STATE OF MINNESOTA
BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

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

XCEL ENERGY'S PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS

November 21, 2014

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The above-entitled matter came for evidentiary hearing before Administrative Law Judge Steve M. Mihalchick on September 29 to October 1, 2014 in St. Paul, Minnesota.

The hearing record closed upon receipt of the post-hearing reply briefs on November 21, 2014.

Appearances:

For Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), Aakash Chandarana, Lead Regulatory Attorney – North, Xcel Energy, Alison C. Archer, Assistant General Counsel, Michael C. Krikava, Elizabeth M. Brama, and Paul J. Hemming, Briggs and Morgan, P.A.;

For the Department of Commerce, Division of Energy Resources, Energy Regulation and Planning Unit ("Department"), Julia E. Anderson, Assistant Attorney General;

For the Office of Attorney General – Antitrust and Utilities Division ("OAG"), Ian Dobson, Ryan P. Barlow, and James W. Canaday, Assistant Attorneys General;

For Flint Hills Resources, LP, Gerdau Ameristeel US Inc., Unimin Corporation, and USG Interiors, Inc. (collectively, "Xcel Large Industrials" or

"XLI"), Andrew P. Moratzka and Sarah Johnson Phillips, Attorneys at Law, Stoel Rives LLP.

STATEMENT OF ISSUES[1]

The Commission directed the Parties to address the following issues in this proceeding:

(1) Whether Xcel Energy's handling of the Monticello Life Cycle Management ("LCM")/Extended Power Uprate ("EPU") Program ("LCM/EPU Program" or "Program") was prudent?

(2) Whether the Company's request for recovery of Monticello LCM/EPU cost overruns is reasonable?

(3) How should costs be allocated between the LCM and EPU parts of the Program?[2]

STANDARD OF REVIEW

A. The Prudent Investment Standard

1. Under the prudent investment standard "a utility is compensated for all prudent investments at their actual cost when made (their 'historical' cost), irrespective of whether individual investments are deemed necessary or beneficial in hindsight."[3]

2. Accordingly, "the focus in a prudence inquiry is not whether a decision produced a favorable or unfavorable result, but rather, whether the process leading to

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[1] A Master Exhibit List, including links to all exhibits received into evidence, was efiled by the court reporter on November 21, 2014 (eDockets Doc. No. 201411-104821-01).

[2] *In the Matter of a Comm'n Investigation into Xcel Energy's Monticello Life Cycle Mgmt./Extended Power Uprate Project and Request for Recovery of Cost Overruns*, No. E002/CI-13-754, ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING at 3 (Dec. 18, 2013).

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

the decision was a logical one, and whether the utility company reasonably relied on information and planning techniques known or knowable at the time."[4]

3. In assessing whether the process leading to a decision was logical, the prudent investment standard does not demand perfection.[5] Rather, performance need only be within a "zone of reasonableness."[6]

> The term "prudent investment" is not used in a critical sense. There should not be excluded, from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures.[7]

4. The Minnesota Supreme Court has similarly articulated that "[r]easonableness is a concept of some flexibility and moderation, not exclusivity; a determination that one course of conduct is reasonable is not a determination that any other course is unreasonable."[8]

5. As a result, the prudent investment standard: (i) requires review of the information that the utility knew or should reasonably have known at the time decisions were made, and not hindsight;[9] (ii) considers the process, rather than the

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[4] *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)).

[5] *Gulf States Utils. Co.*, 578 So. 2d at 85 (citing *Metzenbaum*, Opinion No. 25, 4 FERC 161, 277, 26 P.U.R.4th 144) (standard calls for reasonable decisions, not perfection).

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

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

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

[9] *Duquesne Light Co.*, 488 U.S. at 309; *Gulf States Utils. Co.*, 578 So.2d at 85; *see* 73B C.J.S. Public Utilities § 45 (2004) (stating that "[w]hether or not the investment was prudent must be determined as of the time when it was made"); *In re GPU, Inc.*, 96 Pa. P.U.C. 1, 91-92 (Jun. 20, 2001); *In re Long Island Lighting Co.*, 24 N.Y.P.S.C. 4927, at *6 (Aug. 19, 1981); *Pa. Pub. Util. Comm'n v. Philadelphia Elec. Co.*, 71 Pa. P.U.C. 42 (1989) (noting that the Commission "must assess the reasonableness of a utility's decision-making based on the state of information available when decisions had to be made and without reliance on hindsight.").

results;[10] (iii) addresses only events over which the utility had control;[11] and (iv) imposes a remedy only if imprudence proximately caused damages to customers.[12]

B. <u>Burden of Proof</u>

6. The general rule is that "the burden of proof rests on the party seeking to benefit from a statutory provision."[13] The phrase "burden of proof" is used in two senses; it denotes either the "burden of persuasion" (sometimes referred to as the burden of establishing allegations) or the "burden of producing evidence" (sometimes referred to as the burden of going forward).[14]

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[10] *Gulf States Utils. Co.*, 578 So. 2d at 85 (citing *Metzenbaum*, Opinion No. 25, 4 FERC 61,277, 26 P.U.R.4th 144); *see Kuhl v. Heinen*, 672 N.W.2d 590 (Minn. Ct. App. 2003) (stating that the duty to exercise care is dictated by the exigencies of the occasion, and if no harm is foreseeable, there can be no negligence); *In re GPU, Inc.*, 96 Pa. P.U.C. at 91-92.

[11] *Gulf States Utils. Co.*, 578 So.2d at 85 (citing *Metzenbaum*, Opinion No. 25, 4 FERC 61,277, 26 P.U.R.4th 144).

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

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

[14] 21 Dunnell's Minn. Digest, Evidence § 13.01 (5th ed. 2006); 11 Minn. Prac., Evidence § 301.01, at 128 (4th ed. 2012); *see Schaffer ex. rel. Schaffer v. Weast*, 546 U.S. 49, 56 (2005) (determining which party bears the burden of proof in an administrative hearing); *Stockton E. Water Dist. v. United States*, 583 F.3d 1344, 1360 (Fed. Cir. 2009) ("When dealing with burdens of proof it is essential to distinguish between two distinct burdens, the burden of persuasion and the burden of production (sometimes described as the burden of going forward)").

7. The burden of persuasion is "the duty of creating an affirmative belief on the part of the tribunal in the existence of the fact or facts in issue."[15] The burden of persuasion is generally fixed and does not shift to the other party during the course of a proceeding.[16]

8. The burden of producing evidence (sometimes described as the burden of going forward), refers to the requirement of producing evidence.[17]

9. When the party with the burden of producing evidence offers up a *prima facie* case, the burden then shifts to the opposing party.[18] Such evidence must be competent and probative.[19]

10. Ultimately, "[t]he burden of proof is met by a *prima facie* case if no evidence to rebut it is offered," and "[a]n unimpeached *prima facie* case should prevail as a matter of law."[20]

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[15] 21 Dunnell's Minn. Digest, Evidence § 13.01 (5th ed. 2006); *see Tech. Licensing Corp. v. Videotek, Inc.*, 545 F.3d 1316, 1326-27 (Fed. Cir. 2008) (defining the burden of persuasion as "the ultimate burden assigned to a party who must prove something to a specified degree of certainty").

[16] 21 Dunnell's Minn. Digest, Evidence § 13.01 (5th ed. 2006) ("A party must establish his allegations. He who affirms must prove."); *see* Minn. R. Evid. 301 (2014) (presumptions shift "the burden of going forward with evidence to rebut or meet the presumption, but does not shift to such party the burden of proof in the sense of the risk of nonpersuasion, which remains through the trial upon the party on whom it was originally cast."); *Commercial Molasses Corp. v. New York Tank Barge Corp.*, 314 U.S. 104, 110-11 (1941).

[17] 21 Dunnell's Minn. Digest, Evidence § 13.01 (5th ed. 2006) (describing the burden of production as "the duty of introducing evidence at a particular stage of a trial – of going forward with the evidence"); *see Tech. Licensing Corp.*, 545 F.3d at 1327; *Ryan v. Metro. Life Ins. Co.*, 289 N.W. 557, 560 (Minn. 1939) (discussing the differences between the burden of producing evidence and the burden of persuasion).

[18] 21 Dunnell's Minn. Digest, Evidence § 13.03 (5th ed. 2006); *Tex. Dep't of Cmty. Affairs v. Burdine*, 450 U.S. 248, 252 (1981) (differentiating burden of persuasion, which never shifts, from burden of producing evidence, which shifts upon establishment of a *prima facie* case).

[19] *LaFavor v. Am. Nat'l Ins. Co.*, 155 N.W.2d 286, 291 (Minn. 1967) ("[w]hile the evidence in proof of a crucial fact may be circumstantial, it must not leave it in the field of conjecture").

[20] 21 Dunnell's Minn. Digest, Evidence § 13.03 (5th ed. 2006) ("*Prima facie* evidence of a fact is in law sufficient to establish the fact unless it is rebutted."); *see Fidelity Bank & Trust Co. v. Fitzimons*, 261 N.W.2d 586, 590 (Minn. 1977) ("Where a plaintiff proves a *prima facie* case and it is unrebutted by a defendant, the plaintiff has met his burden of proof."); *Elk River Concrete Prods. Co. v. Am. Cas. Co. of Reading, Pa.*, 129 N.W.2d 309, 314 (Minn. 1964) (holding that the *prima facie* case had been met and the burden of proof going forward switches to the defendant); *United States v. Ahrens*, 530 F.2d 781, 787 (8th Cir. 1976) (holding that the government satisfied its burden of proof to establish a *prima facie* case because the taxpayer failed to rebut the *prima facie* case, and therefore court was required to enter summary judgment in favor of the government).

11. Accordingly, a party may not rebut or reject evidence of prudence merely by averring that it is not convinced, by offering general criticisms of the evidence provided, or by challenging the opposing party to prove the negative—that the utility was not imprudent.[21] A *prima facie* case must be rebutted by competent and probative evidence.[22]

12. This rule applies both in administrative law proceedings and civil cases.[23]

13. Here, upon the Company's establishment of a *prima facie* case of prudence, the burden of production shifts to the opposing parties, which must offer competent and probative evidence, not merely averments, specifically rebutting the Company's evidence.[24]

Based on the evidence in the hearing record, the Administrative Law Judge makes the following:

I. FINDINGS OF FACT

A. Parties

14. Northern States Power Company, a Minnesota corporation, serves Minnesota customers and is a subsidiary of Xcel Energy Inc., a public utility holding company with four utility subsidiaries that serve electric and natural gas customers in eight states.

15. The Department represents the interests of the State's ratepayers in proceedings.

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[21] *See State v. Paige*, 256 N.W.2d 298, 304 (Minn. 1977) (recognizing legal impossibility of proving a negative).

[22] 21 Dunnell's Minn. Digest, Evidence § 13.03 (5th ed. 2006) ("A *prima facie* case simply means one that prevails in the absence of evidence invalidating it.").

[23] *See Rydberg v. Goodno*, 689 N.W.2d 310, 313-14 (Minn. Ct. App. 2004) (holding that plaintiff had established a *prima facie* case for pass-eligible status such that it was "unclear what more the commissioner [of human services] would have [plaintiff] prove" and that "at this point, the burden shifted to the parties opposing pass-eligible status"); *In re Chicago Rys. Co. v. Sullivan*, 175 F.2d 282, 289-90 (7th Cir. 1949) (stating that when a prima facie case is established by evidence and there is an "absence of explanatory or contradictory evidence," then "the finding shall be in accordance with the proof establishing the prima facie case").

[24] 73B C.J.S. Public Utilities § 131; *Gulf States Utils. Co.*, 578 So.2d at 85.

16. The OAG represents the interest of residential and small business ratepayers.

17. XLI includes some of Xcel Energy's large retail electric customers.

B. Procedural Background[25]

18. On September 2, 2013, the Minnesota Public Utilities Commission ("Commission") issued its Findings of Fact, Conclusions, and Order in Xcel Energy's 2012 rate case.[26] In that order, Commission opened this proceeding to investigate the prudence, reasonableness, and rate recoverability of the costs incurred in connection with the LCM/EPU Program at the Monticello Nuclear Generating Plant ("Monticello" or the "Plant").[27] The Commission also directed its staff to work with the Department to develop a proposal for conducting the investigation.[28]

19. On October 18, 2013, the Company submitted a report and related Direct Testimony and schedules to the Commission to help facilitate the investigation. The Company submitted testimony of Company witnesses Mr. James R. Alders,[29] Mr. Timothy J. O'Connor,[30] Mr. J. Arthur Stall,[31] and Mr. Scott L. Weatherby.[32]

20. On November 14, 2013, the Commission met to consider the investigation proposal. The Company, the Department, and the Minnesota Chamber

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25 All documents referenced to in this section are filed with the Department of Commerce eDockets system, Docket Number E002/CI-13-754, and may be viewed through the Search eDockets link at mn.gov/puc.

26 *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46 (Sept. 3, 2013).

27 *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46 (Sept. 3, 2013).

28 *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46 (Sept. 3, 2013).

29 Ex. 2, Alders Direct.

30 Ex. 3, O'Connor Direct.

31 Ex. 4, Stall Direct.

32 Ex. 5, Weatherby Direct; Ex. 6, Weatherby Direct (Trade Secret).

of Commerce ("MCC") attended the meeting and offered their comments on the proposal.[33]

21. On December 18, 2013, the Commission issued its Order Approving Investigation and Notice and Order for Hearing. The Order referred the investigation to the Office of Administrative Hearings for a contested case proceeding.[34]

22. The December 18, 2013 Order also approved the investigation proposal developed by the Commission staff and the Department.[35] The investigation proposal included a draft Request for Proposals ("RFP") to allow the Department to hire an expert.[36] The Commission approved the scope of the investigation as stated in the draft RFP, with the clarification that the scope includes project cost differences between what was initially proposed and what has been presented to the Commission for recovery and the reasons for those changes.[37] The approved RFP identified three issues for the Department's expert to focus on: (a) whether the modifications were necessary because of NRC requirements, the Fukushima incident, or other related factors, (b) whether the cost levels for these modifications were reasonable, and (c) how these costs should be allocated between the LCM and EPU parts of the Program.[38]

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33 *See* NOTICE OF COMMISSION MEETING (Nov. 1, 2013) (eDockets Doc. No. 201311-93193-03); ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING (Dec. 18, 2013) (eDockets Doc. No. 201312-94721-01).

34 ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING (Dec. 18, 2013) (eDockets Doc. No. 201312-94721-01).

35 ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING (Dec. 18, 2013) (eDockets Doc. No. 201312-94721-01).

36 ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING at 7 (Dec. 18, 2013) (eDockets Doc. No. 201312-94721-01).

37 ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING at 7 (Dec. 18, 2013) (eDockets Doc. No. 201312-94721-01).

38 ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING at 2 (Dec. 18, 2013) (eDockets Doc. No. 201312-94721-01).

23. The Commission directed Parties to address the following three issues in this proceeding: 1) whether The Company's handing of the Monticello LCM/EPU Program was prudent? 2) whether the Company's request for recovery of Monticello LCM/EPU cost overruns is reasonable? and 3) how should costs be allocated between the LCM and EPU parts of the Program.[39] At the time the Commission issued its Order Approving Investigation and Notice and Order for Hearing, the only parties to this proceeding were the Company and the Department.[40]

24. Administrative Law Judge Steve M. Mihalchick held prehearing conferences on January 27, 2014, in St. Paul, and February 10, 2014, by telephone.[41] The prehearing conferences were attended by the Company, the Department, the OAG, XLI, MCC, and Commission staff.[42]

25. A First Prehearing Order was issued on February 14, 2014, granting the petitions to intervene filed by XLI and OAG. The First Prehearing Order also set forth the procedures for discovery and provided a schedule for all filing deadlines and the dates for evidentiary hearing.[43]

26. On July 2, 2014, Department witnesses Ms. Nancy A. Campbell,[44] Mr. Mark W. Crisp,[45] Dr. William R. Jacobs, Jr., PhD.[46] and Mr. Christopher J. Shaw[47] filed Direct Testimony and associated schedules.[48]

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[39] ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING at 3 (Dec. 18, 2013) (eDockets Doc. No. 201312-94721-01).

[40] ORDER APPROVING INVESTIGATION AND NOTICE AND ORDER FOR HEARING (Dec. 18, 2013) (eDockets Doc. No. 201312-94721-01).

[41] FIRST PREHEARING ORDER at 1 (Feb. 14, 2014) (eDockets Doc. No. 20142-99455-01).

[42] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-99455-01).

[43] FIRST PREHEARING ORDER at 1 (Feb. 14, 2014) (eDockets Doc. No. 20142-99455-01).

[44] Ex. 313, Campbell Direct; Ex. 314, Campbell Direct Attachments.

[45] Ex. 300, Crisp Direct; Ex. 301, Crisp Direct (Trade Secret); Ex. 302, Crisp Direct MWC-3 (Trade Secret).

[46] Ex. 305, Jacobs Direct; Ex. 306, Jacobs Direct (Trade Secret).

[47] Ex. 309, Shaw Direct; Ex. 310, Shaw Direct Attachments.

[48] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-99455-01).

27. On July 16, 2014, a Joint Prehearing Conference was held by Administrative Law Judges Jeanne M. Cochran and Steve M. Mihalchick to ensure that issues related to this proceeding were coordinated between this docket and the Xcel Energy 2013 general rate case (Docket No. E002/GR-13-868).[49]

28. On July 17, 2014, a Joint Prehearing Order was issued identifying that the following issues would be addressed in this docket:

(i) The issue of the reasonableness and prudence of the costs for the Program;

(ii) The issue of cost allocation between the EPU and the LCM.[50]

29. The issues of whether the EPU should be considered "used and useful" in 2014 and the issue of the recovery and amortization of expenses from the Program would be addressed in Xcel Energy's 2013 general rate case.[51]

30. The Parties[52] filed Rebuttal Testimony on August 26, 2014.[53] The Company filed rebuttal testimony and associated schedules of Company witnesses Mr. Alders,[54] Mr. O'Connor,[55] Mr. Richard J. Sieracki,[56] Mr. David M. Sparby,[57] and Mr.

[49] JOINT PREHEARING CONFERENCE TRANSCRIPT FOR DOCKET NOS. E002/GR-13-868 and E002/CI-13-754 (Jul. 16, 2014) (eDockets Doc. No. 20148-102000-02).

[50] JOINT PREHEARING ORDER (July 17, 2014) (eDockets Doc. No. 20147-101592-01).

[51] JOINT PREHEARING ORDER (July 17, 2014) (eDockets Doc. No. 20147-101592-01).

[52] "Parties" as used herein refers to the Department, the OAG, XLI, and the Company. XLI did not file testimony in this proceeding, and where "Parties" is used to refer to filed testimony, XLI is excluded in those references.

[53] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-99455-01).

[54] Ex. 8, Alders Rebuttal.

[55] Ex. 9, O'Connor Rebuttal; Ex. 10, O'Connor Rebuttal (Trade Secret).

[56] Ex. 11, Sieracki Rebuttal.

[57] Ex. 12, Sparby Rebuttal.

Stall.[58] The OAG filed rebuttal testimony and associated schedules of OAG witness John Lindell.[59]

31. The Parties filed Surrebuttal Testimony on September 19, 2014.[60] The Company filed Surrebuttal Testimony and associated schedules of Company witnesses James R. Alders[61] and Timothy J. O'Connor.[62] The Department filed Surrebuttal Testimony and associated schedules of Department witnesses Ms. Campbell,[63] Mr. Crisp,[64] Dr. Jacobs,[65] and Mr. Shaw.[66] The OAG filed Surrebuttal Testimony and associated schedules of OAG witness Mr. Lindell.[67]

32. The evidentiary hearings were held on September 29 through October 1, 2014, in the Commission's large hearing room in St. Paul, Minnesota.[68] The Administrative Law Judge provided an opportunity for the public to provide comments at the start of the evidentiary hearing, but no members of the public spoke.[69]

33. On October 31, 2014, the Parties filed Initial Briefs.[70]

34. On November 21, 2014, the Parties filed Reply Briefs and Proposed Findings of Fact.[71]

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[58] Ex. 13, Stall Rebuttal.

[59] Ex. 200, Lindell Rebuttal; Ex. 201, Lindell Rebuttal Schedules; Ex. 202, Lindell Rebuttal (Trade Secret); Ex. 203, Lindell Rebuttal Schedules (Trade Secret).

[60] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-99455-01).

[61] Ex. 15, Alders Surrebuttal.

[62] Ex. 16, O'Connor Surrebuttal; Ex. 17, O'Connor Surrebuttal (Trade Secret).

[63] Ex. 315, Campbell Surrebuttal.

[64] Ex. 303, Crisp Surrebuttal.

[65] Ex. 306, Jacobs Surrebuttal.

[66] Ex. 311, Shaw Surrebuttal.

[67] Ex. 204, Lindell Surrebuttal; Ex. 205, Lindell Surrebuttal Schedule.

[68] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-99455-01).

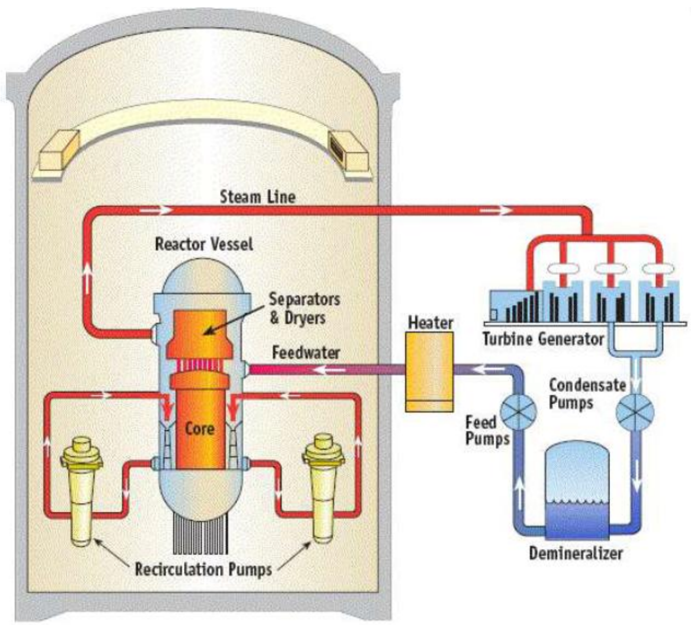
[69] Tr. Vol. I at 11:16-12:1.

[70] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-99455-01).

C. Overview of Monticello Plant

35. Monticello is a boiling water reactor ("BWR") nuclear plant that was constructed in the late 1960s.[72] It produces electricity by boiling water through nuclear fission and producing steam.[73] The steam is directly used to drive a turbine, after which it is cooled in a condenser and converted back to liquid water.[74] A BWR configuration is illustrated in Figure 1.

Figure 1. BWR Configuration[75]



36. A BWR is distinguished from a pressurized water reactor ("PWR") plant, such as the Company's nuclear units at the Prairie Island Nuclear Generating Plant ("Prairie Island").[76] One of the notable features of a BWR (as distinct from a PWR) is

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71 FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-99455-01).

72 Ex. 3, O'Connor Direct at 32:26.

73 Ex. 3, O'Connor Direct at 14:12-13.

74 Ex. 3, O'Connor Direct at 14:10-13.

75 Ex. 3, O'Connor Direct at 15:1-3.

76 Ex. 3, O'Connor Direct at 16:1-10.

that many systems in a BWR plant become radiological and cannot be accessed while the plant is in operation.[77]

37. In 2012, the Plant produced 4,890,374 MW-hours ("MWh") of electricity, or about 10 percent of the Company's customers' annual electric energy requirements.[78]

D. Program Overview

38. In 2005, the Company sought and received Commission approval to construct an independent spent-fuel storage facility ("ISFSI") at Monticello.[79] This approval paved the way for the Company to seek Nuclear Regulatory Commission ("NRC") permission to extend Monticello's operation life from its planned retirement in 2010 to 2030.[80] The ISFSI also provided the Company the opportunity to further investigate and consider the possibility of an EPU at Monticello.[81]

39. In 2006, the NRC renewed Monticello's operating license through 2030.[82] As a condition of obtaining the renewed license, the Company must comply with, among other things four NRC rules designed, in part, to ensure that reactors and plant systems remain safe for the duration of the license.[83] All of these requirements place an obligation on the operator to ensure the facility is designed appropriately to

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77 Ex. 3, O'Connor Direct at 39:21; 80:16; 91:3; 108:8; 109:15-27; Tr. Vol. II (Stall) at 72:13-19 ("And I would just add that there's an increase[d] level of difficulty for Monticello over what we had at FPL because this whole side of the plant at FPL was what we call a clean plant [*i.e.*, PWR], nonradioactive, here it was all radioactive over there [at Monticello], radiation areas, much more difficult than what we had.").

78 Ex. 3, O'Connor Direct at 16:16-17.

79 *See In the Matter of the Application of N. States Power Co., d/b/a Xcel Energy, for a Certificate of Need to Establish an Independent Spent Fuel Storage Installation at the Monticello Generating Plant*, No. E002/CN-05-123, APPLICATION FOR A CERTIFICATE OF NEED at 5-2 to 5-9 (Jan. 18. 2005); *In the Matter of the Application of N. States Power Co., d/b/a Xcel Energy, for a Certificate of Need to Establish an Independent Spent Fuel Storage Installation at the Monticello Generating Plant*, No. E002/CN-05-123, ORDER GRANTING CERTIFICATE OF NEED FOR INTERIM INDEPENDENT SPENT FUEL STORAGE INSTALLATION at 16 (Oct. 23, 2006).

80 Ex. 2, Alders Direct at 16:7-10.

81 Ex. 3, O'Connor Direct at 45:19-24.

82 Ex. 3, O'Connor Direct at 16:25-26.

83 Ex. 3, O'Connor Direct at 18:7-10 and 91:20-92:22; Ex. 4, Stall Direct at 17:13-18:16.

meet relevant design criteria.[84] This means that if, during a planned replacement or inspection, a component is found to be degraded, it must be replaced, even if that replacement was not planned.[85]

40. Simultaneous with the 2006 NRC license renewal, the Company's demand forecast showed a critical need for additional baseload capacity at a time when natural gas and renewable energy prices were relatively high.[86]

41. The Company's 2004 Resource Plan was under consideration by the Commission at this time and,[87] as a result of these factors, the Commission directed the Company to file a Certificate of Need Application for a 71 MW EPU at Monticello to meet the critical need for baseload capacity.[88]

42. In 2008, the Company filed its license amendment request, which is necessary for a nuclear plant to obtain approval to operate at uprate conditions, with the NRC.[89]

43. In 2008, the Company filed the Monticello uprate Certificate of Need Application, which included a Program estimate of $346 million (2008$) (without accounting funds used during construction ("AFUDC")).[90] The Commission granted the EPU Certificate of Need in early 2009.[91]

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[84] *See* Ex. 4, Stall Direct at 17-20;

[85] Ex. 4, Stall Direct at 17:13-18.

[86] Ex. 11, Sieracki Rebuttal at 13:4-10; Ex. 2, Alders Direct at 19:10-16.

[87] Ex. 8, Alders Rebuttal at 8:8-11; *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, REPLY COMMENTS at 9, 26-27 and BASELOAD REPORT at 18, 20-21 (Nov. 23, 2005).

[88] *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).

[89] Ex. 3, O'Connor Direct at 51:24-25, 52:25-26, 53:4-5, and Schedule 17 at 1.

[90] Ex. 2, Alders Direct at 21:14-18; Ex. 3, O'Connor Direct at 29:16-18; Ex. 15, Alders Surrebuttal at 15:9-11.

[91] Ex. 2, Alders Direct at 24:11-14 (citing *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, ORDER GRANTING CERTIFICATE OF NEED AND ACCEPTING ENVIRONMENTAL ASSESSMENT (Jan. 8, 2009)).

44. Approximately two months after receiving the Certificate of Need from the Commission, the Company began the installation work necessary for both the LCM and EPU work related to the Program during the 2009 refueling outage.[92] The Program installation continued through the 2011 and 2013 regularly-scheduled refueling outages.[93] Final component installation for the Program was complete in July 2013.[94]

45. Table 1 summarizes the Program's installed modifications, their final costs, and in-service dates.

Table 1. LCM/EPU Program Modifications, Costs, and In-Service Dates[95]

Electrical Distribution System ($119 million) (In-service: 7/9/13)	Feedwater Heaters[96] ($115.3 million) (In-service: 5/8/09 for CARVs 5/8/09 for Drain & Dump 5/8/09 for Transmitters 5/25/11 for 14 & 15 A/B; 7/9/13 for 13 A/B)	Reactor Feed Pumps and Motors ($93.2 million) (In-service: 7/9/13)
Condensate Demineralizer System ($79.8 million) (In-service: 5/25/11)	Licensing ($65.8 million) (In-service: 10/31/13)	Turbine (high- and low-pressure) ($56.5 million) (In-service: 5/8/09)
Steam Dryer ($37.9 million) (In-service: 5/25/11)	Main and 1AR Transformer ($29.9 million) (In-service: 9/20/09)	Condensate Pumps and Motors ($22.2 million) (In-service: 7/9/13)

92 Ex. 3, O'Connor Direct at 59:4-6.

93 Ex. 3, O'Connor Direct at 78:15-18, 88:13 at Table 12.

94 Ex. 3, O'Connor Direct at 87:20-22.

95 Ex. 3, O'Connor Direct at 21:9-21 and 140:10 at Table 24. Costs are from Ex. 16, O'Connor Surrebuttal at Schedule 1 (Forecast). In-Service Dates are from Ex. 3, O'Connor Direct at Schedule 5.

96 The feedwater heaters modification included replacing six feedwater heaters, cross around relief valves, moisture separator drain tank, thermowell, drains and dumps, main steam line navy nipples, and associated valves and piping. Ex. 3, O'Connor Direct at 117:15-18 and Schedule 25.

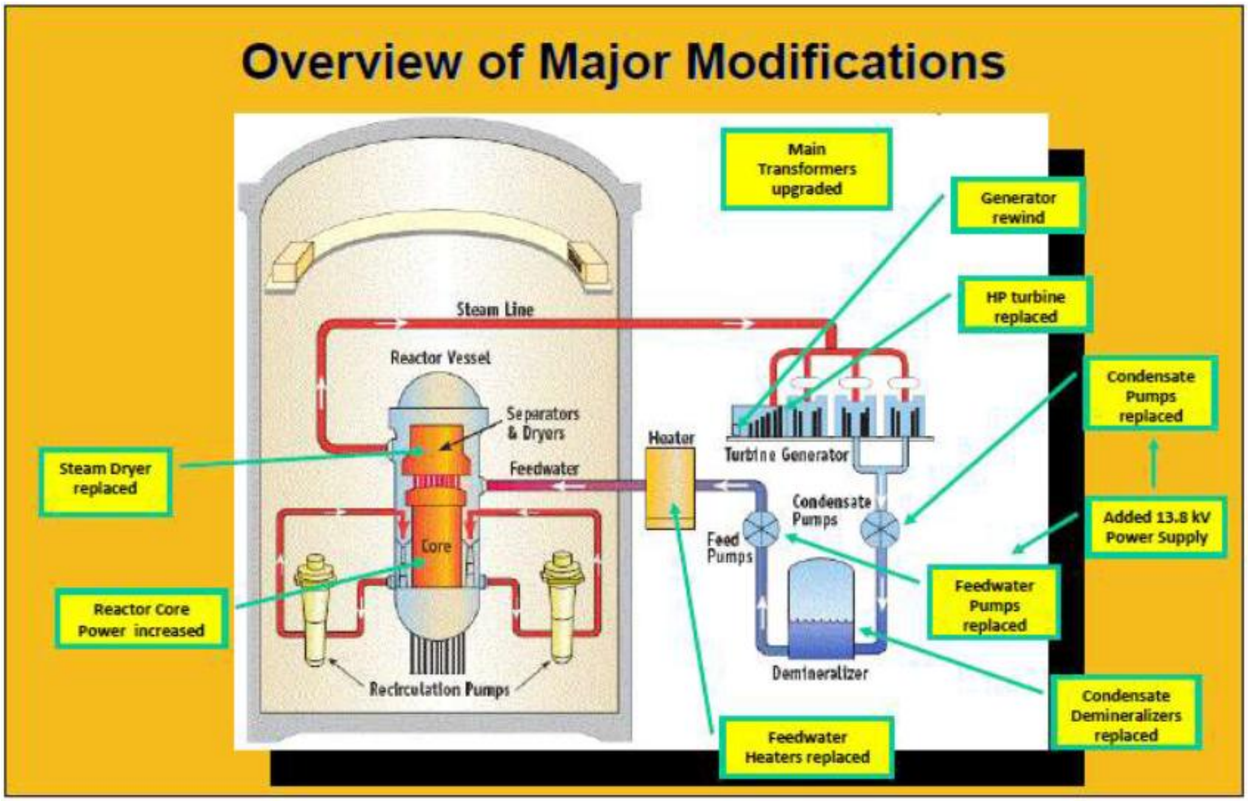
Power Range Neutron Monitor ($17.5 million) (In-service: 9/4/09)	Expansion Joints ($7.0 million) (In-service: 5/8/09)	Generator Rewind ($6.7 million) (In-service: 5/25/11)
Reactor Water Cleanup Capacity Improvement ($5.6 million) (In-service: 12/21/12)	Isophase Bus Cooling Upgrade ($5.4 million) (In-service: 5/8/09)	General Electric ZIP ($2.6 million) (In-service: 5/25/11)
Stator Water Cooler ($2.4 million) (In-service: 5/24/11)	Steam Dryer Instrumentation Removal ($1.2 million) (In-service: 7/9/13)	EQ Transmitters & Detectors ($0.84 million) (In-service: 5/8/09)
Off Gas Dilution Fan Cable ($0.63 million) (In-service: 8/28/09)	PCT Vent & Purge Valve ($0.45 million) (In-service: 7/9/13)	MSIV Solenoid Valve Replacement ($0.34 million) (In-service: 5/8/09)
Drywell Spray Flow Valve Replacement ($0.22 million) (In-service: 5/8/09)	Drywell Brick Removal in Bioshield ($0.15 million) (In-service: 5/8/09)	Exciter Replacement ($0.12 million) (In-service: 9/12/11)
1AR Cable Replacement ($0 – included in Electrical Distribution System) (In-service: N/A; went to non-EPU work order)		

46. Of all the work completed during the Program, 10 modifications comprised about 95 percent of the LCM/EPU Program costs.[97] The 10 major modifications undertaken as part of the Program are identified in Figure 2.[98]

[97] Ex. 3, O'Connor Direct at 21:8-9.

[98] The "Reactor Core Power Increased" label in Figure 2 is the same as what the Company referred to as "Licensing" in its filing.

Figure 2. Monticello 10 Major Modifications[99]



47. In September 2013, the Company was notified that the Advisory Committee on Reactor Safeguards ("ACRS"), the advisory group to the NRC, recommended that the NRC approve the Monticello EPU operating conditions and approve the license amendment request that was submitted in 2008.[100] Monticello is awaiting final NRC approval so that it may begin ascension to the uprate operating conditions that will allow generation of an additional 71 MW.[101]

48. As of August 31, 2014, the Company spent $669.6 million without AFUDC[102] or $752.6 million with AFUDC for the Program (2014$).[103] By December

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[99] Ex. 3, O'Connor Direct at 22.

[100] Ex. 3, O'Connor Direct at 57:22-23 and Schedule 18; Ex. 9, O'Connor Rebuttal at 23:7-8.

[101] Ex. 407, O'Connor Opening Statement at 4-5; *see* Ex. 3, O'Connor Direct at 34:23-26; Ex. 9, O'Connor Rebuttal at 8:22 n.5.

[102] Ex. 16, O'Connor Surrebuttal at 2:15-16 and Schedule 1 at 2.

[103] Ex. 15, Alders Surrebuttal at 7:25 ($83 million AFUDC).

31, 2014, the Company estimates that the total Program cost will be $663.4 million without AFUDC[104] or $746.4 million with AFUDC (2014$) for credits and ascension closeout.[105]

49. The Company is seeking to recover the full amount, with AFUDC, that it has spent to implement the Program.[106]

E. <u>Early History of Monticello (1970-2003)</u>

50. In 1970, Xcel Energy obtained a 40-year operating license from the NRC, which allowed operation of the Plant until September 2010.[107] The Plant was not designed with license renewal in mind, as this was not allowed under the NRC regulations of the day.[108] It was assumed at the time of construction, that original equipment would last the duration of the license and then be retired.[109]

51. In many instances, mechanical and electrical equipment was installed at the Plant, with associated piping, wiring, hangars, and supports field-run, and then containment or support concrete was poured around these components.[110]

52. In 1994, the Minnesota Legislature placed a moratorium on additional dry cask storage in the State of Minnesota, effectively limiting the operation of the Plant to its original operating license.[111]

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104 Ex. 16, O'Connor Surrebuttal at 2:16-18 and Schedule 1 at 4.

105 Ex. 15, Alders Surrebuttal at 7:25 ($83 million AFUDC).

106 *See* Xcel Energy Initial Br. at 1.

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

108 Ex. 3, O'Connor Direct at 33:5-6.

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

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

111 1994 Minn. Laws ch. 641, art. 1, § 2(d).

53. Based on this statutory moratorium, any possibility of further investigation into what would be necessary to extend the operating life of Monticello was foreclosed and impacted LCM planning.[112] From the mid-1990s until 2003, the capital budget for non-regulatory projects was consistently around $5 million per year, and the book value of Monticello had depreciated to $153 million.[113] During this decade, the Plant was being actively managed to its retirement in 2010 and, while other nuclear plants in the country that could seek license extensions undertook modernization efforts, Monticello did not.[114]

F. <u>2003 Change to Minnesota Law</u>

54. Managing the Plant to retirement continued until the statutory moratorium for additional dry cask storage was lifted in 2003.[115]

55. In 2003, the Minnesota Legislature authorized additional dry cask spent fuel storage at Prairie Island and permitted "expansion or establishment of an independent spent-fuel storage facility at a nuclear generation facility in [Minnesota] subject to approval of a certificate of need" by the Commission under Minnesota Statutes Section 216B.243.[116]

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

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

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

[115] 2003 Minn. Laws 1st Spec. Sess. ch. 11, art. 1, § 2.

[116] 2003 Minn. Laws 1st Spec. Sess. ch. 11, art. 1, § 2, subd. 2; *see* Minn. Stat. § 116C.83 (2014).

G. Relicensing of Monticello (2004-2006)

1. ISFSI Certificate of Need

56. In early 2000, the Company became aware of the possibility of a potential change in Minnesota law and began in-depth evaluation of necessary steps to achieve license extension of the Plant from the NRC and the State of Minnesota.[117]

57. After the 2003 change in the law, the Company began its preparation of an ISFSI Certificate of Need Application to authorize on-site spent-fuel storage at Monticello and filed it with the Commission in 2005.[118]

58. The cost estimates for this work that Xcel Energy provided in its 2005 ISFSI Certificate of Need Application were not based on an exhaustive study, but were representative upgrades based on good-faith estimates, prior operating experience at the Plant, and the known nuclear regulatory environment as it existed at the time the application was prepared.[119]

59. The Commission granted the ISFSI Certificate of Need in 2006.[120]

2. NRC License Renewal Application

60. The Company applied for, and received, a license extension for the Plant to operate until 2030 from the NRC in 2006.[121]

61. As a condition of obtaining a renewed license from the NRC, the Company was required to comply with certain rules to ensure that reactors and plant systems remained safe for the duration of the extended license.[122] These rules

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

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

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

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

[121] Ex. 3, O'Connor Direct at 16:25-26.

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

included the Corrective Action Program, Aging Management Rule, Maintenance Rule, Back Fit and Forward Fit Rule.[123]

62. These rules required the Company to make modifications to, or replace, any equipment that did not meet the NRC's relevant design criteria or applicable safety requirements.[124]

63. The maintenance rule, codified at 10 C.F.R. Part 50.56, requires that a nuclear plant be maintained rigorously to ensure that all safety-related systems and those systems, structures, and components that are important to safety will function according to their intended use and purpose.[125] This means that if a safety-related system or a system that is important to safety is in need of repair or replacement, the licensee is obligated to have firm plans in place to resolve the cause of any equipment-reliability issue in a timely manner.[126] Application of the maintenance rule often drives the replacement of older, obsolete equipment or equipment for which spare parts are no longer available.[127]

64. The aging management rule, codified at 10 C.F.R. Part 54, provides the requirements for renewal of operating licenses for nuclear power plants.[128] This rule mandates an aging management review of a plant's systems, structures, and components that are safety-related or important to safety to ensure that the effects of aging will be managed and intended functions will be maintained for the period of the plant's extended operation.[129] In other words, to obtain a license extension from the

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

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

[125] Ex. 4, Stall Direct at 18:6-9.

[126] Ex. 4, Stall Direct at 18:10-14.

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

[128] Ex. 4, Stall Direct at 17:20-22.

[129] Ex. 4, Stall Direct at 17:22-26 (citing 10 C.F.R. § 54.21(a)(1)(i)).

NRC, the operator must commit to replace and repair systems to keep the plant in safe working order throughout its life.[130]

65. Under the NRC regulations, the corrective action program requires that a licensee repair any system, component, or condition that is adverse to safety.[131] The licensee must repair or replace the component prior to completing any other work.[132] Therefore, if during implementation of a project, the licensee encounters degraded systems that impact safety, then those systems must be corrected.[133]

66. The back-fit and forward-fit rules describe a process by which the NRC monitors and analyzes nuclear power plants for compliance with the design of the plant.[134] The NRC requires nuclear operators to "back fit" systems (apply a change in criteria retroactively to an existing licensee) when the NRC can demonstrate that (1) there is a substantial increase in the overall protection of the public health and safety or the common defense and security to be derived from the back fit; and (2) the direct and indirect costs of implementation for that facility are justified in view of this increased protection.[135]

67. The "forward-fit" rule allows the NRC to condition approval of a licensee's voluntary change in its licensing basis on the licensee's agreement to adopt new or revised guidance regardless of whether the condition is predicated on a substantial safety issue.[136]

68. As a result, the NRC's corrective action program, the aging management rule, the maintenance rule, and the back-fit and forward-fit rules, required the

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[130] Ex. 4, Stall Direct at 17:26-18:4.

[131] Ex. 4, Stall Direct at 17:13-15.

[132] Ex. 4, Stall Direct at 17:15-16.

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

[134] Ex. 4, Stall Direct at 19:5-6.

[135] Ex. 4, Stall Direct at 19:6-13 (citing 10 C.F.R. § 50.109).

[136] Ex. 4, Stall Direct at 19:27-20:4.

Company to make modifications to, or replace, any equipment it found that did not meet the relevant design criteria or applicable safety requirements.[137]

H. Company Resource Needs (2004-2009)

69. Simultaneously with its consideration of management and license-renewal options for Monticello, Xcel Energy was developing its 2004 Resource Plan, the results of which had a material impact on the decisions that the Company made regarding the Plant.[138]

70. During this time, Xcel Energy's forecasts indicated the critical need to add a significant amount of new baseload generating capacity in the near- to mid-term.[139] The Company's 2004 Resource Plan filing identified a forecasted increased demand of up to 1,125 MW of new baseload capacity by 2015.[140]

71. At the same time that the Company and the Commission were faced with making decisions about how to met these baseload capacity needs for Xcel Energy's customers, the country was experiencing a very volatile natural gas price environment.[141] Natural gas prices rose from under $6 per MMBTU in early 2005 to near $10 per MMBTU in late 2005, before stabilizing near $8 per MMBTU in late 2006.[142] The hurricane season in 2008 contributed to another spike in prices to an average of nearly $12 per MMBTU.[143]

72. Xcel Energy provided the natural gas forward price curves in the 2004 Resource Plan record to illustrate the dramatic fluctuations that high natural gas prices

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137 Ex. 3, O'Connor Direct at 18:7-15; Ex. 4, Stall Direct at 17:13-18:16.

138 Ex. 3, O'Connor Direct at 2:25-3:3.

139 Ex. 2, Alders Direct at 18:18-20; Ex. 3, O'Connor Direct at 3:1-3:3.

140 Ex. 2, Alders Direct at 18:20-21; *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 1-2 (Nov. 1, 2004).

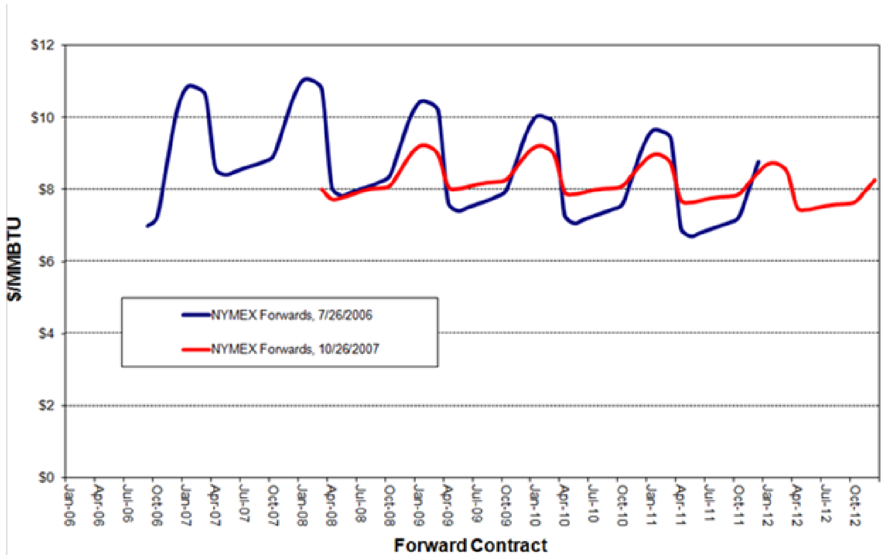
141 Ex. 11, Sieracki Rebuttal at 13:4-9.

142 Ex. 11, Sieracki Rebuttal at 13:6-9.

143 Ex. 11, Sieracki Rebuttal at 13:8-10.

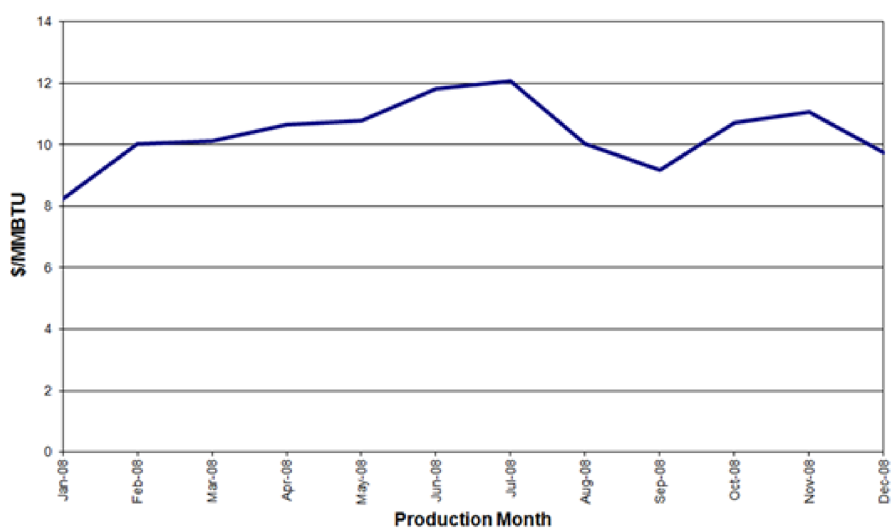
were exhibiting in the relevant timeframe.[144] These price curves are provided in Figure 3.

Figure 3. Natural Gas Price Projections, 2006-2008[145]



73. Furthermore, these forward price curves were confirmed by the Company's actual experience in 2008, as shown in Figure 4.

Figure 4. Actual Natural Gas Costs, 2008[146]



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

[145] Ex. 8, Alders Rebuttal at 11:7 at Figure 1.

[146] Ex. 8, Alders Rebuttal at 12:1 at Figure 2.

74. During the time that the Commission and the Company were evaluating baseload resource options in the mid-2000s, the horizontal drilling and hydraulic fracturing revolution that resulted in today's materially lower natural gas prices was entirely unknown and could not have been known.[147]

75. Given the need for additional baseload resources and the high cost of natural gas at the time, the Company looked at expanding its non-nuclear gas baseload resources in the Company's Report on Baseload Study Development Process Study and Options ("Baseload Report"), filed on November 23, 2005 in the 2004 Resource Plan docket.[148]

76. In the Baseload Report, Xcel Energy identified the possibility of addressing a portion of the pending capacity by implementing combined uprates at Monticello, Prairie Island, and Sherco Unit No. 3.[149]

77. The Baseload Report recognized that the development of baseload resources "requires extremely long planning horizons, and the certificate-of-need-like process for selecting new baseload acquisition" is time- and labor-intensive.[150] As a result, the Company determined that it was important to move forward promptly to build, buy, or otherwise secure the generating capacity required to fulfill those obligations.[151]

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

148 Ex. 8, Alders Rebuttal at 8:8-11; *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, REPLY COMMENTS at 9, 26-27 and BASELOAD REPORT at 18, 20-21 (Nov. 23, 2005).

149 Ex. 8, Alders Rebuttal at 8:13-15.

150 *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).

151 Ex. 2, Alders Direct at 18:23-25.

78. In its July 2006 Order approving the Company's 2004 Resource Plan, the Commission "require[d] the Company to file for any required Commission review or approval of these upgrades" as promptly as possible.[152]

79. While the Commission Order in the 2004 Resource Plan directed the Company to submit its EPU Certificate of Need Application for Monticello by the end of 2006, the preparation of the application required more than six months time and the Commission granted the Company extensions to file the application.[153]

80. Accordingly, the Company responded by developing and filing its Certificate of Need Application for the EPU at Monticello in February 2008.[154]

I. Proceeding with the EPU (2006-2007)

81. In the 2004 Resource Plan proceeding, the Company identified the possibility of an EPU at Monticello in late 2005,[155] but no detailed study work had been performed at the Plant to identify all the necessary system modifications.[156]

1. General Electric Initial Scope

82. In 2006, at Xcel Energy's request, General Electric prepared a Scoping Assessment on the possibility of completing an EPU at Monticello.[157] The results of this Scoping Assessment were provided to Xcel Energy in May 2006, just before the Commission issued its Order on the Company's 2004 Resource Plan.[158]

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152 *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).

153 Ex. 2, Alders Direct at 20:22-24.

154 Ex. 2, Alders Direct at 21:14-15.

155 Ex. 8, Alders Rebuttal at 8:8-11; *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, REPLY COMMENTS at 9, 26-27 and BASELOAD REPORT at 18, 20-21 (Nov. 23, 2005).

156 Ex. 3, O'Connor Direct at 45:5-7.

157 Ex. 3, O'Connor Direct at 45:6-8.

158 Ex. 3, O'Connor Direct at 45:8-9.

83. Xcel Energy selected General Electric to complete the Scoping Assessment and cost estimate primarily because General Electric was the original designer of Monticello and had an ample financial and operational record.[159] General Electric also holds the proprietary rights for many of the critical systems for the Plant.[160] Therefore, given its prior knowledge of the Plant and experience with the work, General Electric was the most logical choice to prepare the Scoping Assessment.[161]

84. The General Electric Scoping Assessment identified the minimally necessary component modifications and replacements to achieve the EPU and also estimated the costs of the necessary work.[162] The Scoping Assessment did not include or evaluate what LCM activities might be necessary for the 20-year license extension that would support the Plant's operation to 2030, as that was not within the scope of General Electric's analysis.[163]

85. Xcel Energy reviewed the Scoping Assessment from May to August 2006, including the proposed implementation schedule.[164]

86. The General Electric Scoping Assessment identified two potential implementation schedules for the Program.[165] The first schedule completed implementation in two sequential refueling outages that would take place in 2009 and 2011.[166] The second implementation schedule completed implementation in the 2011 and 2013 refueling outages.[167]

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159 Ex. 3, O'Connor Direct at 47:21-23; *see* Tr. Vol. II (O'Connor) at 59:5-15.

160 Ex. 3, O'Connor Direct at 47:26-48:2.

161 Ex. 3, O'Connor Direct at 47:26-48:2.

162 Ex. 3, O'Connor Direct at 45:9-10.

163 Ex. 3, O'Connor Direct at 45:9-10.

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

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

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

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

87. Given the magnitude and timing of the impending capacity need identified in the 2004 Resource Plan proceeding, and confirmed in the 2007 Resource Plan proceeding,[168] the Plant's management team, in consultation with the Resource Planning business unit, elected to proceed with targeting Program implementation under the 2009 and 2011 refueling outage schedule.[169]

88. To establish a reasonable estimate for the Program, Xcel Energy used the cost estimate in the Scoping Assessment and also benchmarked the costs incurred by other comparable plants for similar LCM and EPU programs.[170]

89. Because of the Plant's smaller footprint and the estimated increased installation and implementation challenges associated with this, along with the high-dose radiological environment of a BWR plant like Monticello, Xcel Energy developed a cost estimate for the Program that was 75 percent higher than the most expensive benchmarked plant, as shown in Table 2.[171]

Table 2. EPU Cost Comparisons for Early to Mid 2000s[172]

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.

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

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

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

171 Ex. 9, O'Connor Rebuttal at 39:11-17.

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

90. The Company initially authorized $273 million (2006$) for the Program, with implementation outages scheduled in 2009 and 2011.[173] This estimate was designed to complete the necessary EPU work and included costs related to General Electric's Scoping Assessment, obtaining a Certificate of Need from the Commission, and costs of preparing the NRC license amendment request.[174]

91. This cost estimate also included funds related to Xcel Energy's scope of work to complete certain additional LCM modifications, some of which were identified in the 2005 ISFSI Certificate of Need proceeding, and to provide project management and support.[175] This estimate did not include the steam dryer or the 13.8 kV electrical distribution system which were identified later.[176]

2. Integrated Initiative

92. When the Company resolved to pursue the uprate in addition to the LCM work, and as the modification evaluation process continued through 2006, it became readily apparent that, because many of the LCM and EPU modifications impacted the same equipment, these efforts involved significant overlap.[177] Thus, the Company concluded that it should pursue both the LCM activities and the EPU activities as an integrated initiative.[178]

93. Because the Company viewed the Program as a single initiative, the Company used a single parent work order to capture all costs that were incurred.[179] Accounting for the Program was established under a single work order commensurate

[173] Ex. 3, O'Connor Direct at 46:5-7.

[174] Ex. 3, O'Connor Direct at 46:5-10.

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

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

[177] Ex. 9, O'Connor Rebuttal at 12:1-21 and Schedule 5; Ex. 16, O'Connor Surrebuttal at 24:2-20 and Schedules 3-6

[178] Ex. 16, O'Connor Surrebuttal at 23:24-25:5 and Schedules 3-6.

[179] Ex. 5, Weatherby Direct at 8:7-10.

with the expectation at the time that vendors would undertake the major work and perform a central role in Program design.[180] The primary design and study work for the Program was contracted for with General Electric as the lead design vendor, not through individual design contracts for the various systems or modifications.[181]

94. Further, the Company did not segregate its accounting mechanisms by function because the Company's accounting followed the Federal Energy Regulatory Commission ("FERC") uniform system of accounts, correctly accounting for the work by unit of property modified or installed, rather than by function.[182]

3. <u>Partial Installation Estimates</u>

95. In late 2006, the Company executed two agreements with General Electric.[183] The first agreement, the phase one agreement, was executed in September 2006.[184] The second agreement, the phase two agreement, was executed in December 2006.[185]

96. The phase one agreement related to the Company's use of General Electric's intellectual property.[186]

97. The phase two agreement provided that General Electric would prepare the license amendment request and engineer, design, and procure the necessary components and modifications to implement the LCM/EPU Program in 2009 and 2011.[187]

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

181 Ex. 5, Weatherby Direct at 8:11-12.

182 Ex. 5, Weatherby Direct at 2:25-3:7.

183 Ex. 3, O'Connor Direct at 46:16-19.

184 Ex. 3, O'Connor Direct at 46:16-19.

185 Ex. 3, O'Connor Direct at 46:16-19.

186 Ex. 3, O'Connor Direct at 46:22-24.

187 Ex. 3, O'Connor Direct at 46:24-47:1.

98. The phase two agreement did not include installation of the various components in the Plant and modifications to the Plant.[188] These services were to be rendered through a separate contract.[189] Xcel Energy intended to use General Electric as the lead design vendor and separately contract with a third-party as the lead installation vendor.[190] However, the phase two agreement also included $27.5 million for a small portion of the installation that was to be conducted by General Electric.[191]

4. 2007 Refinements

99. Throughout 2006 and 2007, General Electric, Xcel Energy, and specialty designers evaluated the design proposal for various systems at Monticello in more detail.[192]

100. The major modifications for the Program were identified largely in 2006 between receipt of General Electric's Scoping Assessment and executing the General Electric contract.[193] These modifications were subsequently refined in 2007 and set through 2008.[194] The Company made its decisions regarding these modifications based on its experience operating the Plant.[195]

101. In mid-2007, Xcel Energy issued a RFP to Bechtel Corporation, Areva NP, Sargent & Lundy, General Electric/Shaw, and Day Zimmerman to fulfill the role of lead installation vendor.[196]

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[188] Ex. 3, O'Connor Direct at 47:1-2.

[189] Ex. 3, O'Connor Direct at 47:2-3.

[190] Ex. 9, O'Connor Rebuttal at 47:16-18; Tr. Vol. I (O'Connor) at 107:6-11 and 107:15-23.

[191] Ex. 9, O'Connor Rebuttal at 47:8.

[192] Ex. 9, O'Connor Rebuttal at 57:13-25.

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

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

[195] Ex. 3, O'Connor Direct at 102-104. Schedule 23 at 1, Schedule 25 at 1, Schedule 26 at 1, Schedule 27 at 1, and Schedule 28 at 1.

[196] Ex. 3, O'Connor Direct at 49:24-26.

102. The Company thoroughly reviewed the two proposals, one from General Electric/Shaw and a consortium proposal from Day Zimmerman and Sargent & Lundy, with Day Zimmerman as lead. Day Zimmerman maintains nearly half of the U.S. nuclear fleet, with a focus on safety, quality, continuous improvement, and cost reduction.[197] In December 2007, the Company selected the joint proposal of Day Zimmerman/Sargent & Lundy.[198]

J. Uprate Certificate of Need (2008-2009)

103. The Company filed its application for a Certificate of Need to complete the uprate in Docket No. E002/CN-08-185 on February 14, 2008.[199]

104. This application described a series of modifications necessary to obtain 71 MW of additional capacity and to ensure that that the Plant would be able to operate safely and reliably until the expiration of the extended license in 2030.[200]

105. At that time, the Company estimated that the overall cost of the initiative would be approximately $320-346 million.[201] This $320 million estimate was in 2008 dollars[202] and was based on high-level analysis of the projected costs of the LCM/EPU Program.[203]

106. This estimate relied primarily upon the estimates provided by the Company's primary contractor at the time, General Electric, as well as then-existing industry comparables.[204]

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197 Ex. 3, O'Connor Direct at Schedule 13 at 1.

198 Ex. 3, O'Connor Direct at 50:1-10.

199 Ex. 2, Alders Direct at 21:14-15.

200 Ex. 2, Alders Direct at 21:16-18.

201 Ex. 3, O'Connor Direct at 29:16-18.

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

203 Ex. 3, O'Connor Direct at 30:6-14.

204 Ex. 2, Alders Direct at 21:1-4; Ex. 8, Alders Rebuttal at 12:13-15.

107. Prior to granting a Certificate of Need, Minnesota Rules require that the Commission determine that a more "reasonable and prudent alternative" has not been demonstrated by a preponderance of the evidence.[205]

108. Two of the metrics used to compare a proposed project to other proposed alternatives are: (1) the total cost of the project and (2) the cost of the energy supplied by the project.[206]

109. To provide the information needed to make this assessment, the Company had to determine the cost of each additional MW provided by the uprate.[207] This required that the Company attempt to allocate the total cost of the LCM/EPU Program into separate LCM and EPU costs.[208]

110. But because the Company viewed the EPU as integrally intertwined with the ongoing LCM work that was required to keep the Plant viable for an additional 20 years, the Company had not prepared separate cost estimates for the LCM and EPU aspects of the work.[209]

111. To remedy this issue for the uprate Certificate of Need proceeding, the Company developed an artificial engineering split as a conservative allocation of the installations that were part of the Program.[210] This high-level assessment attributed 58.4 percent or $189 million to LCM upgrades and 41.6 percent or $133 million to

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205 *See* Minn. R. 7849.0120(B).

206 Minn. R. 7849.0120(B) ("a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, considering : . . (2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives").

207 Ex. 9, O'Connor Rebuttal at 81:23-26.

208 Ex. 9, O'Connor Rebuttal at 81:23-26.

209 Ex. 15, Alders Surrebuttal at 13:14-16; Ex. 9, O'Connor Rebuttal at 81:11-14.

210 Ex. 9, O'Connor Rebuttal at 81:23-82:24; Ex. 15, Alders Surrebuttal at 13:9-12.

EPU upgrades.[211] This allocation was conducted solely for the purposes of evaluating the 2008 uprate Certificate of Need Application.[212]

112. Using this LCM/EPU split, the Company performed Strategist modeling to compare the Monticello LCM/EPU Program to other alternatives.[213]

113. A present value revenue requirement comparison over the remaining life of Monticello's extended operating license showed that adding 71 MW at Monticello was $169 million less expensive than adding a natural gas combustion turbine,[214] $273 million less expensive than a coal Power Purchase Agreement ("PPA"), and $514 million less than a biomass alternative.[215] Sensitivity analyses confirmed this result.[216]

114. This modeling utilized the same demand assumption as the Company's 2007 Resource Plan.[217]

115. As a result, the Company's modeling demonstrated that proceeding with the upgrades at Monticello was the lowest-cost alternative that was available.[218]

116. The Commission found the Program was appropriate and in the public interest and granted the requested Certificate of Need in January 2009.[219]

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211 Ex. 15, Alders Surrebuttal at 13:9-12; *see* Ex. 9, O'Connor Rebuttal at 81:23-82:24.

212 Ex. 9, O'Connor Rebuttal at 81:2.

213 Ex. 2, Alders Direct at 23:13-15.

214 At the time the Company and the Commission were comparing alternatives to the EPU at Monticello, gas prices had increased to $12 per MMBTU and were not forecasted to decrease. Ex. 11, Sieracki Rebuttal at 13:8-10.

215 Ex. 2, Alders Direct at 23:15-20 (citing *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, INITIAL FILING: CERTIFICATE OF NEED APPLICATION at 6-16, Table 6-6 (Feb. 15, 2008)).

216 Ex. 2, Alders Direct at 23:20.

217 Ex. 2, Alders Direct at 23:13-15.

218 Ex. 2, Alders Direct at 23:13-15.

219 Ex. 2, Alders Direct at 24:11-14 (citing *Petition to the Minn. Pub. Util. Comm'n for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, ORDER GRANTING CERTIFICATE OF NEED AND ACCEPTING ENVIRONMENTAL ASSESSMENT at Findings 85 and 87(Jan. 8, 2009)).

K. 2009 Outage

1. Advance Planning

117. Before the Certificate of Need was granted, the Company made the decision to proceed with its planning for the 2009 outage to begin implementation of the LCM work it had identified and also to begin the EPU implementation work it anticipated to be approved in the pending uprate Certificate of Need proceeding.[220]

118. Advanced preparation enabled the Company to begin installations for the LCM/EPU Program two months after receiving the Certificate of Need.[221]

119. This advanced preparation included procuring equipment, undertaking engineering, and developing plans for installations to take place during the first outage.[222] The Company also worked through many key design issues from 2006 to 2009.[223]

120. The Company incurred significant costs to obtain long-lead-time items, such as a firm order on a block of steel needed to fabricate the new turbine.[224] From the time the Company launched the integrated LCM/EPU Program in mid-2006 through obtaining the Certificate of Need in January 2009, Xcel Energy spent approximately $97 million on the combined LCM/EPU Program.[225] This included about $60 million in progress payments to General Electric, mainly for engineering and design work for the 2009 modifications.[226] Company witness Mr. O'Connor

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[220] Ex. 3, O'Connor Direct at 58:12-26.

[221] Ex. 3, O'Connor Direct at 59:4-6.

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

[223] Ex. 3, O'Connor Direct at 59:11-12.

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

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

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

explained that this $97 million was necessary to position the Company to be able to initiate the 2009 outage mere months after receipt of the Certificate of Need.[227]

121. To prepare for Program implementation, the Company staffed a dedicated project management team.[228] The establishment of a project management team separate from the Monticello operations team is consistent with nuclear safety principles.[229] This allowed for one team, separate from those focused on the safe operation of the Plant, to focus on the engineering, design, and implementation of the complex Program.[230]

122. Additionally, the project management team prepared a project management plan that included a project management framework for scope and quality control.[231] The plan identified Program principles to guide the Company's implementation of the Program with a focus on safety and reliability, incorporating industry experience, and extracting values from economies of scale.[232]

123. The project management plan included a design and engineering process to conduct a systematic review of each system and determine the need for replacement or modification.[233]

124. A multi-layer design and engineering process is necessary to allow for the standard iterative nature of design and engineering that provides for new information to come to light during the process and the revisiting of previous engineering design work.[234]

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[227] Ex. 9, O'Connor Rebuttal at 52:13-15.

[228] Ex. 3, O'Connor Direct at 60:24-25.

[229] Tr. Vol. I (O'Connor) at 104:24-105:4.

[230] Tr. Vol. I (O'Connor) at 105:5-12. During the Program there were some Plant personnel who had experience in Plant operations who were reassigned to the Program. Tr. Vol. I (O'Connor) at 106:11-14.

[231] Ex. 3, O'Connor Direct at 63:4-6.

[232] Ex. 3, O'Connor Direct at 63:6-10.

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

[234] Ex. 3, O'Connor Direct at 65:18-25.

125. Initial engineering designs establish the high-level functional criteria for a design.[235] From this functional criteria, performance criteria at a component- or system-level can be identified through design and licensing basis reviews and impact reviews from the Plant and engineering programs.[236]

126. Once the performance criteria are established, design standards, specifications, calculations, and Plant-specific information are synthesized into a more detailed design and initial equipment specifications, conceptual layout and routing drawings, and calculations are created.[237]

127. Information is then gathered from field walkdowns, equipment vendors, and detailed component configurations before the installation-ready design is finalized.[238]

128. It is customary for nuclear projects to be commenced using preliminary design information (approximately 30 percent of design) rather than holding a project until installation-ready design is finalized.[239] The cost and time commitment to prepare the detailed installation-ready designs is significant and it is often difficult to complete installation-ready design without proceeding with some aspect of a project to investigate existing Plant conditions.[240]

129. The design and engineering process for the Program followed prescriptive procedures to ensure safety principles were adhered to in the development of conceptual to final designs.[241] The Plant implemented the following design phases for the Program to develop detailed designs: study stage, design state,

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235 Ex. 9, O'Connor Rebuttal at Schedule 22 at 2.

236 Ex. 9, O'Connor Rebuttal at Schedule 22 at 2.

237 Ex. 9, O'Connor Rebuttal at Schedule 22 at 2.

238 Ex. 9, O'Connor Rebuttal at Schedule 22 at 2.

239 Ex. 9, O'Connor Rebuttal at Schedule 22 at 3.

240 Ex. 9, O'Connor Rebuttal at Schedule 22 at 3.

241 Ex. 9, O'Connor Rebuttal at Schedule 22 at 3.

Design Review Meetings ("DRMs") at the 30/60/90 percent design levels, Challenge Boards as needs arose, Design Review Boards ("DRBs") after the completion of DRMs, Plant Operating Review Committee ("PORC"), and final design approval by the Design Engineering Supervisor/Design Authority.[242]

130. DRMs are held at the 30 percent, 60 percent, and 90 percent design phases.[243] The first DRM, held when the modification design is 30 percent, is generally conducted once the scope of the modification is defined, alternate design solutions have been evaluated, and the designer is ready to recommend a design approach for the modification.[244]

131. A thoroughly evaluation of the modification including constructability, installation, and testing is not completed until the 90 percent DRM.[245]

132. After all DRMs are complete and any challenge boards have completed their review, the DRB review is completed for a modification.[246] The DRB comprehensively reviews the modification and ensures that all facets of design, construction, maintenance, testing, and operations are properly considered and addressed as part of the modification package.[247]

133. Once the DRB has completed its review of the modification package, the modification is evaluated by the PORC, which is comprised of senior members of the Plant staff, including the Plant manager.[248] The PORC must provide sign-off on

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242 Ex. 9, O'Connor Rebuttal at Schedule 22 at 4-5.

243 Ex. 9, O'Connor Rebuttal at Schedule 22 at 4.

244 Ex. 9, O'Connor Rebuttal at Schedule 22 at 4.

245 Ex. 9, O'Connor Rebuttal at Schedule 22 at 4.

246 Ex. 9, O'Connor Rebuttal at Schedule 22 at 5.

247 Ex. 9, O'Connor Rebuttal at Schedule 22 at 5.

248 Ex. 9, O'Connor Rebuttal at Schedule 22 at 5.

all modification designs before a final design approval is completed by the design authority.[249]

134. Despite this multi-level and detailed process, after construction drawings are completed, construction often reveals that design needs to be modified to accommodate as-found conditions.[250] Changes at this stage are primarily driven by accessibility, interferences, and installation complexities discovered during construction.[251] These changes may require only a few hours of additional design while other may require hundreds of hours of additional design and further approval.[252]

135. In an operating nuclear plant it is normal for designs and scope to evolve as a modification progresses through the complex and multi-level design process.[253] This often requires custom design of new components and installation protocols to fit in the current facilities within the Plant framework that may require the removal and rerouting of large amounts of piping and wiring to access or accommodate the modification.[254]

136. A BWR, like Monticello, further makes design and engineering challenging as there are many areas that are not accessible while the Plant is operating because of high temperature and radiological environments.[255] In an operating nuclear plant, vital areas such as critical switchgear rooms have limited accessibility,

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[249] Ex. 9, O'Connor Rebuttal at Schedule 22 at 5.

[250] Ex. 9, O'Connor Rebuttal at Schedule 22 at 8.

[251] Ex. 9, O'Connor Rebuttal at Schedule 22 at 8.

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

[253] Ex. 9, O'Connor Rebuttal at Schedule 22 at 5.

[254] Ex. 9, O'Connor Rebuttal at Schedule 22 at 5.

[255] Ex. 9, O'Connor Rebuttal at Schedule 22 at 5-6.

even when the Plant is offline, and requires special controls and protections before work in these areas is permitted.[256]

2. Major Modifications Installed in 2009

137. The four major modifications with components installed during the 2009 outage included:[257]

- Turbines[258]
  - High Pressure Turbine Replacement
  - Low Pressure Turbine Modification
- Feedwater Heaters (partial)[259]
  - Cross Around Relief Valve ("CARV") Replacement
  - Main Steam, Feedwater Piping Modifications and New Instrumentation[260]
- Power Range Neutron Monitor ("PRNM") Installation[261]
- Transformers (Partial)[262]
  - 1AR Transformer Replacement

138. Prior to the 2009 outage, the Company estimated that it would incur $25 million in outage implementation for work related to these modifications.[263]

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256 Ex. 9, O'Connor Rebuttal at Schedule 22 at 6.

257 Ex. 3, O'Connor Direct at 72:4 at Table 10.

258 Ex. 3, O'Connor Direct at 72:4 at Table 10.

259 Ex. 3, O'Connor Direct at 72:4 at Table 10.

260 During the 2009 outage, 14 of 18 dump and drain valves were replaced. The majority of the work was done during the 2011 and 2013 outages and additional information about the main steam and feedwater piping modifications and new instrumentation is provided in the 2011 and 2013 summaries.

261 Ex. 3, O'Connor Direct at 72:4 at Table 10.

262 Ex. 3, O'Connor Direct at 72:4 at Table 10.

263 Ex. 3, O'Connor Direct at 72:1, 71:27 and 72:4 at Table 10.

139. The actual cost for the implementation of these modifications during the 2009 outage totaled $34 million.[264]

a. Turbine Major Modification

(1) *Component Purpose in the Plant*

140. The high- and low-pressure turbines at Monticello convert steam to mechanical energy and turn the generator.[265] The steam enters the turbines and passes through a series of blades, sometimes called "buckets."[266] These buckets are attached to a central shaft or rotor that is mechanically connected to the generator.[267] The shape of the blades allow pressurized steam to push against the blades and turn the rotor, that then turns the generator.[268]

(2) *Need for the Modification*

141. The previous high-pressure turbine required replacement or significant annual maintenance to support long-term operations at Monticello.[269] The high- and low-pressure turbines were replaced in 1996.[270] The turbines would have required replacement or refurbishment to enable Monticello to operate until 2030.[271]

142. Turbines need to be inspected periodically and as they age, they frequently need repair for cracked blades.[272] Based on the overall age of the turbine

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[264] Ex. 3, O'Connor Direct at 71:26-27.

[265] Ex. 3, O'Connor Direct at 95:18-23.

[266] Ex. 3, O'Connor Direct at 95:18-23.

[267] Ex. 3, O'Connor Direct at 95:18-23.

[268] Ex. 3, O'Connor Direct at 95:18-23.

[269] Ex. 3, O'Connor Direct at 96:16-17.

[270] Ex. 3, O'Connor Direct at 96:17-18.

[271] Ex. 3, O'Connor Direct at 96:18-19.

[272] Ex. 3, O'Connor Direct at 97:1-2.

and the Company's experience and that of the industry, the Company determined that it was better to replace the turbine as part of the LCM/EPU Program.[273]

143. Additionally, the steam flow under EPU conditions necessitated replacing the high-pressure turbine steam path and portions of the low-pressure turbine.[274] A 2004 feasibility study provided an initial evaluation of two options to address the turbine modification – turbine replacement or a reheat cycle to address limitations in the flow passing capability of the existing high-pressure turbine.[275]

144. The modification included the replacement of the existing high-pressure turbine steam path with a new rotor and diaphragms to accommodate increased steam flow.[276] The modification also included changes to the low-pressure turbine, including replacement of several diaphragm sets, one set of blades, and replacement of selected casing bolts.[277] As part of the modification, the Company also evaluated and replaced the expansion joints, where necessary.[278] Finally, the modification included the installation of a new vibration monitoring system.[279]

(3) *Changes to Design*

145. All design and engineering for the turbine major modification was handled by General Electric through their general design and planning group.[280]

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[273] Ex. 3, O'Connor Direct at 97:3-5.

[274] Ex. 3, O'Connor Direct at 96:21-22.

[275] Ex. 3, O'Connor Direct at 96:22-25.

[276] Ex. 3, O'Connor Direct at 95:3-12.

[277] Ex. 3, O'Connor Direct at 95:3-12.

[278] Ex. 3, O'Connor Direct at 95:3-12.

[279] Ex. 3, O'Connor Direct at 95:3-12.

[280] Ex. 3, O'Connor Direct at Schedule 17 at 1.

(4) *Implementation*

146. The high- and low-pressure diaphragms were installed during the 2009 outage, including the replacement of the high-pressure turbine.[281] Turbine vibration monitoring equipment was installed during the 2011 outage.[282]

147. The installation of the turbine modification went well with only minor issues before start-up.[283]

(5) *Modification Benefits*

148. The new high-pressure turbine eliminated a vibration condition which added maintenance and monitoring expenses.[284] Replacing the old high-pressure turbine with the new turbine with an Advance Vortex design provides superior reduction on secondary losses and profile losses.[285]

b. PRNM Major Modification

(1) *Component Purpose in Plant*

149. The PRNM allows the Plant to better monitor the number of neutrons available for further fission reactions.[286] The PRNM employs in-core neutron detectors to monitor local reactivity for core monitoring purposes.[287] The PRNM provides output to the Plant's Reactor Protection System to allow for timely initiation of rector trips, rod blocks and alarms, and communicates data to the core monitoring computer and other Plant systems.[288]

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281 Ex. 3, O'Connor Direct at Schedule 17 at 1.

282 Ex. 3, O'Connor Direct at Schedule 17 at 1.

283 *See* Ex. 3, O'Connor Direct at Schedule 17 at 1.

284 Ex. 9, O'Connor Rebuttal at 8:9-10 and 103:13-15.

285 Ex. 9, O'Connor Direct at 103:11-12.

286 Ex. 3, O'Connor Direct at 99:15-17.

287 Ex. 3, O'Connor Direct at 99:17-18.

288 Ex. 3, O'Connor Direct at 99:18-22.

(2) *Need for the Modification*

150. Prior to the installation of the PRNM during the Program, the Plant operated with outdated average power neutron monitor and oscillation power range monitor systems which were aged and presented obsolescence and spare parts issues.[289]

(3) *Changes to Design*

151. Design was performed by General Electric for the Nuclear Measurement Analysis and Control PRNM.[290] The intended design, engineering, and installation of the PRNM, as implemented during the Program, did not change from what was planned when General Electric prepared the Scoping Assessment in May 2006.[291]

(4) *Implementation*

152. Installation of the PRNM during the 2009 outage encountered few difficulties.[292]

153. The Company installed the PRNM without start-up issues, which no other nuclear plant in the United States has done.[293] Other nuclear facilities encountered operational impacts after installing similar systems.[294]

(5) *Modification Benefits*

154. The new PRNM provides additional stability functions and additional trip capability.[295] The PRNM provides operation and maintenance benefits in terms of improved system reliability and reduced surveillance and testing requirements.[296]

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289 Ex. 3, O'Connor Direct at 99:26-100:2.

290 Ex. 3, O'Connor Direct at Schedule 21 at 1.

291 Ex. 3, O'Connor Direct at 99:7-9.

292 Ex. 3, O'Connor Direct at 101:11.

293 Ex. 3, O'Connor Direct at 101:11-13.

294 Ex. 3, O'Connor Direct at 101:13-14.

295 Ex. 3, O'Connor Direct at 101:21-23.

296 Ex. 3, O'Connor Direct at 101:23-25.

c. Feedwater Heaters Major Modification – CARV

(1) *Component Purpose in Plant*

155. The CARVs are necessary to provide pressure protection to the Plant's turbine.[297] The CARVs provide an alternate path for steam to the condenser should conditions prevent the turbine from accepting the steam.[298]

(2) *Need for the Modification*

156. Replacement of the CARVs and piping was necessary to support the continued operation of the Plant through 2030.[299]

(3) *Changes to Design*

157. The CARV modification required that the Company develop a new piping design to accommodate the replacement CARVs while the setpoints of the original CARVs were being reset.[300]

(4) *Implementation*

158. The work on the CARV system during the 2009 outage replaced the CARVs and piping to allow greater flow capacity for EPU operation.[301] In 2009, the Company removed the original CARVs, installed temporary spares, and shipped the original CARVs to an outside vendor to reset the setpoints.[302] The Company reinstalled the CARVs with the new setpoints during the 2013 outage.[303]

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297 Ex. 3, O'Connor Direct at 121:15-17.

298 Ex. 3, O'Connor Direct at 121:17-18.

299 Ex. 3, O'Connor Direct at 120:8-10.

300 Ex. 3, O'Connor Direct at Schedule 25 at 2.

301 Ex. 3, O'Connor Direct at 72:4 at Table 10.

302 Ex. 3, O'Connor Direct at 72:4 at Table 10.

303 Ex. 3, O'Connor Direct at Schedule 21 at 1-2.

(5) *Modification Benefits*

159. The CARVs operate well in the Plant and provide necessary over pressure protection.[304]

d. Transformer Major Modification – 1AR Transformer

(1) *Component Purpose in Plant*

160. The 1AR emergency transformer supplies electricity to the Plant from the external transmission system to support the electrical needs of Monticello.[305] The incoming voltage is adjusted through the 1AR transformer to meet Plant equipment needs.[306]

(2) *Need for the Modification*

161. The 1AR transformer needed to be replaced because of its age.[307] The original 1AR transformer was obtained during Plant construction from another nuclear facility when the transformer was already almost 30 years old.[308] This meant that the 1AR transformer was replaced at Monticello when it was approximately 60 years old.[309] The Plant's 1AR transformer was one of the oldest transformers still in service in the United States nuclear fleet when it was replaced.[310]

(3) *Changes to Design*

162. The design of the 1AR transformer went well with few issues once the transformer specifications were identified.[311]

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304 Ex. 3, O'Connor Direct at 121:15-16.

305 Ex. 3, O'Connor Direct at 113:16-17.

306 Ex. 3, O'Connor Direct at 113:18-19.

307 Ex. 3, O'Connor Direct at 115:5.

308 Ex. 3, O'Connor Direct at 115:5-7.

309 Ex. 3, O'Connor Direct at 115:7.

310 Ex. 3, O'Connor Direct at 115:7-9.

311 Ex. 3, O'Connor Direct at Schedule 24 at 1-2.

(4) *Implementation*

163. Installation of the 1AR transformer was completed during the 2009 outage without any notable issues.[312]

(5) *Modification Benefits*

164. The 1AR transformer major modification replaced a 60-year-old transformer at the Plant.[313] In its existing condition, the 1AR transformer would not meet current standards for the extended Plant life and posed reliability risks for Monticello's continued operation.[314]

3. Lessons Learned

165. Under the direction of Day Zimmerman as the lead implementation vendor, the 2009 modifications were implemented successfully.[315]

166. For the first 75 percent of the outage, the modifications ran on schedule but the overall outage duration ended up approximately 10 percent over target.[316]

167. The Company observed reasonably good productivity from its vendors and increases in budgeted amounts were related to the complexity of work.[317]

168. Most of these costs were attributable to the need for additional labor and materials to complete the modifications.[318] During the 2009 outage, approximately 90 percent of the costs paid to Day Zimmerman were for craft labor expenses.[319]

169. After the 2009 outage, the Company performed a lessons learned evaluation and identified opportunities to work more efficiently with the lead design

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312 *See* Ex. 3, O'Connor Direct at 115:23-116:17.

313 Ex. 3, O'Connor Direct at 116:21.

314 Ex. 3, O'Connor Direct at 116:21-24.

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

316 Ex. 3, O'Connor Direct at 73:3-6.

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

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

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

and engineering vendors and monitor quality control.[320] As part of this assessment, the Company determined that, overall, its project management practices were appropriate.[321]

170. Xcel Energy was somewhat concerned about employee turnover with the lead implementation vendor.[322] When Xcel Energy raised these issues with the lead implementation vendor, it learned that employee turnover was fairly common in the nuclear industry given the competitive market.[323] Day Zimmerman assured the Company that it had the bench strength to complete the work heading into the 2011 outage.[324] Xcel Energy continued its relationship with Day Zimmerman as the lead installer for the planning phase into the 2011 outage.[325]

L. 2011 Outage

1. Advance Planning

171. By the end of the 2009 outage, the designs for the 2011 outage modifications were in development and the Company expected to meet its planned outage milestones.[326]

172. As it prepared for the 2011 outage, the Company identified issues with certain design proposals for the 2011 outage.[327]

173. One example is the design for the reactor feed pump modification, where the original design would have required removal of 290 feet of piping but the

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

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

322 Ex. 9, O'Connor Rebuttal at 68:15-20.

323 Ex. 9, O'Connor Rebuttal at 68:15-20.

324 Ex. 9, O'Connor Rebuttal at 68:15-20.

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

326 Ex. 3, O'Connor Direct at 75:13-14.

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

implemented design required removal of only 60 feet of piping.[328] By identifying the requisite design changes, the Company saved nearly $7 million.[329]

174. During this time, Xcel Energy pursued recovery plans to complete designs that would meet Company specifications and utilized internal engineering resources to address any shortcomings in outage planning.[330] Although there were instances where Xcel Energy experienced design issues with General Electric and its subcontractors during the Program, the Company stepped in appropriately to address those issues as they arose.[331]

175. Day Zimmerman conducted similar work for the 2011 outage planning period and through the 2011 outage as it had for the 2009 outage.[332] Day Zimmerman worked with the Company's engineering team to develop work packages for the 2011 outage.[333]

176. The Company experienced difficulties with Day Zimmerman's work package planning for the 2011 outage throughout 2010 and early 2011.[334] The Company rejected all designs that were received in 2010 and pursued recovery plans to complete designs that met the Company's specifications prior to the outage.[335] These recovery plans included supplementing the design process with the Company's internal engineering resources.[336]

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[328] Ex. 9, O'Connor Rebuttal at 63:1-7.

[329] Ex. 9, O'Connor Rebuttal 62:7-8.

[330] Ex. 3, O'Connor Direct at 75:22-25.

[331] Ex. 11, Sieracki Rebuttal at 46:8-10.

[332] Ex. 3, O'Connor Direct at 75:14-15.

[333] Ex. 3, O'Connor Direct at 75:14-15.

[334] Ex. 3, O'Connor Direct at 75:21-22.

[335] Ex. 3, O'Connor Direct at 75:22-23.

[336] Ex. 3, O'Connor Direct at 75:24-25.

177. The Company attributed the difficulties with the work packages received from Day Zimmerman to their recent loss of more experienced planning staff.[337]

2. Decision to Add a Third Outage to the Program

178. In June 2010, the Company also decided to split the 2011 outage into two outages and to defer certain work scheduled for spring 2011 outage to a fall 2011 outage.[338] In addition to the design issues, there were three other issues led Xcel Energy to evaluate implementing the remaining work into to two outages instead of one.[339]

179. First, the need to install the new electrical distribution system presented significant prolonged shutdown risk and required intricate work sequence planning.[340] If the work was not completed in the time allotted for the outage, the Company faced the risk of not having Monticello online during the 2011 summer peak.[341]

180. Second, the NRC license amendment request was on hold while the agency and the Company resolved issues with the Containment Accident Pressure ("CAP") standards.[342]

181. Third, the Company faced fabrication issues with certain equipment and had to work with vendors to identify action plans to correct these issues.[343] The Company believed that while these issues would not be resolved by the spring 2011 outage, they could be resolved by mid-year.[344]

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[337] Ex. 3, O'Connor Direct at 76:4-5.

[338] Ex. 3, O'Connor Direct at 76: 13-14.

[339] Ex. 3, O'Connor Direct at 76:15-24.

[340] Ex. 3, O'Connor Direct at 76:17-18.

[341] Ex. 3, O'Connor Direct at 76:18-19.

[342] Ex. 3, O'Connor Direct at 76:20-21.

[343] Ex. 3, O'Connor Direct at 76:22-24.

[344] Ex. 3, O'Connor Direct at 76:22-24.

182. While the Company initially evaluated an off-cycle fall 2011 outage, the Company ultimately decided to complete the remainder of the LCM/EPU Program work during the regularly scheduled Spring 2013 refueling outage.[345]

3. Major Modifications

183. The 2011 refueling outage began on March 4, 2011, and was scheduled to last 65 days.[346] The planned modifications were completed in 81 days.[347] The cost of the outage was approximately $133 million compared to an initial estimate of about $101 million.[348]

184. During the 2011 outage, the Company installed or began key work on six major modifications including:

- 14A/B and 15A/B Feedwater Heaters
- Certain Electrical Distribution System Work (cable tray conduit support installation and construction of new switchgear room and replacement hot shop)[349]
- Main Transformer
- Condensate Demineralizer System and Control Panel
- Steam Dryer
- Feedwater Heater (11A/B and 12A/B) Drain Line Replacement (half of the piping with the remainder in 2013).[350]

[345] Ex. 3, O'Connor Direct at 77:2-4.

[346] Ex. 3, O'Connor Direct at 78:16-17.

[347] Ex. 3, O'Connor Direct at 78:17-18.

[348] Ex. 3, O'Connor Direct at 68:4 at Table 9.

[349] While this work occurred during the 2011 outage, because the majority of the work associated with the electrical distribution system occurred during the 2013 outage, this work is discussed in detail in that portion of the Findings.

[350] Ex. 3, O'Connor Direct at 79:1 at Table 11.

a. Condensate Demineralizer System

(1) *Component Purpose in the Plant*

185. The condensate demineralizer provides clean, de-aerated, and pre-heated water to the reactor during normal plant operation.[351] The system consists of five large stainless steel vessels that filter the water before it flows to the reactor or reverse flow. The vessels are housed in concrete vaults.[352]

186. A control system is in place to manipulate the valves, control the amount of water flowing through and from the system, and maintain water chemistry for optimum operation.[353] Backwashing of the condensate vessels is required every several days to remove ion exchange resin that accumulates in the filter.[354]

(2) *Need for the Modification*

187. The Company identified several issues with the existing condensate demineralizer system that required replacement of this system. First, typically, resin can be expected to perform sufficiently for approximately two years.[355] By 2010, the vessels and filter elements of the existing system supported the resin for only six months before needing to be recharged.[356] Further, the existing analog control system was challenging from an operational perspective, and the Company had identified water quality issues with the potential to lower Monticello's availability.[357]

188. Based on these issues, the final scope of the condensate demineralizer modification included replacement of the entire condensate demineralizer system, including the five vessels, skid-mounted pre-coat system, holding pumps, associated

[351] Ex. 3, O'Connor Direct at 106:4-5.

[352] Ex. 3, O'Connor Direct at 106:5-6.

[353] Ex. 3, O'Connor Direct at 106:7-8.

[354] Ex. 3, O'Connor Direct at 106:8-9.

[355] Ex. 3, O'Connor Direct at 111:15-18.

[356] Ex. 3, O'Connor Direct at 111:18-20.

[357] Ex. 3, O'Connor Direct at 111:18-20.

piping, valves, and support systems.[358] This modification also included replacing the existing analog control system with a digital control system and installation of a new motor control system.[359]

(3) *Changes to Design*

189. The Company stated that the design process for this modification was the most complex of the 2011 modifications.[360] The design process spanned three years and required multiple iterations due to changes in project scope.[361] The primary issues were the complexity of piping interferences, the condition of system wiring that was not discovered until substantial demolition was completed, and the discovery of the backwash receiving tank design issue that required expedited design changes in the months before the 2011 outage.[362] When a pipe or support required relocation, structural analysis and further design was necessary to ensure safe completion of the modification.[363]

190. Shortly before the 2011 outage began, the Company discovered that the backwash tank was designed as an atmospheric tank and was insufficient to withstand overpressure of the backwash process.[364] Use of an atmospheric tank in this system would have presented significant risk of system failure, resulting in sudden release of contaminated water and resin from the backwash receiving tank.[365] The Company

[358] Ex. 3, O'Connor Direct at 105:18-22.

[359] Ex. 3, O'Connor Direct at 105:22-24.

[360] Ex. 3, O'Connor Direct at 108:21-22.

[361] Ex. 3, O'Connor Direct at 108:21-22.

[362] Ex. 3, O'Connor Direct at 108:22-23.

[363] Ex. 3, O'Connor Direct at 108:23-109:3.

[364] Ex. 3, O'Connor Direct at 109:5-8.

[365] Ex. 3, O'Connor Direct at 109:8-11.

proceeded with parallel processes in the months before the 2011 outage to simultaneously progress the installation and re-design of this modification.[366]

(4) *Implementation*

191. Installation of the condensate demineralizer modification was difficult due to as-found conditions in the Plant, challenges completing the work within the confined spaces of the Plant and difficulties sequencing the work.[367]

192. The condensate demineralizer vessels process reactor water and are highly radiological.[368] To mitigate the risk to Plant workers, the Company added shielding to the location and planned the work to minimize the exposure to its workers.[369]

193. The condensate vessels are contained in concrete vaults approximately eight feet square in size.[370] When the station was originally constructed, the vaults were poured after the vessels, wiring, and piping were installed.[371] Because of the space limitations imposed by the preexisting vaults, the Company spent thousands of hours installing the vessel auxiliaries during the 2011 outage.[372] Moreover, due to these spatial limitations, only two people could work in a vault at one time, and due to the radiological work environment, laborers were required to comply with work permit restriction, personal protective equipment, and step off protocols.[373]

194. While preparing to install new digital controls for the condensate demineralizer system, the Company identified that existing wiring for the controls was

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366 Ex. 3, O'Connor Direct at 109:11-13.

367 Ex. 3, O'Connor Direct at 80:11-13.

368 Ex. 3, O'Connor Direct at 109:18-20.

369 Ex. 3, O'Connor Direct at 134:7-9.

370 Ex. 3, O'Connor Direct at 109:18-20.

371 Ex. 3, O'Connor Direct at 109:21-23.

372 Ex. 3, O'Connor Direct at 109:23-25.

373 Ex. 3, O'Connor Direct at 109:25-110.

degraded and required replacement.[374] This forced the Company to quickly plan for and replace this wiring before proceeding with the rest of the work.[375] The Company was unable to access this wiring for inspection before the start of the 2011 outage.[376]

(5) *Modification Benefits*

195. The new condensate demineralizer system efficiently removes fine debris and resin from the condensate, and as a result the Company expects reduced operation and maintenance costs.[377] The replacement of the existing analog control system with automated, digital controls reduces the Company's reliance on individual operators to consistently run the condensate system.[378]

196. The old system required multiple manual valve manipulations while the new system automated and repositioned the system components.[379] The old system required two plant employees a total labor time of 12 to 16 hours per week to clean the vessels. The total labor time for the new process is approximately four hours per week.[380]

b. Main Power Transformer

(1) *Component Purpose in Plant*

197. The main power transformer distributes electricity generated at the station to the external transmission system.[381] The outgoing voltage is adjusted through this transformer to align with the external 345 kV transmission system.[382]

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[374] Ex. 3, O'Connor Direct at 80:18-21.

[375] Ex. 3, O'Connor Direct at 80:21-22.

[376] Ex. 3, O'Connor Direct at 80:22-23.

[377] Ex. 3, O'Connor Direct at 112:23-24.

[378] Ex. 3, O'Connor Direct at 112:25-27.

[379] Ex. 9, O'Connor Rebuttal at 6:18-23.

[380] Ex. 9, O'Connor Rebuttal at 6:18-23.

[381] Ex. 3, O'Connor Direct at 113:21-22.

[382] Ex. 3, O'Connor Direct at 113:22-23.

(2) *Need for the Modification*

198. The main transformer required replacement due to its age and performance degradation.[383] At 40-years old, the Company's experience with large transformers at its generating facilities indicated that this transformer was near the end of its useful life.[384] The main power transformer was identified in 2001, 2003, and 2006 as due for replacement due to its aged condition.[385]

199. The main transformer was also was also experiencing performance degradation.[386] Through transformer monitoring, via oil analysis, the Company determined that there was a gassing problem with the power transformer that was resulting in transformer degradation within the transformer that potentially could lead to in-service failure.[387]

(3) *Changes to Design*

200. The scope of the main transformer changed to provide additional Plant benefits in that instead of disposing of the main power transformer, the Company decided to refurbish it and store it onsite as a spare transformer.[388] This refurbished main power transformer stored onsite provides the station with a transformer ready for expedient deployment in the event the new main power transformer experiences operational issues.[389] The refurbishment of the main power transformer allowed the Company to avoid the acquisition of a new spare main power transformer as recommended under best practices.[390]

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383 Ex. 3, O'Connor Direct at 114:24-115:2.

384 Ex. 3, O'Connor Direct 114:24-26.

385 Ex. 3, O'Connor Direct at 115: 1-2; Ex. 9, O'Connor Rebuttal at 91:3-5 and Schedules 33 and 34.

386 Ex. 9, O'Connor Rebuttal at 91:17-18.

387 Ex. 9, O'Connor Rebuttal at 91:18-21 and Schedule 32.

388 Ex. 3, O'Connor Direct at 114:9-11.

389 Ex. 3, O'Connor Direct at 114:11-13.

390 Ex. 3, O'Connor Direct at 114:14-16.

(4) *Implementation*

201. As part of the modification, the Company also prepared the main power transformer for movement onsite after delivery, installed main power transformer fire detection and suppression systems to meet insurance requirements, reconciled electrical relay operations between the new transformer and the station electrical system, and reconfigured the isophase bus duct cooling.[391]

202. Because of the transformer's size, the transportation required development of special hauling and transportation precautions to deliver the main power transformer to its location at the Plant after it was delivered on site.[392] These precautions included modifications to the security fence and construction of a temporary storage pad.[393]

203. The Company experienced vendor challenges with the fabrication and delivery of the main power transformer, but the Company incurred no additional costs as a result of these vendor issues.[394] The Company originally intended to replace the main power transformer during the 2009 outage but due to vendor manufacturing issues, the Company deferred this work to the 2011 outage.[395] The vendor also damaged the transformer during delivery to Monticello.[396] The vendor remedied both of these issues at its expense and the Company incurred no additional costs.[397]

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391 Ex. 3, O'Connor Direct at 114:16-21.

392 Ex. 3, O'Connor Direct at Schedule 24 at 1-2.

393 Ex. 3, O'Connor Direct at Schedule 24 at 2.

394 Ex. 3, O'Connor Direct at 116:11-13.

395 Ex. 3, O'Connor Direct at 116:13-15.

396 Ex. 3, O'Connor Direct at 116:15-16.

397 Ex. 3, O'Connor Direct at 116:16-17.

(5) *Modification Benefits*

204. Replacement of the main power transformer improved Plant reliability because if a main power transformer fails, the Plant remains offline until it can be replaced or repaired, which can take a prolonged period of time.[398]

c. Steam Dryer

(1) *Component Purpose in Plant*

205. The steam dryer is a large metal structure placed at the top of the reactor.[399] The steam dryer consists of metal plates.[400] The steam formed in the reactor is forced through these plates to reduce the liquid water content of the steam.[401] This steam is transferred from the reactor to the high and low pressure turbines.[402] The steam dryer reduces moisture content of the steam produced from the reactor to minimize wear on the high and low pressure turbine blades.[403]

206. The actual replacement of the steam dryer occurred during the 2011 outage and the monitoring and evaluation of the steam dryer occurred in 2007 and 2008.[404]

(2) *Need for the Modification*

207. The original steam dryer was designed in the mid-1960s for a 40-year service life.[405] Prior to replacement, the existing steam dryer was experiencing performance issues.[406] This included an inability to maintain moisture carryover

398 Ex. 3, O'Connor Direct at 114:26-115:1.

399 Ex. 3, O'Connor Direct at 102:12.

400 Ex. 3, O'Connor Direct at 102:13.

401 Ex. 3, O'Connor Direct at 102:13-14.

402 Ex. 3, O'Connor Direct at 102:15-16.

403 Ex. 3, O'Connor Direct at 102:16-18.

404 Ex. 3, O'Connor Direct at 102:4-6.

405 Ex. 9, O'Connor Rebuttal at 114:20-21.

406 Ex. 9, O'Connor Rebuttal at 114:21-22.

("MCO") levels.[407] The MCO levels for the original steam dryer were at approximately 0.04 to 0.11 percent prior to replacement and the upper limit for acceptable MCO levels is 0.1 percent.[408]

208. The most significant impacts of the these high MCO are on flow-accelerated corrosion and shutdown radiation levels.[409] Both impact maintenance on other components in Monticello.[410] Increase in corrosion from high MCO levels in the steam dryer adds to wear on steam related components such as the turbine.[411] High MCO levels also led to an increase in radiation levels which makes maintenance activities on the high pressure turbine more difficult and costly.[412]

209. The Company initially believed modifications to the steam dryer would address these operational concerns.[413] In 2007, the Company installed sensors in the steam lines to gather baseline data for analysis.[414] Concurrent with design of this modification, the Company learned of cracking in other units' steam dryers.[415] As a result, the NRC issued guidance that would have required additional inspections and, in all likelihood, significant repairs for steam dryers over 40 years of age.[416] In late 2007, General Electric recommended that the Company replace, rather than modify,

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407 Ex. 9, O'Connor Rebuttal at 114:22-23.

408 Ex. 9, O'Connor Rebuttal at 114:23-25.

409 Ex. 9, O'Connor Rebuttal at 115:1-2.

410 Ex. 9, O'Connor Rebuttal at 115:2-3.

411 Ex. 9, O'Connor Rebuttal at 115:3-4.

412 Ex. 9, O'Connor Rebuttal at 115:5-7.

413 Ex. 3, O'Connor Direct at 103:13-14.

414 Ex. 3, O'Connor Direct at 103:14-15.

415 Ex. 3, O'Connor Direct at 103:15-16.

416 Ex. 3, O'Connor Direct at 103:16-104:1.

the existing steam dryer.[417] Based on these events, the Company decided to replace rather than modify the existing steam dryer.[418]

(3) *Changes to Design*

210. The steam dryer was procured through an RFP process and in early 2009, a procurement agreement with Westinghouse was executed.[419] To design the new steam dryer properly, Westinghouse had to install certain monitoring equipment and perform dimensional verification of the existing steam dryer.[420] Once the specifications were developed, Westinghouse was able to design and fabricate the new steam dryer.[421]

(4) *Implementation*

211. The Company's final costs for the steam dryer modification exceeded its initial estimate by approximately $2 million.[422] The primary driver for this increase is the installation of sophisticated acoustic monitoring instrumentation.[423] The Company installed this monitoring in response to the NRC's concerns over steam dryer failures at other facilities.[424] The Company will use the outputs from this acoustic monitoring to avoid similar incidents.[425] Although this monitoring comprised a smaller portion of the overall modification cost, specialized craft labor was required to install this monitoring equipment.[426]

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[417] Ex. 3, O'Connor Direct at 104:3-4.

[418] Ex. 3, O'Connor Direct at 104:1-3.

[419] Ex. 3, O'Connor Direct at Schedule 22 at 1.

[420] Ex. 3, O'Connor Direct at Schedule 22 at 1.

[421] Ex. 3, O'Connor Direct at Schedule 22 at 2.

[422] Ex. 3, O'Connor Direct at 104:22.

[423] Ex. 3, O'Connor Direct at 104:22-24.

[424] Ex. 3, O'Connor Direct at 104:24-105:1.

[425] Ex. 3, O'Connor Direct at 105:1-2.

[426] Ex. 3, O'Connor Direct at 105:2-4.

(5) *Modification Benefits*

212. The new steam dryer efficiently removes the moisture from the steam produced by the reactor and provides high-quality steam to the turbine.[427] The new steam dryer is reducing moisture carryover to no more than 0.1 percent.[428] This reduction in moisture carryover minimizes corrosion products in the reactor coolant loop, which in turn minimizes impacts to the turbine blading, and reduces the volume of radioactive wastes.[429]

d. Feedwater Heaters – 14A/B and 15A/B

(1) *Component Purpose in Plant*

213. The feedwater heaters are designed to increase the water temperature prior to it entering the reactor pressure vessel to improve the thermodynamic efficiency of the system.[430] The other equipment included in the feedwater modification, the CARVs, moisture separator drain tank, two new jib cranes to ease installation and future maintenance for the feedwater heaters, thermowell, drains and dumps, and main steam line navy nipples, all perform essential functions along the main steam lines of the turbine generators.[431]

214. The feedwater heater modification was completed over several outages.[432] During the 2011 outage, the 14A/B and 15A/B heaters were installed and the heater drain line was replaced for the 11 and 12 feedwater heaters.[433]

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[427] Ex. 3, O'Connor Direct at 105:8-9.

[428] Ex. 3, O'Connor Direct at 105:9-10.

[429] Ex. 3, O'Connor Direct at 105:10-13.

[430] Ex. 3, O'Connor Direct at 117:11-13.

[431] Ex. 3, O'Connor Direct at 117:15-18. The CARV work (with the exception of establishing new setpoints for uprate conditions) and replacement of 14 of 18 drain and dump valves was completed during the 2009 outage. The 14A/B and 15A/B feedwater heaters replacement, half of the drain and dump piping, installation of the two jib cranes, reinforcement of the turbine floor, and replacement of the remaining four drain and dump valves occurred during the 2011 outage while the remaining work was completed during the 2013 outage. Ex. 3, O'Connor Direct at Schedule 25 at 1.

[432] *See* Ex. 3, O'Connor Direct at 78:3-11.

(2) *Need for the Modification*

215. While the Company initially intended to rerate the feedwater heaters, the Company decided during the design phase that replacement was required.[434] The 14A/B and 15A/B heaters required replacement due to age, performance, and design issues.[435]

216. The 14A/B and 15A/B heaters were original equipment and the Company could no longer continue to modify and repair the shell and tube heat exchangers.[436]

217. Also, feedwater heaters 15A/B were operating "well beyond their original size rating" prior to replacement and had operated much longer than the experience of the Company's peer utilities.[437] In fact, in 2010, a tube failure on feedwater heater 15B caused a Plant shutdown.[438]

218. The Company also observed vibration damage at the tube support of the 14 and 15 heaters as well as a certain amount of steam erosion.[439] These heaters experienced service-related degradation, with tube wall thinning and plugging.[440] If they were not replaced, they would have required substantial maintenance requiring longer refueling outages to re-tube them.[441]

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433 Ex. 3, O'Connor Direct at 79 and Table 11.

434 Ex. 3, O'Connor Direct at 118:12-14.

435 Ex. 9, O'Connor Rebuttal at 105:19-106:9.

436 Ex. 3, O'Connor Direct at 118:14-16.

437 Ex. 9, O'Connor Rebuttal at 105:21-23.

438 Ex. 9, O'Connor Rebuttal at 105:24-25.

439 Ex. 9, O'Connor Rebuttal at 106:1-2.

440 Ex. 9, O'Connor Rebuttal at 106:2-4.

441 Ex. 9, O'Connor Rebuttal at 106:4-6.

(3) *Changes to Design*

219. The Company initially intended to rerate (complete modifications to the existing feedwater heaters) the Plant's feedwater heaters.[442] The decision to replace rather than rerate the 14A/B and 15A/B did increase costs for this modification.[443] Feedwater heater designs have changed substantially since the original heaters were installed and their replacement brought the Plant up to industry standards.[444]

(4) *Implementation*

220. When the 14A/B and 15A/B feedwater heaters were delivered on-site at the Plant, inspections revealed defects, including welding slag and moisture in the feedwater heaters.[445] Before the heaters could be installed, the slag and moisture had to be removed from the feedwater heaters, extending the overall modification installation timeline.[446]

221. Additional costs for this modification were incurred because replacement of the 14A/B and 15A/B feedwater heaters with larger heaters required structural analysis and reinforcement of the turbine floor at a cost of approximately $6 million.[447]

222. During the 2011 outage, the Company also replaced 180 feet of asbestos-insulated piping and the remaining four drain and dump valves necessary to support the operation of the feedwater heaters.[448] This work required in-field modifications to replace the piping around existing Plant components.[449]

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[442] Ex. 3, O'Connor Direct at Schedule 25 at 1-2.

[443] Ex. 3, O'Connor Direct at 119:16-19.

[444] Ex. 9, O'Connor Rebuttal at 106:8-9.

[445] Ex. 3, O'Connor Direct at Schedule 25 at 2.

[446] Ex. 3, O'Connor Direct at Schedule 25 at 2.

[447] Ex. 3, O'Connor Direct at 118:20-22.

[448] Ex. 3, O'Connor Direct at Schedule 25 at 1-2.

[449] Ex. 3, O'Connor Direct at Schedule 25 at 1-2.

(5) *Modification Benefits*

223. Given the age, performance issues, and design issues with the existing 14A/B and 15 A/B feedwater heaters, replacement of these heaters will reduce the operation and maintenance costs going forward.[450]

4. <u>Lessons Learned</u>

224. During the 2011 outage, the Company recognized the need to adapt its processes and took steps to plan for the 2013 outage.[451]

225. After the 2011 outage, the Company undertook a project management assessment.[452] This included a post-outage critique by the Project group and identified a number of improvement opportunities.[453]

226. The project group identified specific actions to be taken to improve staffing, construction estimates, design process, safety education, spare parts inventory, project controls and cost tracking to assist the Program team for the final outage.[454]

227. Through this process, the Company gathered the thoughts of Plant personnel on what could have been done differently for Program implementation to date.[455] After the 2011 outage, one employee wrote a several page document (the "2011 Cost History") at the request of the Chief Nuclear Officer outlining that employee's perspective of the Program.[456] The employee that authored the 2011 Cost History was not personally aware of what information was presented by the Plant to

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450 Ex. 3, O'Connor Direct at 121:12-13

451 Ex. 3, O'Connor Direct at 83:9-10.

452 Ex. 3, O'Connor Direct at 83:11-12.

453 Ex. 3, O'Connor Direct at 83:12-13.

454 Ex. 3, O'Connor Direct at 83:13-16.

455 Ex. 9, O'Connor Rebuttal at 63:24-25.

456 Ex. 9, O'Connor Rebuttal at 64:3-4.

inform the Company's final decision making on the Program and wrote the document based on the information available to him at that time.[457]

228. The 2011 Cost History provided a chronology of the Program from 2004 to the end of the 2011 outage.[458] The employee described various milestones through Program implementation.[459]

229. In his evaluation of the Program, the employee was critical of the Program budget and schedule for implementation that the nuclear management team presented to the Company as the project team had recommended a higher budget and longer implementation schedule to the nuclear management team.[460] The employee did not know that the nuclear management team also consulted with other business units within the Company before making its recommendation.[461] The 2011 Cost History was also critical of the design and project management controls that had been put in place for the Program, although it provided no recommendation as to what would have been acceptable to the author.[462] The Company considered these criticisms as it prepared for the final implementation outage advanced planning.[463]

230. The Company also reevaluated whether it should proceed with Day Zimmerman as the lead implementation vendor given that the work scheduled for the 2013 outage was much less mechanical than the prior outages and was much more electrical.[464]

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457 Ex. 9, O'Connor Rebuttal at 64:3-4, 64:8-12, and Schedule 24 at 4.

458 Ex. 300, Crisp Direct at Attachment MWC-3 at 1-2.

459 Ex. 300, Crisp Direct at Attachment MWC-3 at 1-2.

460 Ex. 300, Crisp Direct at Attachment MWC-3 at 3.

461 Ex. 9, O'Connor Rebuttal at 49:19-21.

462 Ex. 300, Crisp Direct at Attachment MWC-3 at 3-5.

463 Ex. 9, O'Connor Rebuttal at Schedule 24 at 1-2 and 5.

464 Tr. Vol. I (O'Connor) at 98:2-15.

231. In mid-2011, the Company elected to hire Bechtel Power Corporation ("Bechtel") to provide comprehensive project management.[465] Bechtel is a large and sophisticated multi-national company with expertise in the area of nuclear generation.[466] The Company required that Bechtel retain Day Zimmerman as its main mechanical subcontractor and to retain institutional knowledge and preserve implementation continuity.[467]

232. In addition to making a strategic change to its implementation vendor, the Company reevaluated its internal management personnel.[468] The Company hired a Vice-President of Nuclear Projects in December 2011 to reorganize the capital projects organization within the nuclear business unit.[469] The new Vice-President: (i) realigned the Projects' group structure; (ii) emphasized individual modification budgeting and forecasting; (iii) established firm design and work package planning outage milestones.[470] A set of processes were also instituted to improve reporting and tracking.[471]

233. Implementing lessons learned in this way was particularly important to the Company given that the 2013 outage work was going to be very labor-intensive and the Company was proactively managing its labor force.[472]

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465 Ex. 3, O'Connor Direct at 83:25-27.

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

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

468 Ex. 3, O'Connor Direct at 63:22-23.

469 Ex. 3, O'Connor Direct at 84:18-21.

470 Ex. 3, O'Connor Direct at 85:3-6.

471 Ex. 3, O'Connor Direct at 85:5-6.

472 Ex. 3, O'Connor Direct at 85:3-6.

M. 2013 Outage

1. Advance Planning

234. To prepare for the 2013 outage, the Company and Bechtel worked collaboratively to develop final cost estimates for the outage and understand the complexities of the Program.[473] As part of this effort, Bechtel prepared an initial overall Program cost estimate in mid-2011 but increased that estimate by the end of 2011 to approximately $587 million.[474]

235. Design and work package preparation work continued through 2012 and by January of 2013, Bechtel increased the overall Program cost estimate to approximately $640 million.[475]

236. In June, during the outage, Bechtel increased the estimate to $655 million.[476]

2. Major Modifications

237. The Company completed the installation of four major modifications during the 2013 outage.[477]

238. For the four major modifications to be installed during the 2013 outage, the Company budgeted $91.1 million.[478] The Company completed the following major modifications during the 2013 outage:[479]

- Reactor Feed Pumps and Motors[480]
- Condensate Pumps and Motors[481]

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473 Ex. 3, O'Connor Direct at 85:21-22.

474 Ex. 3, O'Connor Direct at 85:23-26.

475 Ex. 3, O'Connor Direct at 86:3-9.

476 Ex. 3, O'Connor Direct at 86:9-11.

477 Ex. 3, O'Connor Direct at 88:13 at Table 12.

478 Ex. 3, O'Connor Direct at 89:7 at Table 13.

479 Ex. 3, O'Connor Direct at 88:13 at Table 12 and Schedule 25 at 1-2.

480 Ex. 3, O'Connor Direct at 88:13 at Table 12 and Schedule 25 at 1-2.

- Feedwater Heaters[482]
    - 13A/B Feedwater Heaters
    - Reinstall CARVs with new Setpoints[483]
    - Enlarge Turbine Floor Hatch
    - Complete Piping Replacement
    - 11A/B and 12A Nozzles
- Electrical Distribution System[484]

239. The Company spent $137.2 million to complete the four major modifications during the 2013 outage while all work during the 2013 outage totaled $151 million.[485]

240. Despite the Company's decision to bring in Bechtel and bringing in new personnel to manage the 2013 outage,[486] the 2013 outage was the most challenging of all.[487]

241. The 2013 outage implementation faced challenges with the electrical distribution system installation, the reactor feed pumps and motors replacement, and replacement of the 13A/B feedwater heaters.[488] The implementation and design challenges were further compounded by the NRC's fatigue rule that was not a factor in the prior outages.

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481 Ex. 3, O'Connor Direct at 88:13 at Table 12 and Schedule 25 at 1-2.

482 Ex. 3, O'Connor Direct at 88:13 at Table 12 and Schedule 25 at 1-2.

483 Because the majority of the work for the CARV replacement and reinstallation was performed during the 2009 outage, this portion of the feedwater heater major modification is discussed in the 2009 outage section of the findings.

484 Ex. 3, O'Connor Direct at 88:13 at Table 12 and Schedule 25 at 1-2.

485 Ex. 3, O'Connor Direct at 89:7 at Table 13.

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

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

488 Ex. 3, O'Connor Direct at 89:12-90:2.

a. Reactor Feed Pumps and Motors Replacement

(1) *Component Purpose in Plant*

242. The two reactor feed pumps, each powered by a large motor, are large pumps designed to move treated water (feedwater) into the reactor.[489] The feedwater provides cooling for the reactor and is converted to steam to drive the high- and low-pressure turbines.[490]

(2) *Need for the Modification*

243. The need to replace the reactor feed pumps and motors had been identified as early as 2001 within approximately six years based on chronic performance problems.[491] The Plant's original reactor feed pumps replaced during the 2013 outage were a custom redesign of a 3-stage fire pump into a 2-state reactor feed pump.[492] Because of this design, these pumps were the only ones like it in the world and required frequent overhauls during outages.[493]

244. In 2005, the pump casings required substantial repair to address joint leakage issues.[494] While the rotating assemblies had been previously replaced, the motor stators were original and had never been re-wound.[495] Based on the age of the motors, which were not designed to remain in-service until 2030, replacement was also necessary.[496]

[489] Ex. 3, O'Connor Direct at 123:14-15.

[490] Ex. 3, O'Connor Direct at 123:15-16.

[491] Ex. 9, O'Connor Rebuttal at 109:9-11 and 109:17-21.

[492] Ex. 9, O'Connor Rebuttal at 109:23-24.

[493] Ex. 9, O'Connor Rebuttal at 109:24-110:1.

[494] Ex. 9, O'Connor Rebuttal at 110:1-2.

[495] Ex. 9, O'Connor Rebuttal at 110:4-5.

[496] Ex. 9, O'Connor Rebuttal at 110:5-7.

(3) *Changes to Design*

245. The project team initially investigated adding a third,smaller capacity, supplemental reactor feed pump and motor to accommodate uprate conditions.[497] The addition of a third pump presented challenges for Plant operation due to size limitations and operation procedures.[498] Further, because of legacy equipment repair issues and difficulties locating spare parts, the Company elected to replace the existing pumps and motors with larger capacity equipment.[499]

246. The Company encountered delays in procurement because they had difficulty finding motors that would meet Plant specifications.[500]

247. Also, the pump and motor fabricators encountered delays in providing the components due to difficulty fabricating equipment to meet the necessary specifications for Plant startup and operations.[501]

(4) *Implementation*

248. Space limitations in the reactor feed pump and motor room affected the ability to perform replacement work in the time allotted during the outage.[502]

249. To minimize outage length and allow concurrent installation activities on the pumps and motors, the Company constructed a two-level, load-bearing, structural, scaffold to provide two access points to the equipment, so work on the motors and pumps could occur concurrently instead of in sequence.[503]

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[497] Ex. 3, O'Connor Direct at 124:4-6.

[498] Ex. 3, O'Connor Direct at 124:8-9.

[499] Ex. 3, O'Connor Direct at 124:8-12.

[500] Ex. 3, O'Connor Direct at 125:23-24.

[501] Ex. 3, O'Connor Direct at 125:24-126:3.

[502] Ex. 3, O'Connor Direct at Schedule 26 at 2.

[503] Ex. 3, O'Connor Direct at 125:11-15.

250. Additionally, significant replumbing of the piping feeding to and discharging from pumps was required during the outage.[504] Much of this work was not discoverable until the reactor feed pump and motor room and surrounding equipment was demolished during the outage.[505]

251. The costs for the reactor feed pumps and motors modification would have either been incurred during the 2013 outage or at some time in the near future when the pumps and motors would have required replacement for operational issues.[506]

252. The Company was able to avoid costs by developing a final design that rerouted only 60 feet of piping as well as using lesser diameter piping whereas the initial designs for the reactor feed pumps and motors major modification required rerouting over 290 feet of piping and larger diameter piping.[507] The change also reduced the welding time for the piping by 15 percent.[508]

(5) *Modification Benefits*

253. The decision to replace the reactor feed pumps and motors was driven by service-related degradation issues and obsolescence.[509] The replacement of the reactor feed pumps and motors allowed the Plant configuration and operations to remain consistent during the extended life.[510] This decision has saved countless hours of procedure revisions and operational training.[511]

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[504] Ex. 3, O'Connor Direct at 126:4-6 and Schedule 26 at 2.

[505] Ex. 3, O'Connor Direct at Schedule 26 at 2.

[506] Ex. 3, O'Connor Direct at 125:16-19.

[507] Ex. 9, O'Connor Rebuttal at 63:1-8.

[508] Ex. 9, O'Connor Rebuttal at 63:6-7.

[509] Ex. 9, O'Connor Rebuttal at 109:14-15.

[510] Ex. 3, O'Connor Direct at 126:9-11.

[511] Ex. 3, O'Connor Direct at 126:11-12.

254. Reliability under existing conditions has also improved by addressing and eliminating pumps and motors wear conditions that necessitated preventative and corrective maintenance of this equipment.[512]

b. Condensate Pumps and Motors Replacement

(1) *Component Purpose in Plant*

255. The condensate pumps and motors move water from the hotwell of the condenser to the reactor feed pumps.[513]

(2) *Need for the Modification*

256. Replacement of the condensate pumps and motors was necessary to meet the demand of the new reactor feed pumps.[514] The condensate pumps and motors were replaced with different models to provide for the increased demand for water to the reactor feed pumps.[515]

257. The condensate pumps and motors were supplied by General Electric as original Plant equipment.[516] Performance of the condensate pumps and motors was degrading and was approaching the point where adequate suction flow/pressure could not be provided to the reactor feed pumps.[517]

258. The condensate pump internals had degraded and required replacement for the Plant's continued operation until 2030.[518]

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512 Ex. 3, O'Connor Direct at 126:12-14.

513 Ex. 3, O'Connor Direct at 127:3-6.

514 Ex. 9, O'Connor Rebuttal at 110:25-26.

515 Ex. 9, O'Connor Rebuttal at 110:26-111:2.

516 Ex. 9, O'Connor Rebuttal at 111:14-15.

517 Ex. 9, O'Connor Rebuttal at 111:15-18.

518 Ex. 3, O'Connor Direct at 127:25-128:2; Ex. 9, O'Connor Rebuttal at 111:8-10.

(3) *Changes to Design*

259. In 2009, the Company determined the Net Positive Suction Head required for the pumps was higher than what was available.[519] The Plant increased the hotwell level designs by 0.5 feet to address this issue.[520]

260. The condensate pump and motor vendors encountered fabrications issues in designing and fabricating equipment to meet Plant design specifications.[521]

261. To accommodate the designs, the motor designer had to add sufficient iron to the motor stator to accommodate the Company's pre-defined startup requirements.[522] Once this iron was added, the Company determined in 2011, that the heat produced would require modifications to the condensate room HVAC system.[523]

262. The Program saved approximately $2.2 million by changing design for the HVAC system design related to the condensate pumps and motors modification.[524]

(4) *Implementation*

263. The costs to install this modification were higher than anticipated.[525] The increase in costs are attributable to the in-outage designs required to address piping and wiring interferences encountered during the installation and the overall implementation productivity issues that the Company encountered during the 2013 outage.[526]

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519 Ex. 9, O'Connor Rebuttal at 59:2-4.

520 Ex. 9, O'Connor Rebuttal at 59:2-4.

521 Ex. 3, O'Connor Direct at 128:21-23.

522 Ex. 9, O'Connor Rebuttal at 59:5-7.

523 Ex. 9, O'Connor Rebuttal at 59:7-9.

524 Ex. 9, O'Connor Rebuttal at 63:12-14.

525 Ex. 3, O'Connor Direct at 129:10.

526 Ex. 3, O'Connor Direct at 129:10-14.

(5) *Modification Benefits*

264. Replacing the condensate pumps and motors improved the operating margins on this equipment and improved their reliability.[527]

c. Feedwater Heaters Modification – 13A/B Replacement and Associated Equipment

(1) *Component Purpose in Plant*

265. The 13A/B feedwater heaters provide intermediate heating for the reactor feedwater in the overall heat exchanger train, including over 400 feet of piping, that increases the water temperature prior to it entering the reactor pressure vessel to improve thermodynamic efficiency of the system.[528]

266. The other equipment included in the feedwater heater major modification (moisture separator drain tank, thermowell, drains and dumps, and main steam line navy nipples) all perform essential functions along the main steam lines of the turbine generators.[529]

(2) *Need for the Modification*

267. The original 13A/B feedwater heaters were replaced in 1984 due to severe erosion/corrosion of the original carbon steel materials in these units.[530] By 2006, the 13A/B feedwater heaters demonstrated an early trend of accelerating tube plugging, that was indicative of a need for replacement.[531] Plant engineers had identified as early as 2003 that the "[s]ervice life of feedwater heaters requires they be replaced to support the extended period of operation."[532] The 13A/B feedwater

[527] Ex. 9, O'Connor Rebuttal at 111:23-25.

[528] Ex. 3, O'Connor Direct at 117:11-13.

[529] Ex. 3, O'Connor Direct at 117:15-18.

[530] Ex. 9, O'Connor Rebuttal at Schedule 36 at 1.

[531] Ex. 9, O'Connor Rebuttal at Schedule 31 at 6 and Schedule 36 at 1-2.

[532] Ex. 9, O'Connor Rebuttal at 105:7-11, 105:24-25, and Schedule 34.

heaters were experiencing a trend of tube wear requiring accelerated plugging of tubes.[533]

268. The project team also identified a need to install bypass lines for the 12A drain coolers to limit drain cooler velocity and the 11A/B dump valves to limit the drain cooler flow rates.[534] Through detailed inspections, the project team determined that the 11 and 12 feedwater heaters could be rerated for EPU conditions and did not require replacement.[535]

269. The Company needed to replace 400 feet of drain and dump piping with larger piping and remove associated asbestos insulation for LCM purposes.[536] Although the piping replacement could have been delayed to another outage, because substantial feedwater heater work was already underway as part of the Program in the 2011 and 2013 outages, the Company concluded it was most cost-effective to undertake the replacement concurrent with the Program.[537]

270. Main steam transmitters and drain and dump valves required replacement due to obsolescence to support the extended life of the Plant.[538]

(3) *Changes to Design*

271. The 13A/B feedwater heaters replacement was deferred from the 2011 outage to the 2013 outage due to fabrication issues with the vendor.[539]

272. The replacement of the 400 feet of drain and dump piping required substantial design efforts, both pre- and in-outage.[540] Although the Plant initially

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[533] Ex. 9, O'Connor Rebuttal at Schedule 36 at 1-2.

[534] Ex. 9, O'Connor Rebuttal at Schedule 26 at 1.

[535] Ex. 3, O'Connor Direct at 118:17-18.

[536] Ex. 3, O'Connor Direct at 118:25-27.

[537] Ex. 3, O'Connor Direct at 118:27-119:3.

[538] Ex. 9, O'Connor Rebuttal at Schedule 31 at 4.

[539] Ex. 3, O'Connor Direct at Schedule 25 at 1.

[540] Ex. 3, O'Connor Direct at 120:1-2.

relied on as-builts for the piping designs, once in-outage, modifications were required to accommodate as-found condition in the Plant.[541]

(4) *Implementation*

273. Although installation of the 13A/B feedwater heaters was delayed until the 2013 outage, many of the associated systems, including approximately 200 feet of the 400 feet of piping, work on the moisture separator drain tank, and the remaining dump and drain valve replacement (started in 2009) was completed in 2011.[542] The remaining piping work was completed in 2013.[543]

274. The 2013 outage was also challenged by the removal and replacement of the 13A/B feedwater heaters.[544] The 13A/B feedwater heaters are located under the turbine floor of the Plant and access is through a hatch in the turbine floor.[545]

275. When the original 13A/B heaters were replaced in the 1980s, the removal and reinstallation was difficult because of the turbine floor hatch size.[546] The new 13A/B feedwater heaters are the same length as the old heaters and are less than five inches wider than the old ones.[547] To ease installation during the 2013 outage, the Company decided to make the hatch in the turbine floor larger to accommodate the rigging for this work.[548]

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541 Ex. 3, O'Connor Direct at 120:3-6.

542 Ex. 3, O'Connor Direct at Schedule 25 at 1. The first 14 of the 18 dump and drain valves were replaced during the 2009 outage along with the CARV work. Ex. 3, O'Connor Direct at Schedule 25 at 1.

543 Ex. 3, O'Connor Direct at Schedule 25 at 1-2.

544 Ex. 16, O'Connor Surrebuttal at 13:19-24.

545 Ex. 16, O'Connor Surrebuttal at 14:18-21.

546 Ex. 16, O'Connor Surrebuttal at 21-23.

547 Ex. 16, O'Connor Surrebuttal at 14:25-15:2.

548 Ex. 16, O'Connor Surrebuttal at 23-25.

276. Additionally, there are many pipes and conduits between the turbine floor hatch and the 13A/B feedwater heaters that had to be removed and reinstalled as part of the 13A/B feedwater heater replacement.[549]

(5) *Modification Benefits*

277. The feedwater heaters and associated components work well. The Plant anticipates that operation and maintenance costs for this equipment will be reduced because of the replacement.[550]

d. Electrical Distribution System Modification

278. The 13.8 kV modification added additional buses at 13.8 kV voltage level to supplement the Company's existing lower voltage (4 kV) electrical distribution system in the Plant.[551] The installation of the 13.8 kV system occurred during the 2011 and 2013 outages at a total cost of approximately $119.5 million.[552]

279. This was the most expensive major modification undertaken during the Program, and it was one of the most difficult modifications to complete because the Plant was required to maintain electric service to ensure cooling of the fuel at all times during the installation of the new system.[553] As a result, installation had to be done in stages to ensure that certain power sources were available at the appropriate times.[554]

(1) *Component Purpose in Plant*

280. The electrical distribution system at Monticello is comprised of feeders, breakers, protective relaying, controls, and instrumentation necessary to support the supply of power to many of the critical pumps in the Plant including the reactor feed

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

550 Ex. 3, O'Connor Direct at 121:12-13.

551 Ex. 3, O'Connor Direct at 130:4-6.

552 Ex. 3, O'Connor Direct at 130:6-8.

553 Ex. 3, O'Connor Direct at 130:8-11.

554 Ex. 3, O'Connor Direct at 130:11-13.

pumps, the condensate pumps, and the reactor recirculation motors.[555] The electrical system connects these components to the Plant's electrical busses and permits those pumps to operate as designed.[556]

(2) *Need for the Modification*

281. Before the Program, the Plant operated with a 4 kV system which allowed minimal margin to prevent overloading the electrical busses.[557] Any increased loads on the former system would make the Plant more vulnerable to Plant transients.[558]

282. The existing 4 kV system was operating within 50 volts of trip voltage, creating a fairly significant risk of tripping and the need to sequence loads to avoid voltage excursions.[559] The existing 4 kV switchgear ratings were at the point of being exceeded should new loads be added at the Plant.[560] This would have resulted in a configuration where entire portions of the distribution system could be irreparably damaged by ground fault(s) if these ratings are not maintained.[561]

283. Additionally, the 4 kV horizontal magnablast breakers and switchgear at the Plant are original design equipment that is obsolete and no longer supported by the vendor.[562] Spare parts for this equipment is difficult to find and limiting the equipment and loads on this system was paramount to the continued operation of Monticello.[563]

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555 Ex. 3, O'Connor Direct at 130:18-22.

556 Ex. 3, O'Connor Direct at 130:22-23.

557 Ex. 3, O'Connor Direct at 135:9-11.

558 Ex. 3, O'Connor Direct at 135:11-12.

559 Ex. 9, O'Connor Rebuttal at 97:6-9.

560 Ex. 9, O'Connor Rebuttal at 99:1-2.

561 Ex. 9, O'Connor Rebuttal at 99:2-5.

562 Ex. 9, O'Connor Rebuttal at 97:2-3.

563 Ex. 9, O'Connor Rebuttal at 97:4-13.

284. In 2007, the Company evaluated two electrical options for feasibility, cost, and schedule impact: 1) a 4 kV system to support both the safety- and non-safety-related equipment at the Plant; and 2) replacement of the 1R and 2R transformers to supply new 13.8 kV busses to support the non-safety-related equipment with the existing 4 kV system continuing to support the safety-related equipment.[564]

285. The Company's analysis indicated that the cost associated with a 13.8 kV system was less than one percent over the 4 kV system.[565] Regardless of the voltage selected, the Company intended to select and upgrade that (i) split the safety-related systems from the non-safety-related systems, (ii) would have required construction of new switchgear at the site of the old hot shop or a comparable remote location, (iii) would have required similar lengths of cable and raceway, and (iv) would have required replacement of transformers and other associated equipment.[566]

(3) *Changes to Design*

286. All designs had to be developed around keeping the existing 4 kV system intact to provide service to other equipment in the Plant.[567]

287. Design work also included the identification of viable options for the switchgear room that were of sufficient size but still located reasonably close to the Plant.[568] The first location developed by the designer for the switchgear room was unworkable and resulted in the Company having to transfer the switchgear room design to another designer.[569] The new designer identified the Plant's hot shop as a workable location for the switchgear room and began preparing room and raceway

564 Ex. 3, O'Connor Direct at 131:7-14.

565 Ex. 3, O'Connor Direct at 131:17-18.

566 Ex. 3, O'Connor Direct at 132:19-26; Ex. 9, O'Connor Rebuttal at 15-19.

567 Ex. 3, O'Connor Direct at Schedule 28 at 2.

568 Ex. 9, O'Connor Rebuttal at Schedule 35 at 8.

569 Ex. 3, O'Connor Direct at Schedule 28 at 2.

designs for this location.[570] Even had the Plant chosen to proceed with 4 kV instead of 13.8 kV, the switchgear room and associated raceway designs would have been necessary.[571]

(4) *Implementation*

288. To accommodate the electrical distribution conductor for the non-safety-related systems, bus ducts and cable trays had to be installed throughout the Plant from the switchgear room to pump motors and other equipment.[572]

289. The location of the 13.8 kV switchgear room required that the Monticello hot shop be relocated during the 2011 outage.[573] The former hot shop had to be decontaminated and properly built out, including a new HVAC system with additional particulate filter capability to ensure the air and space were sufficiently clean for the switchgear, to support the new electrical distribution system.[574] This also required that a new hot shop be built at the Plant concurrent with the switchgear room construction.[575]

290. To install the 13.8 kV electrical distribution system, electric cable, more than two inches in diameter and in excess of 100 pounds per foot, required teams of 10 electricians to pull the cable through the conduit.[576] Overall, approximately 14 miles of new five-inch cable and associated raceway had to be installed in the Plant for the 13.8 kV system.[577]

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570 Ex. 3, O'Connor Direct at Schedule 28 at 2.

571 Ex. 9, O'Connor Rebuttal at 99:16-17.

572 Ex. 3, O'Connor Direct at Schedule 28 at 2.

573 Ex. 9, O'Connor Rebuttal at 59:15-17; Ex. 16, O'Connor Surrebuttal at 12:6-10.

574 Ex. 9, O'Connor Rebuttal at Schedule 35 at 8-9.

575 Ex. 3, O'Connor Direct at Schedule 28 at 2.

576 Ex. 3, O'Connor Direct at 90:10-14; Ex. 16, O'Connor Surrebuttal at 11:20-24.

577 Ex. 3, O'Connor Direct at 132:16-17 and 133:23-24.

291. Installation of these cables is challenging as if they are not carefully installed, these cables can be damaged by overstress or tensioning.[578] To accommodate the installation, the cables were pulled in a slow and methodical fashion in 20-foot intervals over 14 miles.[579]

292. The installation of the electrical distribution system modification required over 230,000 man-hours during the 2013 outage.[580]

(5) *Modification Benefits*

293. This upgraded electrical system accommodates the increased electrical demands of the reactor feed pumps and motors, condensate pumps and motors, and other associated equipment to support Plant operations.[581] The modification has also provided the needed increased margin at the Plant, improves reliability, and enhances the flexibility, simplicity, and safety of Plant operations.[582]

294. Also, installing a 13.8 kV system for the non-safety-related equipment allowed the Plant to leave the safety-related equipment on 4 kV, including Monticello's blackout equipment.[583] This not only provided desirable redundancy but also increases the operating margin of the 4 kV system.[584]

295. In addition, this modification has allowed the Plant to avoid a future capital project to upgrade the Plant's electrical distribution system that likely would have become necessary under evolving NRC regulations.[585]

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578 Ex. 3, O'Connor Direct at 133:24-134:1.

579 Ex. 3, O'Connor Direct at 134:1-2.

580 Ex. 3, O'Connor Direct at 134:13-14.

581 Ex. 3, O'Connor Direct at 134:19-21.

582 Ex. 3, O'Connor Direct at 134:21-23.

583 Ex. 9, O'Connor Rebuttal at 100:13-15.

584 Ex. 9, O'Connor Rebuttal at 100:15-16.

585 Ex. 3, O'Connor Direct at 134:23-25.

296. Evolving regulatory requirements have imposed the need to add electric load to the internal distribution system in the form of Fukushima upgrades, EDG Ventilation System upgrades, and security order impacts.[586]

297. Currently, the NRC is examining changes to the rule regarding coping times based on the lessons from Fukushima.[587] Under the NRC's current rule regarding coping times (10 C.F.R. 50.63) Monticello must be able to withstand loss of power for up to four hours.[588] Under the draft rules, this time period could increase to up to 72 hours.[589] This draft rule is expected to be implemented in the 2017 timeframe.[590]

298. To meet this new requirement, Monticello will likely add more battery capacity (direct current) and more battery charging capacity (alternate current).[591] Addition of more battery charging capacity translates into additional load on the distribution system.[592] By adding the 13.8 kV system, the Plant is well-positioned to accommodate additional battery charger load to the Plant's electrical system than it was able to before when there was little margin for new load additions.[593]

299. These recent developments would have substantially outstripped the remaining margin in the legacy system and would have triggered the upgrade.[594] Thus, by having installed the 13.8 kV system the Plant is fortunate to have already-added

[586] Ex. 9, O'Connor Rebuttal at 98:17-19.

[587] Ex. 9, O'Connor Rebuttal at 99:25-26.

[588] Ex. 9, O'Connor Rebuttal at 99:26-100:1.

[589] Ex. 9, O'Connor Rebuttal at 100:1-2.

[590] Ex. 9, O'Connor Rebuttal at 100:2-3.

[591] Ex. 9, O'Connor Rebuttal at 100:3-5.

[592] Ex. 9, O'Connor Rebuttal at 100:5-6.

[593] Ex. 9, O'Connor Rebuttal at 100:6-9.

[594] Ex. 9, O'Connor Rebuttal at 98:20-21.

sufficient margin on the system to absorb these new loads without additional construction.[595]

3. The NRC's Fatigue Rule

300. Labor productivity for the 2013 outage was affected by the NRC's fatigue rule.[596] While the NRC's fatigue rule was not in place for the 2009 or 2011 outages, it was in place and impacted the 2013 outage.[597]

301. The fatigue rule contributed to the Company's existing productivity concerns, which revolved around challenges such as (1) hiring and retaining experienced craft labor due to the competitive nuclear labor market and the hydraulic fracturing boom; and (2) tasks taking longer than estimated because of small work spaces or radiological conditions.[598]

302. In the construction trades, a large project will sometimes deploy workforce on a 12-hour by 7-day schedule.[599] Tradesmen often prefer this aggressive schedule to maximize job-earning potential.[600] The fatigue rule, however, limited workers to a 6-day schedule, thereby creating created a competitive disadvantage for the Program.[601]

303. Tradesmen often prefer the more aggressive schedule to maximize job earning potential and the fatigue rule means that the Company had to compete for workers with jobs that were not nuclear projects and did not have to comply with the

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595 Ex. 9, O'Connor Rebuttal at 98:22-24.

596 Ex. 3, O'Connor Direct at 91:3-5.

597 Ex. 3, O'Connor Direct at 91:20.

598 Ex. 3, O'Connor Direct at 90:27-91:26.

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

600 Ex. 3, O'Connor Direct at 92:4-6.

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

fatigue rule.[602] The NRC's fatigue rule also limited any extended hours for workers after the 60th day of an outage, further compounding work schedule planning.[603]

304. As a result of the fatigue rule, the Company had to compete for workers with jobs that were not nuclear projects and did not have to comply with the fatigue rule.[604]

305. The NRC's fatigue rule limited any extended hours that the Company's employees were permitted to work after the 60th day of an outage.[605] On the 61st day of an outage, the fatigue rule requires the Company to limit its workers' hours meaningfully.[606] This limitation further compounded the Company's difficulties with work-schedule planning.[607]

306. The Company actively managed its challenges throughout the implementation of the Program.[608]

4. <u>2013 and 2011 Implementation Vendor Evaluation</u>

307. After the 2013 outage, the Company evaluated the amounts paid to its project managers for craft labor and project management.[609] The Company estimated that 90 percent of the amounts paid to Day Zimmerman were for craft labor expense in the 2009 and 2011 outages.[610] The Company estimated that approximately 75 percent of the amounts paid to Bechtel to prepare for and implement the 2013 outage were for craft labor expense.[611]

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[602] Ex. 3, O'Connor Direct at 92:4-8.

[603] Ex. 3, O'Connor Direct at 92:10-15.

[604] Ex. 3, O'Connor Direct at 92:4-8.

[605] Ex. 3, O'Connor Direct at 92:10-15.

[606] Ex. 3, O'Connor Direct at 92:10-15.

[607] Ex. 3, O'Connor Direct at 92:10-15.

[608] Ex. 9, O'Connor Rebuttal at 60:6-8.

[609] Ex. 9, O'Connor Rebuttal at 47:22-26.

[610] Ex. 9, O'Connor Rebuttal at 47:22-23.

[611] Ex. 9, O'Connor Rebuttal at 47:23-26.

308. The Company also evaluated its daily expense rate for its primary implementation vendors and compared the 2011 and 2013 daily outage amounts.[612] For both the 2011 and 2013 outages, the Company spent approximately $0.91 million per outage day on project management costs when it included the pre-outage preparation costs and the in-outage costs.[613]

309. The Company concluded that Bechtel spent substantially more time planning for the 2013 outage and managed implementation costs downward through this planning for the outage.[614] In contrast, Day Zimmerman spent less on outage planning but incurred more per outage day for implementation.[615]

310. This comparison, however, showed that the reduction in implementation costs experienced by Bechtel in the 2013 outage came at a cost.[616] Although the two vendors approached the outages differently, there were costs that could not be readily saved by the different approaches to Project implementation.[617]

N. Company Communications of Program Status to the Commission

311. During implementation of the Program, the Company provided updates to the Commission and stakeholders on the difficulties the Company was facing.[618]

312. During the Certificate of Need proceeding, the Company advised the Commission of changes made to the NRC application for license amendment.[619] In November 2009, the Company notified the Commission by letter that the NRC was

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

613 Ex. 9, O'Connor Rebuttal at 74:16 at Table 7.

614 Ex. 3, O'Connor Direct at 74:18-20.

615 Ex. 3, O'Connor Direct at 74:16 at Table 7.

616 Ex. 3, O'Connor Direct at 74:18-20.

617 Ex. 3, O'Connor Direct at 74:20-22.

618 Ex. 12, Sparby Rebuttal at 29:21-30:7.

619 *In the Matter of the Application of N. States Power Co., a Minn. Corp., for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate*, No. E002/CN-08-185, LETTER FROM XCEL ENERGY TO THE COMMISSION (Dec. 5, 2008).

delaying review of Monticello's EPU application, and to advise the Commission of the effect the delay would have on the Program.[620]

313. On November 3, 2010, the Company filed its 2011 rate case.[621] The initial filing included updated costs for the Program of about $361 million through 2011.[622]

314. On May 4, 2011, in the Company's rate case Rebuttal Testimony, it updated the cost estimate for the Program to $399.1 million to reflect costs incurred during the 2011 outage.[623]

315. On August 25, 2011, the Company provided post-hearing Supplemental Testimony to communicate new information regarding Program delays and cost increases, specifically that new estimates show that the Program costs would exceed $500 million.[624] Several months later, the Company's Chief Nuclear Officer provided testimony that the Program was expected to cost between $550 and $600 million.[625]

316. In November 2011, the Company entered into a Stipulation and Settlement committing to undergo this prudence review.[626]

317. After the 2011 rate case stipulation and settlement, the Company filed a Notice of Changed Circumstances on November 22, 2011 in the Monticello EPU Certificate of Need docket notifying the Commission of its decision to delay final

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620 *In the Matter of the Application of N. States Power Co., a Minn. Corp., for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate*, No. E002/CN-08-185, STATUS OF EXTENDED POWER UPRATE AT MONTICELLO NUCLEAR GENERATING PLANT (Nov. 5, 2009).

621 *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-10-971.

622 Ex. 8, Alders Rebuttal at 16 n.27; *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-10-971, INITIAL FILING (Nov. 3, 2010).

623 Ex. 8, Alders Rebuttal at 16 n.27.

624 Ex. 8, Alders Rebuttal at 16 n.27.

625 Ex. 8, Alders Rebuttal at 16 n.27.

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

implementation of the Program to the 2013 outage.[627] The Commission notified the Company on January 6, 2012 that the change in timing of the Program implementation was acceptable without the need to reopen the Certificate of Need.[628]

318. The Company also provided the Commission with cost updates in the Company's 2012 rate case[629] and in the Company's 2013 rate case.[630]

319. The Company provided information on the Program implementation difficulties in the 2011 rate case (Docket No. E002/GR-10-971) and additional updates in the Company's 2012 and 2013 rate cases.[631] In 2011, the Company provided Supplemental Testimony explaining Program delays and cost increases, specifically that the Program costs would exceed $500 million.[632] Several months later, the Company's Chief Nuclear Officer provided testimony that the Program was expected to cost between $550 and $600 million.[633]

320. As part of the 2012 rate case, the Company committed to undertake the prudence review presently at issue in this Docket.[634]

O. NRC License Amendment Request

321. Concurrent with design and implementation of the Program, the Company sought its license amendment request for the uprate from the NRC. The process of obtaining and maintaining a NRC license requires considerable effort.[635]

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627 *In the Matter of the Application of N. States Power Co., a Minn. Corp., for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, NOTICE OF CHANGED CIRCUMSTANCES (Nov. 22, 2011).

628 *In the Matter of the Application of N. States Power Co., a Minn. Corp., for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, ORDER (Jan. 6, 2012).

629 *In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-12-961, O'CONNOR DIRECT at 17 (Nov. 2, 2012).

630 Ex. 12, Sparby Rebuttal at 30:2-5.

631 Ex. 12, Sparby Rebuttal at 30:2-5.

632 Ex. 8, Alders Rebuttal at n. 27.

633 Ex. 8, Alders Rebuttal at n. 27.

634 Ex. 12, Sparby Rebuttal at 30:5-7.

322. The NRC license amendment process consists of a highly detailed and technical review of the facility's proposed construction and operating characteristics.[636]

323. On March 31, 2008, Xcel Energy filed its original EPU license amendment request with the NRC but withdrew that submission based on NRC staff feedback.[637]

324. On November 5, 2008, the Company resubmitted its uprate license amendment request to the NRC and included a new steam dryer instead of making modifications to the existing dryer.[638]

325. For applications filed in and after 2007, the NRC average review time increased by a full year to 2.2 years for license amendment requests at BWRs.[639] This 2.2-year review period is more than twice the NRC's 2007 target of 12 months and four months longer than its amended 18-month target.[640]

326. The Monticello EPU license amendment request was pending review before the NRC for five years.[641]

327. As part of its license amendment request, Xcel Energy provided the NRC with a list of modifications that focused on what components were required for the EPU, not taking into account the condition of those existing components in the Plant or the condition of components not mentioned in the table.[642]

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[635] Ex. 3, O'Connor Direct at 51:14-16.

[636] Ex. 3, O'Connor Direct at 51:7-8.

[637] Ex. 3, O'Connor Direct at 52:25-26, 53:2-4 and Schedule 17 at 1.

[638] Ex. 3, O'Connor Direct at 51:24-25 and 53:4-7.

[639] Ex. 3, O'Connor Direct at 53: 22-23 and 54:1 at Table 8.

[640] Ex. 3, O'Connor Direct at 53: 23-25 and 54:1 at Table 8

[641] Ex. 3, O'Connor Direct at 54:5.

[642] Ex. 9, O'Connor Rebuttal at 87:19-22.

328. While this list accurately reflected the Plant modifications necessary for uprate conditions, it was not developed for the purpose of classifying modifications as either LCM or EPU or as an economic analysis.[643]

329. The Company received over 420 information requests with multiple subparts from the NRC for the EPU license amendment request.[644]

330. These NRC requests related to two main areas of the license amendment request analysis: 1) credit in safety analysis for CAP; and 2) ongoing structural analysis of the new steam dryer.[645]

331. In BWRs like Monticello, an EPU increases the temperature of water in containment, and the higher temperature can affect the ability of the emergency core cooling system to cool the reactor core and containment.[646]

332. Credit for safety analysis for CAP refers to the reliance on a portion of the increased pressure in the primary containment structure to demonstrate acceptable performance, which was acceptable to the NRC in EPUs approved prior to the submission of the Company's license amendment request.[647]

333. In October 2009, the NRC notified the Company that the NRC staff and the ACRS had reached a disagreement on CAP analysis and needed more time to develop additional regulatory guidance on this issue.[648] The NRC and ACRS did not resolve the internal disagreement until April 2011.[649]

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643 Ex. 9, O'Connor Rebuttal at 87:9-14.

644 Ex. 3, O'Connor Direct at 54:15-17.

645 Ex. 3, O'Connor Direct at 54:21-23.

646 Ex. 3, O'Connor Direct at 55:17-20.

647 Ex. 3, O'Connor Direct at 55:22-23.

648 Ex. 3, O'Connor Direct at 55:27-56:2.

649 Ex. 3, O'Connor Direct at 56:2-5.

334. At this time, the Company and the NRC faced another unforeseeable complicating factor, as the catastrophic events at Fukushima unfolded in the spring of 2011.[650]

335. The guidance was published just after the tsunami struck Fukushima and gave NRC staff latitude to require from the Company significant additional analysis to confirm CAP than what had been communicated previously to the Company.[651]

336. This additional analysis, developed 2.5 years after the Company filed its license amendment request and over four years after the Company signed its contract with General Electric to proceed with the EPU, required an additional two years of review and analysis in addition to what had been completed.[652] The NRC increased its expected hours for review of license amendment requests from 5,040 hours to 7,500 hours.[653]

337. The Company estimated that the additional calculations required by the NRC, including the CAP analysis, increased licensing costs by approximately $17 million.[654]

338. The review of the new steam dryer for EPU conditions, which was installed in 2011, included numerous iterations of detailed structural analysis, each of which required significant cost to complete.[655] The cost increase for the steam dryer modification of approximately $2 million was primarily attributed to additional acoustic monitoring the Company had to complete to respond to NRC concerns for steam dryer failures at other facilities.[656]

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650 Ex. 3, O'Connor Direct at 56:27.

651 Ex. 3, O'Connor Direct at 57:1-3.

652 Ex. 3, O'Connor Direct at 57:4-6.

653 Ex. 3, O'Connor Direct at Schedule 17 at 1.

654 Ex. 9, O'Connor Rebuttal at 24:17 at Table 1. Additionally Calculation Costs totally $16 million and CAP Issues total another $1 million.

655 Ex. 3, O'Connor Direct at 57:25-26 and Schedule 22.

656 Ex. 3, O'Connor Direct at 104:22-24.

339. The steam dryer issue was the last substantive license amendment request issue that was resolved with the ACRS in September 2013.[657]

340. In January 2010, Xcel Energy also sought a license amendment related to the Plant's nuclear fuel configuration to allow the Plant to operate more efficiently under General Electric's Maximum Extended Load Line Limit Analysis ("MELLLA+") licensing topical report.[658] MELLLA+ is an engineering analysis that provides for greater operational flexibility and ease to operate units safely at maximum power for longer periods.[659]

341. The Company received over 46 information requests from the NRC for the MELLLA+ license amendment request.[660]

342. The MELLLA+ license amendment has always been scheduled for issuance shortly after receipt of the EPU license amendment from the NRC.[661]

P. <u>Benefits of the LCM/EPU Program</u>

343. The Company's filings in this proceeding also outlined the benefits achieved through completion of the Program.[662] The Company's LCM/EPU Program will allow the Plant to provide clean, reliable, and cost-effective energy to customers at approximately $1,000/kW installed through 2030 and possibly beyond.[663]

344. In addition, extending the life of the Plant maximizes the use of existing infrastructure and takes advantage of the substantial transmission system in the area.[664] Continued operation of Monticello also contributes to the diversity of the

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[657] Ex. 3, O'Connor Direct at 57:22-23 and Schedule 18; Ex. 9, O'Connor Rebuttal at 23:7-8.

[658] Ex. 3, O'Connor Direct at 52:7-10.

[659] Ex. 3, O'Connor Direct at 52:13-15.

[660] Ex. 3, O'Connor Direct at 54:15-17.

[661] Ex. 3, O'Connor Direct at 52:18-20.

[662] *See, e.g.*, Ex. 3, O'Connor Direct at 42, 142-44; Ex. 9, O'Connor Rebuttal at 2-3; Ex. 12, Sparby Rebuttal at 4-5.

[663] Ex. 3, O'Connor Direct at 142:14-16.

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

region's fuel mix and reduces reliance on historically volatile natural gas and other market energy.[665]

345. The Plant's nuclear generation will avoid millions of tons of carbon dioxide emissions annually and completely avoid any oxides of nitrogen, sulfur dioxide, Mercury, or other smokestack pollutants associated with fossil-fuel generation.[666] This serves as a valuable hedge against volatile fossil-fuel prices and evolving fossil-fuel regulations that make new coal plants infeasible and may require existing plants to shut down.[667]

346. Moreover, the Program provided and continues to provide several hundred high-quality craft labor and other jobs, both during the Company's periodic refueling outages and for general operations.[668]

347. For the benefit of Plant operators, the Company made design choices during the Program to ensure that the Plant's new systems would be compatible with prior protocols[669] These systems also provide the Plant with additional safety margins and in some instances restore margins that had been utilized during prior upgrades.[670]

348. During the Program the Company also replaced many components that were near the end of their useful lives.[671] Replacing these components will improve Plant reliability going forward.[672] Accordingly, as a direct result of the Program's improvements, the Company anticipates that the Plant will operate more reliably and efficiently during most of the its remaining operating life.[673]

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

[666] Ex. 3, O'Connor Direct at 142:25-143:1.

[667] Ex. 9, O'Connor Rebuttal at 3:17-24; 143:1-3.

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

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

[670] Ex. 3, O'Connor Direct at 143:9-22.

[671] Ex. 3, O'Connor Direct at 144:10-12

[672] Ex. 3, O'Connor Direct at 144:10-12.

[673] Ex. 3, O'Connor Direct at 144:6-12.

Q. **Potential Life After 60**

349. Current federal law and regulations governing the safety of nuclear reactors in the United States only allow utilities to renew nuclear plant operating licenses for 20 years beyond their original 40-year license term.[674]

350. Currently, however, the NRC is reviewing the potential for civilian nuclear reactors to continue operations after 60 years.[675] This initiative, which the NRC refers to as the "subsequent license renewal," is being developed to ensure that extending operating plants' lives beyond 60 years is safe, manageable, and economical.[676]

351. Accordingly, while the Company does not currently have authority to operate Monticello beyond 2030, the Company anticipates based on the quality of work and equipment installed as part of the LCM/EPU Program, that the Plant is in a favorable position for potential future life extensions.[677]

R. **Position of the Parties**

1. Whether Xcel Energy's Handling of the LCM/EPU Was Prudent?

a. Was the Company's Decision to Proceed Prudent?

(1) *Initial Cost Estimates*

(a) *The Department*

352. The Department took issue with the Company's initial estimates for the Program, particularly the accuracy of initial estimates and whether initial estimates in the uprate Certificate of Need proceeding were in 2006 dollars or 2014 dollars.[678]

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674 Ex. 9, O'Connor Rebuttal at 10:4-6.

675 Ex. 9, O'Connor Rebuttal at 10:6-9.

676 Ex. 9, O'Connor Rebuttal at 10:6-10 and Schedule 2.

677 Ex. 9, O'Connor Rebuttal at 9:21-10:11 and Schedule 2.

678 Department Initial Br. at 72-73.

353. As to the accuracy of the initial estimates, the Department argued that the Company failed to apply proper cost estimating procedures in its uprate Certificate of Need Application.[679]

354. Specifically, the Department argued that the Company should have included a 50-100 percent contingency on top of its cost estimate, resulting in a $480-640 million estimate without AFUDC instead of the $346 million estimate without AFUDC presented by the Company in the Certificate of Need proceeding.[680] The Department's witness, Mr. Crisp, concluded that the Company should have undertaken more detailed design and engineering analysis to develop better cost estimates for the Program before providing a cost estimate in the Certificate of Need Application.[681]

355. Additionally, the Department concluded, based on the 2011 Cost History, that the Company had information at the time it provided its initial cost estimates with the Certificate of Need Application that internal resources at the Plant estimated the cost of the Program at $362.5 million and should have used that number as its initial estimate.[682]

356. The Department also argued that the Company should have known the complexity of the Program and included those costs in its initial estimate.[683] Department witness Mr. Crisp noted that installation costs accounted for 40 percent of the cost increases for the Program.[684]

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[679] Department Initial Br. at 43-44.

[680] Department Initial Br. at 44.

[681] Department Initial Br. at 44-45; *see* Ex. 9, O'Connor Rebuttal at 51:5-8.

[682] Department Initial Br. at 29.

[683] Department Initial Br. at 35-36.

[684] Ex. 300, Crisp Direct at 15-19.

357. The Department also argued that the Certificate of Need estimate, escalated to 2014 dollars, was $346 million not the $397.5 million supported by the Company.[685]

(b) *The OAG*

358. The OAG argued that the Company should be held to the lowest end of its Certificate of Need estimates of $320 million.[686]

(c) *XLI*

359. XLI did not specifically take a position on Xcel Energy's initial estimate, but generally supported the Department's position on the Company's estimate in the uprate Certificate of Need proceeding.[687]

(d) *Xcel Energy*

360. In the Certificate of Need proceeding, Xcel Energy provided the Commission with an estimated cost of the Program of approximately $320-346 million (2008$) for modeling purposes for the Commission to consider alternatives to the 71 MW associated with the EPU.[688]

361. The Company stated that the $320-346 million estimate is the General Electric contract amount, including Xcel Energy's additions for their own work and the results of its benchmarking analysis, ($270-293 million) plus the electrical distribution system initial estimate ($21 million) plus the steam dryer estimate ($29-32 million) in 2009 dollars.[689] Additionally, the Company provided testimony that the

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[685] Department Initial Br. at 88-89. The Department's Brief and Ms. Campbell's testimony at the Evidentiary Hearing states that the escalation was to escalate the uprate Certificate of Need estimate "in 2013 dollars". Tr. Vol. IV (Campbell) at 127-128. However, Ms. Campbell's prefiled testimony states that the $346 million is the amount "when escalated to current (2014) dollars." Ex. 313, Campbell Direct at 19:6-12.

[686] OAG Initial Br. at 1 and 45.

[687] XLI Initial Br. at 8 n.33.

[688] Ex. 15, Alders Surrebuttal at 15:10.

[689] Xcel Energy Initial Br. at 86; *see*Ex. 9, O'Connor Rebuttal at 39:13-17.

$346 million in 2008 dollars equates to $397.5 million in 2014 dollars.[690] With AFUDC added, the uprate Certificate of Need estimate in 2014 dollars is $453 million.[691]

362. The Company argued that its initial estimate was appropriate based on the information it knew or reasonably should have known at the time of filing its uprate Certificate of Need Application.[692]

363. The Company responded to the Department's criticism that it should have used the $362.5 million estimate identified in the 2011 Cost History and developed by the internal Plant project team in the Certificate of Need proceeding by stating the cost estimate the Company used was developed with the best information available to the Company at the time and included input from multiple sources.[693] Even if the Company had used $362.5 million in the Certificate of Need proceeding, it was only marginally closer to the final Program costs.[694]

364. The Company responded to Mr. Crisp's criticism that the Company failed to include contingencies in estimating costs for the Program by pointing out that the Company included contingencies throughout the course of the Program in a variety of ways.[695] The initial estimate of $320-346 million included "$15.431 million plus $7 million in 2006 dollars for two different contingencies."[696] Regardless, the Company stated that presence or absence of cost contingencies would not have made the overall cost of the Program higher or lower.[697]

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690 Xcel Energy Initial Br. at 86 (citing Ex. 15, Alders Surrebuttal at 15:14-15).

691 Xcel Energy Initial Br. at 86 (citing Ex. 15, Alders Surrebuttal at 15:12-15).

692 Xcel Energy Initial Br. at 86-96.

693 Ex. 9, O'Connor Rebuttal at 39:9-17.

694 Ex. 9, O'Connor Rebuttal at 44:20-23.

695 Ex. 9, O'Connor Rebuttal at Schedule 13.

696Ex. 9, O'Connor Rebuttal at Schedule 13 at 2.

697 Ex. 9, O'Connor Rebuttal at 40:9-10.

365. The Company objected to the Department's position that the Company should have added a contingency of 100 percent to its Certificate of Need estimates.[698] Xcel Energy argued that the Department incorrectly relied on a document entitled "Cost Estimate Classification System" related to the "Expected Accuracy Range" to support its 100 percent "contingency."[699] The Company pointed out that this document is inapplicable to nuclear projects and, instead, applies only to "production of chemical, petrochemicals, and hydrocarbon processing."[700] The Company also argued that even if the document was applicable to a nuclear project, the document does not support Mr. Crisp's contention that a 100 percent contingency should be used in this phase of a project.[701]

366. Xcel Energy also disagreed with the Department's conclusion that cost estimates could have been better had the Company done more detailed design before submitting the Certificate of Need Application.[702] The Company determined that had it completed more design work before proceeding with the licensing and procurement, the initial cost estimate might have been more accurate, but the estimate would not have reached the actual Program cost and the Program would have been delayed as many as four years, which would not have met the forecasted baseload need that was present at the time.[703]

367. In developing its estimate, the Company evaluated the costs incurred for similar projects at other nuclear plants around the county and set its initial cost estimate 75 percent higher than the benchmarked projects as shown in Table 2

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698 Xcel Energy Initial Br. at 92.

699 Xcel Energy Initial Br. at 92-93.

700Ex. 303, Crisp Surrebuttal at Schedule 1 at 2.

701 Xcel Energy Initial Br. at 92.

702 Xcel Energy Initial Br. at 90.

703 Xcel Energy Initial Br. at 36 (citing Ex. 9, O'Connor Rebuttal at 52:17-54:5 and Figure 2; Ex. 11, Sieracki Rebuttal at 12:6-12).

above.[704] The Company argued that no circumstances existed to justify supporting costs significantly greater than it included in its uprate Certificate of Need estimates.[705]

368. The Company also relied on testimony from Dr. Jacobs, the Department's witness, that "the cost increases at the St. Lucie and Turkey Point were significantly more than the cost increases as Monticello, but they had the same – similar challenges"[706] to support that they were not alone in the magnitude of the Program cost increases.[707]

369. The Company noted that Florida Power and Light, the operator of St. Lucie and Turkey Point, was authorized to recover 100 percent of its costs for the LCM and EPU activities undertaken at these facilities at the same time the Program was being implemented Monticello.[708]

(e) *Conclusion*

370. The $346 million evaluated in the 2008 uprate Certificate of Need proceeding is equivalent to $397.5 million without AFUDC and $453 million with AFUDC in 2014 dollars. While the Department's calculation results in the same $346 million amount based on its assumptions, its conclusion that the $346 million was the uprate Certificate of Need estimate escalated to 2014 dollars is not supported by the record.

371. The Company prudently developed its initial cost estimate of $346 million for the Program in the 2008 uprate Certificate of Need proceeding by relying on the information it knew or should have reasonably known at the time based on input from General Electric, the Company's own review of other similar projects, and

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704 Xcel Energy Initial Br. at 89.

705 Xcel Energy Initial Br. at 89.

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

707 Xcel Energy Initial Br. at 38.

708 Tr. Vol. III (Jacobs) at 105:6-19; *see* Ex. 4, Stall Direct at 8:12-20 (explaining that LCM activities were coordinated with the EPU at the Florida facilities although their program was referred to as "EPU").

including an additional amount over other similar projects to attempt to account for the small footprint and other known conditions at Monticello.

372. The Company has met its burden of proof in providing evidence to support that it undertook a reasonable and appropriate process to develop the initial cost estimates for the Program.

373. No Party presented evidence sufficient to rebut the Company's *prima facie* case.

(2) *Parallel Path to Licensing, Design, Procurement, and Implementation*

(a) *The Department*

374. The Department was critical of the Company's multi-track approach to the Program.[709] Specifically, Mr. Crisp questioned the reasonableness and effectiveness of the Company's decision to adopt the multi-track approach.[710] Mr. Crisp concluded that this approach "likely resulted in increased" cost of the LCM/EPU Program.[711]

375. To support this argument and Mr. Crisp's conclusion, the Department relied on the 2011 Cost History and the criticisms contained therein.[712] Specifically, the Department quoted language from the 2011 Cost History that criticized the 2009/2011 implementation schedule: "This made all work activities 'fast track' with little ability to meet outage milestones."[713] Additionally, the Department claimed that the Xcel Energy "Board chose the completion date to be 2011 rather than select a 2013 date" recommended by the project team.[714]

709 Department Initial Br. at 10.

710 Ex. 419, Crisp Opening Statement at 1.

711 Ex. 419, Crisp Opening Statement at 1.

712 Department Initial Br. at 29 and 32-35.

713 Department Initial Br. at 29.

714 Department Initial Br. at 33.

376. Mr. Crisp, however, disclaimed that he was testifying as to whether the parallel approach undertaken by the Company was imprudent.[715] Mr. Crisp further indicated that cost increases for a project of this size are possible without any imprudence.[716]

(b) *The OAG*

377. The OAG agreed with the Department's criticisms of the Company's decision to multi-track the Program.[717] The OAG argued that the 2009 and 2011 outage schedule was not reasonable and a longer implementation schedule would have avoided "a significant portion of the cost overruns."[718]

378. The OAG argued that Xcel Energy's decision to multi-track the Program was not reasonable because the Company's employees and contractors did not have time to effectively scope the Program and complete design work.[719]

(c) *XLI*

379. XLI relied on the Department's analysis of the multi-track approach for its position.[720] XLI generally agreed with the Department's conclusion that the parallel path approach to the Program contributed to increased Program costs.[721]

(d) *Xcel Energy*

380. Xcel Energy argued that proceeding in parallel with design, licensing, procurement, and implementation was necessary from a resource planning perspective

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

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

717 OAG Initial Br. at 20.

718 OAG Initial Br. at 21.

719 OAG Initial Br. at 21.

720 XLI Initial Br. at 6.

721 XLI Initial Br. at 6.

to meet forecast customer needs.[722] The Company concluded that this approach was sound and allowed the Company to proceed promptly under the circumstances it knew or reasonably had reason to know at the time it made the decision to proceed on a parallel path.[723]

381. The Company explained that its decision to proceed on a parallel path 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; and (4) the need to upgrade certain Monticello systems to support the Plant's continued operation during the license extension.[724]

382. The Company also explained that the earlier schedule allowed the Company to address the much–needed LCM investments sooner rather than later.[725] During its planning for, and implementation of, the 2009 and 2011 outages, certain Plant equipment was already experiencing operational issues that necessitated replacement before the 2011 or 2013 outages had the later schedule been selected at the outset.[726]

383. Further, the Company explained that it was in the customers' best interest to pursue the 2009/2011 schedule. As Mr. O'Connor testified:

> We sought to move quickly to capture the customer benefits of increased output over the license renewal period. It was in our customers' best interest to get the fuel savings from the upgrades for as long as possible and to spread the costs of significant construction over as long a period as possible.[727]

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[722] Xcel Energy Initial Br. at 36 (citing Ex. 3, O'Connor Direct at 3:1-10; Ex. 8, Alders Rebuttal at 8:17-19 and n.17; Ex. 11, Sieracki Rebuttal at 11:11-21).

[723] Xcel Energy Initial Br. at 89.

[724] Xcel Energy Initial Br. at 36.

[725] Ex. 9, O'Connor Rebuttal at 58:13-18.

[726] *See* Ex. 9, O'Connor Rebuttal at 105:24-25

[727] Ex. 3, O'Connor Direct at 58:22-27.

384. In response to the Department's reliance on the 2011 Cost History, the Company provided additional context for the document.[728] Specifically, the Company stated that the author of the 2011 Cost History was not personally aware of all the information or discussions that supported the Company's decisions.[729]

385. The Company argued that while the 2011 Cost History reflects an internal project team recommendation of a 2011 and 2013 implementation schedule, the Company chose to recommend a 2009 and 2011 implementation to meet system demand needs and input from other departments within the Company.[730]

386. Finally, Company witness Mr. Sieracki concluded that Xcel Energy's approach was reasonable and necessary for the Program under the circumstances known or reasonably should have known at the time the decisions to proceed in this manner were made by the Company.[731]

(e) *Conclusion*

387. The Department, OAG, and XLI raised several concerns with the multi-track approach adopted by the Company for the Program. Specifically, the Department's witness, Mr. Crisp concluded that approaching a project on a parallel path can increase overall costs. However, Mr. Crisp also testified that costs for a project can increase absent imprudence and that he was not testifying that the decision to proceed on a parallel path was imprudent.

388. The Department's reliance on the 2011 Cost History to criticize the parallel path approach implemented by the Company is not supported by the record. The 2011 Cost History is a critical analysis of the implementation of the Program through 2011 but is not dispositive as to what the Company did or did not do as it

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[728] Xcel Energy Initial Br. at 36-37.

[729] Xcel Energy Initial Br. at 36-37.

[730] Xcel Energy Initial Br. at 104.

[731] Ex. 11, Sieracki Rebuttal at 24:21-22.

only represents the opinion of one Company employee with limited knowledge of overall deciding factors.

389. While the author of the 2011 Cost History may have recommended a 2011 and 2013 implementation schedule, the record supports that the Company's decision to proceed with the 2009/2011 schedule was reasonable.

390. Specifically, the Company had to consider multiple factors at the time it made its decision of whether to proceed on a parallel path or proceed sequentially with design, licensing, procurement, and implementation. While there may be information today that indicates the Company could have delayed the implementation of the Program by several years because of changes in demand and natural gas prices, that information was not available to the Company at the time it elected to proceed on a parallel path. In addition, the condition of the Plant equipment necessitated expedient replacement.

391. The Company has met its burden of proof by providing evidence to support that its decision to multi-track the design, licensing, and implementation of the Program was reasonable and appropriate given the concerns the Company was facing with baseload capacity forecast needs and the condition of Plant equipment.

392. No Party presented evidence sufficient to rebut the Company's *prima facie* case.

b. Was the Company's Management of the Project Prudent?

(1) *Scope of Initiative*

(a) *Department*

393. The Department argued that the Company's lack of detailed scoping at the outset of the LCM/EPU Program was not reasonable and likely resulted in

increased costs.[732] The Department relied on testimony provided by Mr. Crisp to support this assertion.[733]

394. Mr. Crisp testified that the key to cost-effective project management is extensive, highly detailed, and accurate pre-project definition and scope.[734]

395. Mr. Crisp pointed out that Company should have updated its as-built drawings after the 1998 uprate as a starting place for planning the LCM/EPU Program.[735] Mr. Crisp testified that maintaining updated as-built drawings was the industry standard in 2008 and continues to be the industry standard today.[736]

396. In addition to using as-built drawings, Mr. Crisp also criticized the Company's lack of initial detailed design and lack of reasonable, detailed initial scope.[737]

397. Mr. Crisp concludes that

> failure to properly scope, failure to include installation costs for major equipment, and failure to include installation costs for major equipment, and failure to include equipment in the scope drove up the costs over the initial EPU CN estimate, likely resulting in costs being higher than costs otherwise would have been.[738]

(b) *OAG*

398. The OAG argued that had the Company completed more detailed designs at the outset of the Program, it would have reduced total costs.[739]

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732 Department Initial Br. at 25-30.

733 Department Initial Br. at 25-30.

734 Ex. 300, Crisp Direct at 6.

735 Ex. 300, Crisp Direct at 5.

736 Ex. 303, Crisp Surrebuttal at 15.

737 Ex. 300, Crisp Direct at 11.

738 Ex. 419, Crisp Opening Statement at 1 and 3.

739 OAG Initial Br. at 28.

399. The OAG also challenged the Company's documentation of its decision-making process in changing the work scope from the initial scope.[740]

400. The OAG argued that with the exception of the 13.8 kV distribution system, the Company failed to provide a discussion of the Company's decision-making process for changing the scope of the other modifications or what alternatives the Company considered once the decision was made.[741] The OAG also argued that the Company failed to provide documentation to show that modification changes were made based on a cost benefit evaluation.[742]

(c) *XLI*

401. XLI relied on the analysis provided by the Department's witnesses related to the Company's LCM/EPU Program scope.[743]

(d) *Xcel Energy*

402. The Company countered the criticisms from the other Parties by stating that the overall scope of the Program never changed.[744] The Company explained that the dual purpose of the Program was always to perform the work necessary to: (i) allow Monticello's continued safe and reliable operation until 2030; and (2) achieve uprate operating conditions.[745]

403. While Mr. Crisp criticized the Company's initial scoping efforts, the Company pointed out that Mr. Crisp acknowledged that the Company satisfied the several steps required for prudent management.[746] Namely, the Company appropriately set the overall scope of the Project to meet the twin LCM and EPU

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[740] OAG Initial Br. at 14.

[741] OAG Initial Br. at 15-16.

[742] OAG Initial Br. at 18.

[743] XLI Initial Br. at 5-7.

[744] Xcel Energy Initial Br. at 96.

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

[746] Xcel Energy Initial Br. at 97.

goals at the start of the Project.[747] Mr. Crisp agreed that it was reasonable for the Company to rely of industry expert, General Electric, to assess the existing condition of the Plant equipment in order to determine the scope of the modifications.[748]

404. After setting the overall scope, design proceeded into a seven-phase process that included study, design, DRMs, challenge boards, DRBs, PROC review, and design approval.[749]

405. The Company also responded to Mr. Crisp's critique that the Company should have utilized as-builts from the 1998 uprate as a starting point for development of the Program.[750] The Company explained, and Mr. Crisp agreed, that the 1998 uprate was primarily an analytical exercise that only required modest changes to Plant components.[751] As a result, the 1998 uprate did not involve or require updating the Plant's as-builts.[752]

406. The Company further explained that the as-builts that were available at the time were often not accurate, as is common with nuclear plants of this vintage.[753]

407. Mr. O'Connor also testified that in the 1980s, the Plant committed to document safety-related electrical systems and in 2008 began updating all mechanical, electrical, and civil as-built conditions when discrepancies were found.[754]

408. The Company responded to Mr. Crisp's critique that the Company should have completed more detailed designs prior to implementing the Program by pointing out that such detailed designs would have delayed completion of the Project

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747 Tr. Vol. III (Crisp) at 37:7-24.

748 Tr. Vol. III (Crisp) at 38:20-39:4.

749 Ex. 9, O'Connor Rebuttal at Schedule 22.

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

751 Ex. 9, O'Connor Rebuttal at 17:7-19:9; Tr. Vol. III (Crisp) at 50:5-17.

752 Ex. 9, O'Connor Rebuttal at 17:7-19:9

753 Ex. 9, O'Connor Rebuttal at 17:7-19:9.

754 Ex. 9, O'Connor Rebuttal at 18:25-19:6.

by at least four years.[755] Given the age of the equipment and the need for additional baseload resources, the Company stated that such a delay would not have been feasible.[756]

409. In addition, the Company questioned whether more detailed designs would have reduced costs for the Program.[757] The Company stated that even with detailed designs, the Company would not have been able to fully account for as-found conditions, for hidden interferences, and things like degraded wiring that were discovered during the actual installations.[758]

410. The Company further pointed out that Mr. Crisp did not criticize: (i) the reasonableness of the scope additions to these modifications, (ii) the costs necessary to complete these modifications; (iii) the benefits the Company derived from each modification.[759]

411. In response to the OAG's criticism that the Company did not provide evidence of the design process it employed and the alternatives it considered, the Company explained these items were indeed provided by the Company.[760] The Company stated that it provided a detailed explanation of the design process employed by the Company and the options and alternatives the Company considered in designing the 10 major modifications.[761] The Company noted that Schedule 32 of Mr. O'Connor's Rebuttal Testimony provides a 57-page detailed discussion of its

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755 Ex. 9, O'Connor Rebuttal at 53:1 at Figure 2.

756 Ex. 9, O'Connor Rebuttal at 56:11-13.

757 Ex. 9, O'Connor Rebuttal at 77:12-14.

758 Ex. 9, O'Connor Rebuttal at 54.

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

760 Xcel Energy Initial Br. at 40-41.

761 Ex. 3, O'Connor Direct at 93-146 and Schedules 17,19, 21-28; Ex. 9, O'Connor Rebuttal at Schedule 32.

analysis of its analysis in support of its decision to replace and upgrade systems at the Plant and the alternatives that were explored during that process.[762]

(e) *Conclusion*

412. The Department, the OAG, and XLI raised concerns with the Company's process to develop the initial scope of the Program and make changes to the scope throughout the duration of the Program.

413. The Company provided background on how its initial scope was developed and further explained that many system conditions could not be fully assessed or evaluated until detailed design or even implementation were undertaken because of the configuration of the Plant components. The Company provided substantial and fact-based reasons explaining the designs selected and the options and alternatives that the Company considered.

414. While the Department and OAG suggested that if the Company had completed more detailed initial designs at the beginning it could have avoided additional costs, no party challenged the final design for the installed modifications.

415. The Company met its burden of proof by providing evidence that it acted reasonably in establishing the initial scope for the Program.

416. The Company met its burden of proof by providing evidence varying its initial designs based on changing circumstances encountered during the course of this eight-year Program was reasonable to support the continued safe operation of the Plant and meet the objectives of the Program.

417. No Party presented evidence sufficient to rebut the Company's *prima facie* case.

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762 Ex. 9, O'Connor Rebuttal at Schedule 32.

(2) *Vendor Management*

(a) *Department*

418. The Department alleged that the Company failed to properly manage contractors throughout the Program.[763]

419. The Department also argued that the Company failed to properly utilize its on-site team to assist with the Program.[764]

(b) *OAG*

420. The OAG questioned the Company's use of outside contractors to perform "virtually every action taken to finish the [Program]."[765] Given the Company's dependence on contractors, the OAG concluded that it was necessary to develop a robust system to manage contractors to ensure that the work was completed efficiently.[766]

421. The OAG questioned the Company's decision to retain General Electric.[767] The OAG stated that because General Electric held the proprietary rights to the design basis for Monticello, General Electric held "enormous leverage" over the Company and the contract with General Electric "likely cost more than it would have if there had been effective competition for the design work."[768]

422. The OAG also criticized the Company's use of Nuclear Management Company ("NMC") to initially mange the Program as it is unusual to see a contractor used as a general manager in the nuclear industry, and that the typical procedure is to

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763 Department Initial Br. 39-42.

764 Department Initial Br. at 42.

765 OAG Initial Br. at 30-31.

766 OAG Initial Br. at 31.

767 OAG Initial Br. at 31.

768 OAG Initial Br. at 31.

have a vice president from the utility act as the general manager of such a large construction project.[769]

(c) *XLI*

423. XLI did not specifically address the issue of contractor management.

(d) *Xcel Energy*

424. The Company responded to the OAG's critique of its use of General Electric by noting that as the original designer of the Plant, General Electric held proprietary rights to the aspects of the design basis and it was most efficient to use their prior knowledge and experience for the LCM/EPU Program.[770] The practice of hiring the initial designer for any significant Plant modification work is a consistent with the practice of other utilities and good nuclear practice.[771]

425. The Company also pointed out that General Electric had extensive experience with uprates and with the NRC licensing process.[772]

426. With regard to NMC, Xcel Energy explained NMC was the contract operator of Monticello, not just the manager of a single project.[773] When NMC ceased its operating functions at Monticello in 2008, the management functions were absorbed back into the Company. Company witness Mr. Sieracki explained that the Company's use of a management company like NMC is consistent with the practice of some other utilities.[774] Mr. Sieracki noted that when a management company is used, a company must still provide oversight for this management company, which is what Xcel Energy did for the Program.[775]

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[769] OAG Initial Br. at 33.

[770] Ex. 3, O'Connor Direct at 47:21-48:31.

[771] Ex. 3, O'Connor Direct at 47:21-48:31

[772] *See* Ex. 3, O'Connor Direct at Schedule 11 at 1.

[773] Ex. 3, O'Connor Direct at 61:4-7.

[774] Tr. Vol. II (Sieracki) at 28:3-15.

[775] Tr. Vol. II (Sieracki) at 24:13-15; 30:16-24.

427. The Monticello LCM/EPU Program vendors were subject to numerous quality control site inspections, audits and oversight throughout the course of the Program.[776] The quality control function reviewed the work products, designs, and goods and services procured from the Company's vendors.[777]

(e) *Conclusion*

428. The OAG criticized the Company's decision to use General Electric, the original Plant designer and also the sole designer and manufacturer of BWRs in the United States, as its lead design vendor.

429. The Company met its burden of proof by providing evidence that selection of the original Plant designer for design services of modification projects is consistent with good nuclear utility practice. Additionally, General Electric has extensive experience with EPU and LCM designs and refurbishments.

430. The Company managed its vendors throughout the course of the Program, including performing quality control inspections and reviews.

431. The Company has met its burden of proof by providing evidence of reasonable and appropriate hiring and management of its vendors and vendor activities throughout the Program.

432. No Party presented evidence sufficient to rebut the Company's *prima facie* case.

(3) *Vendor Changes*

(a) *The Department*

433. The Department concluded that Company decisions to change its design and implementation vendors "likely resulted in higher costs."[778] Department witness, Mr. Crisp, stated that the first change the Company made in its vendors was to chose

[776] Ex. 3, O'Connor Direct at 67:5-9.

[777] Ex. 3, O'Connor Direct at 67:5-9.

[778] Department Initial Br. at 39.

the team "of Day Zimmerman/Sargent Lundy instead of [General Electric] to complete the" Program.[779]

434. Mr. Crisp then concluded that in 2010 "[p]oor performance on the part of Day Zimmerman/Sargent Lundy led to transfer some project scope to" the Company "and then on to other contractors."[780] Finally, Mr. Crisp identified a third change in 2011 where the Company retained Bechtel "to take over and complete the" Program.[781] The Department identified these as "course corrections" and that each of these occurred "at a time when significant cost increases were experienced".[782]

435. The Department also concluded that contractor changes by the Company were an indication "of poor initial planning".[783]

436. The Department clarified that Mr. Crisp did not, however, provide any opinion as to whether any of the decisions made by the Company regarding its vendors were reasonable.[784]

(b) *The OAG*

437. The OAG generally agreed with the Department criticisms of the Company's decisions to change vendors. The OAG argued that the Company's management of its vendors "led to increased costs due to inefficient work and considerable delays."[785]

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[779] Department Initial Br. at 39.

[780] Department Initial Br. at 40.

[781] Department Initial Br. at 40.

[782] Department Initial Br. at 40.

[783] Department Initial Br. at 40.

[784] Department Initial Br. at 39.

[785] OAG Initial Br. at 34.

(c) *XLI*

438. XLI relied on the testimony of the Department's witnesses regarding the Company's decisions on its vendor controls.[786]

(d) *Xcel Energy*

439. The Company argued that the driving force behind its contracting and management strategy to accomplish all the work within the Program centered on selecting the right contractor for the work it had before it.[787]

440. The Company further argued that the Department's characterization that the vendor management process was "disjoined" or that it had "stops and starts" had no support.[788] Instead, the Company represented that it hired well-known and widely-used design and installation vendors to achieve the most appropriate results for the Program.[789]

441. Mr. O'Connor testified that the Company's lead design vendor was, and remained, General Electric throughout the Program although certain work was moved to more specialized vendors as design progressed.[790] The Company pointed to Mr. Crisp's testimony "that the Company's reliance on General Electric [to lead the design effort] was 'absolutely' reasonable."[791]

442. Further, the Company argued that changing vendors "over the course of the Program is common because design and contractor performance issues have become more frequent in" the complex nuclear power industry.[792] The Company argued that it responded to the design challenges it faced in 2010 appropriately by

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786 XLI Initial Br. at 6.

787 Xcel Energy Initial Br. at 104.

788 Xcel Energy Initial Br. at 104.

789 Ex. 3, O'Connor Direct at Schedule 10, Schedule 12, Schedule 13, and Schedule 16.

790 Ex. 9, O'Connor Rebuttal at 66:24-25, 78:23-26, 80:8-9, and Schedule 28.

791 Xcel Energy Initial Br. at 105 (citing Tr. Vol. III (Crisp) at 32:17-19).

792 Xcel Energy Initial Br. at 106.

"occasionally moving some work to other contractors with more specialized expertise."[793] The Company clarified that any movement of work in 2010 was design-related and not installation-related as Mr. Crisp had claimed.[794]

443. The Company sought to develop the most appropriate project team for the Program by issuing an RFP for installation to five vendors: Bechtel, Sargent & Lundy, Areva NP, General Electric/Shaw, and Day Zimmerman.[795]

444. The Company did not receive proposals from Bechtel or Areva NP but did receive joint consortium proposals from General Electric/Shaw and Day Zimmerman/Sargent & Lundy.[796] Both proposals involved time-and-materials type pricing structures and based on a quantitative and qualitative analysis, the Company selected Day Zimmerman/Sargent & Lundy.[797]

445. The Company also argued that the Department's characterization of Xcel Energy's selection of Day Zimmerman/Sargent & Lundy as lead installation vendor as a "change" in vendors was not accurate because Day Zimmerman/Sargent & Lundy was hired as the original installation vendor.[798]

446. The Company provided evidence to support its retention of Bechtel as lead implementation vendor for the 2013 outage.[799] The Company stated that while Day Zimmerman's primary expertise was in mechanical-related work activities that were relevant for the primarily mechanical work required in the 2009 and 2011 outages, the work required for the 2013 outage was different.[800]

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793 Xcel Energy Initial Br. at 107.

794 Xcel Energy Initial Br. at 107.

795 Ex. 3, O'Connor Direct at 49:24-26.

796 Ex. 3, O'Connor Direct at 50:1-3.

797 Ex. 3, O'Connor Direct at 50:5-10.

798 Xcel Energy Initial Br. at 106.

799 Xcel Energy Initial Br. at 107.

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

447. The 2013 outage was primarily focused on the installation of the electrical distribution system major modification.[801] In light of this, the Company retained Bechtel for overall installation project management, but required that it keep Day Zimmerman on as a subcontractor to retain the experience and mechanical expertise.[802]

448. Throughout the Program, the Company also continued to evaluate its project management structure and performance to make necessary changes along the way.[803] Specifically, after the 2011 outage, the Company made modifications to its internal project management structure to reorganize the capital projects organization for management efficiencies.[804]

449. The Company argued that Mr. Crisp never attempted to address the Company's position that replacing contractors to better suit the work being performed is more efficient and that it is a prudent project management practice to assess which contractor will provide the best overall value as aspects of a project change.[805] The Company argued that, instead, Mr. Crisp noted there exist "very real justifications" for changing contractors but did not opine as to whether the changes the Company made were reasonable.[806]

(e) *Conclusion*

450. The Department, the OAG, and XLI all criticize the Company for its approach to vendor management, specifically moving design work from General Electric to more specialized vendors and changing the lead installation vendor after the 2011 outage as the Program moved from mechanical-intensive installations to

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

[802] Xcel Energy Initial Br. at 107.

[803] Ex. 9, O'Connor Rebuttal at 71:20-23.

[804] Ex. 3, O'Connor Direct at 63:20-24 and 84:18-23.

[805] Xcel Energy Initial Br. at 108.

[806] Xcel Energy Initial Br. at 108.

electrical-intensive installations. The Company has provided extensive testimony on the reasons it made the changes it did and even identified cost savings because of its design changes.

451. While the Company could have made different decisions along the way regarding its vendor management, the Company met its burden of proof by providing evidence that its decisions to change vendors were a reasonable and appropriate under the circumstances.

452. No Party presented evidence sufficient to rebut the Company's *prima facie* case.

(4) *Installation Complexities*

(a) *Department*

453. The Department took issue with the Company's explanation that one of the three main cost drivers for the Program was the complexity of installing the required modifications.[807]

454. The Department's witness, Mr. Crisp, noted that the Company's installation costs caused 40 percent of the Program's cost overruns and represented a 955 percent increase over the Company's initial cost estimate of $27.5 million.[808]

455. Mr. Crisp argued that the installation aspect of the Program should not have caused so much of a cost overrun because this was an area where (i) the Company and the Company's contractors had the most control and (ii) advanced planning and information should have negated this area as a cause of cost overruns.[809]

456. To these points, Mr. Crisp further testified that "Xcel and GE, the original designer of Monticello, and the contractor hired by Xcel to perform initial

[807] Ex. 300, Crisp Direct at 9,15.

[808] Ex. 300, Crisp Direct at 15-19.

[809] Ex. 300, Crisp Direct at 16.

scoping, design, and to provide cost estimating services knew or should have known about the physical arrangement inside the power block."[810]

457. For example, Mr. Crisp pointed out that for the feedwater heater modification, the Company knew the dimensions of the containment room and should have taken 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.[811]

458. In sum, the Department agreed that the age, design, and small footprint of Plant increased the complexity of the installation but the Department counters that these controlling factors should not have been a surprise to the Company. As a result, installation complexity "should not have been the cause of such high cost overruns."[812]

(b) *OAG*

459. The OAG did not specifically address installation complexity as a source of cost increases for the Program.

(c) *XLI*

460. XLI did not specifically address installation complexity as a source of cost increases for the Program.

(d) *Xcel Energy*

461. The Company explained that the $27.5 million in installation costs used by the Department was only General Electric's portion of the installation costs and the Company's overall initial cost estimate included a significant amount of non-segregated common costs, including installation costs.[813]

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[810] Ex. 300, Crisp Direct at 17.

[811] Ex. 300, Crisp Direct at 19.

[812] Ex. 300, Crisp Direct at 19.

[813] Ex. 9, O'Connor Rebuttal at 47:8-13.

462. The Company countered Mr. Crisp's assertion that the Company should have known about the Plant's physical arrangement prior to embarking on the LCM/EPU Program by noting that during prior outages the Company's ability to verify or create as-built drawings was limited by the short duration of these outages.[814] As critical baseload resources, the Company aims to limit the amount of time that its nuclear plants are offline for outages.[815]

463. The Company explained that the increase in the installation costs can be attributed to two key reasons: (i) emergent work and (ii) productivity.[816]

464. With regard to emergent work, the Company explained that in total, the Program had approximately 2,000 field changes.[817] The Company stated that these field changes took a variety of forms and required design and implementation adjustments that necessarily increased costs.[818]

465. The Company provided several examples of emergent work that necessitated additional installation costs during implementation of the Program.[819]

466. As an example, the Company stated that during installation of the condensate demineralizer system vaults, the piping and electrical runs were rerouted due to the "as-found" rebar locations within the walls and floors.[820] The Company noted that his system had limited as-built drawings that were developed during the initial construction but these did not match the as-found conditions in these highly radiological vaults.[821] Thus the Company was required to utilize a highly interactive

[814] Ex. 9, O'Connor Rebuttal at 48.

[815] Ex. 9, O'Connor Rebuttal at 48.

[816] Xcel Energy Initial Br. at 55.

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

[818] Xcel Energy Initial Br. at 55.

[819] Xcel Energy Initial Br. at 55-56.

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

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

approach to identify the piping routes while at the same time doing the engineering analysis to support the proposed reroute.[822]

467. With regard to construction labor productivity (i.e., the number of person hours required to complete defined installation tasks), the Company explained that its anticipated productivity was lower than projected due to a variety of factors challenging work conditions, difficulties hiring experienced craft labor due to the competitive nuclear labor market, and restrictions on work schedules imposed by the NRC's fatigue rule, and difficulties with vendors.[823]

468. In explaining the challenging working conditions encountered, the Company explained that the Plant was a turn-key plant, and at the time it was constructed, it was not designed to facilitate major equipment replacements.[824] As a result, the Plant was designed on a small footprint with many tight and confined spaces.[825] The Company testified that these confined, and in some cases highly radiological, spaces impacted labor productivity.[826] This is because workers have to do tasks sequentially (rather than in tandem) because space limitation preclude the number of workers in a given area.[827]

469. The Company pointed out that installation of the condensate demineralizer vessels was challenging as these vessels are highly radioactive and are, therefore, encased in eight foot square concrete vaults.[828] These small vaults meant that only two workers could work in the vault at one time.[829] In addition, due to the

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

[823] Ex. 3, O'Connor Direct at 40:3-12.

[824] Ex. 3, O'Connor Direct at 32:26-33:11.

[825] Ex. 4, Stall Direct at 32:13-17.

[826] Ex. 3, O'Connor Direct at 109:15-20.

[827] Ex. 4, Stall Direct at 32:13-17.

[828] Ex. 3, O'Connor Direct at 109:15-20.

[829] Ex. 3, O'Connor Direct at 109:20-26.

radiological work environment, workers had to comply with work permit restrictions and other protocols that decreased productivity.[830] In such an environment, workers are required to limit their amount of time in radioactive contaminated areas and also have to wear protective clothing which can hamper their movements and pace of work.[831]

470. The Company also stated that productivity was impacted by the Company's difficulty in finding and retaining experienced craft laborers.[832] Overall there is declining supply of qualified nuclear professionals, which is a result of a large percentage of this workforce approaching retirement age and fewer new workers taking their place.[833] The Company estimates that for the 2009 outage, 90 percent of its craft labor was nuclear experienced.[834] By the 2011 outage, this number declined to 45 percent.[835]

471. The Company cited the NRC fatigue rule as impacting the Company's ability to attract and retain qualified workers.[836]

472. The Company also alleged that productivity was impacted by issues with the design vendors.[837] The Company explained that during the Program it rejected design drawings that were not up to the Company's standards and took additional time to improve the constructability of certain designs.[838]

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

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

832 Xcel Energy Initial Br. at 57-58.

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

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

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

836 Xcel Energy Initial Br. at 58.

837 Xcel Energy Initial Br. at 58-59.

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

(e) *Conclusion*

473. The Company met its burden of proof by providing substantial evidence that the installation costs incurred were necessary to install the components needed to complete the LCM/EPU Program.

474. No Party presented evidence sufficient to rebut the Company's *prima facie* case.

(5) *Single Work Order Accounting*

(a) *Department*

475. The Department took issue with the Company's use of a single common work order to account for the costs of the LCM/EPU Program.[839]

476. The Department stated that the Company should have separately tracked LCM and EPU costs for the Program and that failure to do so made it very difficult for the Department to separately review the actual costs of the Program.[840]

477. The Department found the Company's use of a single work order was unreasonable because: (i) the LCM and EPU projects were subject to separate Certificate of Need proceedings before the Commission; (ii) costs for the Program are not transparent; and (iii) the Company's accounting resulted in needlessly higher costs for this prudence review as the Department had to hire a consultant to split the costs in LCM and EPU.[841]

(b) *OAG*

478. The OAG did not address the Company's use of a single work order to account for the costs of the Program.

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[839] Department Initial Br. at 74-75.

[840] Ex. 315, Campbell Surrebuttal at 12.

[841] Ex. 315, Campbell Surrebuttal at 12.

(c) *XLI*

479. XLI did not address the Company's use of a single work order to account for the costs of the Program.

(d) *Xcel Energy*

480. The Company defended its accounting for the Program by stating that it followed the FERC uniform system of accounts, which has been adopted by the Commission.[842] The Company explained that this accounting mechanism requires that the Company account for costs based on work orders that correspond to specific units of property.[843] This system of accounting does not require accounting based on functionality or allocation between separate but related LCM and EPU.[844]

481. The Company also argued that while a single work order may have increased the cost of the investigation into the Program it did not increase the Company's costs associated with the Program.[845]

(e) *Conclusion*

482. The Company has met its burden of proof by providing evidence that the Company's accounting for the Program was consistent with FERC uniform system of accounts and did not increase costs of the LCM/EPU Program.

483. No Party presented evidence sufficient to rebut the Company's *prima facie* case.

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842 Xcel Energy Initial Br. at 134.

843 Xcel Energy Initial Br. at 134.

844 Xcel Energy Initial Br. at 134.

845 Xcel Energy Initial Br. at 134-35.

(6) *Company Communications with the Commission*

(a) *Department*

484. The Department argued that the Company's communications updating the Commission and stakeholders about the status and costs of the LCM/EPU Program were inadequate.[846]

485. Specifically, in support of this argument, the Department pointed to the fact that the Company's NOCC, filed on November 22, 2011 in the Monticello EPU Certificate of Need proceedings, did not address the increased costs of the Program.[847]

(b) *OAG*

486. Similarly, the OAG argued that the Company failed to mention in its November 2011 NOCC filing to the Commission that the Program was running $180 million over budget.[848]

487. The OAG further argued that the Company did not furnish any additional information on the status of the Program until its 2012 rate case at which time it requested full recovery of the Program's costs.[849]

(c) *XLI*

488. XLI did not address issues relating to the Company's communications with the Commission.[850]

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[846] Dpartment Initial Brief at 82-85; *see* Ex. 315, Campbell Surrebuttal at 23:6-10.

[847] Department Initial Brief at 83; *see In the Matter of the Application of N. States Power Co., a Minn. Corp., for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, No. E002/CN-08-185, NOTICE OF CHANGED CIRCUMSTANCES (Nov. 22, 2011).

[848] OAG Initial Brief at 5-6; *see* Ex. 305, Jacobs Direct at 5.

[849] OAG Initial Br. at 5-6; *see In the Matter of the Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, No. E002/GR-12-961, ORDER: FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 17-22 (Sept. 3, 2012).

[850] *See* XLI Initial Br.

(d) *Xcel Energy*

489. The Company argued that it provided regular updates to the Commission regarding the Program's cost increases.[851]

490. The Company provided a detailed chronology of instances where it provided the Commission with new and updated Program information, including Program cost estimates and implementation schedules.[852]

(e) *Conclusion*

491. The Department and OAG's characterizations of the Company's communications to the Commission regarding the Program's costs are not supported by the record.

492. The Company met its burden of proof by providing evidence that its communications with the Commission regarding the Program's increased costs were reasonable and appropriate for the purposes of rate recovery.

493. No Party presented evidence sufficient to rebut the Company's *prima facie* case.

(7) *Other Issues at the Plant*

(a) *Department*

494. The Department also documented several other recent issues at Monticello during this proceeding.[853] These include: (i) an NRC "yellow" finding associated with the need to satisfy applicable flood protection requirements; (ii) a weld inspection issue at the Plant pertaining to one of the dry casks (iii) an NRC finding of "human performance" issues at the Plant that did not relate to the implementation of

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[851] Xcel Energy Initial Br. at 100-02.

[852] Ex. 12, Sparby Rebuttal at 29:21-30:7.

[853] Department Initial Br. at 80-82.

the LCM/EPU Program; and (iv) a malfunction in an unrelated circulating water pump that has caused the Plant to be derated in the fall of 2014.[854]

495. The Department stated that while it is confident that the Company is working to resolve these issues that "there can be no doubt that such issues caused higher regulatory costs and may have contributed to delay of the EPU."[855]

(b) *OAG*

496. The OAG took no position on these other issues identified by the Department.

(c) *XLI*

497. XLI took no position on these other issues identified by the Department.

(d) *Xcel Energy*

498. The Company responded to the Department's criticisms by stating that none of the items at issue constitute safety violations or otherwise created any risk to the community.[856] The Company also explained that it takes its NRC compliance obligations very seriously and are working diligently to resolve each of these issues.[857]

499. The Company further argued that these other issues raised by the Department are not relevant to the Company's prudence in implementing the LCM/EPU Program and there is no record evidence to suggest that any of these issues caused the costs of the Program to increase.[858] This is because none of these issues are related to the LCM/EPU Program itself.[859]

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854 Ex. 313, Campbell Direct at 3:22-23; Ex. 436, Campbell Opening Statement at 1 and 4.

855 Department Initial Br. at 82.

856 Ex. 9, O'Connor Rebuttal at 33:9-13.

857 Ex. 9, O'Connor Rebuttal at 33:9-13.

858 Xcel Energy Initial Br. at 137.

859 Xcel Energy Initial Br. at 137.

(e) *Conclusion*

500. These other issues raised by the Department are not relevant to the determination of prudence of the Company's actions related to the LCM/EPU Program.

2. Which Cost Increases Are Due: 1) Solely to the EPU; 2) Solely to the LCM; and 3) Both Projects?

a. The Department

501. Department witness Dr. Jacobs provided an analysis of an allocation of costs between LCM and EPU in this proceeding.[860] His analysis focused on indentifying modifications used to support the EPU and assigning costs related to those EPU-related modifications.[861]

502. To make his allocations, Dr. Jacobs relied, primarily, on a letter submitted by Xcel Energy to the NRC on November 5, 2008 ("NRC Letter").[862] The letter accompanies the Company's license amendment request for the EPU.[863]

503. Dr. Jacobs relied on the NRC Letter because it was signed "under penalty of perjury" by Company witness Mr. O'Connor and was a contemporaneous document prepared by the Company rather than later in time such as when the Company was providing testimony in this proceeding.[864] Thus, Dr. Jacobs considered the NRC Letter to provide the "best source" of the Company's "determination of the need for each project."[865]

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[860] Ex. 305, Jacobs Direct.

[861] Ex. 305, Jacobs Direct at 7:8-11.

[862] Ex. 305, Jacobs Direct at 9:4-9 and Attachment WRJ-2.

[863] Ex. 305, Jacobs Direct at 8:12-14; Department Initial Br. at 48.

[864] Ex. 305, Jacobs Direct at 8:27-9:9; Department Initial Br. at 52.

[865] Ex. 305, Jacobs Direct at 9:7-9.

504. In addition to the NRC Letter, Dr. Jacobs also relied on information gathered by speaking with Xcel Energy employees during a Plant visit on April 29, 2014 and his own experience with other EPU projects.[866]

505. In classifying modifications, Dr. Jacobs relied on a basic criterion that if Monticello could not operate at the higher EPU power level without the particular modification, Dr. Jacobs considered modification to be an EPU project.[867]

506. Dr. Jacobs provided two justifications for why it was reasonable to include as EPU modifications the work that would not have been completed but for the EPU.[868] First, Dr. Jacobs testified that LCM modifications are often "like-for-like" replacements that can be done at significantly less cost than replacements with larger components required for an EPU.[869] Second, Dr. Jacobs testified that LCM projects are often completed over several if not many years during normal refueling outages and, often at significantly lower cost than modifications completed for an EPU.[870]

507. Dr. Jacobs deviated from the NRC's Letter's classification of the 13.8 kV modification as an LCM project by applying his basic criterion that the Plant could not have operated at the higher EPU without this modification.[871] Dr. Jacobs testified that the 13.8 kV modification was needed "only to provide the power to the larger reactor feedwater and condensate pumps necessitated by the increased secondary side flow rates."[872]

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[866] Ex. 305, Jacobs Direct at 11:9-10; Ex. 421, Jacobs Opening Statement.

[867] Ex. 421, Jacobs Opening Statement.

[868] Ex. 305, Jacobs Direct at 13:5-9; Tr. Vol. IV (Jacobs) at 61-64.

[869] Ex. 305, Jacobs Direct at 13:5-9.

[870] Tr. Vol. IV (Jacobs) at 61-64.

[871] Ex. 305, Jacobs Direct at 9:12-10:9.

[872] Ex. 305, Jacobs Direct at 11:16-19.

508. Dr. Jacobs also based this allocation of the 13.8 kV modification to EPU based on discussions with Mr. O'Connor during a visit to the Plant.[873] Dr. Jacobs testified that when he asked Mr. O'Connor if the 13.8 kV modification would have been needed absent the EPU that he responded that it would not have been needed.[874]

509. Once he classified the modification as EPU, LCM, both LCM and EPU, or "Items not in the NRC Letter," Dr. Jacobs assigned costs to the modifications based on the actual costs for these modifications identified in O'Connor's Direct Testimony.[875]

510. Dr. Jacobs concluded that $569.5 million or 85.7 percent of the LCM/EPU costs were required to support the EPU and the remaining $95.4 million or 14.3 percent were not required to support the EPU.[876]

511. The Department took issue with the Company's position that the 58.4/41.6 percent LCM/EPU split from 2008 Certificate of Need proceeding should be used in this proceeding.[877] The Department explained that allocating only 41.6 percent of the final total costs to the EPU would be unreasonable because it is based on the Company's initial cost estimates in 2008 which were underestimated.[878] The Department further argued that the 2008 split does not consider the impact of the final costs of major EPU components such as the $119 million for the 13.8 kV modification that shifted the cost ratio to EPU projects.[879]

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[873] Ex. 305, Jacobs Direct at 11:9-24.

[874] Ex. 305, Jacobs Direct at 11:23-24.

[875] Ex. 305, Jacobs Direct at 9:12-17; Department Initial Br. at 48-49.

[876] Ex. 421, Jacobs Opening Statement.

[877] Department Initial Br. at 60.

[878] Ex. 307, Jacobs Surrebuttal at 16:5-14.

[879] Ex. 307, Jacobs Surrebuttal at 16:5-14.

512. The Department also argued that the Company's 78/22 percent LCM/EPU split prepared for purposes of this proceeding was unreasonable.[880] The Department stated that the Company's "avoided cost analysis" approach, which focused on costs that could be avoided if the Company did not undertake the EPU, essentially assumes that all costs are LCM costs unless proven otherwise.[881]

513. The Department explained that to allocate costs based on the costs avoided absent the EPU would have required a significant effort that was not provided by the Company.[882] Dr. Jacobs explained that to allocate costs for a project required for both LCM and EPU would require "detailed cost estimates for each project with and without requirements imposed by the EPU. The cost difference between the project needed to support the EPU and the hypothetical LCM project assuming no EPU could then be used to allocate costs between LCM and EPU."[883]

514. The Department also took issue with the Company's approach of allocation costs for some modifications required for both LCM and EPU based on the ratio of EPU capacity to total Plant capacity.[884] The Department argued that such an allocation does not reflect the higher costs that the Company incurred to install the larger equipment necessary for the uprate.[885]

b. OAG

515. The OAG did not prepare an independent allocation of costs between the LCM and EPU.

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880 Department Initial Br. at 60.

881 Ex. 307, Jacobs Surrebuttal at 13:1-2.

882 Ex. 307, Jacobs Surrebuttal at 13:3-5.

883 Ex. 307, Jacobs Surrebuttal at 13:3-7.

884 Department Initial Br. at 61.

885 Ex. 307, Jacobs Surrebuttal at 16:11-14.

c. XLI

516. XLI did not prepare an independent allocation of costs between the LCM and EPU but stated that it has no objection to the (14.3/85.7) cost allocation developed by the Department.[886]

d. Xcel Energy

517. The Company argued that an allocation of costs between LCM and EPU is inappropriate because the Company considered the Program an integrated effort which is overwhelming cost-effective as a whole.[887]

518. The Company pointed out that the Commission has previously used the LCM/EPU split in prior rate cases, before the Plant had its uprate license, to determine which portions of the Program costs were attributable to the EPU and could be excluded from rate base as not yet "used and useful."[888] The Company argued that while the LCM/EPU split could be used for that purpose, the split has no relevance to a prudence inquiry.[889]

519. The Company stated that if a split is applied in this proceeding, that the 58.4/41.6 percent LCM/EPU split used in the 2008 Certificate of Need should be utilized.[890] The Company argued that this split was developed at the same time as the Certificate of Need and that no other party contested its accuracy.[891]

520. If the 2008 Certificate of Need split analysis is not utilized, the Company argued that its after-the-fact 78/22 percent LCM/EPU cost allocation should be utilized rather than Dr. Jacobs' 85.7/14.3 percent allocation.[892]

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886 XLI Initial Br. at 10.

887 Xcel Energy Initial Br. at 78 (citing Ex. 309, Shaw Direct at 14:1-2).

888 Xcel Energy Initial Br. at 78.

889 Xcel Energy Initial Br. at 78.

890 Xcel Energy Initial Br. at 78.

891 Xcel Energy Initial Br. at 79.

892 Xcel Energy Initial Br. at 116-128.

521. The Company's 78/22 LCM/EPU allocation was conducted as part of the Company's initial filing in this docket.[893] The Company's approach was to segregate the costs of the initiative between those costs that were unavoidable LCM work and those costs that constitute avoidable EPU work.[894]

522. Under this analysis, the Company categorized the costs for specific modifications in one of three ways: (1) LCM-only costs: costs there were solely related to LCM activities; (2) EPU-only costs: costs that were solely related to EPU activities, including licensing costs; and (3) LCM costs that include some incremental EPU costs over and above what would have been needed absent the EPU.[895]

523. To conduct this allocation the Company relied on information that learned during completion of LCM/EPU Program such as the condition of the existing components discovered during installation.[896]

524. The Company explained that the purpose of this split analysis was not to assess the prudence of the Company's initial decision-making in 2008 but was intended to aid the Company's modeling efforts to show the incremental value of the EPU MW under current conditions.[897]

525. The Company argued that Dr. Jacobs' allocation was unreasonable given it did not account for the age and condition of the Plant components prior to the LCM/EPU Program.[898]

526. The Company also took issue with Dr. Jacobs' reliance on a single document, the NRC Letter, to support his cost allocations.[899] The Company

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[893] Ex. 3, O'Connor Direct at 145:4-6.

[894] Ex. 3, O'Connor Direct at 145:26-146:1.

[895] Ex. 9, O'Connor Rebuttal at 83:7-12.

[896] Ex. 3, O'Connor Direct at Schedule 29.

[897] Ex. 9, O'Connor Rebuttal at 84:6-9.

[898] Ex. 9, O'Connor Rebuttal at 84:18-20.

[899] Xcel Energy Initial Br. at 115.

explained that the purpose of the NRC Letter was not to classify modifications as LCM or EPU but rather to provide an overview of work that the Company intended to complete as part of the Program.[900] Thus, the Company's descriptions in the NRC Letter were merely for context and convenience rather than to classify the underlying purpose of the modification.[901]

527. The Company also argued that the fact that the NRC Letter was provided under oath and penalty of perjury was not a distinguishing feature as Mr. O'Connor's pre-filed and live testimony in this proceeding which provided a vastly different LCM/EPU allocation was also provided under oath.[902]

528. The Company further contended that Dr. Jacobs' exclusive reliance on the NRC Letter as a contemporaneous document was unreasonable given that the Company produced over 3,000 documents.[903] The Company asserted that these other contemporaneous documents provide tremendous insight into the state of the Plant prior to the Program.[904] They show the existing system condition assessments related to the Plant and long-range plans outlining needed future improvements dated prior to or contemporaneous with the 2008 Certificate of Need.[905]

529. The Company also pointed out that Dr. Jacobs' allocation is inconsistent with the approach that he employed in an earlier Florida proceeding as a consultant for the Florida Office of Public Counsel related to the St. Lucie and Turkey Point EPUs.[906] In these prior proceedings, Dr. Jacobs attributed only the incremental cost of the increased size of the components to the EPU and relegated the remainder of

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[900] Ex. 9, O'Connor Rebuttal at 87:9-14.

[901] Ex. 9, O'Connor Rebuttal at 87:12-14.

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

[903] Tr. Vol. III (Jacobs) at 100:15-18.

[904] Xcel Energy Initial Br. at 115.

[905] Xcel Energy Initial Br. at 115.

[906] Xcel Energy Initial Br. at 117-118.

the costs to LCM.[907] The Company contrasted this prior approach with Dr. Jacobs approach in this proceeding which was to attribute all costs to EPU so long as he believed any increment of the overall cost was attributable to the uprate.[908]

530. The Company alleged that Dr. Jacobs' inconsistent approach was driven by Florida's unique Nuclear Plant Cost Recovery requirement.[909] Florida permits a utility to annually recover costs related to an uprate but those costs related to normal maintenance or replacement, *i.e.*, unrelated LCM modifications, must be recovered through normal base rate cost recovery mechanisms.[910]

531. The Company argued that in the Florida proceedings, Dr. Jacobs had an incentive to minimize costs attributed to the EPU to minimize the utilities' cost recovery.[911] In contrast, the Company alleged that in this case he appears to have maximized costs attributable to the EPU to support a disallowance utilizing the Department's breakeven analysis.[912]

532. The Company also disagreed with Dr. Jacobs' statement that the Company could have saved costs, absent the uprate, by replacing aging equipment on a "like-for-like" basis.[913] The Company explained that "like-for-like" replacement of nearly 40-year old components "would require extensive reverse engineering, which is simply not cost-effective, efficient, or smart."[914] For example, the existing condensate demineralizer system was an antiquated analog system that required multiple

[907] Xcel Energy Initial Br. at 118.

[908] Xcel Energy Initial Br. at 118.

[909] Xcel Energy Initial Br. at 118.

[910] Fla. Admin. Code R. 25-6.0423 (2014).

[911] Xcel Energy Initial Br. at 118.

[912] Xcel Energy Initial Br. at 118.

[913] Xcel Energy Initial Br. at 116.

[914] Ex. 13, Stall Rebuttal at 15:3-5; Ex. 9, O'Connor Rebuttal at 117:4-12.

manipulations to be performed manually and required two operators to clean two vessels each week for approximately six to eight hours.[915]

533. Based on the Company's argument, Dr. Jacobs redefined "like-for-like" replacements as "replacing equipment with new equipment with similar performance specifications and physical characteristics."[916] But the Company pointed out that Dr. Jacobs' definition is inconsistent with the NRC's longstanding definition of these terms as "replacement of an item with an item that is identical" and "was purchased at the same time from the same vendor."[917]

534. The Company further argued that there is no evidence sufficient to prove that "like-for-like" replacements would have resulted in substantial cost savings because installation and removal costs would have been similar.[918]

e. Conclusion

535. The LCM/EPU split is not relevant to the determination of prudence in this proceeding. The LCM/EPU Program was an integrated project 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.

536. If any split is used at all, then the Commission should continue to use the 58.4/41.6 percent LCM/EPU split developed in good faith contemporaneously with the 2008 decision to proceed with the Program.

537. For purposes of assessing a remedy, if imprudence is found, then the Commission should not use a split given the integrated nature of the Program. If, however, a split is desired to assess harm, then the split that correctly conveys the actual harm caused by the imprudence is one that shows what work could have been

[915] Ex. 9, O'Connor Rebuttal at 117:14-18.

[916] Ex. 307, Jacobs Surrebuttal at 6:6-11.

[917] Ex. 429, NRC – Licensee Commercial-Grade Procurement and Dedication Programs (Generic Letter 91-05) at 3.

[918] Ex. 9, O'Connor Rebuttal at 118:10-12.

avoided had the imprudence not occurred. If the LCM work was going to be performed absent the EPU, then no damages should be assessed because the imprudence, even if found, did not cause any harm.

538. Using this basis, the following is a discussion of the ten major modifications and whether these modifications should be allocated to (1) LCM, (2) EPU, or (3) a combination of LCM and EPU.

(1) *1AR Transformers, PRNM, and Steam Dryer*

539. Both Dr. Jacobs and the Company classify replacement of the 1AR transformer, the PRNM System, and the steam dryer as LCM modifications.[919]

540. These allocations are supported by the evidence in the record.

(2) *Main Transformer*

541. Dr. Jacobs classified this modification as 100 percent EPU given that the NRC Letter states that the new main transformer will "provide increased operating margins under EPU conditions."[920]

542. The Company classified replacement of the main power transformer as primarily LCM with a portion (10 percent) attributed to EPU to account for the larger sized transformer that was used to accommodate uprate conditions.[921]

543. The Company's classification is reasonable given the age and performance issues that were documented on the record.

544. The main transformer was 40-years old and a 2001 power point presentation and a 2003 capital projects summary identify the main power transformer for replacement by the Company due to age-related deterioration.[922]

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[919] Ex. 305, Jacobs Direct at Attachment WRJ-3.

[920] Ex. 305, Jacobs Direct at Attachment B at 10.

[921] Ex. 9, O'Connor Rebuttal at 90:13-15.

[922] Ex. 9, O'Connor Rebuttal at 90:20-91:5.

545. The Company provided an oil analysis for the main power transformer that showed there was a gassing problem that was resulting in transformer degradation within the transformer and potentially could lead to in-service failure.[923]

(3) *13.8 kV Distribution System*

546. Dr. Jacobs classified the 13.8 kV distribution system modification as entirely EPU and the Company classified this modification as entirely LCM.[924]

547. The record shows that the Plant's existing distribution system had inadequate margins and needed to be upgraded to support extended operation of the Plant regardless of the uprate. In addition, several components of the existing distribution had been identified for replacement due to age and condition. As a result, the 13.8 kV distribution modification should be classified as entirely LCM. This conclusion is supported by the NRC Letter that stated that the 13.8 kV upgrade is an "LCM modification to increase margin in the on-site distribution system."[925]

548. Prior to the 13.8 kV upgrade, the Plant was operating at less than a one percent margin, which increases the vulnerability of the Plant and limits operators' ability to respond to events.[926] In addition, the Plant experienced under-voltage conditions when starting motors and pumps and had to sequence these large loads.[927] The existing 4 kV buses were also very close to maximum fault ratings prior to the LCM/EPU Program.[928] Notably, bus #11 was at 99% of its maximum rating.[929] Dr.

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[923] Ex. 9, O'Connor Rebuttal at 91:18-21.

[924] Ex. 9, O'Connor Rebuttal at 85:16 at Table 10.

[925] Ex. 305, Jacobs Direct at Attachment B at 13.

[926] Ex. 9, O'Connor Rebuttal at 95:8-11.

[927] Ex. 9, O'Connor Rebuttal at 95:19-22.

[928] Ex. 9, O'Connor Rebuttal at 95:24-26.

[929] Ex. 9, O'Connor Rebuttal at 95:24-26.

Jacobs admitted that these types of problems indicated a need to upgrade the system.[930]

549. Several components of the existing 4 kV distribution system were also aging and required replacement.[931]

550. The record supports allocating 100 percent of the costs for the 13.8 kV system to LCM.

(4) *Feedwater Heaters*

551. Dr. Jacobs classified the feedwater heater replacement modification as 88 percent EPU and 12 percent LCM; the Company classified it as 10 percent EPU and 90 percent LCM.[932]

552. The Company provided evidence and contemporaneous documents supporting that much of the equipment installed as part of the feedwater heater modification had reached the end of its useful life and required replacement regardless of the uprate.

553. Four of the six feedwater heaters the Company replaced during the Program were original Plant equipment and the other two were 30 years old.[933] Feedwater heaters 14 and 15 also were experiencing service-related degradation, with tube wall thinning and plugging.[934]

554. In 2006, the Company evaluated the condition of the six feedwater heaters and found that "replacement is an LCM item since the existing units could be justified for use under EPU conditions . . . ."[935]

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[930] Tr. Vol. IV (Jacobs) at 34:22-35:7.

[931] Ex. 9, O'Connor Rebuttal at Schedule 33 at 13 and Schedule 34 at 20.

[932] Ex. 9, O'Connor Rebuttal at Table 10.

[933] Ex. 9, O'Connor Rebuttal at 105:19-21.

[934] Ex. 9, O'Connor Rebuttal at 106:2-4.

[935] Ex. 9, O'Connor Rebuttal at Schedule 36.

555. Also, Dr. Jacobs acknowledged that in prior testimony he has stated feedwater heaters typically require replacement at the end of a nuclear plant's initial operating license.[936]

556. Given these age-related issues, the Company's allocation of 90 percent of the costs of this modification to LCM is appropriate. The allocation of 10 percent of the costs to EPU is also appropriate, as larger sized heaters were required to be installed to support the uprate.

(5) *Condensate Demineralizer System*

557. Dr. Jacobs classified the condensate demineralizer system modification as 100 percent EPU; the Company classified it as 25 percent EPU and 75 percent LCM.[937] The Company attributed 25 percent of the costs for replacement of the vessels and piping to EPU given that these components were larger to support the uprate.[938]

558. The Company provided evidence of age-related deterioration in the condensate demineralizer system vessels and filters that necessitated replacement of these components.[939] By 2010, documents demonstrate that the vessels and filter elements supported resin for only six months before needing to be recharged.[940] In addition, the wiring for the system had degraded to a point where it required immediate replacement.[941]

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936 Tr. Vol. IV (Jacobs) at 30:6-10.

937 Ex. 9, O'Connor Rebuttal at Table 10.

938 Ex. 9, O'Connor Rebuttal at 107:2-5.

939 Ex. 9, O'Connor Rebuttal at 107.

940 Ex. 9, O'Connor Rebuttal at 107:21-22.

941 Ex. 9, O'Connor Rebuttal at 108:12-13.

559. In addition, the old analog control system for the existing system was obsolete, out of date, and challenging from an operational perspective because it required multiple manual manipulations.[942]

560. The Company also stated that replacement parts for this aging system were also becoming harder to procure.[943] Replacements of the pneumatic flow controllers and the stepping switch controller were no longer available.[944]

561. These issues with the existing system caused the Company to place this system on the Long Range Plan for replacement in 2000.[945]

562. The record supports the Company's allocation of 75 percent of the costs to LCM is supported by the obsolescence and age-related deterioration of the existing system.[946]

(6) *Condensate Pumps and Motors*

563. The Company allocated 25 percent of this modification to LCM and 75 percent to EPU while Dr. Jacobs attributed the entire cost to the uprate.[947]

564. The condensate pumps were original Plant equipment and their performance was degraded and approaching a point where adequate suction flow/pressure could not be provided to the reactor feed pumps.[948]

565. With regard to the condensate pump motors, retaining the old motors would have required approximately two additional 10-year major bearing replacement preventative maintenance (removing rotors) events if EPU was not pursued.[949] The

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[942] Ex. 9, O'Connor Rebuttal at 108:3-5.

[943] Ex. 9, O'Connor Rebuttal at 108:1-2; *see* Ex. 3, O'Connor Direct at 124:9-11.

[944] Ex. 9, O'Connor Rebuttal at 108:1-2.

[945] Ex. 9, O'Connor Rebuttal at 107:10-11.

[946] Ex. 9, O'Connor Rebuttal at 107:8-10.

[947] Ex. 9, O'Connor Rebuttal at Table 10.

[948] Ex. 9, O'Connor Rebuttal at 111:12-19.

[949] Ex. 9, O'Connor Rebuttal at 111:21-23.

Company acknowledged that without the uprate it is likely that these issues could have been resolved through maintenance or replacement of the internal components.[950]

566. Given that replacement of the condensate pumps and motors could have been delayed absent the uprate, the Company's allocation of 25 percent of this modification to LCM is reasonable.

(7) *Reactor Feed Pumps and Motors*

567. The Company allocated 93 percent of this modification to LCM while Dr. Jacobs attributed the entire cost to EPU.[951] The Company's allocation of 7 percent of the costs to the uprate was based on the fact that these components were sized to support the uprate.[952]

568. The Company's decision to replace the reactor feed pumps and motors was driven by service-related degradation issues and obsolescence.[953] The Company had identified replacement of this system in its 2001 Long Range Plan as necessary to increase Plant reliability for the license extension period and had stated that not replacing this component could potentially lead to an extended shutdown of the Plant.[954]

569. The pumps and motors experienced chronic performance problems that could be addressed by replacing them with modern equipment.[955] The Company anticipated that it would face the need to replace the pumps in the next several cycles

[950] Ex. 9, O'Connor Rebuttal at 111:8-10.

[951] Ex. 9, O'Connor Rebuttal at Table 10.

[952] Ex. 9, O'Connor Rebuttal at 109:23-24.

[953] Ex. 9, O'Connor Rebuttal at 109:14-15.

[954] Ex. 9, O'Connor Rebuttal at 109:9-13.

[955] Ex. 9, O'Connor Rebuttal at 109:17-19.

(approximately six years)[956] and as a result determined it was prudent to accelerate this replacement and to attribute 93 percent of the cost of this modification to LCM.[957]

570. The record supports the Company's allocation of the reactor feed pumps and motors of 93 percent to LCM and 7 percent to EPU.

(8) *Turbine*

571. Dr. Jacobs attributed the entire cost of replacement of the high pressure turbine to EPU while the Company attributed 99 percent to LCM and one percent to EPU.[958] The Company attributed one percent to EPU given that while the turbine was sized to support additional steam flows from the uprate, the cost to replace the turbine was comparable whether or not the EPU was undertaken.[959]

572. The first turbine installed in the Plant lasted 25 years.[960] If the existing turbine was not replaced, it would have had to have lasted 35 years to reach the end of the extended license.[961] Given the service-life of the prior turbine, this is not a reasonable assumption.

573. Given the age of the existing turbine, the Company's allocation of 99 percent of the costs of this modification to LCM is reasonable.

3. Whether the Company's Request for Recovery of the Monticello LCM/EPU Project Cost Overruns is Reasonable?

574. The prudence standard is based on (i) a reasonable person standard; (ii) the information the utility knew or reasonably should have known at the time decisions were made and actions were taken, and not on hindsight; (iii) the process

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956 Ex. 9, O'Connor Rebuttal at 109:19-21.

957 Ex. 9, O'Connor Rebuttal at Table 10.

958 Ex. 9, O'Connor Rebuttal at Table 10.

959 Ex. 9, O'Connor Rebuttal at 102:20-22.

960 Ex. 9, O'Connor Rebuttal at 103:5.

961 Ex. 9, O'Connor Rebuttal at 103:5-6.

undertaken by the utility, rather than favorable or unfavorable results; and (iv) only those events over which the utility had control.[962]

575. The prudence standard requires that any disallowance must be supported by evidence establishing that the specific acts of imprudence caused harm to ratepayers.[963] This principle has been likened to the requirement to prove negligence in that, even if imprudence is found, a cost disallowance is not permitted unless the alleged imprudence is the real and proximate cause of some injury.[964]

a. The Department

576. The Department calculated a $402.1 million cost overrun for the Program based on a $748.1 million in final estimated cost on a total Company basis, including AFUDC.[965]

577. The Department pointed out that there is Commission precedent to deny recovery of costs in excess of the amount approved by the Commission during a Certificate of Need proceeding.[966] However, Department witness, Ms. Campbell expressed concern about imposing a similar disallowance in this proceeding.[967] Ms. Campbell observed the amount of the cost overrun is significantly higher than any cost overrun that the Department has ever reviewed and higher than any Minnesota

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[962] *See Potomac Elec. Power Co.*, 661 A.2d at 141-42.

[963] *See Potomac Elec. Power Co.*, 661 A.2d at 141-42; *State ex rel. Associated Natural Gas Co.*, 954 S.W.2d at 530 (stating that to disallow a utility's recovery costs from its ratepayers, a regulatory agency must find that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers) (citing *Bus. & Prof'l People v. Ill. Commerce Comm'n*, 525 N.E.2d 1053, 1059 (Ill. Ct. App. 1988); *New England Power Co.*, 31 FERC 61,047 at 61,089 n.38 (noting that the issue of the utility's prudence was relevant only if it caused harm to the utility's consumers)).

[964] *Pa. Pub. Util. Comm'n*, 63 Pa. P.U.C. at 352; *In re GPU, Inc.*, 96 Pa. P.U.C. 1, 91-92 (2001) ("Even if imprudence is found, a cost disallowance cannot be justified unless the utility's imprudent conduct was the real and proximate cause of some injury to customers."); *Pa. Pub. Util. Comm'n*, 71 Pa. P.U.C. at 45-46 (same).

[965] Department Initial Br. at 73.

[966] Department Initial Br. at 93.

[967] Ex. 313, Campbell Direct at 27.

public utility has ever incurred.[968] Ms. Campbell stated that given the amount of the cost overrun, that she was concerned whether the Company could continue to operate the Plant safely if such as large disallowance was imposed.[969]

578. Instead, the Department recommended a disallowance equal to the portion of the EPU cost overrun that would render the Plant not cost-effective as compared to other alternatives considered during the 2008 Certificate of Need proceeding.[970]

579. Department witness, Mr. Shaw utilized the Strategist model used in the 2008 Certificate of Need proceeding to determine extent to which the total estimated costs for the Program render the EPU not cost-effective.[971] The Department's cost-effective analysis also relied on other three assumptions: (i) natural gas prices in 2008, cost of complying with carbon dioxide regulations, and other cost factors in 2008; (ii) Dr. Jacob's split determination which determined that 85.7 percent of the total Program costs are EPU-costs; and (iii) Mr. Crisp's determination that the Company knew or should have known in 2008 that its initial cost estimates should have been 100 percent to 150 percent higher than the Company estimated.[972]

580. This analysis concluded that the breakeven point over which the EPU costs would not have been cost-effective is 73 percent of the total LCM/EPU Program costs or $485,390,000.[973]

581. The Department calculated that this cost-effective analysis would result in a $71.42 million reduction in capital costs for the Program resulting in a $10.237 million revenue requirement downward adjustment for 2015 on a Minnesota

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968 Ex. 313, Campbell Direct at 27.

969 Ex. 313, Campbell Direct at 27.

970 Department Initial Br. at 74.

971 Department Initial Br. at 65.

972 Department Initial Br. at 65.

973 Department Initial Br. at 65.

jurisdictional basis, over the remaining life of the Plant and stepped down each year due to accumulated depreciation.[974]

582. The Department argued that its cost-effectiveness disallowance approach was reasonable in that it attempts to balance the Company's needs with the need to protect ratepayers.[975]

b. OAG

583. The OAG contended that the Commission should disallow all cost overruns that were the result of Xcel Energy's poor management.[976]

584. The OAG stated that there are four specifically identifiable costs that can be attributed to this poor management.[977]

585. First, the OAG points out that Xcel Energy's installation costs escalated from an initial estimate of \$27.5 million to a final cost of \$288.6 million.[978] The OAG concluded that the cost overruns of \$261.1 million were imprudently incurred and recovery should be disallowed.[979]

586. Second, the OAG noted that the cost of the 13.8 kV electric distribution system escalated from \$20.9 million to \$119.5 million.[980] The OAG relied on testimony from Department witness Dr. Jacobs to conclude that such an increase was not reasonable and should be disallowed.[981]

587. Third, the OAG argued that the costs for the feedwater heater modification increased from an estimated \$37 million to \$114.9 million and that this

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974 Department Initial Br. at 74.

975 Department Initial Br. at 74.

976 OAG Initial Br. at 40.

977 OAG Initial Br. at 40-42.

978 OAG Initial Br. at 40.

979 OAG Initial Br. at 40.

980 OAG Initial Br. at 40.

981 OAG Initial Br. at 41.

overrun was not reasonable because Xcel Energy should have been able to anticipate the costs for this modification.[982]

588. The OAG acknowledged that the cost overruns for the 13.8 kV and the feedwater heater modifications were included in the larger installation cost overrun.[983]

589. Fourth, the OAG relied on the testimony of Company witness Mr. O'Connor to identify other costs it considers unreasonable.[984] The OAG pointed out that Mr. O'Connor identified \$25-\$30 million in expenses for field changes, \$13 million for duplicative design work, and \$11 million for abandoned work.[985] The OAG recommended that the Commission disallow 50 percent of the duplicative design and abandoned costs, as well as 25 percent of the expenses for field changes, for a total disallowance of \$19.5 million.[986]

590. The OAG stated that the cost overruns that were specifically identified (installation costs of \$261.1 million and costs identified by Mr. O'Connor of \$19.5 million) account for 65.5 percent of the total cost overruns of \$428.1 million.[987] The OAG argued that the record establishes that there were additional costs associated with the Company's mismanagement but that these costs cannot be specifically identified due to the Company's unreasonable accounting practices.[988] Based on this uncertainty, the OAG recommended that the Commission apply a percentage proxy to determine which costs were the result of poor management.[989] The OAG

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982 OAG Initial Br. at 41.

983 OAG Initial Br. at 41.

984 OAG Initial Br. at 41.

985 OAG Initial Br. at 41.

986 OAG Initial Br. at 42.

987 OAG Initial Br. at 42.

988 OAG Initial Br. at 42.

989 OAG Initial Br. at 42.

recommended denial of at least 75 percent of the $428.1 million in cost overruns as imprudent and unreasonable.[990]

591. Alternatively, the OAG argued that if the Commission is concerned about the difficultly in tying cost overruns to mismanagement that the Commission should order a forensic accounting analysis to provide additional analysis.[991]

592. The OAG also recommended that the Commission deny a return on any cost overruns that are allowed.[992] The OAG argued that denying a return on cost overruns was appropriate because allowing a return would allow the Company to profit on costs that resulted from poor management and imprudence.[993]

c. XLI

593. XLI concurred with the Department and the OAG that in this proceeding, Xcel Energy failed to demonstrate that its handling of the Program was prudent and that its request for full recovery was reasonable.[994]

594. XLI further argued that because the Company did not demonstrate that that the cost overruns it incurred were reasonable and prudent, that a significant disallowance was justified and necessary to protect ratepayers form the current Project's mismanagement and to set a precedent to encourage utilities to prudently bid and manage future projects.[995]

595. XLI presented two policy concerns with the Department's method of calculating its proposed disallowance.[996]

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990 OAG Initial Br. at 42.

991 OAG Initial Br. at 42-43.

992 OAG Initial Br. at 46.

993 OAG Initial Br. at 45.

994 XLI Initial Br. at 8.

995 XLI Initial Br. at 8.

996 XLI Initial Br. at 10.

596. First, XLI argued that the Department's method relies too heavily on the its analysis of the split of costs between LCM and EPU portions of the Program.[997] XLI pointed out the Company's method of tracking Program costs makes it difficult to separate cost between LCM and EPU components.[998] XLI further pointed out that if the Commission determines that a different split is appropriate such that a lower percentage of costs is attributed to the EPU, then the Department's disallowance is reduced and may not be proportional with the level of concerns the Department's investigation identified.[999]

597. Second, XLI expressed concern that the Department's cost-effectiveness proposal potentially sets a bad precedent for the future.[1000] XLI argued that limiting a disallowance of cost overruns to the amount above the next least-cost alternative provides no incentive to control costs above the cost estimate provided in a Certificate of Need proceeding, but only to control costs to the next least-cost alternative.[1001]

598. Based on these concerns with the Department's methodology, XLI recommended a third alternative disallowance technique which would foreclose any return on the entire cost overrun.[1002] XLI relied on Department witness Ms. Campbell's calculation that no return on the $402.1 million cost overrun would result in a $25.796 million downward revenue adjustment for 2015 on a Minnesota jurisdictional basis and then stepped down every year during the life of the Plant.[1003]

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997 XLI Initial Br. at 10.

998 XLI Initial Br. at 10.

999 XLI Initial Br. at 10.

1000 XLI Initial Br. at 10.

1001 XLI Initial Br. at 11.

1002 XLI Initial Br. at 11.

1003 XLI Initial Br. at 8.

599. XLI stated its proposed disallowance is the best remedy to strike a balance between utility recovery and ratepayer protections.[1004]

d. Xcel Energy

600. The Company argued that its actions and decisions should be judged under the prudent investment standard. The prudent investment standard: (i) requires review of the information the utility knew or should reasonably have known at the time decisions were made, and not hindsight; (ii) considers the process, rather than the results; (iii) addresses only events over which the utility had control; and (iv) imposes a remedy only if imprudence proximately caused damages to customers.[1005]

601. The Company asserted that its decisions about the Program were prudent and that no disallowance of the Program costs is appropriate.[1006]

602. The Company disagreed with the Department's cost-effectiveness based disallowance methodology.[1007] The Company contended that this cost-effectiveness methodology was not relevant to a prudency inquiry as it does not specifically find imprudence or specific damages caused by any alleged imprudence.[1008] Further the Company argued that the Department's method injected hindsight into the analysis by using 2013 actual costs and a LCM/EPU split that was developed in this proceeding rather than the cost estimates and split used in the 2008 Certificate of Need proceeding.[1009]

603. The Company stated that if the Commission wishes to apply a cost-effectiveness disallowance that the $97 million in sunk costs that the Company

[1004] XLI Initial Br. at 13.

[1005] Xcel Energy Initial Br. at 15.

[1006] Xcel Energy Initial Br. at 143.

[1007] Xcel Energy Initial Br. at 138-141.

[1008] Xcel Energy Initial Br. at 138.

[1009] Xcel Energy Initial Br. at 138.

incurred prior to issuance of the Certificate of Need should be excluded.[1010] The Company explained that sunk costs should not be included in a cost-effectiveness analysis because the Company cannot avoid the expense by taking a different course of action.[1011] If the $97 million in sunk costs are removed, the Company argued that this would shift the Department's analysis enough to show that the EPU aspect is virtually cost-effective.[1012]

604. The Company also contended that capping costs at Certificate of Need levels is not appropriate because (i) costs often cannot be completely predicted during the Certificate of Need stage; (ii) the Company made investments in reliance on the prudent investment standard, and a retroactive change in that standard would not be appropriate; and (iii) the Company's investors already committed funds to the Program with the understanding that the Company's prudence in incurring those costs would be assessed in the future, rather than subject to a pre-established cap.[1013]

605. The Company also opposed the OAG's proposed disallowance by arguing that it disregarded the Company's stated reasons for cost increases and focused instead on disallowing a specified percentage of costs (75%) over the 2008 Certificate of Need cost estimate.[1014] The Company also stated that the OAG's proposed disallowance was based on an arbitrary percentage penalty rather than specific findings of imprudence and a quantification of harm resulting from that imprudence.[1015]

606. The Company also took issue with the OAG's proposal to deny a return on investment for any recovery over the $320 million initially estimated in the

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[1010] Xcel Energy Initial Br. at 139.

[1011] Xcel Energy Initial Br. at 140.

[1012] Xcel Energy Initial Br. at 141.

[1013] Ex. 8, Alders Rebuttal at 14:15:25.

[1014] Xcel Energy Initial Br. at 141.

[1015] Xcel Energy Initial Br. at 141.

Certificate of Need stage.[1016] The Company argued that if such costs were deemed to be prudently incurred, that the Company should be allowed to recover these costs with a return.[1017]

607. The Company further responded to the OAG's argument that the Commission disallow 50 percent of the duplicative design and abandoned costs, as well as 25 percent of the expenses for field changes, for a total disallowance of $19.5 million. The Company stated that such a disallowance is not reasonable as the Company provided evidence explaining the reasonableness of these costs.

e. Conclusion

608. The prudent investment standard requires both a finding of imprudence and a finding of specific damages tied to that imprudence.

609. While the Company has acknowledged that the final costs of the Program were higher than originally estimated, no party has tied these higher costs to an imprudent act or decision by the Company.

610. The record supports a finding that the Company's implementation of the LCM/EPU Program was overall reasonable and prudent under the circumstances, and therefore no disallowance is warranted.

II. CONCLUSIONS OF LAW AND RECOMMENDATIONS

1. At the time the Commission granted the EPU Certificate of Need in 2009, the Company estimated that the LCM/EPU Program would cost $346 million (without AFUDC) in 2008 dollars. This estimate, escalated to 2014 dollars is $397.5 million (without AFUDC) and is $453 million with AFUDC.

2. The Company estimates that the final cost of the Program will be $663.4 million (without AFUDC) in 2014 dollars, and $746.4 million with AFUDC, after all

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1016 Xcel Energy Initial Br. at 141-42.

1017 Xcel Energy Initial Br. at 142.

adjustments related to vendor credits have been resolved and included in the Program accounting.

3. To determine prudence, the fact finder must consider what a reasonable utility would have done in the conditions and circumstances which were known or reasonably should have been known at the time a decision.

4. The Company provided adequate evidence to satisfy its burden of proving the reasonableness of its decisions and actions, including its decision to proceed with the Program and management of the Program. No Party presented evidence sufficient to rebut the Company's *prima facie* case.

5. Although the final costs of the Program exceeded the estimates provided by the Company in the 2008 Certificate of Need proceeding before the Commission by approximately 67 percent,[1018] these costs were prudently incurred to ensure the continued operation of the Plant and to allow the Plant to operate at EPU conditions.

6. The facts in the record do not support a disallowance of costs incurred by the Company to implement the Program.

7. That the Commission find the final Program cost of $663.4 million (without AFUDC) and an additional $83 million of AFUDC were reasonable and prudent.

8. That the Commission find that the Company's actions and costs incurred in furtherance of the LCM/EPU Program were reasonable and prudent.

9. That this matter be incorporated into the 2013 rate case proceeding.

Dated: December 31, 2014

Steve M. Mihalchick
Administrative Law Judge

[1018] [($663.4-$397.5)/$397.5]*100 = 66.9 percent.

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 20 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, Metro Square Building, Suite 350, 121 7th Place East, St. Paul, Minnesota 55101-2147. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions of Law and Order should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument with their filed exceptions or reply. Exceptions must be e-filed with the Commission.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

Under Minn. Stat. § 14.63, subd. 1, the Commission is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.