and corrective maintenance of this equipment to accommodate the new, larger pumps and motors.

[9] A similar size spare motor was purchased from Siemens in 1995 as a rotating spare. During the 1996 rerate, new Johnson pumps were procured to increase margin for the rerate. In 1997, a second Siemens motor was purchased as one of the GE motors could not be cost effectively rebuilt. At this point we had two Siemens motors and one rotating spare, the remaining GE motor.

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the old motors would have required approximately two additional 10 year major bearing replacement preventative maintenance (PM) (removing rotors) if EPU was not pursued. In light of the need to replace the pumps, we concluded it was more appropriate to replace the motors at the same time.

Given their service-related issues and age, these older pumps and motors needed to be replaced, rather than repaired, to support long-term operations but needed to be sized larger to support uprate conditions. We allocated the proportionate cost of the larger equipment to the EPU. As a result, we allocated the costs between LCM and EPU as described in O'Connor Schedule 30, as supplemented in response to DOC-58, line 27.

13.8 kV Distribution System

The decision to add the 13.8 kV System to the existing plant's distribution capacity was driven mainly by the desire to improve the design and increase operating margins as well as obsolescence considerations. We analyzed many options with the existing 4 kV busses or adding new busses at a higher voltage. These additional design requirements were previously provided in an extended discussion of the need for the 13.8 kV System in response to Information Request DOC-83.

First, as to the desire to update the design and increase operating margins, the existing system operating margin was consumed by addition of loads over the 40-year life of the plant. Addition of new distribution capacity (at whatever voltage) was mandatory to recover margin and have reliable safety switchgear and breakers. The breakers were discussed in a 2003 capital project summary sheet as the Company began to explore a license extension. We provide a copy of this document as Attachment D to this response that addresses this need. An example of this was the 4 kV System which had essentially no margin to accommodate additional load. We ultimately concluded that adding busses at 13.8 kV addressed all of the design requirements including the additional capacity for approximately the same investment.[10]

While the design requirements were complex, they were also safer to install in a separate area as a new 13.8 kV System, rather than modify or replace the 4 kV

[10] The 13.8 kV system provided significant improvement in electrical system operating fault margin on bus 11 (from -1% to +43% with EPU loading) over the former 1960's 4 kV system. The existing 4 kV system interrupting fault current would have been exceeded by 1%. The new 13.8 kV system would accommodate new loads with 43% margin to the fault interrupting current rating and with room to grow as additional loads were added.

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System on a piecemeal basis. The 4 kV System consists of 6 busses and 36 cubicles with rotating spare breakers. The existing 4 kV System and room were not designed to facilitate being taken out of service for replacement, because the electrical systems must operate continuously to protect the health and safety of the public at all times.

Busses 11 & 12 were replaced with the 13.8 kV project. The addition of the 13.8 kV busses freed up additional cubicles in addition to 4 kV breakers spares for use in maintaining the remaining 4 kV breakers. The cubicles were experiencing tracking deterioration and if not aligned, this interfered with safe operations. Specifically, if the cubicles are not aligned, it makes it difficult to rack a breaker in and out of its cubicle and potentially could electrically short across the bus. *See* Attachment E to this response, Equipment Improvement Long Range Plan Request (EIR) for Breakers and Switchgear October 23, 2012.

Note that this project also incorporates the attached EIR that was tracked as PRG Log # 2011-008, Protective Relay Replacement 4.16 kV Switchgear. *See* Attachment F to this response. That project had been stand-alone, but was later merged with this project per the PRG meeting minutes from April 9, 2012. The funding for the two portions of this project has been broken out for each portion separately and in total in the Long Range Plan Data section below.

The decision to add new distribution capacity at a different voltage was also influenced by the obsolescence of the 4kV equipment.[11] The 4 kV horizontal, magnablast breakers and switchgear were original design equipment that was obsolete and no longer supported by the vendor. Further, the breakers themselves are no longer available. Spare parts to prolong breaker life are difficult to find.

Finally, when we decided to install the 13.8 kV busses, we needed to replace the 1R and 2R transformers to provide 13.8 kV voltage to the new 13.8 kV busses to feed the reactor feed pump, condensate pumps, and recirculation MG set motors. In addition, the replacement of the 1R and 2R transformers was needed due to aging and operating considerations. We note that these transformers (1R

[11] The 4 kV breakers are horizontal magnablast breakers that are no longer manufactured by GE which has resulted in increasing difficulty in maintenance, reliability, and availability issues with adequate spare parts for rebuild. The four remaining busses and switchgear have been evaluated for LCM options necessary to replace or upgrade some (or all) of the remaining 4 kV busses and breakers at some point in the plant's remaining period of extended operation to ensure safe operation of the plant through the end of life.

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and 2R) are different than the transformer major modification that is discussed below.

The original 2R transformer was a 50 MVA, 3 winding with low voltage Automatic Load tap changers Delta/wye/wye 34.5/4.16/4.16 kV. The 2R transformer was installed in 1985 when the Unit Auxiliary Transformer was replaced.

The original 1R transformer was a 37.3 MVA, 3 winding with fixed tap no auto load tap changing HV's 33,333/37,333 KVA LV's 16,667/18667 KVA wye/wye/wye 115/4.16/4.16 kV. The 1R transformer was of 1967 vintage (47 years old). The original 1R transformer was recognized as a low margin transformer from 1998 re-rate from 1670 MWT to 1775 MWT. Further, the existing 1R transformer did not meet Company standards for operability.

The Company's long range planning prior to developing the LCM/EPU Program included 1R transformer replacement. We provide a copy of this document as Attachment G to this response that addresses this need. The 1R transformer would have had to serve as a reliable source of off-site power to a nuclear plant for 63 years (2030) at the end of plant life, well beyond typical service life. The 1R transformer would likely have had to been replaced for reliability, and nuclear risk mitigation during the remaining plant life as noted in the long-range plan.

The 2R transformer would have been 45 years old in 2030, but since the 2R transformer provides the plant's primary source it is loaded at approximately 50% of rating for nearly 100% of the remaining service life and thus undergoing a shorter service life than the 1R transformer. While neither the 1R nor 2R transformers were experiencing equipment degradation concerns indicative of near term replacements (i.e., approximately 5 year time frame) both transformers would likely have reached a point of operation where there replacement would have been pursued to ensure high reliability of off-site power for the remaining plant operating period.

The 13.8 kV modification is one where we have attributed the work to LCM work (O'Connor Schedule 30, as supplemented in response to DOC-58, line 12). As we considered the long-term viability of the plant we concluded that adding significant distribution capacity upgrades would have been necessary for the plant to remain viable for the extended license period irrespective of the uprate.

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PRNM

This modification included design, engineering, and installation of a GE Nuclear Measurement Analysis and Control power range neutron monitoring system (PRNM) to replace the station's old analog monitoring systems. This modification also included an upgrade of the Plant Process Computer to a state-of-the-art processing system. Each of the four considerations discussed above were part of our decision to replace the existing PRNM system and to categorize the project as unavoidable LCM.

This equipment did not perform well and needed to be replaced. In regards to the service-related degradation, testing showed that the system was experiencing performance-related degradation. In response to a repeated failure of an electrolytic capacitor in a safety-related flow controller, we undertook a major effort to identify those key electronic components susceptible to aging effects. This evaluation was based on EPRI guidelines for managing such effects (TR1008166 Guidelines for the Monitoring of Aging of I&C Electronic Components, October, 2004 and TR1003568 Collected Field Data on Electronic Part Failures and Aging in Nuclear Power Plant I&C Systems, September, 2002).

Related to the design consideration, design deficiencies in the existing system began emerging that caused the site to modify it. For example, the HI-HI Trip APRM output to the Reactor Protection System (RPS) was masked by the INOP output during quarterly system functional testing. While this limitation may have been accepted earlier in plant life, increased emphasis on assuring that all aspects of required surveillance testing be met resulted in the need to modify the flow control trip reference card to allow the HI-HI Trip output to be tested individually.

With regard to end-of-life considerations, the age of several components of the existing PRNM system meant that these components needed to be replaced or repaired to support operations through 2030. Those components identified to be susceptible to one or more of the aging mechanisms were replaced, refurbished, or placed on a PM schedule to manage the effects. This effort was initially known as ARDEC (Age Related Degradation of Electronic Components). It was eventually merged into the PM program. Most ARDEC components were individual circuit boards in transmitters, trip units, power supplies, or alarm circuits. As a result, they could be replaced with spare units which had already been replaced or refurbished and then cycled through the same process refurbishment/replacement process. However, there were a number of systems that contained so many individual electronic components

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susceptible to aging effects that it was impossible to efficiently cycle each subcomponent through such a process while maintaining the operability of the system. Thus, the only feasible solution was a wholesale system replacement.

The nuclear instruments (NI) are examples of just such systems. The NIs are made up of the Startup Range and Power Range instruments which monitor the neutron flux of the core throughout all modes of reactor operation, even when shutdown. This system measures the reactor core parameters and provides the operator information on the operation of the core. A failure of this instrumentation would have potential reactivity impacts. Source Range Monitors (SRMs) and Intermediate Range Monitors (IRMs) are used during shutdown and refueling conditions while the Average Power Range Monitors (APRMs) and Rod Block Monitors (RBMs) are used during power operations (the range of each instrument type overlaps). The original APRM system (including flow converters and transmitters) contained in excess of 170 electronic boards distributed over 8 chassis in 5 panels.

The analog components of the APRMs and RBMs are what were replaced in 2009 under the power range neutron monitoring system. Since these components are required to monitor the core parameters during power operations, they could only be replaced wholesale during a refueling outage.

For the obsolescence criterion, the prior system was an analog system that presented several operational and practical issues. Due to its age, we had for some time had difficulty in obtaining replacement equipment. For instance, obtaining replacement parts for the APRMs and RBMs had already become an issue. Moreover, General Electric – Hitachi's (GEH) was not expected to support this old analog technology for much longer because GEH replacement system is a digital system that had been designed for and installed at 22 other sites prior to Monticello. These new digital parts and equipment are incompatible with the existing analog system and cannot be used to repair or replaced analog components.

In addition to alleviating the aging electronic component issue, replacement provided a number of improvements making the system more reliable and easier to maintain. For example, while the quarterly calibration of the flow instrumentation associated with the original analog system required the plant to be in a risky ½ SCRAM condition for two 8-hour days, the calibration requirement of the digital systems flow components was reduced to bi-annually and did not require ½ SCRAM conditions. Similarly, while the every-2000-

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operating-hours calibration of the LPRMs required operators or reactor engineers to tweak a potentiometer on each of the 96 LPRM cards, the digital system calculates the new gain values with the help of the plant process computer and, once validated by the operator, gets automatically updated with the push of a button. As such, both the cost of maintaining the system and the risk associated with performing the required testing of the system decreased substantially.

A consideration of the four factors resulted in our determination that replacement, rather than repair, of the PRNM was needed to support continued operation of the plant through the period of extended operation regardless of energy/capacity output. Thus, we categorized the project as unavoidable LCM. *See* O'Connor Schedule 30, as supplemented by our response to DOC-58, line 1.

HP Turbine Replacement

Xcel Energy had replaced the HP turbine at Monticello in 1996 (after 25 years of operation) with major recalibration in 1998. Our nuclear insurer (NEIL) requires that our turbines be inspected and overhauled approximately every 10 years. This requires dismantling the turbine, preparing a detailed assessment, repairing or replacing components, and bringing the turbine back to 'like-new' condition. After the major recalibration in 1998, the next major overhaul was scheduled for the 2009 outage (consistent with our NEIL obligations).

As it relates to the four categories mentioned above, there are two primary reasons we concluded the HP turbine should be replaced, rather than repaired, as part of the LCM/EPU Program. First, we recognized the existing HP turbine would present end-of-life considerations during the extended life of the Monticello plant. The first turbine lasted 25 years, and we did not find that the current turbine would last 35 years, regardless of the uprate. While it was not worn out yet, we recognized it needed to be replaced ultimately to support the plant to 2030 and concluded it was better to accelerate that replacement to maximize the value of the equipment and spread its cost over the remaining life of the plant. We note that, industry experience has shown that these types of turbines age, they need more frequent repair for cracked blades and ultimately require replacement. Partial replacement of the blades is not the preferred repair path because it could lead to vibration and imbalance conditions due to mixing old and new blades. In addition, the mixed blades could impact steam flow efficiency. Thus, in light of this conclusion that the turbine would reach the end of its useful life prior to expiration of the extended operating license, we planned

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for this work in the 2009 outage as that replacement could be undertaken in lieu of the required major overhaul.

The second reason for replacement (rather than repair) related to the obsolescence of the existing turbine and the need to modernize this equipment to improve reliability and efficiency. Since 1996 when the existing turbine was placed in-service, GE has made major advancements in turbine design. Replacing the existing HP turbine with a turbine with an Advance Vortex design provides superior reduction on secondary losses and profile losses. This is due to the new design providing efficiencies across the turbine which reduced steam flow losses, thus resulting in greater steam flow. The Advance Vortex design also incorporates a monoblock rotor design which is not prone to blade or rotor failures, and thus improves the reliability of the turbine. Finally, the Advance Vortex design incorporates the latest modern manufacturing technique to improve the quality and consistency of manufacturing vanes which is the bases of the Advanced Design Steam Path (ADSP).

System performance considerations also impacted our decision to replace the HP turbine. For a number of years we experienced about 5 mil of vibration on the turbine floor from an unknown source in the rotating elements of the turbine. This raised a serious concern that the vibration could result in fatigue failure if this vibration continued over the long term. We had worked to resolve the vibration but were unable to do so. Our engineers believed that the cause of this vibration was the existing HP turbine. Since the HP turbine has been replaced, the vibration has ceased.

As it pertains to our allocation between LCM and EPU, even though the new HP turbine was sized to support additional steam flows, we were able to determine that the cost of the replacement turbine was comparable whether or not the EPU was undertaken. As a result, we attributed the cost of the turbine itself as unavoidable LCM. *See* O'Connor Schedule 30, as supplemented by our response to DOC-58, line 4. We note that this modification included the installation of a new vibration monitoring system, which was complicated by the EPU. *See* O'Connor Schedule 30, as supplemented by our response to DOC-58, line 34. Thus, we allocated the costs for the installation of the new vibration monitoring system to the EPU. Note that Schedule 29 of Mr. O'Connor's testimony contained an error in the chart describing the HP turbine. This was corrected in our response to DOC-123 which provides a corrected Schedule 29.

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Steam Dryer
As it related to the four categories outlined above, there are two primary reasons we concluded the steam dryer should be classified unavoidable LCM regardless whether the uprate had been pursued: (1) service-related degradation; and (2) design/operating margin. While we acknowledge the steam dryer was an important component of the NRC's analysis in deciding whether to grant our EPU license, we conclude that the steam dryer would have needed to be replaced prior to 2030 regardless of the uprate. As a result, based on our avoidable EPU versus unavoidable LCM analysis, we concluded that the steam dryer replacement is most appropriately categorized as unavoidable LCM.

The critical factor that lead us to classify this modification as unavoidable LCM was service-related degradation considerations with the existing steam dryer. We provide an extensive discussion of the need to replace the steam dryer to support long-term operations in response to Information Request DOC-72. As described in more detail in that answer, the original steam dryer was designed in the mid-1960s. Over time, its operability decreased and we believe the steam dryer could not have been maintained through 2030 whether or not we pursued the uprate.

The steam dryer was experiencing performance issues and continuing performance-related degradation such that the critical factor performance of this equipment was marginally acceptable at the time we began planning for the LCM/EPU Program. An example of a performance-related degradation that supported our decision was the original steam dryer's inability to maintain Moisture Carryover (MCO) levels.[12] *See* Attachment H to this response. The most significant impacts of the MCO are on flow-accelerated corrosion and shutdown radiation levels. Both are impacts on maintenance. Increase in corrosion adds to wear on steam related components such as the turbine. An increase in radiation levels makes maintenance activities more difficult and costly.[13] The new steam dryer is operating with MCO levels that are a factor of

[12] The original steam dryer was designed to maintain MCO to 0.1% or below. While the original steam dryer typically stayed near this original MCO design level, some operation above this level did occur. For instance, in 2009, levels reached 0.11%. Further, the original steam dryer had three cracks with two being due to fatigue failure and one from intergranular stress corrosion cracking. Stress analysis for evaluation of acoustic loads on the original steam dryer were pursued based on feedback from our vendor that was expected to be able to evaluate the dryer with no need for physical modifications. Physical modifications were possible but would be extremely radiation dose intensive and would be costly to analyze and install.

[13] Both had been evaluated for increasing MCO from 0.1% to 0.5%. It was predicted that shutdown radiation levels of certain components would increase by a factor of up to 11.3. These issues would have increased maintenance costs if not corrected.

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10 or more below the design MCO value of 0.1% which will reduce future maintenance costs.

Also related to the service-degradation criterion, was the fact that repairing the old steam dryer would have been expensive due to the very radiation dose intensive nature of the work related to such a repair. The existing GE dryer was in-service for 40 years and thus had become irradiated.

From a risk-management perspective, another area of concern was the prescriptive requirements imposed by the BWR Vessel Internals Program (BWRVIP) for inspection of vessel internals. These requirements were targeted at old steam dryers like the one at Monticello. This program requires that we comply with any recommendations arising out of the inspection or submit an explanation to the BWRVIP executive committee. Further, the results of the inspection are reported directly to the NRC. After an issue is reported, the NRC will require corrective actions with industry-wide applicability. The new steam dryer installed at Monticello is the first of its kind in the United States. As a result, the only time that an issue would be reported to the NRC that would require corrective actions would be related to our specific equipment rather than being subject to issues related to all aging vessel internals. In contrast, if an issue came up related to the old steam dryer vessel internals or those at any other plant, this would be subject to NRC mandated corrective actions. This raised the risk of extended outage if we were required to replace the old dryer and prohibited from operating until it had been replaced. This risk existed regardless of whether we pursued the EPU.

Due to the service-related and design/operating consideration, this modification is one where we have attributed the work to LCM work (O'Connor Schedule 30, as supplemented in response to DOC-58, lines 10, 11, 18, and 24). As we considered the long-term viability of the plant we concluded that replacing the steam dryer would have been necessary for the plant to remain viable for the extended license period irrespective of the uprate and in late 2007, GE recommended we replace, rather than modify the existing steam dryer.

Transformers
End-of-life considerations were the primary factor that drove our decision to replace, rather than repair, the original main GSU and 1AR transformers, which were 40-year-old and 60-year-old, respectively. Evaluation by Xcel Energy

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Transmission and Distribution transformer expert concluded replacement was required for both the main GSU and 1AR transformers as they were nearing end of life due to insulation degradation. Both of these transformers were identified for replacement in the 2003 capital projects summary sheet. We provide a copy of the capital projects summary sheet from 2003 as Attachment G to this response that addresses this need. Additionally, on the GSU main transformer, we had received a significant operating experience report from INPO, requiring that we inspect the GSU transformer because industry experience showed it was a vulnerable system and to replace it as necessary. This all led us to conclude that the transformers would need to be replaced regardless of the uprate and replacing this system soon was in the best interest of the plant.

A second factor that supported replacement of these transformers was performance degradation considerations. Through transformer monitoring, via oil analysis, we determined that there was a gassing problem with the GSU transformer that was resulting in transformer degradation within the transformer that potentially could lead to in-service failure. See Attachment I to this response. Replacement of the GSU transformer was the best option to correct this gassing issue.

The replacement of the 1AR transformer is one where we have attributed the work to LCM work (O'Connor Schedule 30, as supplemented in response to DOC-58, line 17). As we considered the long-term viability of the plant, we concluded that replacing this system would have been necessary for the plant to remain viable for the extended license period irrespective of the uprate. By contrast, the main transformer is allocated between LCM and EPU (O'Connor Schedule 30, as supplemented in response to DOC-58, line 26) since we needed to replace the GSU but recognize that we did so with a larger one to accommodate the increased energy production from the uprate.

Licensing
The licensing effort to obtain the EPU was allocated solely to the EPU as described in Schedule 30, line 25, as supplemented by our response to DOC-58. Note that Schedule 29 of Mr. O'Connor's testimony contained an error in the chart describing the Licensing. This was corrected in our response to DOC-123 which provides a corrected Schedule 29.

Other Modifications
As described in Schedule 29 and 30 (as supplemented by our response to DOC-58, there were a series of smaller projects (17 Child Work Orders) for other

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smaller projects, totaling about $34.6 million or about 5% of the overall Program total. We provide the following discussion about selected projects within this category. Note that Schedule 29 of Mr. O'Connor's testimony contained an error in the chart describing the Other Modifications category. This was corrected in our response to DOC-123 which provides a corrected Schedule 29.

Additional EPU Projects
We undertook a number of other projects that were specifically needed as part of the uprate. These projects are shown on O'Connor Schedule 30 (as updated by our response to DOC-58) lines 19, 20, 21, 22, 23, and 24. All of these projects were undertaken specifically to address the increased capacity, flow and heat associated with the uprate. Attachment J to this response is a 2003 capital project summary sheet related to EPU projects.

Additional LCM Projects
We undertook a number of other projects that were specifically needed as part of the plant's life-cycle maintenance program. These projects are shown on O'Connor Schedule 30 (as updated by our response to DOC-58 lines 2, 3, 6, 7, 8, 9, 14, 15, and 16). All of these projects were undertaken to address specific issues that needed to be dealt with to facilitate the long-term operations of the plant. The descriptions in Schedule 30 (as supplemented by our response to DOC-58), provides the rationale for all of these projects. *See* Attachment K to this response.

Generator Rewind
Line items 14, 15, and 16 of O'Connor Schedule 30 (as supplemented by our response to DOC-58), addresses our project to rewind the generator at Monticello.

As it relates to the four criterions as outlined above, the generator rewind was driven by considerations related to the end-of-life and service-related degradation considerations of the existing generator.

With regard to end-of-life considerations, in our 2003 evaluation of the plant in support of our license extension analysis, we recognized that the existing generator was original equipment and needed significant work to support long-term operations at the plant. We also note that, when we moved the old rotor to Chicago after its removal, we had the contractor conduct a test of its performance ability. The equipment failed that test, meaning it was at the end of

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its useful life and was near the stage where it would have failed had we left it in place.

We considered replacing the generator entirely because it was over forty years old and nearing end of life. However, on further analysis, we concluded that major components of the generator were still viable and that rewinding the insulation within the generator was sufficient to bring the equipment to adequate operating standards for the long-term. The Company has significant experience with rewinding generators as this is a common repair needed for older generators and we were confident that this action would support continued operations.

Along with the generator rewind, the Company replaced the exciter as it had reached its end of life and was showing service related degradation. The Company evaluated replacement with a static exciter but a like-for-like replacement was determined to be the most cost effective.

The original exciter was capable of supporting plant operation at EPU power levels however GE recommended that the exciter be replaced in any event to ensure reliable operation over the next 20 years of plant operation due to its age. The original exciter was original plant equipment and therefore had been in service since 1971, or approximately 40 years when it was replaced; thus it was at or beyond the expected designed service life. A 2003 capital project summary sheet for the exciter is provided as Attachment L to this response. The following issues had to be considered for a 40 year old exciter:

a. Condition of stator insulation and winding support components
b. Field winding issues (distortion, fatigue, etc)
c. Condition of the cooling water tubes in the air cooling section
d. Condition of misc components (collector ring, control wiring and associated components, etc)
e. The exciter had experienced elevated vibrations (bearing and structural) over most of its life

We did investigate static excitation systems as a potential replacement for the exciter. Significant challenges were identified and it was concluded that installing a static excitation system was possible but would be unduly expensive. As a result, Company personnel concurred that it was prudent to replace the exciter and made the decision to install a replacement like for like rotating exciter.

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The decision to replace the stator water cooling was based on design and service-related degradation considerations. On the design front, replacing the stator water cooling resolved a single point vulnerability that we were experiencing with the existing system. The replacement system provides for a second heat exchanger in the event a leak was to occur in the first one, thereby creating redundancy and increased reliability. Also, replacement addressed tube degradation issues related to the original stator water cooling equipment.

End-of-life and service-related degradation considerations drove the decision to rewind the generator and replace the static exciter, the stator water cooling equipment. In regard to allocating these costs, we attributed these modifications to LCM as, shown on Schedule 30, as supplemented in response to DOC-58, lines 14, 15, and 16, because the generator was already sized sufficient to support operations at the increased capacity associated with the uprate. As a result, we did not do any additional work on this modification beyond what was necessary for life cycle management purposes.

Additional Combination Projects
We undertook a number of smaller projects that were combination projects that addressed aging equipment that needed to be upsized to address the uprate. These projects are shown on O'Connor Schedule 30 (as updated by our response to DOC-58, lines 30, 33, and 35). All of these projects were undertaken to address specific issues that needed to be dealt with to facilitate both the long-term operations of the plant as well as to address the additional flow/heat/capacity necessary for the uprate. Our descriptions in Schedule 30 (as supplemented by our response to DOC-58), provides the rationale for all of these projects.

In addition, we provide the additional discussion about line-item number 30 relating to the Cross-Around Relief Valve ("CARV"). This modification replaced the CARV and piping to allow greater flow capacity for EPU operation. In 2009 we removed the original CARVs, installed spares, and shipped the original CARVs to Wiley Labs to reset the set points. The CARV work is included in the feedwater system major modification.

The CARV replacement was somewhat complicated due to the fact that high radiation levels during plant operation prevented the ability to inspect the as-built system installed configuration prior to the 2009 outage. This was a consequence of the decision to move forward on parallel paths to make resources available to

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our customers as soon as possible. Therefore, adjustments to the piping and pipe support design had to be made during installation.

c) In response to subpart (a) and (b) above, we describe our decision to replace or repair each particular piece of equipment. Specifically to the example raised in this question, please see our discussion in part (b) above on the condensate demineralizer replacement and our consideration of relining the vessels and why we chose the replacement option.

Attachments E and F are marked "Non-Public" in their entirety as they contain confidential security data that the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). Due to security information policies and concerns, the information provided in this response has been marked Non-Public. The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp. 3.

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Northern States Power Company

Northern States Power Company

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Replace Feedwater Heaters		Monticello NGP		
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply - NSP	2003	2012	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$ 1,000,000	$ 1,000,000	$ 2,000,000	$2,000,000

DESCRIPTION:
Service life of feedwater heaters requires they be replaced to support the extended period of operation. There are 5 heaters in each of two trains of feedwater.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability and efficiency for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc...):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

Annual General Capital Requirements

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Capital Projects <$1M		Monticello NGP		
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply - NSP	2003	2012	TBD	TBD

ESTIMATED CASH FLOW					
ANNUAL	PREVIOUS YRS	Annually			
	$0	$ 7,000,000	-	-	-

DESCRIPTION:
Example of annual capital projects are: Feed Pump Motor and Pump Replacement, Cooling Tower Repair, Replace Drywell coolers, CRD Stub tube UT inspection for IGSCC in HAZ of housing-to-stub tube welds, refurbish the recirculation suction and discharge valves and replace stems, replace RPV closure stud bolts refurbish, replace internals of the SRVs, implement long term plans for safe end weld overlays or replacement, replace refueling and seal bellows carbon steel components, replace the recirculation pump shafts, impellers, motors, replace and upgrade battery cells, and refurbish RWCU pumps, motors and Hx.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Feedwater & Main Steam Pipe Replacement		Monticello NGP		
OPERATING CO	**DATE SUBMITTED**	**IN SERVICE DATE**	**PLANT CONTACT**	**JDE BU Number**
Energy Supply – NSP	2003	2012	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$ 500,000	$1,500,000	$1,000,000	$500,000

DESCRIPTION:
Replace portions of feedwater and main steam pipe that are susceptible to erosion and corrosion.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability and safety for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
4KV Breaker Replacement		Monticello NGP		
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	IDE BU Number
Energy Supply – NSP	2003	2012	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012
	$0	$5,000,000	-	-	$5,000,000

DESCRIPTION:
Replace 4 KV breakers due to aging and wear.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc,...):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

PUBLIC DOCUMENT:
TRADE SECRET INFORMATION AND
NON-PUBLIC DATA EXCISED

Docket No. E002/CI-13-754
DOC Information Request No. 124
Attachments E & F – Page 1 of 1

Monticello Nuclear Generating Plant

NON-PUBLIC DOCUMENT: CONTAINS TRADE SECRET INFORMATION ENTIRE DOCUMENT IS NON-PUBLIC

Attachments E and F contain confidential security data that the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). Due to security information policies and concerns, the information provided in this response has been marked Non-Public. The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. Thus, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp. 3.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Transformer Replacement		Monticello NGP	$0	$4,000,000
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2003	2011	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2007	2009	
	$0	$2,000,000	$2,000,000	

DESCRIPTION:
Replacement of the Main Transformer and the 1R Transformer to support operation for 20 more years. Potential synergies exist with an extended power uprate project. Xcel has recommended the Main Transformer be replaced to due its service life.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing.
2)

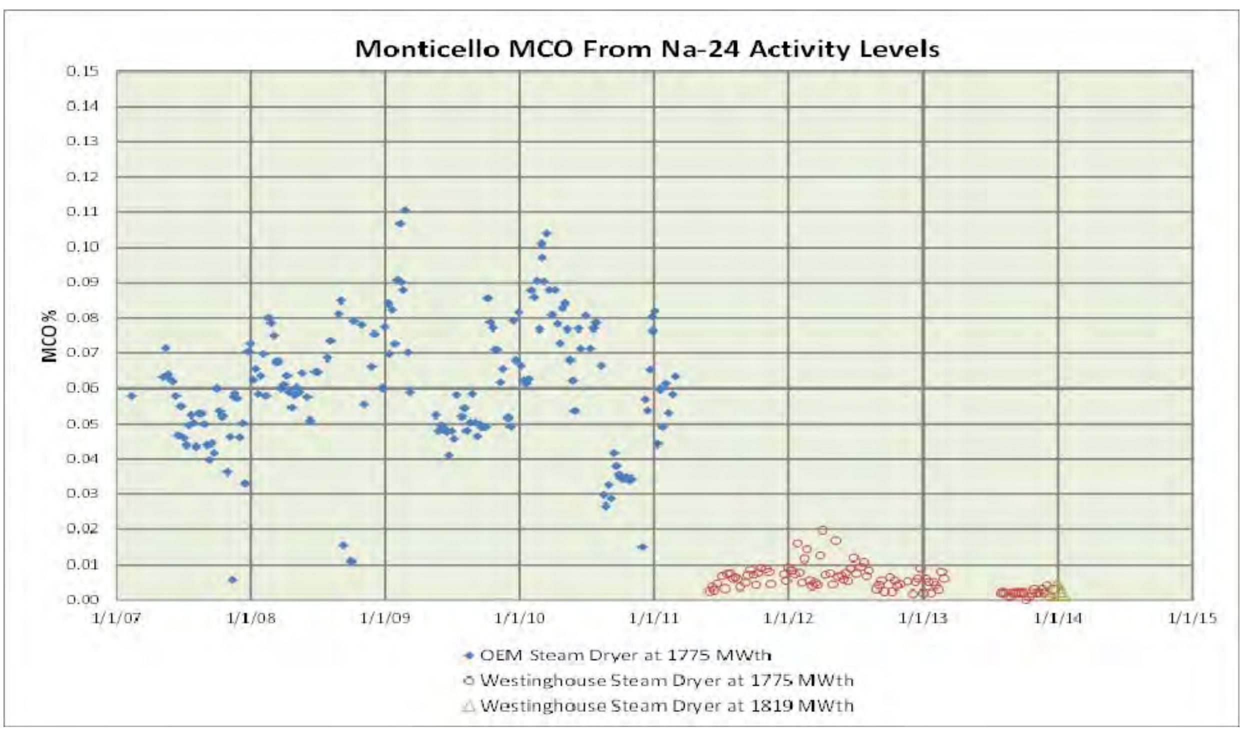
FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

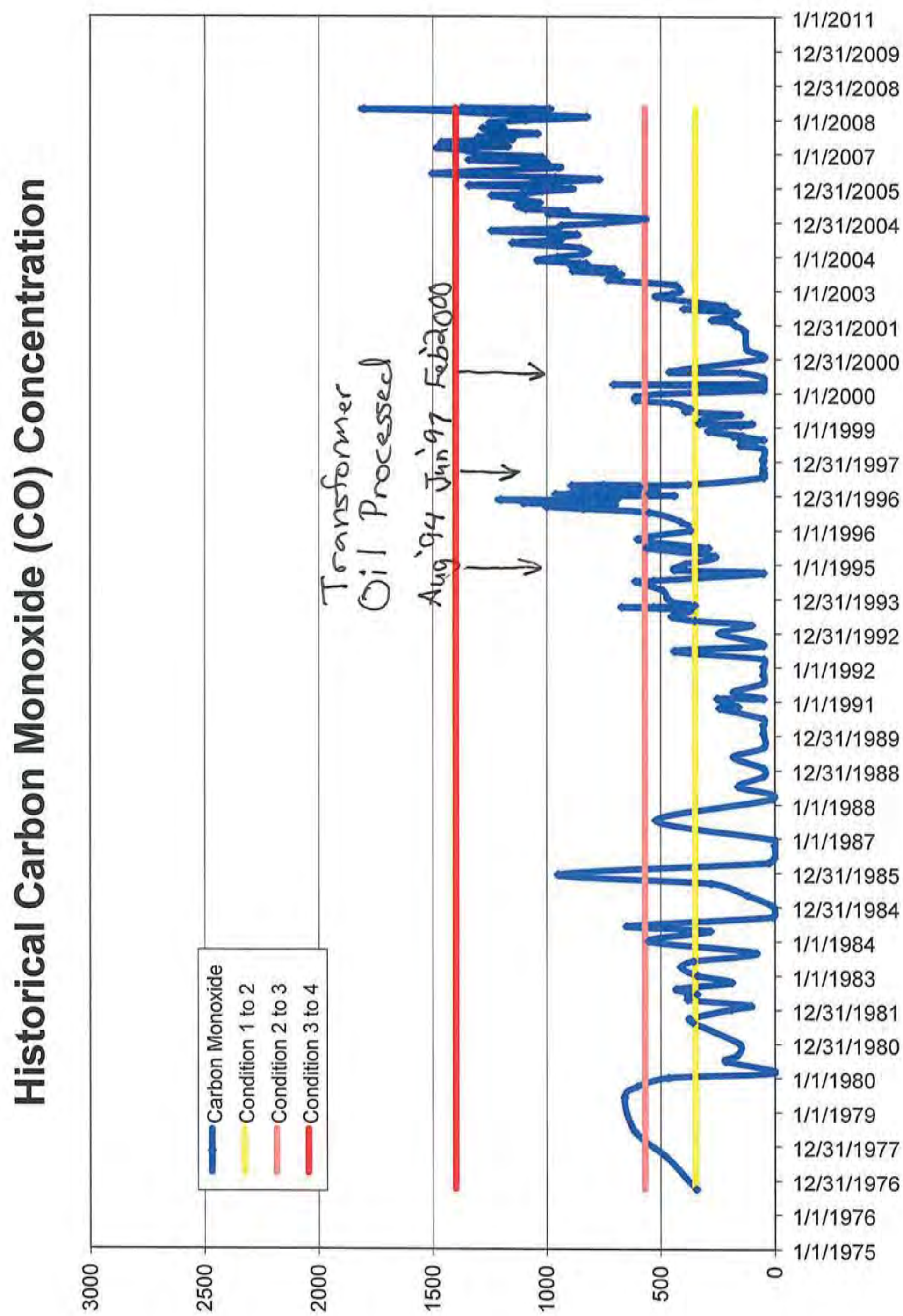
ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

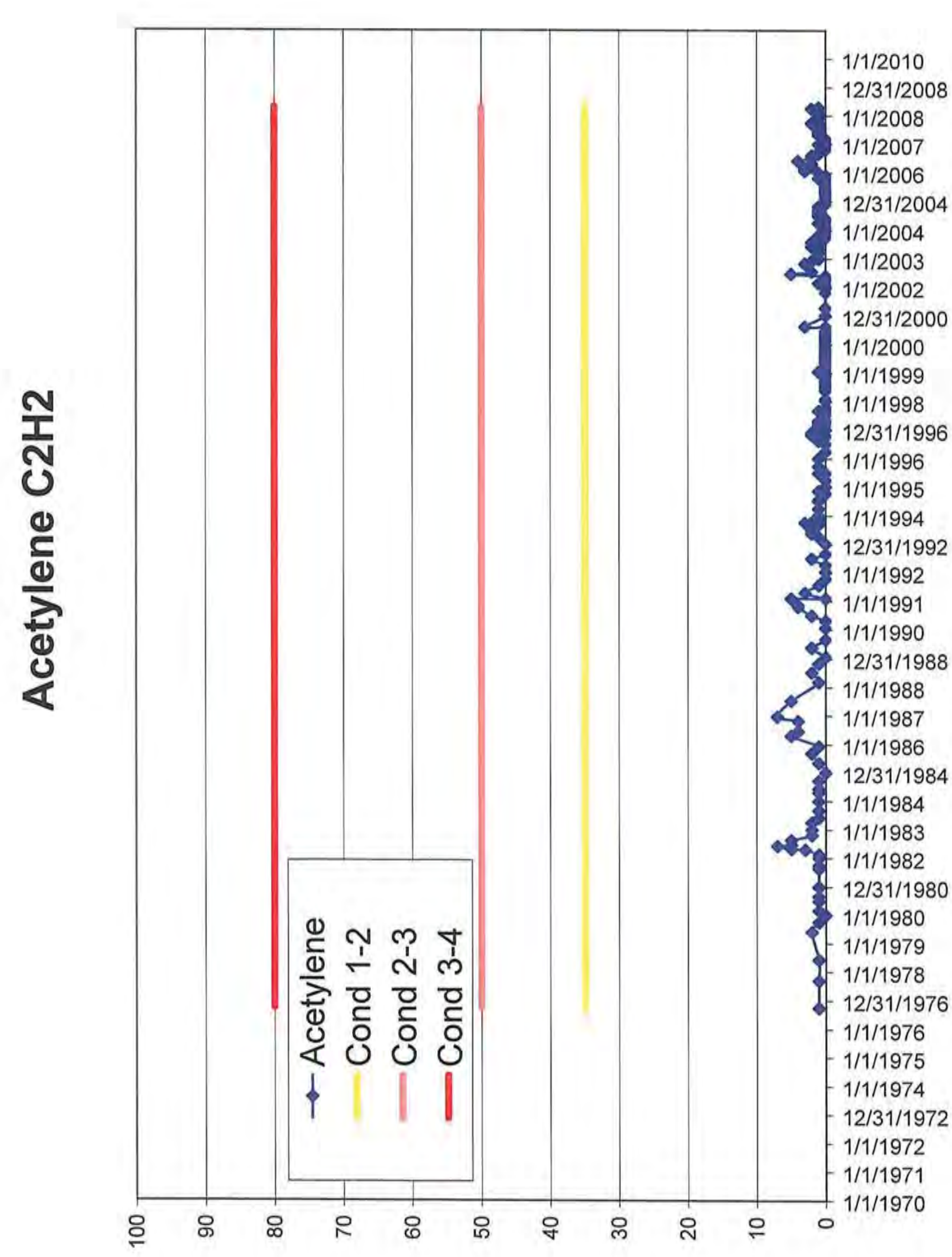
Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

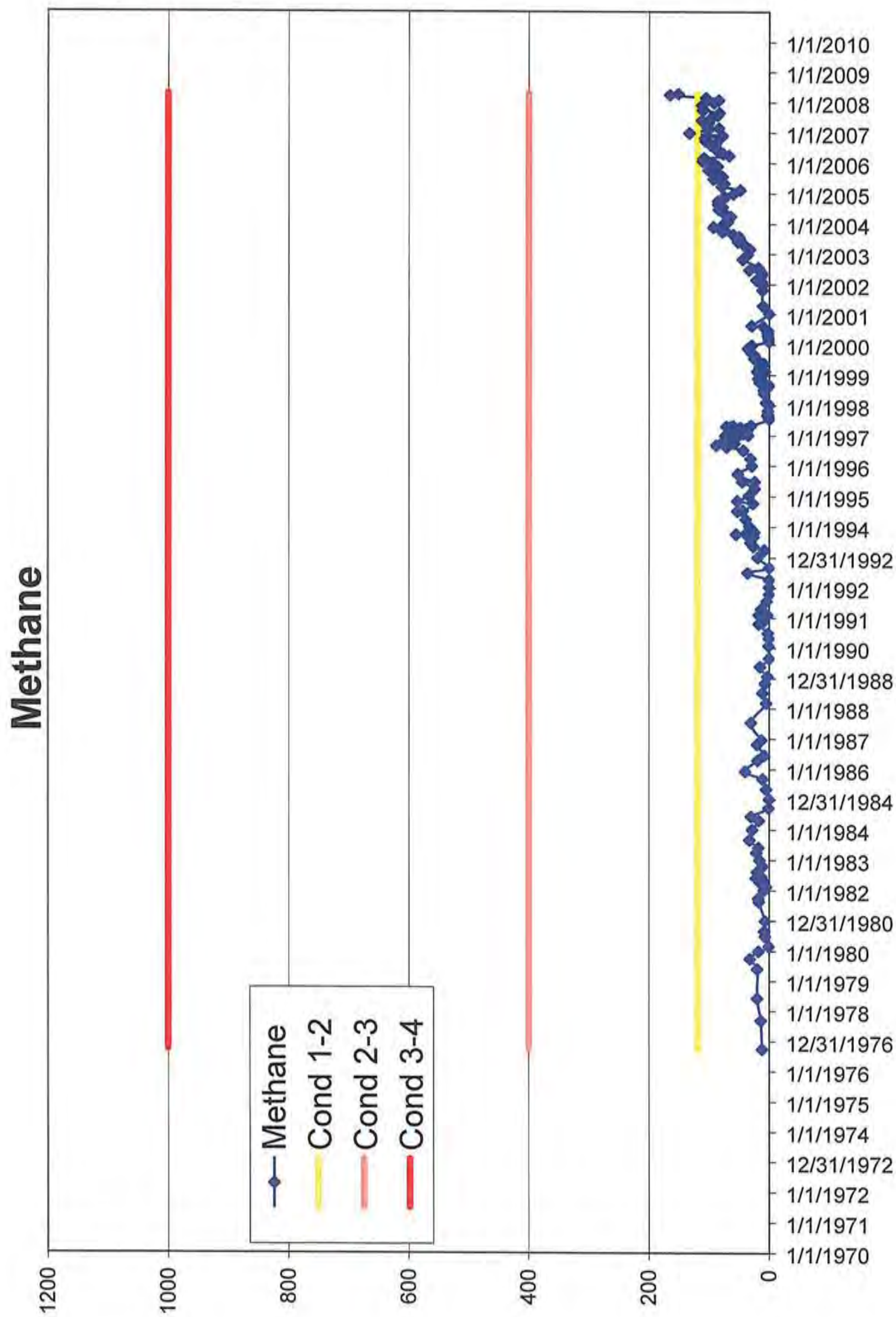

Monticello MCO From Na-24 Activity Levels
MCO %
0.15
0.14
0.13
0.12
0.11
0.10
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
1/1/07
1/1/08
1/1/09
1/1/10
1/1/11
1/1/12
1/1/13
1/1/14
1/1/15
OEM Steam Dryer at 1775 MWth
Westinghouse Steam Dryer at 1775 MWth
Westinghouse Steam Dryer at 1819 MWth

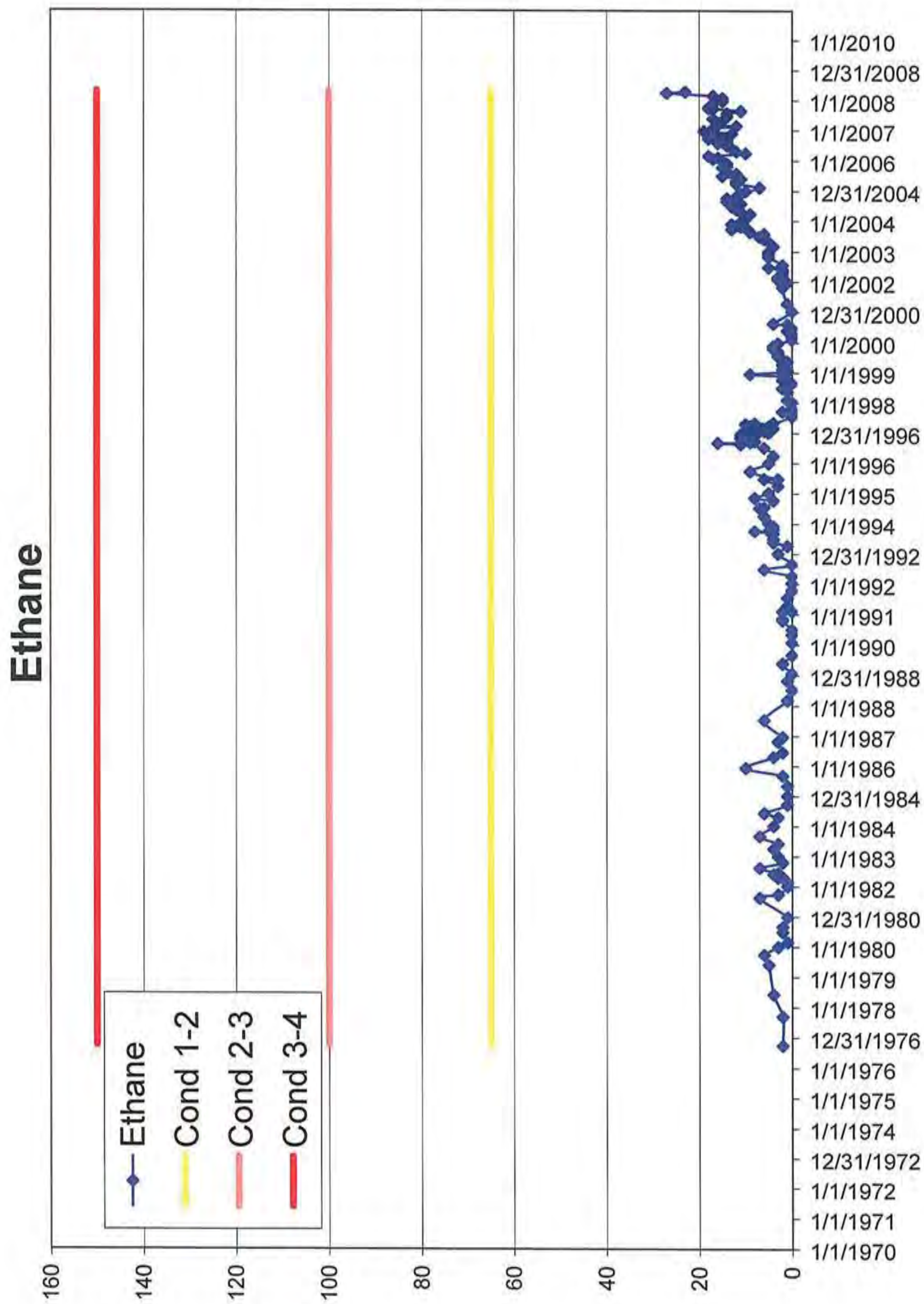
Docket No. E002/CI-13-754
DOC Information Request No. 124
Attachment I - Page 1 of 11



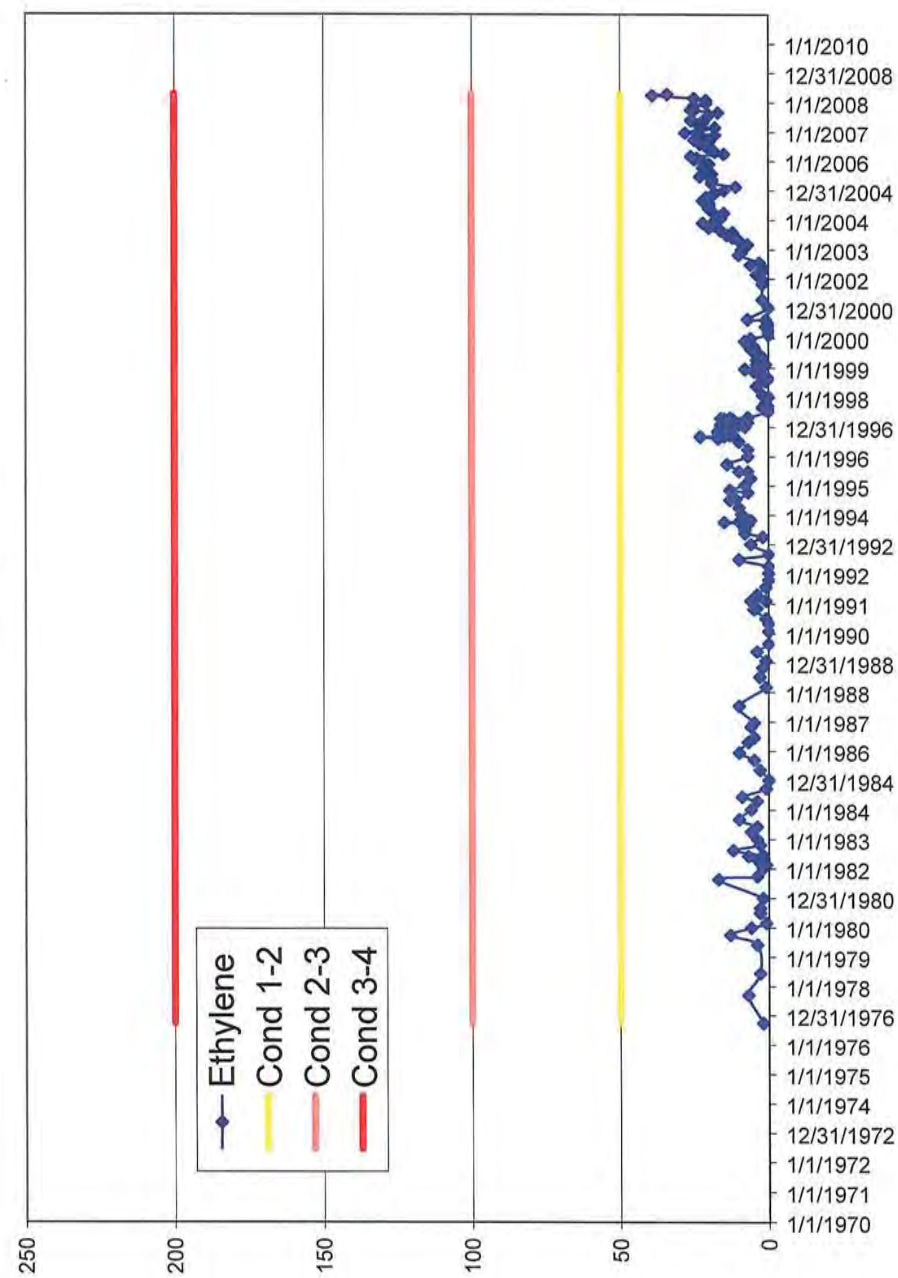
Northern States Power Company


Acetylene C2H2
Acetylene
Cond 1-2
Cond 2-3
Cond 3-4
100
90
80
70
60
50
40
30
20
10
0
1/1/2010
12/31/2008
1/1/2008
1/1/2007
1/1/2006
12/31/2004
1/1/2004
1/1/2003
1/1/2002
12/31/2000
1/1/2000
1/1/1999
1/1/1998
12/31/1996
1/1/1996
1/1/1995
1/1/1994
12/31/1992
1/1/1992
1/1/1991
1/1/1990
12/31/1988
1/1/1988
1/1/1987
1/1/1986
12/31/1984
1/1/1984
1/1/1983
1/1/1982
12/31/1980
1/1/1980
1/1/1979
1/1/1978
12/31/1976
1/1/1976
1/1/1975
1/1/1974
12/31/1972
1/1/1972
1/1/1971
1/1/1970


Methane
Methane
Cond 1-2
Cond 2-3
Cond 3-4
1200
1000
800
600
400
200
0
1/1/1970
1/1/1971
1/1/1972
12/31/1972
1/1/1974
1/1/1975
1/1/1976
12/31/1976
1/1/1978
1/1/1979
1/1/1980
12/31/1980
1/1/1982
1/1/1983
1/1/1984
12/31/1984
1/1/1986
1/1/1987
1/1/1988
12/31/1988
1/1/1990
1/1/1991
1/1/1992
12/31/1992
1/1/1994
1/1/1995
1/1/1996
1/1/1997
1/1/1998
1/1/1999
1/1/2000
1/1/2001
1/1/2002
1/1/2003
1/1/2004
1/1/2005
1/1/2006
1/1/2007
1/1/2008
1/1/2009
1/1/2010


Ethane
Ethane
Cond 1-2
Cond 2-3
Cond 3-4
160
140
120
100
80
60
40
20
0
1/1/2010
12/31/2008
1/1/2008
1/1/2007
1/1/2006
12/31/2004
1/1/2004
1/1/2003
1/1/2002
12/31/2000
1/1/2000
1/1/1999
1/1/1998
12/31/1996
1/1/1996
1/1/1995
1/1/1994
12/31/1992
1/1/1992
1/1/1991
1/1/1990
12/31/1988
1/1/1988
1/1/1987
1/1/1986
12/31/1984
1/1/1984
1/1/1983
1/1/1982
12/31/1980
1/1/1980
1/1/1979
1/1/1978
12/31/1976
1/1/1976
1/1/1975
1/1/1974
12/31/1972
1/1/1972
1/1/1971
1/1/1970

Ethylene


Ethylene
Cond 1-2
Cond 2-3
Cond 3-4
250
200
150
100
50
0
1/1/2010
12/31/2008
1/1/2008
1/1/2007
1/1/2006
12/31/2004
1/1/2004
1/1/2003
1/1/2002
12/31/2000
1/1/2000
1/1/1999
1/1/1998
12/31/1996
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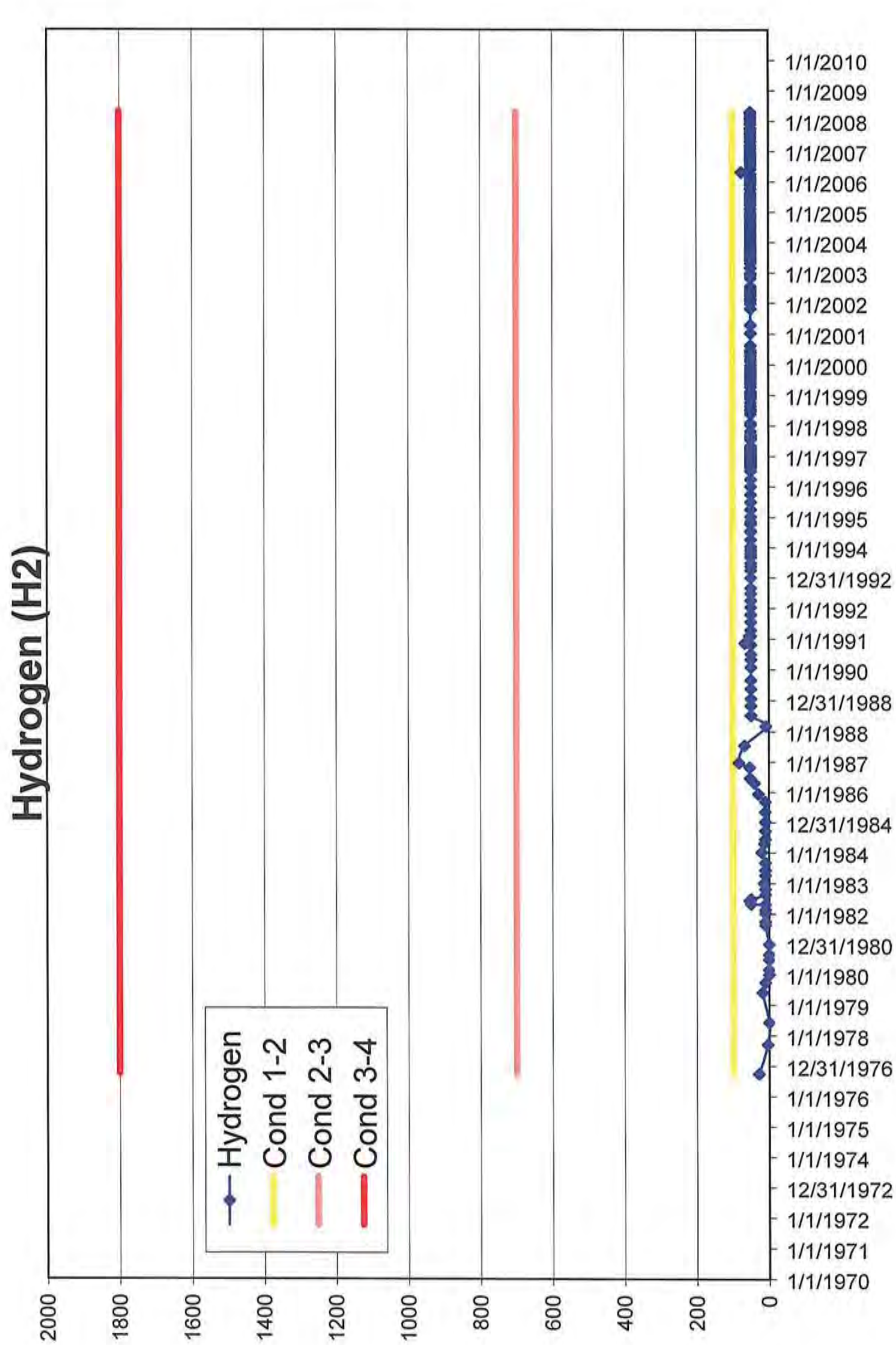
12/31/1984
1/1/1984
1/1/1983
1/1/1982
12/31/1980
1/1/1980
1/1/1979
1/1/1978
12/31/1976
1/1/1976
1/1/1975
1/1/1974
12/31/1972
1/1/1972
1/1/1971
1/1/1970


Hydrogen (H2)
Hydrogen
Cond 1-2
Cond 2-3
Cond 3-4
2000
1800
1600
1400
1200
1000
800
600
400
200
0
1/1/2010
1/1/2009
1/1/2008
1/1/2007
1/1/2006
1/1/2005
1/1/2004
1/1/2003
1/1/2002
1/1/2001
1/1/2000
1/1/1999
1/1/1998
1/1/1997
1/1/1996
1/1/1995
1/1/1994
12/31/1992
1/1/1992
1/1/1991
1/1/1990
12/31/1988
1/1/1988
1/1/1987
1/1/1986
12/31/1984
1/1/1984
1/1/1983
1/1/1982
12/31/1980
1/1/1980
1/1/1979
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12/31/1976
1/1/1976
1/1/1975
1/1/1974
12/31/1972
1/1/1972
1/1/1971
1/1/1970

Monticello D596225 1 M

Labworks #	Date	Acetylene	Ethane	Ethylene	Methane	Carbon Dioxide	Hydrogen	Carbon Monoxide	Oxygen	Date	Comments	% Extracted Gas	DGA Total Combustible Gas
MZ72121	10/1/1976	1	2	2	12	1680	28	343	11	10/1/76			N/A
MZ64409	9/14/1977	1	2	7	14	1700	4	477	3.3	9/14/77			N/A
MZ64350	6/9/1978	1	4	3	20	2600	0	614	3.55	6/9/78			N/A
MZ64184	6/1/1979	2	5	4	20	2550	18	658	15	6/1/79			N/A
MZ64146	10/1/1979	1	6	13	32	3070	10	602	9.44	10/1/79			N/A
MZ64021	1/1/1980	0	3	6	18	1870	0	464	2.69	1/1/80			N/A
MZ64053	3/1/1980	1	1	1	1	37	0	0	0	3/1/80			N/A
MZ63999	7/1/1980	1	2	3	7	2160	0	215	13	7/1/80			N/A
MZ63923	9/1/1980	1	2	3	8	1510	0	166	2.07	9/1/80			N/A
MZ63805	12/31/1980	1	1	2	7	1080	0	153	2340	12/31/80			N/A
MZ63345	8/21/1981	1	7	17	17	2700	10	360	19	8/21/81			N/A
MZ63223	10/1/1981	1	3	4	18	2580	10	374	2.86	10/1/81			N/A
MZ72406	1/7/1982	1	1	2	9	992	10	192	1.25	1/7/82			N/A
MZ72438	2/19/1982	1	1	1	5	645	10	106	0.589	2/19/82			N/A
MZ72473	4/19/1982	3	3	4	16	2100	10	380	1.5	4/19/82			N/A
MZ63143	4/29/1982	5	2	2	9	1920	50	380	11.3	4/29/82			N/A
MZ62960	6/5/1982	7	4	7	22	2400	54	380	5.9	6/5/82			N/A
MZ72579	6/21/1982	5	3	2	13	1750	50	340	4.85	6/21/82			N/A
MZ62804	8/18/1982	5	7	12	20	2310	10	430	16.5	8/18/82			N/A
MZ62623	10/25/1982	2	2	3	11	974	10	189	1.72	10/25/82			N/A
MZ62536	1/4/1983	2	3	4	16	1468	14	337	4.38	1/4/83			N/A
MZ62596	4/6/1983	2	4	6	21	2253	10	412	4.21	4/6/83			N/A
MZ62526	6/7/1983	1	3	4	18	10	10	357	2.11	6/7/83			N/A
MZ62289	9/6/1983	1	7	10	33	2920	10	80	1.88	9/6/83			N/A
MZ62045	1/6/1984	1	4	6	28	736	20	552	1.26	1/6/84			N/A
MZ61964	4/24/1984	1	3	4	17	1140	13	282	1.07	4/24/84			N/A
MZ61759	6/13/1984	1	6	9	30	2560	10	649	8.81	6/13/84			N/A
MZ61256	9/24/1984	1	1	1	1	161	10	10	1.82	9/24/84			N/A
MZ61186	1/8/1985	0	1	0	0	60	10	6	1.09	1/8/85			N/A
MZ72861	5/9/1985	1	1	3	5	1000	10	119	2.24	5/9/85			N/A
MZ60777	9/12/1985	2	2	5	11	1630	10	279	2.87	9/12/85			N/A
MZ60636	12/12/1985	1	10	10	40	2400	29	950	3	12/12/85			N/A
MZ72933	4/23/1986	5	4	7	19	2000	40	25	2.3	4/23/86			N/A
MZ60430	6/19/1986	4	2	5	8	1340	52	0	15	6/19/86			N/A
MZ72889	10/29/1986	4	3	6	20	1700	53	0	9.6	10/29/86			N/A
MZ59951	12/23/1986	7	2	5	13	1050	83	0	1.93	12/23/86			N/A
MZ59282	7/17/1987	5	6	10	30	2400	67	520	4.6	7/17/87			N/A
MZ73022	3/6/1988	1	1	1	5	300	8	10	0.68	3/8/88			N/A
MZ73340	7/11/1988	2	0	3	11	1200	49	160	6800	7/11/88			N/A
MZ71995	11/2/1988	1	1	2	7	900	49	49	1200	11/2/88			N/A
MZ71790	1/25/1989	0	0	1	3	260	49	49	850	1/25/89			N/A
MZ71617	5/23/1989	2	2	4	15	1300	49	180	15000	5/23/89			N/A
MZ71169	9/1/1989	0	0	0	0	0	49	49	0	9/1/89			N/A
MZ70711	1/31/1990	0	0	0	1	120	49	49	1200	1/31/90			N/A
MZ70369	5/3/1990	0	0	0	0	0	49	49	0	5/3/90			N/A
MZ69893	7/5/1990	2	0	1	2	130	49	49	150	7/5/90			N/A
MZ69416	10/25/1990	4	2	5	17	1200	49	240	2800	10/25/90			N/A
MZ69450	11/12/1990	4	2	4	11	770	66	160	1100	11/12/90			N/A
MZ58273	2/7/1991	5	2	6	17	440	54	250	750	2/7/91			N/A

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MZ69106	2/8/1991	0	0	1	3	140	49	49	280	2/8/91	N/A
MZ68996	4/18/1991	3	1	4	13	620	49	180	770	4/18/91	N/A
MZ68488	7/25/1991	1	1	1	4	190	49	50	310	7/25/91	N/A
MZ68216	10/21/1991	0	0	0	0	0	49	49	0	10/21/91	N/A
MZ67992	1/14/1992	0	0	0	0	0	49	49	0	1/14/92	N/A
MZ67769	4/8/1992	0	0	0	0	0	49	49	0	4/8/92	N/A
MZ67484	6/29/1992	2	6	10	36	2200	49	440	11000	6/29/92	N/A
MZ67149	9/1/1992	0	0	0	0	0	49	49	0	9/1/92	N/A
MZ66863	1/5/1993	0	3	6	19	1300	49	240	1700	1/5/93	N/A
MZ66647	4/5/1993	1	1	2	8	530	49	100	1200	4/5/93	N/A
MZ66439	5/19/1993	2	4	8	26	1900	49	350	1900	5/19/93	N/A
MZ66311	7/1/1993	2	4	8	31	2100	49	450	890	7/1/93	N/A
MZ66053	9/7/1993	1	4	7	26	1900	49	370	1500	9/7/93	N/A
MZ65957	10/6/1993	3	8	15	55	3600	49	670	12000	10/6/93	N/A
MZ65901	10/11/1993	2	5	10	39	2500	49	530	2600	10/11/93	N/A
MZ65805	10/29/1993	1	4	6	25	1700	49	350	4300	10/29/93	N/A
MZ65713	12/6/1993	1	4	8	29	2200	49	450	2800	12/6/93	N/A
MZ65662	1/12/1994	1	5	9	33	2100	49	470	3500	1/12/94	N/A
MZ65606	4/7/1994	1	6	10	39	2400	49	490	1400	4/7/94	N/A
MZ57950	7/11/1994	1	7	13	53	3200	49	610	7500	7/11/94	N/A
MZ65140	7/21/1994	1	6	11	44	3100	49	530	11000	7/21/94	N/A
MZ57818	10/11/1994	0	4	7	27	1500	49	49	1600	10/11/94	N/A
MZ64557	11/10/1994	1	8	13	53	3100	49	440	10000	11/10/94	N/A
MZ57661	1/10/1995	0	5	8	34	2000	49	390	2200	1/10/95	N/A
MZ57257	4/5/1995	0	3	6	24	1500	49	260	3500	4/5/95	N/A
MZ56874	6/30/1995	1	6	10	45	2800	49	560	7100	6/30/95	N/A
MZ56872	6/30/1995	0	3	7	24	1400	49	290	1200	6/30/95	N/A
MZ56324	9/28/1995	1	9	14	52	3500	49	600	16000	9/28/95	N/A
MZ55980	1/4/1996	1	5	7	29	1700	49	370	7800	1/4/96	N/A
MZ55758	4/1/1996	0	4	7	31	1300	49	410	4000	4/1/96	N/A
MZ55386	7/8/1996	0	6	10	43	1200	49	550	2300	7/8/96	N/A
MZ55266	8/16/1996	1	11	17	71	4600	49	840	2100	8/16/96	N/A
MZ55192	9/5/1996	1	16	23	88	5900	49	1000	9800	9/5/96	N/A
MZ55203	9/11/1996	1	9	15	67	4500	49	830	2900	9/11/96	N/A
MZ55128	9/16/1996	1	11	17	74	4900	49	960	4000	9/16/96	N/A
MZ55150	9/23/1996	1	8	13	65	4100	49	790	2100	9/23/96	N/A
MZ55168	9/30/1996	1	8	12	58	3600	49	700	3500	9/30/96	N/A
MZ55119	10/7/1996	1	9	15	72	4300	49	870	2100	10/7/96	N/A
MZ55003	10/14/1996	0	9	15	71	4300	49	1100	1900	10/14/96	N/A
MZ55015	10/21/1996	1	10	16	73	4600	49	1000	5800	10/21/96	N/A
MZ54947	10/28/1996	1	10	16	68	4200	49	900	1900	10/28/96	N/A
MZ54964	11/4/1996	2	11	17	75	4400	49	860	2600	11/4/96	N/A
MZ54980	11/11/1996	1	11	17	73	4400	49	1100	3000	11/11/96	N/A
MZ54891	11/18/1996	1	9	15	72	4100	49	1200	3100	11/18/96	N/A
MZ54900	11/19/1996	1	9	14	59	3800	49	780	1800	11/19/96	N/A
MZ54933	11/25/1996	2	10	15	64	4000	49	820	1500	11/25/96	N/A
MZ54856	12/2/1996	1	8	13	59	3400	49	690	1900	12/2/96	N/A
MZ54886	12/9/1996	1	8	13	58	3300	49	730	2300	12/9/96	N/A
MZ54756	12/16/1996	1	11	16	70	4100	49	880	1900	12/16/96	N/A
MZ54766	12/23/1996	1	8	12	57	3400	49	740	1700	12/23/96	N/A
MZ54774	12/30/1996	1	8	14	73	4000	49	950	1600	12/30/96	N/A
MZ54708	1/6/1997	0	5	8	35	2200	49	440	2400	1/6/97	N/A
MZ54742	1/13/1997	1	8	12	50	3300	49	700	1500	1/13/97	N/A
MZ54680	1/20/1997	1	10	16	67	4000	49	960	2100	1/20/97	N/A
MZ54673	1/28/1997	1	6	10	43	2600	49	550	990	1/28/97	N/A

Northern States Power Company

MZ54685	2/3/1997	1	10	16	69	4200	49	890	1400	2/3/97		N/A
MZ54690	2/10/1997	1	10	14	59	3800	49	860	1100	2/10/97		N/A
MZ54615	2/17/1997	1	7	12	57	3500	49	840	2000	2/17/97		N/A
MZ54620	2/24/1997	1	8	12	52	3200	49	650	1300	2/24/97		N/A
MZ54628	3/3/1997	1	4	7	37	2100	49	520	1600	3/3/97		N/A
MZ54568	3/10/1997	1	9	13	58	3500	49	710	1400	3/10/97		N/A
MZ54585	3/17/1997	0	8	12	57	3400	49	760	2400	3/17/97		N/A
MZ54593	3/24/1997	0	5	8	39	2300	49	530	1300	3/24/97		N/A
MZ54596	3/31/1997	1	9	14	59	3700	49	830	1200	3/31/97		N/A
MZ54550	4/7/1997	1	8	12	48	3100	49	590	1500	4/7/97		N/A
MZ54484	4/14/1997	0	10	15	64	4000	49	800	1600	4/14/97		N/A
MZ54499	4/21/1997	1	10	16	71	4400	49	890	4600	4/21/97		N/A
MZ54513	4/28/1997	1	8	13	60	3600	49	750	3300	4/28/97		N/A
MZ54434	5/5/1997	0	4	7	30	1900	49	380	3600	5/5/97		N/A
MZ54287	7/22/1997	0	0	0	0	9	49	49	660	7/22/97		N/A
MZ54217	8/6/1997	0	0	1	1	150	49	49	4600	8/6/97		N/A
MZ54157	8/11/1997	0	0	0	1	120	49	49	7800	8/11/97		N/A
MZ54113	8/20/1997	0	0	1	0	51	49	49	1400	8/20/97		N/A
MZ54137	8/25/1997	0	0	1	1	110	49	49	1200	8/25/97		N/A
MZ54087	9/5/1997	1	0	2	3	380	49	49	7400	9/5/97		N/A
MZ54060	9/18/1997	0	2	0	2	190	49	49	1400	9/18/97		N/A
MZ53780	10/29/1997	0	0	1	2	310	49	49	2900	10/29/97		N/A
MZ53566	1/13/1998	0	0	0	0	0	49	49	0	1/13/98		N/A
MZ53366	2/4/1998	0	1	2	5	280	49	51	3100	2/4/98		N/A
MZ53129	5/22/1998	0	1	4	8	730	49	49	16000	5/22/98		N/A
MZ52845	6/30/1998	0	2	3	9	1000	49	150	14000	6/30/98		N/A
MZ52717	7/20/1998	0	1	1	5	430	49	93	600	7/20/98		N/A
MZ52412	8/28/1998	0	1	2	8	740	49	150	1600	8/28/98		N/A
MZ52411	8/28/1998	0	0	0	0	0	49	49	0	8/28/98		N/A
MZ52288	10/6/1998	0	2	3	16	1200	49	180	21000	10/6/98		N/A
MZ52287	10/6/1998	0	1	2	8	530	49	140	2300	10/6/98		N/A
MZ51990	11/23/1998	0	2	5	18	1600	49	290	5200	11/23/98		N/A
MZ51947	12/18/1998	0	9	8	15	1200	49	250	1600	12/18/98		N/A
MZ51973	1/18/1999	1	1	3	13	1000	49	210	1300	1/18/99		N/A
MZ51978	1/19/1999	1	1	2	9	800	49	150	3200	1/19/99		N/A
MZ51815	2/15/1999	0	1	1	7	520	49	100	620	2/15/99		N/A
MZ51814	2/15/1999	0	2	4	20	1500	49	330	2100	2/15/99		N/A
MZ51569	4/12/1999	0	2	4	16	1500	49	300	7500	4/12/99		N/A
MZ51410	5/20/1999	0	1	2	9	730	49	150	1300	5/20/99		N/A
MZ51293	6/21/1999	0	2	3	18	1400	49	390	400	6/21/99		N/A
MZ51058	7/21/1999	0	3	5	25	2200	49	370	12000	7/21/99		N/A
MZ50887	8/27/1999	0	3	6	25	2500	49	410	3100	8/27/99		N/A
MZ73720	9/21/1999	0	3	5	29	2600	49	450	9000	9/21/99		N/A
MZ73888	10/21/1999	0	4	7	32	3400	49	610	2600	10/21/99		N/A
MZ73934	11/22/1999	0	4	8	35	2600	49	610	5300	11/22/99		N/A
MZ74136	12/27/1999	0	3	6	29	2600	49	500	6100	12/27/99		N/A
MZ74308	2/10/2000	0	0	0	0	22	49	49	1700	2/10/00		N/A
MZ74393	3/15/2000	0	0	0	1	270	49	49	17000	3/15/00		N/A
MZ74533	4/17/2000	0	0	0	2	280	49	49	6900	4/17/00		N/A
MZ74007	5/25/2000	0	1	1	2	460	49	49	2600	5/25/00		N/A
MZ74730	6/21/2000	0	0	0	2	270	49	49	7500	6/21/00		N/A
MZ75055	8/14/2000	0	1	1	10	1300	49	150	10000	8/14/00		N/A
EE32734	8/20/2000	3	4	7	29	1930	49	460	1990	8/20/00	2.9	503
MZ75731	1/12/2001	0	0	0	0	0	49	49	0	1/12/01		N/A
MZ75907	4/16/2001	0	1	2	10	920	49	120	8900	4/16/01		N/A

MZ77276	10/29/2001	0	2	2	11	1300	49	130	5200	10/29/01			N/A
MZ77483	12/27/2001	0	1	2	11	960	49	170	1500	12/27/01			N/A
EE13379	1/31/2002	0	3	3	12	944	49	185	1480	1/31/02		1.5	203
EE16028	2/26/2002	1	3	4	21	1620	49	274	2220	2/26/02		2.6	307
EE19130	4/4/2002	0	2	2	14	1160	49	211	956	4/4/02		1.7	232
EE21538	5/7/2002	0	2	2	11	868	49	164	1070	5/7/02		1.2	179
EE23149	5/29/2002	0	2	2	13	1010	49	195	1070	5/29/02		1.5	212
EE26522	6/25/2002	5	5	6	33	2300	49	398	7930	6/25/02		6.7	447
EE29325	7/23/2002	2	2	3	18	1260	49	218	821	7/23/02		1.9	256
EE38999	10/29/2002	3	5	10	44	2690	49	517	2840	10/29/02		4.8	619
EE42297	12/3/2002	2	5	9	39	2370	49	448	3810	12/3/02		4.7	533
EE44350	12/30/2002	1	5	9	36	2220	49	414	1870	12/30/02		4.2	465
EE49696	3/5/2003	1	4	7	32	1890	49	433	5110	3/5/03		5.2	477
EE54170	4/28/2003	1	5	10	42	2600	49	730	2120	4/28/03		5	788
EE57418	6/2/2003	2	6	12	52	3240	49	686	9840	6/2/03	Very slight increase in organic gases from previous	9.4	758
EE60267	6/30/2003	1	7	14	49	3300	49	672	3530	6/30/03	No significant change from previous	7.7	743
EE64167	8/1/2003	2	6	12	50	3230	49	884	8840	8/1/03	No significant change from previous	9.5	954
EE66602	8/25/2003	1	9	16	60	4040	49	702	2800	8/25/03	No significant change from previous	6.5	788
EE70207	9/29/2003	0	13	20	78	4250	49	893	6520	9/29/03	No significant change from previous	7.5	1004
EE71825	10/20/2003	1	10	18	74	4280	49	826	4100	10/20/03	No significant change from previous	7	929
EE72427	10/27/2003	1	11	18	79	4200	49	856	7130	10/27/03	No significant change from previous	9.3	965
EE74671	11/24/2003	0	13	22	93	4440	49	1040	6880	11/24/03	No significant change from previous	8.2	1165
EE76736	12/29/2003	0	11	18	76	3740	49	951	6290	12/29/03	No significant change from previous	7.7	1056
EE78678	1/27/2004	0	10	16	69	4230	49	843	3900	1/27/04	No significant change from previous	7.3	938
EE81089	2/26/2004	0	10	16	68	4360	49	818	3670	2/26/04	No change from previous analysis	7.5	912
EE84130	4/1/2004	1	9	15	64	3730	49	848	3020	4/1/04	No change from previous analysis	7.5	937
EE86687	4/26/2004	0	11	19	73	4980	49	952	4070	4/26/04	No change from previous analysis	6.5	1065
EE89914	5/27/2004	0	12	20	76	5090	49	1150	5350	5/27/04	No change from previous analysis	8.4	1255
EE93416	6/30/2004	1	13	20	84	5320	49	937	10600	6/30/04	Slight increases from previous analysis	13	1055
EE96369	7/29/2004	1	11	20	78	5460	49	977	7270	7/29/04	No change from previous analysis	10.3	1087
EE99156	8/27/2004	1	14	22	85	5430	49	867	4580	8/27/04	No change from previous analysis	8.7	989
EF02397	10/4/2004	1	14	21	85	4860	49	1240	7750	10/4/04	No change from previous analysis	10.8	1356
EF05061	10/29/2004	1	12	19	76	4960	49	951	6960	10/29/04	No change from previous analysis	10.7	1059
EF06388	11/29/2004	0	11	18	75	5100	49	934	4370	11/29/04	No change from previous analysis	6.3	1038
EF08526	12/30/2004	0	10	15	60	3760	49	747	8020	12/30/04		6.5	832
EF14871	2/14/2005	0	7	11	48	2770	49	569	12200	2/14/05	Slight decreases from previous analysis	10.3	656
EF18860	3/31/2005	0	12	19	79	4040	49	988	2510	3/31/05	Methane is up slightly from previous analysis	7.9	1116
EF21047	5/2/2005	0	12	19	75	4490	49	912	5270	5/2/05	No change from previous analysis	8.8	1032
EF22322	5/24/2005	0	11	19	80	5030	49	1090	4440	5/24/05	No change from previous analysis	9.3	1202
EF26938	6/28/2005	0	15	23	93	5950	49	1130	4800	6/28/05	Slight increases from previous analysis	10.3	1277
EF32821	7/28/2005	0	12	19	78	5340	49	1030	5290	7/28/05	Slight decreases from previous analysis	9.7	1143
EF34141	8/24/2005	0	14	20	85	5630	49	1090	7880	8/24/05	No change from previous analysis	10.7	1210
EF36835	10/14/2005	0	15	22	101	6410	49	1240	4570	10/14/05	Slight increases from previous analysis	10.3	1399
EF38926	10/26/2005	1	14	21	93	5730	49	1110	3640	10/26/05	No change from previous analysis	9.3	1240
EF41561	11/28/2005	0	14	20	86	5570	49	1020	6730	11/28/05	No change from previous analysis	10	1143
EF44389	12/29/2005	1	15	22	93	6160	49	892	3050	12/29/05	No change from previous analysis	9.3	1023
EF45945	1/26/2006	3	17	25	111	5390	49	1340	4670	1/26/06	Slight increases from previous analysis	9.5	1486
EF46818	2/13/2006	3	16	24	106	4790	49	1070	4780	2/13/06	No change from previous analysis	9.5	1223
EF48693	3/2/2006	3	18	26	109	5210	49	1060	4210	3/2/06	No change from previous analysis	9.1	1212
EF51435	4/3/2006	2	10	15	67	4030	49	768	8180	4/3/06	Overall decreases from previous analysis	9.9	862
EF53076	4/26/2006	2	12	18	77	5350	75	962	7760	4/26/06	Slight increases from previous analysis but	10.2	1146
EF56482	6/1/2006	4	13	20	86	6490	49	1500	4090	6/1/06	Slight increases from previous analysis	9.7	1622
EF60595	7/7/2006	2	14	20	89	7250	49	49	3490	7/7/06	Carbon monoxide was not detected due to instrument failure	9.9	125
EF65194	8/7/2006	2	16	23	97	4970	49	947	3750	8/7/06	Slight increase in methane from previous analysis	8.2	1085
EF65530	8/28/2006	1	14	20	89	5150	49	1100	6470	8/28/06	No change from previous analysis	9.8	1225

SIDN		Acetylene	Ethane	Ethylene	Methane	Carbon Dioxide	Hydrogen	Carbon Monoxide	Oxygen	Expr1	CM01	Percent Extracted Gas	DGA Total Combustible Gas
EF68639	9/26/2006	1	18	25	106	5410	49	1000	2670	9/26/06	Slight increases from previous analysis	8.9	1152
EF72489	10/27/2006	0	16	23	107	5810	49	1340	5950	10/27/06	Carbon oxides are up slightly from previous analysis	10.3	1489
EF72490	11/27/2006	0	13	18	78	4730	49	1020	4000	11/27/06	Overall decreases from previous analysis	7.5	1120
EF75310	12/27/2006	1	19	28	133	5950	49	1300	5330	12/27/06	Overall increases from previous analysis	10.1	1484
EF76206	2/2/2007	0	17	23	102	5870	49	1350	3510	2/2/07	No change from previous analysis	9.2	1494
EF78090	3/1/2007	0	12	18	84	4800	49	1480	9010	3/1/07	Organics are down from previous analysis	11.5	1598
EF79594	3/16/2007	0	16	23	103	5360	49	1170	4930	3/16/07	Slight increases from January sample but	10.2	1311
EF84819	5/1/2007	1	15	22	101	5630	49	1460	6380	5/1/07	No change from previous analysis	11.2	1602
EF85409	6/1/2007	1	17	26	112	6080	49	1150	5080	6/1/07	Slight increases from previous analysis	9.7	1306
EF89700	6/27/2007	1	14	21	97	6690	49	1300	4730	6/27/07	Organics are down slightly from previous analysis	10	1433
EF93593	8/3/2007	1	14	20	86	5880	49	1040	12300	8/3/07	No change from previous analysis	11.5	1164
EF94501	8/31/2007	1	11	17	83	5350	49	1260	9830	8/31/07	No change from previous analysis	13.5	1376
EF98387	10/1/2007	2	17	25	111	6480	49	1280	5070	10/1/07	Overall increases from previous analysis	9.9	1438
EF99241	10/5/2007	1	18	26	109	5920	49	1190	7110	10/5/07	No change from previous analysis	9.6	1344
EG00444	11/28/2007	1	17	25	112	5760	49	1250	3700	11/28/07	No change from previous analysis	9.2	1402
EG01720	12/26/2007	1	15	21	92	4650	49	1090	3010	12/26/07	No change from previous analysis	7.6	1219
EG03829	2/1/2008	1	15	21	84	4060	49	823	9350	2/1/08	No change from previous analysis	9.2	944
EG06182	2/28/2008	1	17	25	105	7060	49	1240	3240	2/28/08	Overall increases from previous analysis	9	1386
EG09047	4/3/2008	2	27	39	165	8990	49	1500	3290	4/3/08	Overall increases from previous analysis	9.4	1732
EG09733	4/17/2008	1	23	34	151	6400	49	1800	3250	4/17/08	Slight decreases from previous analysis	9.2	2006

Extended Power Uprate

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Extended Power Uprate		Monticello NGP	$0	$22,000,000
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2003	2007	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007	2009
	$0	$0	$1,000,000	$2,500,000	$3,500,000	$10,000,000	$5,000,000

DESCRIPTION:
Perform analysis and physical plant modifications to extend the power level up to at least 1880 Mwth. The power uprate project performed in 1996 performed many of the analysis at the 1880 Mwth power level. Additionally the GE topical reports provide the bases for extending power up to 120% of the license value or 2004 Mwth. One of the key aspects of this project would be to perform an optimization study, taking into consideration synergies with replacement of components for license renewal to determine the optimum power level.

Potential projects to support an uprate are: Upgrade turbine flow path, upgrade generator cooling and excitation, Upgrades to the feedwater system valves, and pumps and heaters.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):
Benefits of performing this project are to increase the plant output.

ALTERNATIVES:

1) Do nothing.
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

TBD- The financial benefit of extending the power level will be significant.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Power Cable Replacement		Monticello NGP	-	
OPERATING CO.	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	IDE BU Number
Energy Supply – NSP	2003	2012	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2009	2010	2011	2012	
	$0	$ 10,000,000	$ 15,000,000	$10,000,000	$10,000,000	

DESCRIPTION:
Replace aged cables to increase plant reliability.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc....):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

XCEL ENERGY – ESG
2003 CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE		Plant/State	2003 EXPENDITURE	TOTAL EXPENDITURE
Static Excitation System		Monticello NGP	$0	$2,075,000
OPERATING CO	DATE SUBMITTED	IN SERVICE DATE	PLANT CONTACT	JDE BU Number
Energy Supply – NSP	2003	2005	TBD	TBD

ESTIMATED CASH FLOW

ANNUAL	PREVIOUS YRS	2003	2004	2005	2006	2007
	$0	-	$1,575,000	$500,000	-	-

DESCRIPTION:
The self-excitation of the generator should be replaced to support extended plant operation.

JUSTIFICATION/NECESSITY AND BENEFITS (including risks associated with project):

Increase plant reliability for the extended period of operation.

ALTERNATIVES:

1) Do nothing
2)

FINANCIAL IMPACT (SVA, NPV, GENVAL, etc….):

The cost benefit of replacing these components where included in the financial analysis of the license renewal project.

ENVIRONMENTAL ISSUES: None

ASSUMPTIONS/RISKS/OPEN ISSUES:

Not replacing these components could potentially lead to an extended shutdown. Other risks are still being determined.

EPU Cost History

2004 – First full EPU cost study completed by [redacted] Project resulted in a high cost estimate of [redacted].

2006 – The feasibility study was redone by GE [redacted]. Results were documented in GENE-0000-0050-8232, Extended Power Uprate Cost Scoping Assessment, in May of 2006. Two schedules were considered with one doing major modifications in 2009 and 2011 and the second showing major modifications in 2011 and 2013.
Total cost was estimated as [redacted] installed for those items required to implement EPU.

Following consideration of the GE study, the site projects group in July of 2006 recommended a budget of $362.5M with final implementation in the 2013 RFO. The higher cost was to recognize the uncertainty associated with work scope and estimate quality. The Xcel Board of Directors approved a $273M budget with a 2011 project completion in August of 2006.

The GE Phase 1 PO was issued on 9/8/06 to allow start of licensing activities. The GE Phase 2 PO was issued on 12/21/06 to allow start of work on GE scope modification activities.

2007 – In 2007 project cash flow was very near budget and total project costs were projected to increase by $6M. Primary issues during 2007 were MISO grid studies, steam dryer analysis, main steam line monitoring to define steam dryer loads and RFP studies.

2008 – Costs for 2008 were $9.6M over predicted values for the year. Costs were above base EPU projections for condensate demin panel upgrade, RWCU upgrade, *fuel pool heat exchangers,* Main Steam and FW Piping Upgrade, Moisture Separator drains, stator cooling heat exchanger, 1AR, *summer derates*, *SJAE Valve upgrades*, turbine instrumentation upgrades, *circ water and cooling tower upgrades*, *under vessel cables* and 50% of capacitor banks. In addition, no money was in the budget to cover implementation preparations for the 2009 RFO. <u>Italicized projects were dropped from the final scope in an attempt to balance the budget as cost increases continued.</u>

Based on Budget Create, a final project completion budget of $49.4M above the original $273M budget was required when including the steam dryer replacement and 13.8 kv modifications (approved by the Financial Council in December). The increase was due to increased spending in 2008 and the increased authorization for 13.8 kv and steam dryer.

2009 – Costs for 2009 were $28M above projected based on Budget Create at end of 2008. Major costs included the refueling outage being $10.5M above predicted values (delta's to predicted were [redacted], materials - $1.2M and plant direct - $1.2M). Cost issues are not specifically identified but major activities were main transformer, PRNM, turbine replacement, CARV replacement and steam dryer preparation.

The projected total project cost increased by $39.4M based on Budget Create from 2008 to 2009. Most of this increase was due to 2009 expenditures being $28M above predicted. CARV replacement was significantly more complicated then anticipated due to limited ability to as-built the system from radiation levels.

2010 – Costs for 2010 were $6.2M above predicted values with reasons for cost increases not specifically identified. Major ongoing work activities were 13.8 kv, RFP work and main transformer. Cost of moving 13.8 kv and RFP modifications from GE to other vendors was major portion of impact.

EPU Cost History

The projected total project cost increased by $49.9M based on Budget Create from 2009 to 2010.

2011 – Costs for 2011 were $164.7M year to date (10/13/11). This is $43.3M above the year end projected cash flow from Budget Create at end of 2010.

[redacted] over predicted values for work performance when considering the fact that significant work was removed from outage scope that was projected to be completed. Significant issues on outage cost and planning were major drivers to budget over runs.

Significant Work Activity Cost History

Scope	GEH Cost Scoping Study Installed Estimate	GEH Purchase Order Cost Projection	Actual Installed Costs
Licensing of EPU and MELLLA+ (GE costs only)	[redacted]	[redacted]	$25.3M
Condensate Demin with Control System Upgrade	[redacted]	[redacted]	$77.2M
Steam Dryer Replacement with Instrumentation	[redacted]	[redacted]	$39.5M
Turbine/Generator Upgrades	[redacted]	[redacted]	$59.9M
CARV Replacement	[redacted]	[redacted]	$18.4M
Main Transformer Replacement	[redacted]	[redacted]	$26.2M
PRNM Upgrade	[redacted]	[redacted]	$17.5M
FW Capacity Upgrade	[redacted]	[redacted]	$24M Final cost - $66.3M Changed to replacement of RFPs
13.8 kv Upgrades	[redacted]	[redacted]	$31.95M Final cost – TBD $70M estimate
Totals	[redacted]	[redacted]	$400.3M

*Does not include many installation items or the BOP scope for an additional $26M.

EPU Cost History

PROJECT RISK RELATED TO COST

1. **INITIAL SCOPE AND SCHEDULE WERE INADEQUATE**

   a. The Board approval of a $273M budget in August 2006 was $90M below the Project Team recommendation. The 2006 Cost Scoping Assessment was based on a limited review of possible modifications that addressed identified pinch points; the identification of pinch points was successful since few additional issues were identified. The cost estimate had high uncertainty since little engineering was done on the design concepts suggested. The NSP EPU project team position was that each project should have a more detailed review to define final scope and cost. Design and installation would be handled by bids for each modification. This would have resulted in each modification obtaining more detailed estimates as it progressed through design and installation phases to provide final cost numbers. The Project Team recommended a budget of $362.5M that reflected uncertainty in the Scoping Assessment and also the fact that GE work did not did not cover all required scope to allow implementation.

   b. The EPU project team recommended installation in the 2011 and 2013 RFOs. This was based on the amount of work required and the expected impact on site resources and capabilities. NSP Board approval was based on a 2011 implementation date. This made all work activities “fast track” with little ability to meet outage milestones. The project never caught up to work load. Ideally the project needed to be working on two outages at the same time to be able to complete required design and implementation planning work. This was not successful. Work on the subsequent outage always lagged until completion of the current outage with an additional schedule impact after the outage for “rest and recovery”. There were insufficient experienced, qualified personnel to manage workload of doing two outages at once. This resulted in outage milestones being challenged.

      i. Engineering and construction costs were poorly estimated and resulted in significant overruns and delays. The inability to complete work in a timely fashion contributed to this issue.

2. **SCOPE CONTROL**

   a. The use of [redacted] defeated the ability to obtain detailed bids for each modification and locked in preliminary modification scope suggested in Cost Scoping Study. The work prior to GE contract issuance did not include any detailed engineering and had very limited site input. Requests during the Cost Scoping Study for site involvement were unsuccessful since <6 hours of site input was provided. This resulted in a project scope defined by firm price contract that had a defined scope that had not been agreed to by the site. Use of the estimate, design and installation phases for design approval typical of other design/project work would have provided an opportunity for site input.

   b. The EPU project team/site comments on the GE purchase order were not incorporated into the contract. Issues on scope and wording were provided. Only some of these comments were addressed by NMC management that controlled the contract negotiations. Many were dropped since insufficient time was available to negotiate solutions with GE. This led to the need for the site to create many modifications around the base scope in the GE contract to allow installation to occur, i.e. fire protection, logic, structural issues, interferences, etc. These

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were typically covered by NSP since additional scope could be completed more cost effectively then using GE. This required the addition of significant design engineering and project management resources beyond original project staffing plans for these groups.

c. The steam dryer budget did not include disposal of the original steam dryer or removal of steam dryer instrumentation. Not including these costs did not provide a full picture of costs.

3. **LACK OF SITE OWNERSHIP**

a. Not using operational experience that recommended EPU team organization contributed to scope changes and strained project resources for responding to potential design issues. Benchmarks and BWROG NEDO-33159 Guidance suggested staffing of EPU project teams with "a dedicated site team reporting to site senior management. This will ensure site ownership of the project. Staff the project sufficiently to minimize the effect on routine site resources. Use best available site personnel for the team. Fill their original positions with contractors if needed. This will help ensure that expertise gained from the project is not lost."

b. There was very limited capability for the project team to obtain a scope change decision that balanced scope and cost. The project principle to enhance equipment margins became a reason to change scope. Reviews during Site Steering Committees and design review meetings often led to increased scope. In 2007 the modifications defined by contract were brought to the Site Steering Committee to insure site management team acceptability since there had been no site involvement in the Cost Scoping Assessment. The most significant scope changes from this review were decisions to essentially replace the full condensate demin system and a requirement to switch from a supplemental RFP to an upgrade to the capacity of the reactor feedwater pumps. RFP replacement eventually led to the 13.8 kv upgrade. These large cost changes did not appear to be approved by management in any detail. Part of the reason for this was that schedule restraints forced parallel work and required significant cost commitments to be made to achieve goals.

c. The site did not have cost ownership of the budget and plant desired scope was added without the cost impact of the changes being known. Site Steering Committee review meetings resulted in significant scope being added due to this. Examples include all condensate demin valves, turbine expansion joints, redundancy for isophase bus, selected cable replacements, #13 feedwater heater replacement, stator water cooling heat exchanger replacement, RWCU capacity improvements and turbine generator vibration system upgrade.

4. **INSUFFICIENT PROJECT CONTROLS**

a. Changes to scope with an appropriate consideration of cost were challenged by "fast track" schedule. The modification to upgrade the original RFPs was given to [redacted] that included engineering and material procurement for a price of [redacted] There were no activities to cover project cost estimating or approval of engineering phase costs. This resulted in the loss of management approval for these cost items. Poor performance [redacted] eventually led to the transfer of this work to NSP in 2010 with decisions to have other contractors perform the work.

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b. The expected cost impact was not reviewed by appropriate management with requests to revisit past decisions to pursue added scope if scope costs were large. Costs were reflected in Budget Create numbers for the next calendar year and in communications with management prior to Budget Create.

c. Projects did not have separate cost tracking with many projects rolling up to a single charge number. Not having a budget by project resulted in a challenge to project managers to be able to control and forecast cost. This also allowed changes in scope to be “covered” by deleting selected projects. The low level of cost tracking that resulted from having one bucket for many projects was insufficient to allow early identification of cost issues. Management attention was not applied to address these issues.

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 NO. 48-2500-31139

CERTIFICATE OF SERVICE

Jill N. Yeaman certifies that on the 12th day of February, 2015, she filed a true and correct copy of **XCEL ENERGY EXCEPTIONS AND CLARIFICATIONS TO ALJ REPORT** by posting the same on www.edockets.state.mn.us. Said document is also served via U.S. Mail or email as designated on the Official Service List on file with the Minnesota Public Utilities Commission in the above-referenced docket.

s/ Jill N. Yeaman
Jill N. Yeaman

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