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

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

OAH Docket No. 68-2500-31182
MPUC Docket No. E002/GR-13-868

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

October 14, 2014

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The above-entitled matter came for evidentiary hearing before Administrative Law Judge Jeanne M. Cochran on August 11-15, 2014 in St. Paul, Minnesota. Public hearings were held in Eden Prairie, Mankato, Minneapolis, St. Cloud, St. Paul, and Woodbury between June 23, 2014 and June 27, 2014. Public comments were received until July 7, 2014.

Post-hearing briefs were filed on September 23, 2014, and responsive briefs were filed on October 14, 2014. The hearing record closed upon receipt of the last post-hearing briefs on October 14, 2014.

The parties to this proceeding are: Northern States Power Company, doing business as Xcel Energy (Company or Xcel Energy or NSPM); the Minnesota Department of Commerce, Division of Energy Resources (Department); the Minnesota Office of Attorney General – Antitrust and Utilities Division (OAG); the Xcel Energy Large Industrials (XLI); the Minnesota Chamber of Commerce (MCC); the Commercial Group (Commercial Group); the Energy CENTS Coalition (ECC); the Suburban Rate Authority (SRA); the Industrial, Commercial and Institutional Customer Group (ICI); Minnesota Center for Environmental Advocacy, Izaak Walton League of America-Midwest Office, Fresh Energy, Sierra Club, and Natural

Resources Defense Council, collectively the Environmental Interveners (EIs); and the American Association of Retired Persons (AARP).

The Company sponsored prefiled written testimony of 34 witnesses and the intervenors collectively sponsored prefiled written testimony of 21 witnesses.

Appearances were made by the following: For Xcel Energy, Aakash Chandarana, Lead Regulatory Attorney - North, Xcel Energy, Kari L. Valley, Assistant General Counsel, Xcel Energy, James R. Denniston, Assistant General Counsel, Xcel Energy, Stephen E. Fogel, Assistant General Counsel, Xcel Energy, Richard J. Johnson and Patrick Zomer, Moss & Barnett, PA; for the Department, Julia E. Anderson, Linda S. Jensen, and Peter Madsen, Assistant Attorneys General; for the OAG, Ian Dobson and Ryan Barlow, Assistant Attorneys General; for the SRA, James Strommen, Attorney at Law, Kennedy & Graven; for MCC, Benjamin Gerber, Attorney at Law, Richard J. Savelkoul, Attorney at Law, Martin & Squires; for XLI, Andrew P. Moratzka and Sarah Johnson-Phillips, Attorneys at Law, Stoel Rives LLP; for the Commercial Group, Alan R. Jenkins, Attorney at Law, Jenkins at Law, LLC; for ECC, Pam Marshall, Executive Director, Energy CENTS Coalition; for ICI Group, Peder Larson and Connor T. McNeillis, Attorneys at Law, Larkin Hoffman; for the EIs, Kevin Reuther and Samantha Williams, Attorneys at Law; and for AARP, John B. Coffman, Attorney at Law.

STATEMENT OF THE ISSUES[1]

On November 4, 2013, the Company filed a petition to increase its electric rates in Minnesota. The Company sought authority to increase electric rates through a multi-year rate plan (MYRP) pursuant to Minn. Stat. § 216B.16, subds. 1 and 19 (MYRP Statute). The Company's MYRP is a two-year proposal, with the first year revenue requirement calculated from a traditional test year (2014) and the second year

[1] A Master Exhibit List, including links to all exhibits received into evidence, was efiled by the court reporter on September 19, 2014 (eDockets Doc. No. 20149-103157-01).

(2015 Step) limited to specific capital additions and related costs.[2] The Company's MYRP requested a two-year increase that includes an increase of $192.7 million, or 6.9 percent, for 2014 (test year), and an additional increase of $98.5 million, or 3.5 percent, for 2015 (2015 Step) for a total increase of $291.2 million, or 10.4 percent.[3] The 2014 and 2015 revenue deficiencies are based on a 10.25 percent return on equity. The Company also requested an interim rate increase of $127.4 million, or 4.57 percent, on an annualized basis until the Commission decides final rates.[4]

On January 2, 2014, the Commission issued a Notice and Order for Hearing, referring the matter to the Office of Administrative Hearings for contested case proceedings. The Notice and Order for Hearing set forth the following issues to be addressed:

(1) Is the test year revenue increase sought by the Company reasonable or will it result in unreasonable and excessive earnings by the Company?
(2) Is the rate design proposed by the Company reasonable?
(3) Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?
(4) Has the Company fully complied with past Commission orders?
(5) How should the Commission incorporate into this case the results of the ongoing investigation into the prudence of Xcel's expenditures for life cycle management and the extended power uprate at the Monticello Nuclear Generating Plant?
(6) How should the proceeds of any insurance claims and litigation proceeds related to the Company's Sherburne County Generating Station Unit 3 be incorporated into Xcel Energy's rates?
(7) What will be the short- and long-term consequences of the rate mitigation strategy proposed by the Company?

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

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[2] Ex. 12, Filing Letter at 1.
[3] Ex. 12, Filing Letter at 1.
[4] Ex. 12, Filing Letter at 1.

FINDINGS OF FACT

I. INTRODUCTION AND OVERVIEW

A. Summary of the Application

1. The Company's Application to increase electric rates in Minnesota requested an increase of $192.7 million, or 6.9 percent, for 2014, and an additional increase of $98.5 million, or 3.5 percent, for 2015, for a combined total requested increase of $291.2 million, or 10.4 percent, effective January 3, 2014. The Application was based on a 2014 test year, a 2015 Step Year, and a Minnesota jurisdiction electric operations overall retail revenue requirement of $3.081 billion.[5]

2. The Company's Application also included two rate moderation proposals. The first relates to amortization of theoretical depreciation reserve surplus for the Company's transmission, distribution, and general assets. The second relates to the use of settlement payments from the Department of Energy (DOE).[6] The Company stated that these rate moderation proposals will enable more moderate and predictable year-to-year rate increases by offsetting the immediate impacts related to the Company's anticipated capital additions.[7]

3. In the course of this proceeding, many issues were resolved among the parties. The Company also updated its cost of service as new information became available.

4. In Rebuttal Testimony, the Company revised its requested increase to $169.5 million for 2014, and $95.1 million for 2015, for a combined total requested increase of $264.5 million.[8]

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[5] Ex. 88, Heuer Direct at 1.
[6] Ex. 99, Clark Direct at 26-30.
[7] Ex. 99, Clark Direct at 29.
[8] Ex. 90, Heuer Rebuttal at 1-2.

5. During the evidentiary hearing, the Company revised its requested increase to $142.2 million for 2014, and $106.0 million for 2015, for a combined total requested increase of $248.1 million.[9]

6. In its October 7, 2014 updated Final Issues List, the Company revised its requested increase to $142.2 million for 2014, and $106.9 million for 2015, for a combined total increase of $249.0 million.[10]

B. The Parties

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

8. The Minnesota Department of Commerce, Division of Energy Resources (Department) represents the interests of the State's ratepayers in rate proceedings. Department staff reviews the testimony and schedules filed by the Applicant and other parties to assure their accuracy and completeness. The Department filed testimony and arguments addressing the reasonableness of the elements of the rate.

9. The Office of Attorney General –Antitrust and Utilities Division (OAG) represents the interests of residential and small business ratepayers. Its staff reviews the testimony and schedules filed by the Applicant and other parties. The OAG filed testimony and arguments intended to protect those interests.

10. The Xcel Large Industrials (XLI) includes some of Xcel Energy's large retail electric customers. Their costs of production could be significantly affected by a rate increase.

11. The Minnesota Chamber of Commerce (MCC) represents over 2,400 businesses throughout the State of Minnesota. Many of its members are within Xcel

[9] Ex. 140, Heuer Opening Statement at 8.
[10] COMPANY'S FINAL ISSUES LIST (Oct. 7, 2014) (eDockets Doc. No. 201410-103651-01).

Energy's service territory. The MCC is involved in policy issues that affect business, including energy policy, on behalf of its members.

12. The Commercial Group is an association of large commercial operators of retail facilities and distribution centers in Minnesota, many of which are served by Xcel Energy. It is concerned with any rate increase to Xcel Energy's commercial customers.

13. The Energy CENTS Coalition (ECC) is a non-profit organization that promotes affordable utility service for low and fixed-income individuals. ECC intervened in this proceeding to protect the financial interests of low-income customers of the Company.

14. The Suburban Rate Authority (SRA) is a municipal joint powers association. Its members are suburban municipalities within the Twin Cities metropolitan area, and most of its members are served by Xcel Energy.

15. The Institutional Customer Intervention Group (ICI) is an ad hoc group of large industrial, commercial, and institutional customers that receive electric service from Xcel Energy and U.S. Energy Services, Inc. The outcome of this case could impact the ICI Group's production costs.

16. The Natural Resource Defense Council, Fresh Energy, Sierra Club, and the Izaak Walton League of America-Midwest Office (collectively, the Clean Energy Intervenors (CEI)) are non-profit organizations that share an interest in advancing resource choices that minimize or eliminate pollutant emissions, and maximize energy efficiency. The CEI supports policies designed to decrease electric consumption.

17. The American Association of Retired Persons (AARP) is a non-profit organization that advocates on behalf of people who are 50 years of age and older. AARP has 652,000 members in Minnesota, many of whom are residential electric customers of Xcel Energy. AARP intervened in this proceeding to protect the

financial interests of people aged 50 and over who are more vulnerable to increases in energy prices.

C. Procedural Background[11]

18. On October 3, 2013, the Company filed sales forecast data, as required by the Commission's Order in the Company's prior electric rate case (Docket No. E002/GR-12-961)[12] to be provided 30 days in advance of the filing of the Company's subsequent rate case.[13]

19. On November 4, 2013, the Company filed its Application to increase electric rates in Minnesota.[14] In its Application, the Company requested authority to increase electric rates through a MYRP pursuant to Minn. Stat. § 216B.16, subds. 1 and 19.[15] The Company structured its MYRP to be a two year proposal, with the first year revenue requirement calculated from a traditional test year (2014) and the second year (2015 Step) limited to specific capital additions and related costs.[16] The Company requested a two-year increase of $192.7 million, or 6.9 percent, in 2014, and $98.5 million, or 3.5 percent, in 2015 for a total increase of $291.2 million, or 10.4 percent based on present revenues.[17] The Company requested approval of an interim rate increase of 4.57 percent beginning January 3, 2014.[18]

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[11] All documents referenced to in this section are filed with the Department of Commerce eDockets system, Docket Number 13-868, and may be viewed through the eDockets Search at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showeDocketsSearch&showEdocket=true&userType=public.

[12] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 18, Docket E-002/GR-12-961 (Sept. 3, 2013) (*hereinafter* 2013 RATE CASE ORDER).

[13] Ex. 1, Pre-Filing Sales Forecast Data.

[14] Exhs. 12-19, Application Vol. 1-6 and Errata.

[15] Ex. 12, Filing Letter at 1.

[16] Ex. 12, Filing Letter at 1.

[17] Ex. 12, Filing Letter at 1.

[18] Ex. 12, Filing Letter at 1.

20. On December 12, 2013, the Commission held a hearing on interim rates and whether the Company's application should be deemed complete and referred to the Office of Administrative Hearings (OAH) for a contested case proceeding.[19]

21. On December 31, 2013, the Company submitted a filing required by Order Point 9 of the Commission's 2013 Rate Case Order, which required the Company to provide an analysis and report on the Sherco Unit 3 total costs, insurance recoveries, and costs not covered by insurance in its November 2013 rate case filing, and to provide the completed accounting and report by December 31, 2013.[20]

22. The Commission issued its Notice and Order for Hearing on January 2, 2014. On that same date, the Commission issued two other orders, one finding that the rate case filing was substantially complete,[21] and one setting an interim rate schedule for the duration of this proceeding.[22]

23. On January 2, 2014, when the Commission issued its Notice and Order for Hearing, the only parties to this proceeding were the Company, the Department, and the OAG.[23]

24. On January 31, 2014, the Company filed its "Bad Debt Study – Supplemental Information" in compliance with Order Point 31 from the Commission's 2013 Rate Case Order.[24]

25. Administrative Law Judge (ALJ) Jeanne M. Cochran held a Prehearing Conference on January 28, 2014. A First Prehearing Order was issued on February 14, 2014, setting forth the procedures for discovery and hearing preparation, as well as the dates of the evidentiary hearing. The First Prehearing Order also granted the

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19 NOTICE OF COMMISSION MEETING (Dec. 6, 2013) (eDocket Doc. No. 201311-94124-07).
20 Ex. 3, Pre-filing Sherco 3 Root Cause Report.
21 ORDER ACCEPTING FILING, SUSPENDING RATES, AND REQUIRING SUPPLEMENTAL FILING (Jan. 2, 2014) (eDockets Doc. No. 20141-95050-01).
22 ORDER SETTING INTERIM RATES (Jan. 2, 2014) (eDockets Doc. No. 20141-95066-01).
23 NOTICE AND ORDER FOR HEARING (Jan. 2, 2014) (eDockets Doc. No. 20141-95049-01).
24 Ex. 10, Bad Debt Study Supplemental Information.

petitions to intervene of the Commercial Group, ECC, the SRA, the ICI Group, and XLI.[25]

26. On February 7, 2014, the Company filed a letter agreeing to waive the statutory deadline for the Commission's decision such that the Commission's final decision in this proceeding will be issued on or about March 24, 2015.[26]

27. On March 5, 2014, the petitions to intervene of MCC and CEI were granted.[27]

28. On March 14, 2014, the petition to intervene of AARP was granted with limitations.[28]

29. On March 14, 2014, the petition to intervene of Minnesota Power was denied.[29]

30. On June 5, and June 6, 2014, the Intervenors filed Direct Testimony.[30]

31. Public hearings were held the week of June 23, 2014, according to the following schedule:

- June 23, 2014, Earle Brown Heritage Center, Minneapolis, and Sabathani Community Center, Minneapolis;
- June 24, 2014, West Minnehaha Recreation Center, St. Paul, and Woodbury Central Park, Woodbury;

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[25] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
[26] WAIVER OF STATUTORY DEADLINE (Feb. 7, 2014) (eDockets Doc. No. 20142-96267-01).
[27] ORDER GRANTING INTERVENTION TO THE MINNESOTA CHAMBER OF COMMERCE AND TO FRESH ENERGY, THE IZAAK WALTON LEAGUE, THE SIERRA CLUB, THE NATURAL RESOURCES DEFENSE COUNCIL, AND THE MINNESOTA CENTER FOR ENVIRONMENTAL ADVOCACY (March 5, 2014), (eDockets No. 20143-97071-01).
[28] ORDER GRANTING PETITION TO INTERVENE OF AARP WITH LIMITATIONS (March 14, 2014)(eDockets Doc. No. 20143-97340-01). This Order limited AARP's participation to issues of rate design and decoupling, as well as any service quality issues that affect the unique interests of its members.
[29] ORDER REGARDING PETITION TO INTERVENE OF MINNESOTA POWER (March 14, 2014), (eDocket Doc. No. 20143-97340-02). This Order stated that Minnesota Power could file an *amicus curiae* brief of up to 40 pages in length no later than Sept. 30, 2014.
[30] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01); *See* SECOND PREHEARING ORDER AND ORDER GRANTING MOTION FOR EXTENSION OF TIME (June 25, 2014) (eDockets Doc. No. 20146-100778-01).

- June 25, 2014, Civic Center, Mankato;
- June 26, 2014, Eden Prairie City Center, Eden Prairie; and
- June 27, 2014, Lake George Municipal Complex, St. Cloud.

32. The Parties filed Rebuttal Testimony on July 7, 2014.[31]

33. On July 16, 2014, a Joint Prehearing Conference was held by ALJ Cochran and ALJ Steve M. Mihalchick to ensure that issues related to the investments at the Monticello Nuclear Generating Plant were coordinated between this docket and the Monticello prudence investigation docket (Docket No. E002/CI-13-754 (Prudence Investigation)).[32]

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

> (1) The issue of whether the Extended Power Uprate should be considered "used and useful" during 2014; and
>
> (2) The issue of the recovery and amortization of expenses from the Prudence Investigation.

35. The Parties filed Surrebuttal Testimony on August 4, 2014.[33]

36. On August 8, 2014, a Prehearing Conference was held to facilitate an orderly and efficient evidentiary proceeding.[34]

37. The evidentiary hearings were held on August 11-15, 2014, in the Commission's large hearing room in St. Paul, Minnesota.

38. On September 10, 2014, the Company filed an Issues List identifying all issues raised in the course of the rate proceeding and specifying which issues had been

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[31] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
[32] Transcript of July 16, 2014 Joint Prehearing Conference in Docket Nos. E002/GR-13-868 and E002/CI-13-754.
[33] FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
[34] Transcript of August 8, 2014 Prehearing Conference.

resolved and which issues remained in dispute.[35] The same day, the Company also filed a Financial Adjustment Summary.[36]

39. On September 23, 2014, the Parties filed Initial Briefs.[37]

40. On September 30, 2014, Parties filed comments on the Company's Issues List.[38]

41. On October 7, 2014, the Company filed an updated version of the Issues List, incorporating the comments from the other parties.[39]

42. On October 14, 2014, the Parties filed Reply Briefs and Proposed Findings of Fact.[40]

D. Summary of Public Comments

43. Hundreds of written comments were filed by members of the public before the July 7, 2014 deadline.[41] In addition, approximately 100 people also provided oral comments during the seven public hearings that were held from June 23, 2014 to June 27, 2014 across the Company's service territory.

44. Members of the public raised a variety of specific concerns but the most frequently issue raised was about the size of the Company's proposed rate increases in 2014 and 2015.[42] Ratepayers commented that the proposed rate increases are excessive and would be difficult to afford on limited or set incomes.[43] Several members of the public also stated that they felt that they were being penalized for their conservation efforts with higher rates.[44] Ratepayers also commented that, as a

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35 COMPANY DRAFT ISSUES LIST AND FINANCIAL SUMMARY (Sept. 10, 2014) (eDockets Doc. No. 20149-102963-01).
36 COMPANY DRAFT ISSUES LIST AND FINANCIAL SUMMARY (Sept. 10, 2014) (eDockets Doc. No. 20149-102963-01).
37 FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
38 FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
39 COMPANY FINAL ISSUES LIST (Oct. 7, 2014) (eDockets Doc. No. 201410-103651-01).
40 FIRST PREHEARING ORDER (Feb. 14, 2014) (eDockets Doc. No. 20142-96450-01).
41 Tr. Vol. 1 at 43 (ALJ Cochran).
42 Tr. Vol. 1 at 44 (ALJ Cochran).
43 Tr. Vol. 1 at 44 (ALJ Cochran).
44 Tr. Vol. 1 at 45-46 (ALJ Cochran).

regulated monopoly, Xcel Energy has no incentive to control costs and that the Company should do a better job at cost control.[45] Finally, ratepayers raised specific concerns about executive and employee compensation, corporate aviation costs, and naming rights costs.[46]

E. Legal Standard

45. The Commission must set rates that are just and reasonable, balancing the interests of the utility and its customers.[47] A reasonable rate enables a utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in the capital market.[48] Minnesota law recognizes this principle when it defines a fair rate as the rate which, when multiplied by the rate base, will give a utility a reasonable return on its total investment.[49]

46. The Commission acts in both a quasi-judicial and quasi-legislative capacity in setting rates. It evaluates facts, including the claimed costs, and also evaluates the reasonableness of placing the burden of the costs on the ratepayers.[50] The Commission acts in a quasi-legislative capacity and has greater discretion with regard to rate design.[51] In contrast, the Commission is subject to the substantial evidence standard with respect to revenue issues.[52]

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[45] Tr. Vol. 1 at 46 (ALJ Cochran).
[46] Tr. Vol. 1 at 47 (ALJ Cochran).
[47] Minn. Stat. § 216B.03.
[48] Ex. 30, Tyson Direct at 17-21.
[49] Minn. Stat. § 216B.16.
[50] *In re Northern States Power Co.*, 416 N.W.2d at 722-723.
[51] *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n.*, 302 N.W.2d 5, 9 (Minn. 1980); *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n,* 312 Minn. 250, 260, 251 N.W.2d 350, 357 (Minn. 1977) ("Once revenue requirements have been determined, it remains to decide how, and from whom, the additional revenue is to be obtained.… The commission may then balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among customer classes… It is clear that when the commission acts in this area it is operating in a legislative capacity…").
[52] *In re Request of Intestate Power Co. for Authority to Change its Rates for Gas Service*, 574 N.W.2d 408, 413 (Minn. 1998); establishing the standard of review for revenue requirement under the substantial evidence test; *Hibbing Taconite Co.*, 302 N.W.2d at 9 ("The *St. Paul Chamber* case enunciated the PSC's two functions and the related standards of review. In applying those standards, we now hold that the establishment of a rate of return involves a factual determination which the courts will review under the substantial evidence standard.").

47. The utility seeking an increase in its rates has the burden of proving by a preponderance of the evidence that its proposed change is just and reasonable.[53] In the context of a rate proceeding, the "preponderance of evidence" is defined as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considering together with the Commission's statutory duty to enforce the state's public policy that retail customers of utility services shall be furnished such services at reasonable rates."[54] Any doubt as to the reasonableness of the proposed rates is to be resolved in favor of the consumer.[55]

48. The general rule is that "the burden of proof rests on the party seeking to benefit from a statutory provision."[56] In *Northern States Power Company for Authority to Change its Schedule of Rates for Electric Services*, the Minnesota Supreme Court described the utility's burden of proof as follows:

> In evaluating the validity of a rate increase application, the Commission should apply the classic burden of proof analysis employed in civil cases in determining whether the utility has established the amount of a claimed cost as a judicial fact.[57]

49. The burden of proof in civil cases has two aspects: "the burden of persuasion and the burden of producing evidence."[58]

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[53] Minn. Stat. § 216B.16, subd. 4.
[54] *In re Northern States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).
[55] Minn. Stat. § 216B.03.
[56] *C.O. v. Doe*, 757 N.W.2d 343, 352 (Minn. 2008); *Reliance Life Ins. Co. v. Burgess*, 112 F.2d 234, 238 (8th Cir. 1940) ("It is a fundamental rule that the burden of proof in its primary sense rests upon the party who, as determined by the pleadings, asserts that the affirmative of an issue and it remains there until the termination of the action. It is generally upon the party who will be defeated if no evidence related to the issue is given on either side."); *See* Minn. Stat. § 216B.16, subd. 4.
[57] 416 N.W.2d 710, 722 (Minn. 1987); *In re Interstate Power Co.*, 419 N.W.2d 803, 807 (Minn. Ct. App. 1988),
[58] Minnesota Practice, Vol. 11, Evidence § 301.01 (2013). *See also Schaffer ex re. Schaffer v. Weast*, 546 U.S. 49, 56 (2005) (determining which party bears the burden of proof in an administrative hearing); Stockton East Water Dist. v. U.S., 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").

50. 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."[59] The burden of persuasion is generally fixed before the hearing and does not shift to the other party.[60] Here, the Company has the burden of persuasion, both as provided by Minn. Stat. § 216B.16, subd. 4, and under the general rule. The burden of persuasion "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."[61] This general rule applies both in administrative law proceedings and civil cases.[62]

51. The burden of production is "the duty of introducing evidence at a particular stage of a trial – of going forward with the evidence."[63] While the Company has the burden of proof, the burden of production may shift throughout a proceeding. The general rule is as follows:

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[59] 21 Dunnell Minn. Digest, Evidence § 13.01 (5th ed. 2006); *see Technology 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").

[60] Minnesota Practice, Vol. 11, Evidence § 301.01 (2013); 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); *see e.g., Texas Dept. of Community Affairs v. Burdine*, 450 U.S. 248, 253 (1981) ("[t]he ultimate burden of persuading the trier of fact that the defendant intentionally discriminated against the plaintiff remains at all times with the plaintiff").

[61] 21 Dunnell Minn. Digest, Evidence § 13.03 (5th ed. 2006); *See also Fidelity Bank & Trust Co v. Fitzimons*, 261 N.W.2d 586, 590 (Minn. 1977) ("[w]here 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 Products Co. v. American 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); *Bass v. Ring*, 299 N.W. 679, 681 (Minn. 1941) (finding that the "plaintiff made a prima facie case, one which without opposing evidence should have prevailed," and that "the burden of going on with evidence" should have shifted to the defendant upon the plaintiff's production of all evidence to be expected of him").

[62] *E.g.*, *Rydberg v. Goodno*, 689 N.W.2d 310, 313 (Minn. Ct. App. 2004) (applying the court's rule from *Fidelity Bank & Trust Co v. Fitzimons*, 261 N.W.2d 586, 590 (Minn. 1977) and finding 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," such that "at this point, the burden shifted to parties opposing pass-eligible status"); *In re Chicago Rys. Co.*, 175 F.2d 282, 281 (7th Cir. 1949) (finding 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").

[63] 21 Dunnell Minn. Digest, Evidence § 13.01 (5th ed. 2006). *See Technology Licensing Corp. v. Videotek, Inc.*, 545 F.3d 1316, 1327 (Fed. Cir. 2008); *Ryan v. Metropolitan Life Ins. Co.*, 298 N.W. 557, 560 (Minn. 1939) (discussing the differences between the burden of producing evidence and the burden of persuasion).

> A prima facie case shifts to the opponent of the one having the burden of proof, the burden of producing evidence to overcome it.[64]

52. In Minnesota, the statutes and Rules set forth specific requirements for a complete rate application that details, supports and ties out revenues, costs and investments. That filing, coupled with its testimony and other evidence in support of the filing, constitutes substantial evidence, which establishes the Company's prima facie case. Any portion of the prima facie case that is unrebutted must prevail as a matter of law.[65]

53. By establishing its prima facie case, the burden of producing evidence (as opposed to mere argument, conjecture, or policy disagreement) shifts to the other parties.[66] If the prima facie case is rebutted with such evidence then the Company still has the burden of persuasion, but, again, to establish a rebuttal to the prima facie case, the other parties bear the burden of producing actual evidence. And, such evidence must be competent and probative.[67]

54. In this case, the ultimate burden of proving the reasonableness of the proposed change in rates remains with the Company. But the burden of producing evidence to rebut the Company's initial case is on other parties.

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[64] 21 Dunnell Minn. Digest, Evidence § 13.03 (5th ed. 2006).
[65] *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 since the taxpayer failed to rebut the prima facie case, and therefore court was required to enter summary judgment in favor of the government).
[66] *Texas Dept. of Community Affairs v. Burdine*, 450 U.S. 248, 252-56 (1981) (explaining that if the plaintiff establishes a prima facie case, then the burden of production shifts to the defendant to rebut the presumption raised by the prima facie case. If the defendant does not rebut the prima facie case and the plaintiff's evidence is believed by the trier of fact, then the court must enter judgment for the plaintiff).
[67] *LaFavor v. American National Insurance Company*, 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).

II. KEY DISPUTED ISSUES

A. Return on Equity (ROE) (Issue # 1)

55. The basic standards for the determination of return on equity (ROE) are found in the United States Supreme Court's decisions in *Hope*[68] and *Bluefield*[69] and in Minn. Stat. § 216B.16. The standards established in *Hope* and *Bluefield* require that the Company's ROE should be: 1) consistent with other businesses having similar or comparable risks; 2) sufficient to support credit quality and access to capital; and 3) sufficient to maintain financial integrity.[70] Minn. Stat. § 216B.16, subd. 6 requires the Commission to consider multiple factors when establishing the Company's ROE, including "the need of the public utility for revenue sufficient to enable it…to earn a fair and reasonable return upon [its] investment…."

56. Under all of the applicable standards, the ROE allowed by the Commission should be: 1) comparable to returns investors expect to earn on other investments of similar risk; 2) adequate to maintain and support the Company's credit and to attract debt and equity capital; and 3) sufficient to assure confidence in the Company's financial integrity.[71]

57. Establishing the ROE is a factual determination that is to be supported by substantial evidence.[72]

1. Market Conditions and the Multi-Year Rate Plan

58. The Company's expert witness, Mr. Robert B. Hevert, explained that interest rate environment has changed significantly since the Company's previous rate case.[73] Current long-term interest rates have risen significantly from the historic low

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[68] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).
[69] *Bluefield Waterworks Improvement Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*).
[70] *Hope*, 320 U.S. at 603-05; *Bluefield*, 262 U.S. at 692-95.
[71] Ex. 27, Hevert Direct at 7; *see also* Ex. 400, Amit Direct at 3.
[72] *Petition of Xcel Energy*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER, Docket No. E002/GR-06-1429 at 34 (September 10, 2007), (eDockets Doc. No. 4768622).
[73] Ex. 27, Hevert Direct at 11, 15.

levels observed in 2012 and 2013.[74] These increases are in part the result of uncertainty associated with the Federal Reserve's quantitative easing stimulus program; this uncertainty represents a meaningful risk to investors in general and a greater risk to investors in debt and equity securities of electric utilities.[75] The recent increases likely reflect investors' anticipation of the eventual "tapering" of the quantitative easing program.[76] Analyst projections indicate further interest rate increases in both the near and long-term.[77]

59. Mr. Hevert explained that the increased interest rates have been accompanied by a decrease in the stock value of utility companies.[78] Even though the prices for utility stocks do not move in lockstep with interest rates, these decreased stock values suggest an increase in the cost of equity.[79]

60. As a capital-intensive company that requires continual access to external sources of funds, the Company is exposed to the increased risks and costs resulting from market conditions such as interest rates.[80]

61. Anticipated increases in interest rates are especially important in light of the MYRP presented in this proceeding. Mr. Hevert stated that because interest rates and price instability are expected to increase during the term of the MYRP, investors necessarily will incorporate a larger risk premium as compensation for the risk that the Company is unable to recover increases in its market-required cost of equity during that longer period.[81]

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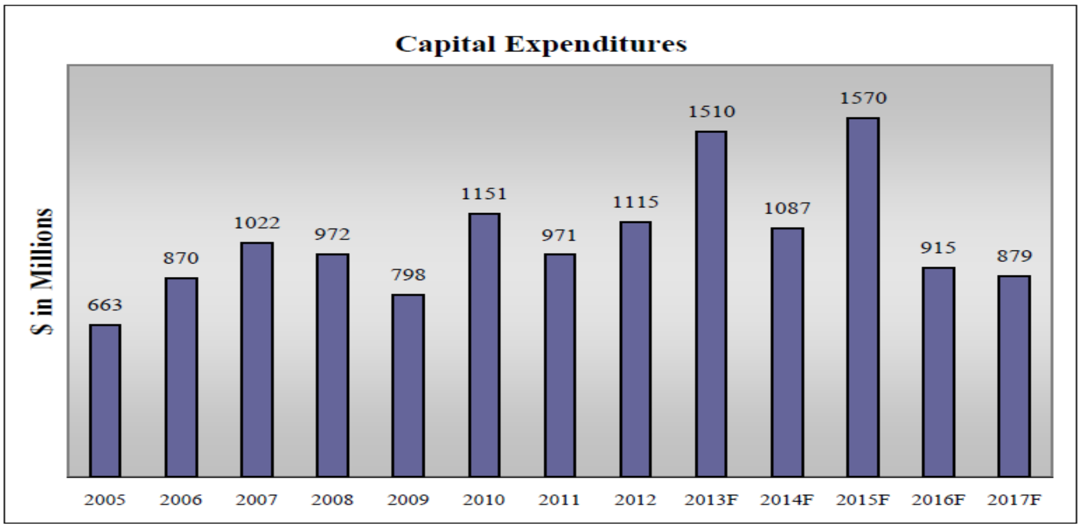
[74] Ex. 27, Hevert Direct at 11-12.
[75] Ex. 27, Hevert Direct at 10.
[76] Ex. 27, Hevert Direct at 10.
[77] Ex. 27, Hevert Direct at 11-12.
[78] Ex. 27, Hevert Direct at 12-13.
[79] Ex. 27, Hevert Direct at 13.
[80] Ex. 27, Hevert Direct at 15.
[81] Ex. 27, Hevert Direct at 52-53.

2. The Company's Capital Investments and ROE Realization

62. The Company remains in a period of very substantial capital investment, which began in 2005 and will continue through 2017. The Company has invested approximately $7.6 billion from 2005 through 2012, and projects additional capital expenditures averaging slightly less than $1.2 billion per year from 2013 through 2017,[82] as follows:



63. Investments through 2012 included the MERP projects, wind generation, nuclear Life Cycle Management and the Monticello extended power uprate, and transmission and other infrastructure.[83] To fund investments through 2013, the Company currently has approximately $4.2 billion in long term debt outstanding,[84] and has been reinvesting earnings at a rate of 85 percent for 2007 through 2013, with reinvestment of over 100 percent of earnings in 2005, 2006, and 2013.[85]

64. The Company will continue to invest capital, regardless of capital market conditions.[86] The projected capital expenditures will be needed to complete the

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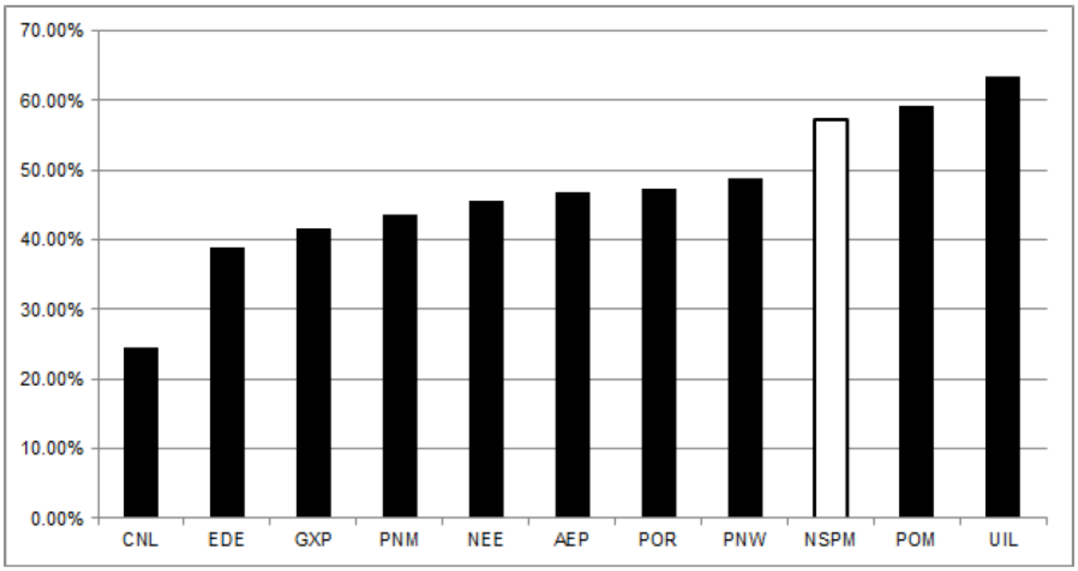
82 Ex. 30, Tyson Direct at 5, 14, and Schedule 3.
83 Ex. 30, Tyson Direct at 14.
84 Ex. 31, Tyson Rebuttal at 5.
85 Ex. 31, Tyson Rebuttal at 13.
86 Ex. 30, Tyson Direct at 16; Ex. 31, Tyson Rebuttal at 10.

CapX2020 transmission project, the Prairie Island Unit 2 steam generator replacement, and several transmission and distribution infrastructure replacement projects.[87] These capital expenditures are needed to meet reliability standards and other compliance requirements and to support the infrastructure necessary to serve the Company's customers.[88]

65. The Company's projected capital expenditures are at the top of the range of comparable electric utilities:[89]



66. The Company's significant capital expenditures have been accompanied by a trend: in recent years, the Company has not achieved its authorized ROE.[90] The Company has not achieved its authorized ROE since 2007 for its Minnesota Electric Retail Jurisdiction, the NSPM Total Company Electric Utility, or Total Company Financial Reporting (Form 10-K) basis.[91] NSPM's weather-normalized ROEs have

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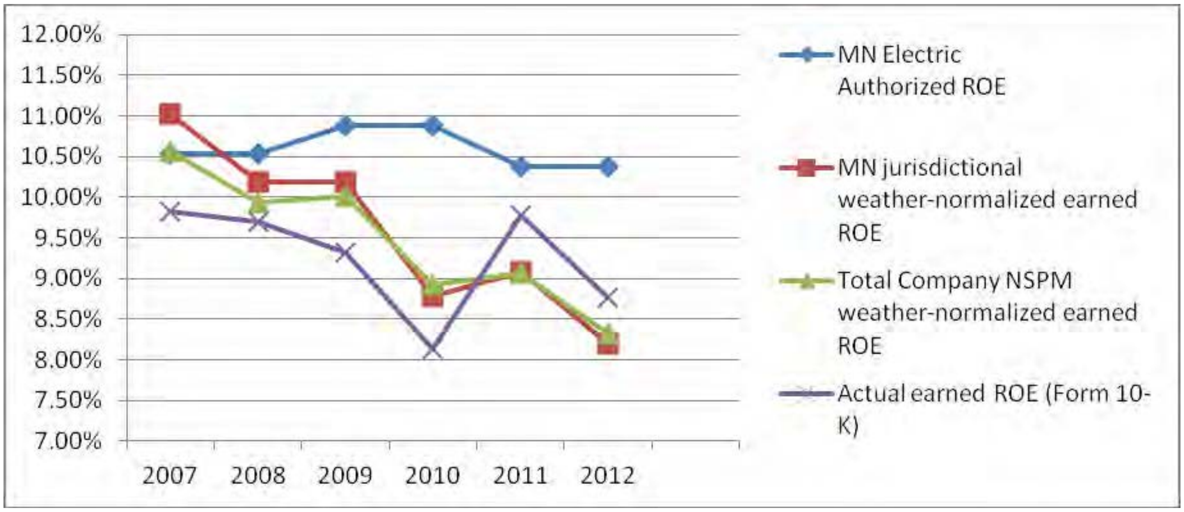
[87] Ex. 30, Tyson Direct at 16.
[88] Ex. 30, Tyson Direct at 5.
[89] Ex. 28, Hevert Rebuttal at 11 (comparing the Company's projected capital expenditures to Dr. Amit's FECG); *see also* Ex. 27, Hevert Direct at 46-47 (comparing the Company's projected capital expenditures to Mr. Hevert's Electric Proxy Group).
[90] Ex. 30, Tyson Direct at 14-15.
[91] Ex. 30, Tyson Direct at 14.

also been significantly below reasonable levels since 2009 and its actual ROEs have been significantly below reasonable levels since 2007:[92]



67. As shown above, since 2007, the Company's Minnesota jurisdictional weather-normalized earned ROE has decreased from approximately 11.00 percent (which was above its authorized ROE of 10.50 percent for one year in 2007) to less than 8.50 percent in 2012. For 2013, the Company's Minnesota jurisdictional weather normalized ROE was 8.22 percent.[93] This pattern of high capital expenditures and unreasonably low earned ROEs has caused the Company to submit rate case filings more frequently than the Company would have preferred.[94]

68. The Company will need regular access to capital markets to fund its planned levels of capital expenditures.[95] For example, NSPM plans to issue $300 million of long-term debt during 2014, to repay short-term debt incurred to fund its utility operations and construction program.[96]

69. Mr. Hevert explained that the Company's credit rating and outlook depend substantially on the extent to which rating agencies view the regulatory

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[92] Ex. 30, Tyson Direct at 15, Chart 1.
[93] Tr. Vol. 3 at 167 (Heuer).
[94] Ex. 30, Tyson Direct at 15.
[95] Ex. 30, Tyson Direct at 16-17.
[96] Ex. 30, Tyson Direct at 16.

environment as being supportive.[97] The Commission's decisions in this proceeding, including the ROE that it authorizes, will affect the Company's ability to finance capital expenditures internally and will have a particularly strong effect on investor and rating agency perceptions of NSPM.[98] Investors and credit rating agencies are aware that NSPM has investments that are very heavily weighted toward its electric business.[99] They are also aware that NSPM's customers are concentrated in Minnesota, making the Minnesota retail electric jurisdiction NSPM's primary jurisdiction.[100] Rating agencies and bond and equity investors also know that the Commission is fully informed about NSPM's investment plans.[101] As a result, they will likely consider the Commission's decisions regarding the financial components of our overall ROR and electric rates as a reflection of the level of support for those investment plans.[102]

70. For example, in its August 12, 2013 Credit Opinion for NSPM, Moody's notes the importance of regulatory support in the context of capital expenditures:

> The continuation of this regulatory support, in particular in the 2014 electric rate case, is all the more important now as the company reaches the peak of its large capital program.[103]

Another example is that in response to the Commission's summer 2013 decisions, J. P. Morgan downgraded the Company's stock (and Barclay's expressed similar concern).[104]

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[97] Ex. 27, Hevert Direct at 16; Ex. 30, Tyson Direct at 17.
[98] Ex. 30, Tyson Direct at 18.
[99] Ex. 30, Tyson Direct at 18.
[100] Ex. 30, Tyson Direct at 18-19.
[101] Ex. 30, Tyson Direct at 19.
[102] Ex. 30, Tyson Direct at 19.
[103] Ex. 30, Tyson Direct at 23.
[104] Ex. 30, Tyson Direct at 21.

3. Determination of the Cost of Equity and Use of the DCF Models

a. Summary of the Company's and the Department's Analyses

71. While the cost of debt can be directly measured, the cost of equity is market-based and, therefore, must be estimated based on observable market information.[105]

72. The DCF model, which is based on the theory that a stock's current price represents the present value of all expected future cash flows, is widely used to estimate the cost of equity in regulatory proceedings and is typically applied in Minnesota.[106] In its simplest form, the DCF model expresses the cost of equity as the sum of the expected dividend yield and long-term growth rate.[107] Both the Company and the Department relied primarily on their Constant Growth DCF and Two Growth DCF results in arriving at their ROE recommendations.[108] The Two Growth DCF is applied when the mean growth rate of a particular company may be considered a high or low outlier relative to the proxy group.[109]

73. The Company, through Mr. Hevert, conducted a DCF analysis using (1) an Electric Proxy Group; and (2) a Combination Proxy Group.[110]

74. The Company also relied on the CAPM and Bond Yield Plus Risk Premium approaches.[111] The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security).[112] The Bond Yield Plus Risk Premium approach estimates the cost of equity as the sum of the premium over the return an investor would have earned as a

[105] Ex. 27, Hevert Direct at 28.
[106] Ex. 27, Hevert Direct at 30.
[107] Ex. 27, Hevert Direct at 30.
[108] Ex. 27, Hevert Direct at 31-39; Ex. 400, Amit Direct at 6.
[109] Ex. 27, Hevert Direct at 34.
[110] Ex. 27, Hevert Direct at 18-27.
[111] Ex. 27, Hevert Direct at 39.
[112] Ex. 27, Hevert Direct at 39-40.

bondholder (the Equity Risk Premium) and the yield on a particular class of bonds.[113] The Company also considered other factors, including its capital expenditure program, its proposed partial decoupling mechanism, and the MYRP.[114]

75. Taking all of this information into consideration, the Company concluded that a rate of return on common equity in the range of 10.00 percent to 10.70 percent represents the required rate of return for NSPM in today's capital market environment.[115] Within that range, the Company recommended an ROE of 10.25 percent.[116]

76. In Rebuttal Testimony, the Company updated its DCF results, as shown below:[117]

	Low Growth Rate	*Mean Growth Rate*	*High Growth Rate*
Revised Electric Proxy Group Results			
30-Day Average	9.04%	9.97%	11.18%
90-Day Average	9.09%	10.02%	11.23%
180-Day Average	9.20%	10.13%	11.34%
Weighted Average Results (80% Revised Electric / 20% Combination)			
30-Day Average	9.02%	9.92%	11.03%
90-Day Average	9.09%	9.98%	11.10%
180-Day Average	9.12%	10.01%	11.13%

77. Based on these updated figures, the Company maintained its 10.25 percent ROE recommendation, and range of 10.00 percent to 10.70 percent.[118]

78. The Department, through Dr. Eilon Amit, conducted a DCF analysis using (1) a Final Electric Comparison Group (FECG); and (2) a Final Combination Comparison Group (FCCG).[119]

113 Ex. 27, Hevert Direct at 44.
114 Ex. 27, Hevert Direct at 45-53.
115 Ex. 27, Hevert Direct at 55.
116 Ex. 27, Hevert Direct at 55.
117 Ex. 28, Hevert Rebuttal at 56.
118 Ex. 28, Hevert Rebuttal at 1-2, 54-58.

79. The Department relied on the CAPM approach as a check.[120] The Department assigned a weight of 60 percent to the FECG and 40 percent to the FCCG, concluding that the Company's required rate of return ranges from a low of 8.97 percent to a high of 10.62 percent.[121] Within that range, the Department recommended an ROE of 9.80 percent.[122]

80. In surrebuttal, the Department performed an updated DCF analysis based on updated dividend yields from June 7, 2014 to July 7, 2014, updated growth rates, adjustments to the FECG and FCCG, and other updated information.[123] The Department recommended a ROE of 9.64 percent, the midpoint of the updated range of 8.93 percent to 10.39 percent.[124]

b. Areas of Agreement Between the Company and the Department

81. Both the Company and the Department followed Commission practices relating to the methodology for their ROE analyses:

- They each used a combination of the constant growth DCF model and a Two-Growth DCF model, and analyzed current and expected dividend yield as part of those models;[125]
- They each used and weighted two groups: a group of electric companies and a group of combined gas and electric companies like the Company.[126]
- They each presented well-documented explanations of how they used screening criteria to select the companies for their electric and combination comparable groups.[127] These criteria

119 Ex. 400, Amit Direct at 8-22.
120 Ex. 400, Amit Direct at 37-42.
121 Ex. 400, Amit Direct at 43.
122 Ex. 400, Amit Direct at 43.
123 Ex. 403, Amit Surrebuttal at 3-11.
124 Ex. 403, Amit Surrebuttal at 2, 11.
125 Ex. 27, Hevert Direct at 29, 31-39; Ex. 28, Hevert Rebuttal at 6; Ex. 400, Amit Direct at 6.
126 Ex. 27, Hevert Direct at 18-27, 34; Ex. 28, Hevert Rebuttal, at 8; Ex. 400, Amit Direct at 8-22, 43; Ex. 443, Amit Opening Statement at 2.
127 Ex. 27, Hevert Direct at 18-27; Ex. 400, Amit Direct at 8-22.

were similar to criteria that the Commission has accepted in the past.[128]

- They each used earnings projections from Zacks, First Call, and Value Line to determine growth for the DCF model;[129]
- They each made adjustments for the recovery of flotation costs;[130]
- They each used the CAPM as a check on their DCF analyses;[131]
- They agreed no adjustment to the Company's ROE was necessary for decoupling;[132] and
- They agreed Construction Work in Progress (CWIP) did not need to be included in the rate base.[133]

c. Support for the Company's Recommended ROE

82. The Company presented a detailed explanation of the analysis underlying its proposed ROE of 10.25 percent.[134]

83. First, Mr. Hevert explained how he selected the groups of proxy companies. To select his Electric Proxy group, he began with a group of companies classified by Value Line as Electric Utilities, and then excluded companies that do not consistently pay quarterly dividends, companies not covered by at least two equity analysts, companies with lower-than-investment-grade bond or credit ratings, companies whose regulated operating income comprised less than 60 percent of the company's total operating income, companies whose regulated electric operating income over the last three years represented less than 90 percent of regulated operating income, and companies known to be party to a merger or other transaction.[135] The result was a group of seventeen companies.[136] He then excluded

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128 Ex. 27, Hevert Direct at 23.
129 Ex. 27, Hevert Direct at 31; Ex. 28, Hevert Rebuttal, at 7; Ex. 400, Amit Direct at 24.
130 Ex. 27, Hevert Direct at 35-39; Ex. 28, Hevert Rebuttal, at 8; Ex. 400, Amit Direct at 32-33.
131 Ex. 27, Hevert Direct at 39; Ex. 28, Hevert Rebuttal, at 8; Ex. 400, Amit Direct at 37-42.
132 Ex. 27, Hevert Direct at 51-52; Ex. 403, Amit Surrebuttal, at 26-28.
133 Ex. 27, Hevert Rebuttal at 47-48; Ex. 403, Amit Rebuttal at 16.
134 Ex. 27, Hevert Direct; Ex. 115, Hevert Opening Statement at 1-5; Tr. Vol. 1 at 54-101 (Hevert).
135 Ex. 27, Hevert Direct at 22-23.
136 Ex. 27, Hevert Direct at 23-24.

Edison International because of its recent financial problems, and he excluded IDACORP, Inc. and Hawaiian Electric Industries, Inc. to adhere to the Department's practice of excluding companies with mean DCF results below 8 percent.[137]

84. To select his Combination Proxy Group, Mr. Hevert began with a group of companies classified by Value Line as Electric Utilities and Natural Gas Utilities.[138] He applied a similar list of exclusions, and also excluded Xcel Energy because including it would be circular, resulting in sixteen companies.[139] He further excluded Consolidated Edison, Inc. and Sempra Energy in order to adhere to the convention of excluding companies with mean DCF results of less than eight percent.[140] The result was a Combination Proxy Group comprised of fourteen companies.[141]

85. Mr. Hevert explained the formulas underlying the Constant Growth DCF model.[142] For the price inputs to the Constant Growth DCF analysis, Mr. Hevert used the average daily closing prices for the 30, 90, and 180 trading days ended September 30, 2013.[143] For the dividend input, he used the annualized dividend per share as of September 30, 2013, with an adjustment to reflect quarterly dividend increases.[144] He then calculated the Constant Growth DCF results using each of three sets of growth estimates: Zacks, First Call, and Value Line.[145]

86. Mr. Hevert also calculated Two Growth DCF results. In his Two Growth DCF model, Mr. Hevert used the Zacks, First Call, and Value Line growth rates for the first two years, and then for the remaining "terminal period," he used the

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137 Ex. 27, Hevert Direct at 24.
138 Ex. 27, Hevert Direct at 25.
139 Ex. 27, Hevert Direct at 25-27.
140 Ex. 27, Hevert Direct at 27.
141 Ex. 27, Hevert Direct at 27.
142 Ex. 27, Hevert Direct at 30-31.
143 Ex. 27, Hevert Direct at 31.
144 Ex. 27, Hevert Direct at 31, 32-33.
145 Ex. 27, Hevert Direct at 31.

proxy group average growth rate, excluding outliers, as the Commission has used in other proceedings.[146]

87. Mr. Hevert then made an adjustment for flotation costs.[147] To do so, he divided the expected dividend yield by (1 – percentage flotation costs); this is the methodology used by the Commission in prior cases.[148]

88. In his CAPM model, Mr. Hevert used three different risk-free rates of return: the current 30-day average yield, the projected yield, and the long-term projected yield, on 30-year Treasury bonds.[149] Based on data from Bloomberg and Value Line, he developed a forward-looking estimate of the Market Risk Premium for use in the CAPM model.[150] He also used Beta coefficients derived from Bloomberg and Value Line.[151] The results of Mr. Hevert's CAPM approach were in the same general range as his Constant Growth DCF model.[152]

89. Mr. Hevert's Bond Yield plus Risk Premium approach demonstrated that the ROE should be between 10.33 and 10.90 percent.[153]

90. Mr. Hevert also considered the impact of the Company's capital expenditure program, and its proposed partial decoupling mechanism.[154]

91. Considering all of these factors, and using a weighting of 80 percent on the Electric Proxy Group and 20 percent on the Combination Proxy Group, Mr. Hevert concluded to the updated DCF results set forth above.[155] Mr. Hevert recommended an ROE of 10.25 percent.[156]

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[146] Ex. 27, Hevert Direct at 34.
[147] Ex. 27, Hevert Direct at 35-39.
[148] Ex. 27, Hevert Direct at 38.
[149] Ex. 27, Hevert Direct at 41.
[150] Ex. 27, Hevert Direct at 41.
[151] Ex. 27, Hevert Direct at 42.
[152] Ex. 27, Hevert Direct at 43.
[153] Ex. 27, Hevert Direct at 44-45.
[154] Ex. 27, Hevert Direct at 45-53.
[155] Ex. 27, Hevert Direct at 55.
[156] Ex. 27, Hevert Direct at 55.

92. Mr. Hevert explained that a ROE of 10.25 percent is reflective of the business risks the Company faces in a rapidly changing environment, especially considering market conditions and the Company's capital investments.[157] Although the Company's investments affect customer rates, the Company has offered a mitigation plan to address these rate impacts.[158]

93. Mr. Hevert stated that by establishing the Company's ROE at the requested level, the Commission will be signaling to the investment community that it is supportive of the Company's investments to provide safe and reliable electric service while meeting the State's evolving energy policies.[159] He further noted that the current period also represents a peak of the Company's multi-year investment cycle and therefore it is necessary for the Company to obtain a reasonable cost of capital during this period to support the necessary investments.[160]

d. The Department's Recommended ROE

94. The differences between the Department's updated recommended ROE and the Company's requested ROE mainly result from two differences in the DCF analyses. First, for the price inputs to the Constant Growth DCF analysis, the Company used average daily closing prices for 30, 90, and 180 trading day periods,[161] whereas the Department used the closing prices for only a 30-day period.[162] Second, the Company used an 80/20 weighting of the electric and combination company groups,[163] whereas the Department used a 60/40 weighting.[164]

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157 Ex. 115, Hevert Opening Stmt. at 1.
158 *See* Ex. 99, Clark Direct at 26-30.
159 Ex. 27, Hevert Direct at 47-50.
160 Ex. 27, Hevert Direct at 47.
161 Ex. 27, Hevert Direct at 32; Ex. 28, Hevert Rebuttal at 55-56.
162 Ex. 400, Amit Direct at 24-25; Ex. 403, Amit Surrebuttal at 3.
163 Ex. 27, Hevert Direct at 21.
164 Ex. 400, Amit Direct at 43.

i. Time Period Used for Prices

95. The Department critiqued the Company's use of historical prices over periods longer than 30 days (*i.e.*, 90 trading days and 180 trading days).[165] But, the Company responded that the Department's reliance on a 30-day period is not appropriate because it does not take into account market volatility and was undertaken at a time when utility stocks were trading at aberrantly high levels. In other words, the Company's use of the longer periods prevents the results from being skewed by anomalous results, which is important considering the unstable market conditions in 2013.[166]

96. The Company's argument about the unreliability of the Department's 30-day snapshot due to market volatility was borne out by market activity: from Dr. Amit's Direct Testimony to his Surrebuttal Testimony, the average dividend yield for Dr. Amit's FECG fell by 54 basis points and the average dividend yield for his FCCG fell by 26 basis points.[167] These significant and sudden decreases in dividend yields were the result of the fact that utility stock prices were unusually high during the period when Dr. Amit calculated his DCF results.[168] Since July 2014, though, utility stock prices have declined relative to the overall stock market and moved more in line with historical levels.[169] This decline in utility stock valuations is consistent with the market expectation of increasing interest rates over the coming two years.[170]

97. The Commission has recently recognized that unstable market conditions may justify looking at data from more than a single 30-day period when

[165] Ex. 400, Amit Direct at 57-58.
[166] Ex. 27, Hevert Direct at 32.
[167] *Compare* Ex. 400, Amit Direct at 30, 35 *to* Ex. 403, Amit Surrebuttal at 3.
[168] Ex. 115, Hevert Opening Statement at 2.
[169] Ex. 115, Hevert Opening Statement at 2.
[170] Ex. 115, Hevert Opening Statement at 2.

determining the ROE.[171] In addition, other regulatory commissions, including FERC, traditionally look at price data from periods longer than 30 days.[172]

98. In light of the fact that the ROE set by the Commission in this proceeding will remain in effect for two years, the Commission should not rely on the Department's updated analysis, because is based only on a one-month snapshot of the financial market during this period of non-representative market behavior exhibiting instability in the cost of equity.

ii. Weighting of Company Groups

99. The Department critiqued Mr. Hevert's 80/20 weighing of the Electric Proxy Group and the Combination Proxy Group.[173] Mr. Hevert explained that because this proceeding will be setting electric rates, and the Company's concentration in electric service is highly consistent with the Electric Proxy Group and Dr. Amit's FECG, the 80 percent weighting is actually conservative.[174]

100. The Company contended that the Department's 60/40 weighting of the FECG and FCCG gives too much weight to non-electric operations.[175] Dr. Amit's FECG includes companies which, on average, derived 90.00 percent of their net income from regulated electric utility operations.[176] Thus, it already incorporates companies that reflect proportions of regulated electric operations that are highly consistent with the Company.[177] There is no need for further weighting to the

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171 *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority To Increase Its Rates for Natural Gas Service In Minnesota*, Docket No. G007,011/GR-10-977 (Deliberation Sept. 25, 2014).

172 *See, e.g.*, EL11-66-001, FERC OPINION 531 at 10 (June 19, 2014); *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*. and *Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers*, Cases 08-E-0539 and 08-M-0618 at 121 (April 24, 2009); *Application of Public Service Company of New Mexico For A Revision Of Its Electric Service Rates*, Case No. 10-00086-UT, FINAL ORDER PARTIALLY APPROVING CERTIFICATION OF STIPULATION at 58 (July 28, 2011).

173 Ex. 400, Amit Direct at 60.

174 Ex. 28, Hevert Rebuttal at 18.

175 Ex. 28, Hevert Rebuttal at 18.

176 Company Initial Brief at 30.

177 Ex. 28, Hevert Rebuttal at 19.

FCCG.[178] The purpose of this proceeding is to set electric rates, which suggests that there should be no reflection of the lower costs of capital of gas operations (through the combination company data).[179]

101. The Department critiqued Mr. Hevert's weighting on the basis that the investment risks of the electric comparable companies and the combination comparable companies are similar.[180] But, the record shows that there are significant differences between the DCF results for the electric comparable companies and for the combination comparable companies, suggesting that the investment risks of the two groups may not be similar.[181]

102. The Department also argued against the Company's 80/20 weighting on the basis that all of the Company's electric and combination comparable companies are identified under the same Value Line and SIC code categories.[182] However, these very general classifications do not establish comparability: the Value Line codes used by the Company established a universe of 48 electric companies and 59 combination companies[183] which Mr. Hevert reduced to a final comparable group of 14 electric companies and 14 combination companies.[184]

103. Ultimately, selection of the weighting is a subjective decision.[185] Both the Company and the Department presented reasonable weightings. Thus, both weightings should be considered in determining the ROE.

iii. Market Expectations and Other Utilities

104. The Department's recommended ROE of 9.64 percent would represent a significant reduction to the Company's currently authorized ROE of 9.83 percent.

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178 Ex. 28, Hevert Rebuttal at 20.
179 Ex. 27, Hevert Direct at 21.
180 Department Initial Brief at 27; Ex. 400, Amit Direct at 60.
181 Ex. 28, Hevert Rebuttal at Schedule 1 (30-day, 60-day, and 180-day mean DCF results are 16 – 27 basis points lower for the electric comparable group than for the combination comparable group).
182 Department Initial Brief at 28; Ex. 400, Amit Direct at 61.
183 Ex. 27, Hevert Direct at 22, 25.
184 Ex. 27, Hevert Direct at 25, 27.
185 Ex. 400, Amit Direct at 43-44.

Mr. David M. Sparby testified that a ROE of 9.64 percent would require the Company to reduce costs or under-earn its ROE in key areas.[186] Adverse market reaction can occur in response to a Commission decision that reflects a more difficult regulatory environment for the Company. Market considerations are among the factors for consideration by the Commission under Minn. Stat. § 216B.16, subd. 6.

105. The average ROE authorized for vertically-integrated utilities in 2014 is 9.84 percent, whereas the average ROE authorized for distribution-only utilities in 2014 is 9.51 percent.[187] The Commission recently authorized a 9.59 percent ROE for CenterPoint.[188] The business risks posed to distribution-only utilities and natural gas utilities are quite different than the risks that the Company, with its two nuclear generating plants, large transmission system, and significant ongoing capital expenditures, faces.

106. The Company's currently authorized ROE of 9.83 percent is in the lowest one-third of ROEs authorized from 2012 through May 2014 for utilities that provide generation, transmission and distribution services and in the lowest 39 percent of ROEs authorized from August 2013 through May 2014.[189] Moving downward to 9.64 percent would put the Company in the bottom 10 percent of ROEs since 2012, and within the bottom 20 percent of returns authorized since August 2013.[190]

107. The Company argued that authorizing the Department's recommended ROE of 9.64 percent would send a clear negative signal to investors that the Minnesota regulatory environment is not supportive of the Company's capital

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[186] Tr. Vol. 1 at 30 (Sparby).
[187] Ex. 225, Chriss Direct, at Schedule 3.
[188] *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 32, Docket No. GR-13-316 (June 9, 2014).
[189] Company Initial Brief at 26.
[190] Company Initial Brief at 24.

expenditure program, especially because it would be the second successive ROE decrease, and would represent a return near industry lows.

iv. The Department's DCF Calculations Closely Overlap with the Company's Requested ROE

108. The Commission has previously noted the significance of an overlap of ROE ranges in determining the ROE.[191] Both the Company's requested 10.25 percent ROE and the currently authorized 9.83 percent ROE are within the Department's DCF range for the Final Electric Comparison Group.[192] Even if the Commission used the Department's approach of a 30-day period and a 60/40 weighting, the results for the period ending May 30, 2014 is 9.86 percent.[193] The overlap between the Department's figures and the Company's analysis further demonstrates that the Company's proposed ROE of 10.25 is reasonable.

e. Other ROE Proposals

109. The ICI, through Mr. Glahn, recommended that the Commission set the Company's ROE at 9.00 percent.[194] There were inconsistencies and errors in how Mr. Glahn selected his comparable companies;[195] in particular, the screening criteria he used to select a proxy group were flawed because they included companies with substantial unregulated operations.[196] In response to questions from the Department, Mr. Glahn was unable to explain how he had selected his comparable companies.[197]

110. Mr. Glahn applied four DCF analyses, but the Company argued that all were flawed because (1) three contained a mismatch between the expected growth rates used to calculate the expected dividend yield and the expected growth rate of the

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[191] *In the Matter of Otter Tail Power Company*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 59, Docket No. E017/GR-07-1178 (Aug. 1, 2008); *In the Matter of Northern States Power Company*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 11-12, Docket No. E002/GR-08-1065 (Oct. 23, 2009).
[192] Ex. 400, Amit Direct at 37.
[193] Ex. 28, Hevert Rebuttal at Schedule 1, pages 1 and 4.
[194] Ex. 250, Glahn Direct at 23; Ex. 251, Glahn Surrebuttal at 4.
[195] Ex. 402, Amit Rebuttal at 3-6; Ex. 443, Amit Opening Statement at 3.
[196] Ex. 28, Hevert Rebuttal at 34.
[197] Tr. Vol. 3 at 118-134 (Glahn).

DCF; (2) all contain companies with unreasonably low ROEs; (3) he wrongly used short-term rather than long-term expected growth rates; and (4) he refused to make any allowance for flotation costs.[198] Two of his DCFs used a "sustainable growth" analysis that has not been accepted by the Commission in any prior Company rate case.[199] Historical market data and independent research also indicate that Mr. Glahn's sustainable growth model is unreliable.[200]

111. All of the growth rates on which Mr. Glahn relied were dividend growth rates, provided solely by Value Line.[201] But, analysts and investors focus on earnings growth, which indicates that earnings growth is the appropriate measure for the DCF model.[202] Prior research indicates that investors rely on analysts' earnings growth projections in valuing equity securities.[203]

112. Mr. Glahn pointed to three rate cases from other states in which the authorized ROE was 9.75 percent or lower, but failed to acknowledge nine other instances where companies received ROEs of 10.00 percent or higher.[204]

113. The Commercial Group did not perform an independent analysis of the cost of equity.[205] However, through Mr. Chriss, the Commercial Group stated that the Company's recommended 10.25 percent ROE was too high, noting that other commissions had awarded ROEs for vertically integrated utilities that averaged 10.3 in 2012-2014 and were 9.84 percent in 2014.[206] But, Mr. Chriss relied on outdated data.[207] Based on Mr. Chriss' approach, the average authorized ROE for vertically

[198] Ex. 402, Amit Rebuttal at 2-13; Ex. 443, Amit Opening Statement at 3; Ex. 28, Hevert Rebuttal at 35-41; Tr. Vol. 4 at 40-42 (Amit).
[199] Ex. 28, Hevert Rebuttal at 33, 37.
[200] Ex. 28, Hevert Rebuttal at 37.
[201] Ex. 250, Glahn Direct at 20-21.
[202] Ex. 28, Hevert Rebuttal at 36.
[203] Ex. 28, Hevert Rebuttal at 38, *citing* Roger A. Morin, PhD, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 298-303.
[204] Ex. 28, Hevert Rebuttal at 32.
[205] Ex. 28, Hevert Rebuttal at 45.
[206] Ex. 225, Chriss Direct at 8-9.
[207] Ex. 402, Amit Rebuttal at 15.

integrated utilities has been approximately 10.00 percent, which is within the Company's recommended range.[208]

114. The Commercial Group further recommended that if CWIP is included in the rate base, the ROE should be reduced because CWIP shifts risk from the Company to ratepayers.[209] Both Dr. Amit and Mr. Hevert disagreed with the Commercial Group position regarding CWIP, noting the Commission's long-standing policy regarding CWIP, which indicates that the market had already taken that position into account.[210] Mr. Hevert explained that recovery of CWIP is commonly allowed by regulatory commissions.[211]

115. The AARP recommended that if decoupling is approved by the Commission, a 10-basis point reduction in ROE should be made or the ROE should be set at the low end of the range of reasonable ROEs.[212] The AARP stated that a number of utility Commissions have decided to lower ROE because of decoupling.[213]

116. Both the Department and the Company disagreed with this recommendation regarding decoupling.[214] Moreover, the AARP's recommendation is based on a selective review of decisions by other commissions, and ignores the fact that most commissions do not make an adjustment for decoupling.[215] A Brattle Group study concluded that there is no significant difference in the cost of capital between electric utilities with and without decoupling.[216] The issue is how the Company compares to the comparable companies, not how decoupling may affect the Company on a stand-alone basis.[217] Mr. Hevert agreed with Dr. Amit and explained

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208 Ex. 28, Hevert Rebuttal at 47.
209 Ex. 225, Chriss Direct at 11.
210 Ex. 28, Hevert Rebuttal at 47-48; Ex. 402, Amit Rebuttal at 16.
211 Ex. 28, Hevert Rebuttal at 48.
212 Ex. 310, Brockway Direct at 18; Ex. 311, Brockway Rebuttal at 18.
213 Ex. 311, Brockway Rebuttal at 18.
214 Ex. 28, Hevert Rebuttal at 49-54; Ex. 403, Amit Surrebuttal at 27.
215 Ex. 28, Hevert Rebuttal at 53; Ex. 29, Hevert Surrebuttal at 2-7.
216 Ex. 28, Hevert Rebuttal at 52; Ex. 403, Amit Surrebuttal at 27.
217 Ex. 403, Amit Surrebuttal at 28.

that relative risk compared to other comparable companies is the significant point.[218] Likewise, the CEI, through Mr. Cavanaugh, recommended that if the Commission approves a decoupling mechanism in this case, it should not change the Company's ROE for any reasons associated with the adoption of decoupling.[219]

4. Conclusion

117. The Company's recommended ROE of 10.25 percent is reasonable and appropriately addresses the effects of unsettled stock prices and the mandatory two-year effect of the ROE in this case. The Company's ROE is also comparable to other vertically-integrated utilities and takes into consideration a broader range of information than just the results of the Department's analysis of data from June 7, 2014, to July 7, 2014.

B. Monticello LCM/EPU Project – Used and Useful (In-Service Date) (2014 and/or 2015 Step) (Issue #2)

1. Background

118. The Monticello nuclear power generating plant (Monticello) has been in operation since 1971. Under its original license from the Nuclear Regulatory Commission (NRC), Monticello was only licensed to operate until 2010. In 2006, the Company obtained a license extension from the NRC allowing the plant to operate until 2030.[220]

119. The Monticello Life Cycle Management and Extended Power Uprate program (LCM/EPU Program) was a complex project undertaken to prepare the plant for its 20-year extended operating life while increasing the plant's capacity from 600 to 671 megawatts (MW).[221]

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218 Ex. 28, Hevert Rebuttal at 49; Ex. 29, Hevert Surrebuttal at 7-8; Tr. Vol. 1 at 83, 86, 93-94 (Hevert).
219 Ex. 290, Cavanaugh Direct at 5-6, 12; Ex. 294, Cavanaugh Rebuttal at 6; Tr. Vol. 3 at 61, 69-71 (Cavanaugh).
220 Ex. 51, O'Connor Direct at 16.
221 Ex. 51, O'Connor Direct at 15.

120. In 2008, the Company filed a License Amendment Request (LAR) with the NRC to increase or uprate the plant's capacity to 671 MW. That same year, the Company requested a Certificate of Need from the Commission to increase the plant's capacity to meet growing demand needs.[222]

121. In February 2009, the Commission approved the Certificate of Need for the uprate.[223]

122. The Company stated that the LCM and EPU are an integrated project (LCM/EPU Program) and were managed as such.[224] The LCM/EPU Program was implemented over approximately eight years, and replaced nearly all of the components that support the reactor and power generation equipment.[225]

123. The Company included costs for the LCM/EPU Program in its 2013 rate case. In that case, the ALJ concluded that the EPU portion of the LCM/EPU Program was not in service for purposes of rate setting "because the Company does not have the NRC license amendment required to operate at uprated EPU level."[226] The ALJ attributed 41.6 percent of the LCM/EPU Program costs to the EPU based on the allocation of costs used by the Company during the 2008-2009 Certificate of Need proceeding.[227]

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222 *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate,* PETITION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE MONTICELLO NUCLEAR GENERATING PLANT FOR EXTENDED POWER UPRATE, Docket No. E002/CN-08-185 (Feb. 14, 2008).

223 *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate,* ORDER GRANTING CERTIFICATE OF NEED AND ACCEPTING ENVIRONMENTAL ASSESSMENT, Docket No. E002/CN-08-185 (Jan. 8, 2009).

224 Ex. 51, O'Connor Direct at 16; Ex. 53, O'Connor Rebuttal at 15-16.

225 Ex. 51, O'Connor Direct at 15.

226 *In the Matters of the Application of the Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATION at ¶ 79, Docket No. E-002/GR-12-961(July 3, 2013)(emphasis added)(*hereinafter* ALJ REPORT IN 2013 RATE CASE).

227 ALJ REPORT IN 2013 RATE CASE at 17 ("The 41.6 percent apportionment of costs between the EPU and LCM represents the Company's own estimate of the proportion of costs attributable to the EPU part of the project. While the Company maintains that the estimate was an early, high level figure, the Company has not produced an incremental cost study or any other reliable accounting study to show that the estimate is no longer reasonable.")

124. The Commission accepted the ALJ's recommendation and concluded that the EPU portion of the Monticello LCM/EPU Program was not yet "used and useful" for purposes of the 2013 test year, and suggested that the Company may be able to recover costs once the EPU is licensed by the NRC:

> The Commission agrees with the ALJ that only the LCM portion of the LCM/EPU project is used and useful. The Commission also agrees that 41.6% is the portion of the project properly attributable to the Extended Power Uprate, which cannot serve ratepayers until it is licensed by the NRC.… The Commission therefore determines that 41.6% of the LCM/EPU costs for 2011 and 2012 additions added to the rate base in this case, 41.6% of 2013 May plant addition costs, and 100% of Nuclear Regulatory Commission license fees should be moved from plant in-service to CWIP, as well as the related depreciation reserve, deferred taxes, depreciation expense, AFUDC, and any other applicable costs. The Company may be allowed to recover those costs in future rate cases once the EPU is in service, subject to the plant being used and useful and subject to a determination that the costs – including cost overruns – were prudent.[228]

125. The Commission also deferred a review of the reasonableness of the underlying costs of the Monticello LCM/EPU Program to a separate prudence proceeding (Docket No. E002/CI-13-754 (Prudence Investigation)).[229]

126. In December 2013, the Company received NRC approval of the EPU license amendment that allowed the plant to begin the power uprate ascension.[230]

127. In March 2014, the plant operated at 640 MW for approximately 20 days.[231]

128. In March 2014, the Company received the MELLLA+[232] license amendment which was required to achieve uprate above 640 MW.

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[228] 2013 RATE CASE ORDER at 18.
[229] 2013 RATE CASE ORDER at 19-20.
[230] Ex. 53, O'Connor Rebuttal at 4.
[231] Tr. Vol. 1 at 231 (O'Connor).

129. With receipt of the LAR approvals for both the EPU and the MELLLA+, since March 2014 Monticello has been operating under an amended license that allows it to operate up to approximately 671 MW.[233]

130. Prior to operating at the new 671 MW level, the Company must first complete the power ascension process.[234] Power ascension is a prescribed acceptance testing process required by the NRC, and is a necessary element to support and evaluate nuclear plant operations and output during the power uprate startup phase.[235] The license amendments for the power uprate require ascension monitoring and testing to ensure the safe, reliable operation of the plant.[236]

131. During the evidentiary hearing, Company witness Mr. Timothy J. O'Connor stated that the plant is currently operating at 600 MW. Mr. O'Connor also testified that he anticipates that the plant will complete its power ascension testing protocol and fully ascend to 671 MW by the end of 2014.[237]

132. The July 17, 2014 Joint Prehearing Order issued in this rate case and the Prudence Investigation requires that the prudence of total Program costs and the division of LCM/EPU Program costs between the LCM and EPU are to be addressed in the Prudence Investigation.[238] The same Prehearing Order further notes that the issues to be decided in this rate case proceeding are: (i) whether the EPU aspect of the Program should be considered "used and useful" for purposes of 2014 and/or 2015

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232 MELLLA+ stands for "Maximum Extended Load Line Limit Analysis." MELLLA+ is an engineering analysis that provides for greater operational flexibility, permits more efficient reactor startup, maximizes fuel utilization, and improves fuel cycle economics. Ex. 51, O'Connor Direct at 20.
233 Ex. 53, O'Connor Rebuttal at 5.
234 Ex. 53, O'Connor Rebuttal at 5-6.
235 Ex. 53, O'Connor Rebuttal at 5-6.
236 Ex. 53, O'Connor Rebuttal at 5-6.
237 Tr. Vol. 1 at 232, 235 (O'Connor).
238 JOINT PREHEARING ORDER at 2, Docket Nos. E-002/GR-13-868 and E-002/CI-13-754 (July 17, 2014) (eDockets Doc. No. 20147-101591-01).

rates; and (ii) how expenses from the Prudence Investigation should be recovered and amortized.[239]

2. Parties' Positions

a. MCC's Position

133. The MCC proposed to treat the delay in ascending fully to 671 MW similar to a mechanical failure, consistent with the Commission's 2013 decision regarding treatment of Sherco Unit 3.[240] This would require the Company to: (i) remove depreciation and direct expenses related to the Monticello EPU from the 2014 test year and amortize them over the life of the facility; (ii) remove increased replacement fuel and power costs ($11.1 million) and allow the Company to recover the costs over the life of the facility; and (iii) require the Company to provide status updates of the ascension to the 671 MW uprate level.[241]

134. The MCC's proposal reduces 2014 test year revenue requirements by $12.227 million and increases 2015 Step revenue requirements by $11.680 million, subject to further adjustment depending on the Commission's decisions in the Monticello Prudence Investigation.[242]

135. The Department opposed MCC's proposal for several reasons: (1) the Company has not shown that the EPU will be used and useful in 2014; (2) neither the Company nor MCC has shown that deferral of costs to periods outside of the 2014 test year is reasonable; and (3) MCC's proposal would allow recovery of 2014 EPU costs from ratepayers, with a return, even though ratepayers are not receiving a benefit from the EPU, while it would defer the costs of fuel and replacement power that ratepayers are using and from which they are receiving a benefit.[243]

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[239] JOINT PREHEARING ORDER at 2, Docket Nos. E-002/GR-13-868 and E-002/CI-13-754 (July 17, 2014) (eDockets Doc. No. 20147-101591-01).
[240] Ex. 341, Schedin Rebuttal at 8.
[241] Ex. 341, Schedin Rebuttal at 9.
[242] Tr. Vol. 3 at 141, 152-53 (Heuer); Ex. 90, Heuer Rebuttal at Schedule 17.
[243] Department Initial Brief at 91-92.

136. During the evidentiary hearing, the Company accepted the MCC's proposal.[244] The Company contended that the MCC's approach reasonably reflects the current status of Monticello and balances the interests of all stakeholders by recognizing that the EPU is used and useful even though the plant has not operated at full uprate capacity.[245]

137. The Company also stated that the MCC's approach also best reflects that the causes of delaying full ascension are not licensing or operational issues, but rather data issues the utility is in the process of reconciling for the benefit of all stakeholders.[246]

138. The Company further noted that the MCC's proposal also has the benefit of treating the fuel clause and rate base issues in a reasonable manner by offering customers a reduction in rate base that would offset the cost of alternative replacement capacity.[247] As such, construction cost recovery is deferred and recovery of replacement fuel costs are spread over a longer period, reducing the overall impact of the Program delays on customers.

139. The Company disagreed with the Department's characterization that the MCC's proposal may require deferral approvals from the Commission that the Parties have not requested in this proceeding.[248] The Company stated that the MCC's proposal is similar to the Commission's treatment of costs in its 2013 rate case with respect to the extended Sherco 3 outage, where the Commission did not require a deferred accounting petition.[249] Rather, the Company noted that in the 2013 rate case, the Commission recognized that "the task at hand is to equitably balance the interests

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[244] Ex. 134, Clark Opening Statement at 1; Ex. 140, Heuer Opening Statement at 2.
[245] Ex. 134, Clark Opening Statement at 1.
[246] Company Initial Brief at 37.
[247] Ex. 342, Schedin Surrebuttal at 4-5.
[248] Company Initial Brief at 40.
[249] Company Initial Brief at 40 *citing* 2013 RATE CASE ORDER at 23.

of the ratepayers and the shareholders"[250] and struck an appropriate balance between those interests based on the facts in that record.[251]

b. XLI's Position

140. XLI argued that the Monticello EPU will not be used and useful until the plant is operating at 671 MW.[252] XLI recommended that the Commission make a proportional adjustment based on the date when the plant achieves 671 MW. As the Company estimated that the plant will achieve full operation in December 2014, XLI recommended that 11/12ths of the EPU costs ($28.6 million) be excluded from the 2014 revenue requirements.[253]

141. The Company contended that XLI's proposal to allow only 11/12ths of the Monticello LCM/EPU project costs into rate base does not reflect how rate base is calculated.[254] The Company noted that it has historically used beginning of year/end of year (BOY/EOY) averages for test year rate base determination.[255] It would be inappropriate to use a 13-month average for this one capital project while using a BOY/EOY average for all other forecasted rate base items.[256]

142. The Department also disagreed with XLI's position. The Department argued that because the Company has failed to demonstrate that the uprate is used and useful or that it is likely to be used or useful by the end of 2014, there is no reasonable basis to allow any EPU-related costs in 2014 rates.[257]

c. Department's Position

143. The Department recommended that because the Company has not shown that the EPU is or will be used and useful by the end of 2014, the revenue

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[250] 2013 RATE CASE ORDER at 22.
[251] Company Initial Brief at 40.
[252] Ex. 260, Pollack Direct at 22.
[253] Ex. 260, Pollack Direct at 22-23.
[254] Ex. 94, Perkett Rebuttal at 46.
[255] Ex. 94, Perkett Rebuttal at 46.
[256] Ex. 94, Perkett Rebuttal at 46.
[257] Department Initial Brief at 93.

requirement should be reduced by $31.284 million such that 2014 depreciation expense and rate base return on the Monticello EPU are excluded from the 2014 test year.[258]

144. For the 2015 Step, assuming that plant is operating at 671 MW by January 2015 and the NRC has approved the plant to operate at this level, the Department recommended rate base treatment and recovery of associated depreciation costs.[259]

145. If the plant is not operating at 671 MW by January 2015 and the NRC has not approved the plant to operate at this level, the Department recommended that the Commission require the Company to refund any amounts collected in rates through the refund mechanism for the MYRP.[260]

d. Company's Position

146. The Company argued that if MCC's proposal is not accepted, the Monticello LCM/EPU Program should be considered used and useful in 2014.[261] The Company argued that with the receipt of all necessary NRC licenses amendments to operate at EPU levels, the LCM/EPU should be viewed as the unified project that it is, comprised of common plant utilized for both LCM and EPU purposes.[262]

147. The Company stated that completion of the ascension process is not a prerequisite to in-servicing the LCM/EPU, as the capital investment has been dedicated to public use and it should be expected that less than full performance of the plant would occur as systems are checked and validated.[263]

148. The Company pointed out that since the Commission's decision in the Company's last rate case there several important factual changes that have occurred

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[258] Ex. 450, Campbell Opening Statement at 3.
[259] Ex. 450, Campbell Opening Statement at 3-4.
[260] Ex. 450, Campbell Opening Statement at 3-4.
[261] Company Initial Brief at 42.
[262] Company Initial Brief at 41.
[263] Company Initial Brief at 40-41 citing *State ex rel. Utilities Comm'n v. Eddleman*, 358 S.E.2d 339, 352 (N.C. 1987) and *State ex rel. Missouri Public Service Co. v. Fraas,* 627 N.W.2d 882 (Mo. App. 1982).

that warrant a finding in this case that the EPU is "used and useful." These include: (1) the Company has now received all NRC licenses and amendments necessary to operate at uprate levels, including our EPU license amendment and MELLLA+ license;[264] (2) the Company is using all of the assets implemented as part of the LCM/EPU Program, resulting in higher safety margins and more efficient baseline output for customers;[265] (3) the plant has achieved a partial uprate, ascending to 40 of the additional 71 MW additional capacity expected from the Program;[266] and (4) the Company anticipates achieving full ascension by the end of 2014, through the relatively normal process of validating post-licensing data for the NRC.[267] As a result, the Company stated that the undisputed record evidence establishes not only that all assets are in use, but also that the Company has all licensing necessary to operate at uprate levels, has begun the ascension process and achieved 56 percent of the EPU capacity, and expects to achieve full ascension in 2014.[268]

149. Further, the Company noted that the Department's used and useful analysis depends on the assumption that it is possible and appropriate split LCM and EPU equipment such that one can designate certain assets or expenditures as not "used and useful" until the plant fully ascends.[269] The Company explained that the LCM/EPU split used in its prior rate case was intended to recognize that the Company had not yet procured the license amendments necessary to operate at uprate conditions, but this split is no longer relevant to a "used and useful" analysis.[270] As Mr. O'Connor discussed in hearings and pre-filed testimony in some length,[271] the NRC uprate licensing obtained by the Company was not limited to certain assets or

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[264] Tr. Vol. 1 at 227 (O'Connor); Ex. 53, O'Connor Rebuttal at 4; Ex. 100, Clark Rebuttal at 23-24.
[265] Tr. Vol. 1 at 220 (O'Connor); Ex. 53, O'Connor Rebuttal at 14; Ex. 100, Clark Rebuttal at 24.
[266] Tr. Vol. 1 at 231 (O'Connor); Ex. 53, O'Connor Rebuttal at 10; Ex. 100, Clark Rebuttal at 24.
[267] Tr. Vol. 1 at 231-233 (O'Connor); Ex. 55, O'Connor Surrebuttal at 5.
[268] Company Initial Brief at 42.
[269] Company Initial Brief at 38-39.
[270] Company Initial Brief at 38-39.
[271] Tr. Vol. 1 at 220 (O'Connor); Ex. 53, O'Connor Rebuttal at 14.

equipment, and it is not possible to identify standalone systems that are operational solely upon receipt of the license.

150. The Company explained that the plant as a whole is operating more safely and efficiently, and the plant as a whole will operate at increasing levels as output increases. The Company pointed out that while the ascension process is underway, the Company has "gained some efficiencies with some of the equipment that's already been replaced as part of the lifecycle management EPU; and we're operating a little bit better, in terms of total output, now that those modifications have been completed."[272] Moreover, "[t]oday, the plant is achieving over 90% of its potential [and] [i]t has already reached 95% of its potential safely…."[273]

3. The Used and Useful Standard

151. Under Minnesota law, just and reasonable rates include a fair and reasonable return upon the investment in property which is "used and useful" in rendering service to the public.[274]

152. To establish that property is "used and useful," the utility has the burden to prove: "(1) that the property [will be] 'in service;' and (2) that it [will be] 'reasonably necessary' to the efficient and reliable provision of utility service."[275] "The thing devoted by the investor to the public use is not specific property, tangible and intangible, but capital embarked in the enterprise."[276]

153. The "used and useful" standard is not a bright line test; rather, the determination of whether property is "useful" requires consideration of what is reasonable given the policy considerations and factual circumstances surrounding any

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[272] Tr. Vol. 1 at p. 245 (O'Connor).
[273] Ex. 53, O'Connor Rebuttal at 15.
[274] Minn. Stat. § 216B.16, subd. 6.
[275] *Senior Citizens Coalition v. Minnesota Public Utilities Commission,* 355 N.W.2d 295, 300 (Minn. 1984).
[276] *State of Missouri ex. Rel. Southwestern Bell Telephone Company v. Public Service Commission of Missouri et. al.*, 262 U.S. 276, 290-291 (1923) (Brandies, J. concurring).

given capital asset.[277] "[I]t must be re-emphasized that the "used and useful" concept, if administered inflexibly and without regard to other equitable and policy considerations, may fail the interests of both the electric utility industry and its ratepayers."[278]

154. For purposes of this case, it is notable that the "used and useful" standard does not require property to be used to its full capacity or maximum benefit at all times to be considered used and useful.[279]

155. Moreover, the "used and useful" standard does not require immediate provision of benefits to customers; rather, as the United States Energy Administration has noted, the "used and useful" standard requires that "an asset currently provide or be capable of providing a needed service to customers."[280]

4. Conclusion

156. MCC's proposal presents a reasonable approach and is consistent with the Commission's decision regarding the Company's extended Sherco 3 outage. The MCC's approach should be adopted for recovery of costs for the EPU portion of the Monticello LCM/EPU Program, with the final adjustment to be determined by the Commission's decisions in the Monticello Prudence Investigation.

157. If the Commission decides not to adopt the MCC's proposal, the EPU portion of the Monticello LCM/EPU Program should be considered "used and

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277 *In re Connecticut Light & Power Co.*, Connecticut Department of Public Utility Control Docket, No. 97-05-12 1997 WL 866679 ** 8-9, 19-21 (December 31, 1997) (*Connecticut Light & Power Decision*) (citing *Pennsylvania Public Utility Comm'n v. Metro. Edison Co.*, 37 PUR4th 77, 86 (1979)).

278 Order No. 298, *Construction Work in Progress for Public Utility; Inclusion Costs in Rate Base,* [1982-1985 Regs. Preambles] F.E.R.C. Stats. & Regs. r[30,455, at 30,507, 48 Fed. Reg. 24,323 (1983). *aff'd in part, vacated and remanded in part, Mid-Tex Elec. Coop. v. FERC*, 773 F.2d 327 (D.C. Cir. 1985). *See also Consolidated Gas Supply Corp. v. FPC*, 520 F.2d 1176, 1185 (D.C. Cir. 1975) ("The legal system does not compel rigidity, or bureaucratic inflexibility, least of all in the area of energy policy where flexibility may be essential to the public interest.").

279 *See City of Evansville v. Southern Indiana Gas and Electric Co.*, 167 Ind. App. 472, 515-20, 339 N.E.2d 562, 589-91 (1975) (cited in *Senior Citizens Coalition*, 355 N.W.2d at 300).

280 U.S. Energy Information Administration Glossary, available online at http://www.eia.gov/tools/glossary/index.cfm?id=U (last visited on Sept. 17, 2014) (emphasis added).

useful" as these assets and systems are fully in use and benefiting customers, regardless of whether the plant operate at a full 671 MW.

C. Depreciation and Plant Retirements in the 2015 Step – Passage of Time (2015 Step) (Issue #10)

1. Background

158. The Company's present application is the first MYRP filed in the state of Minnesota. The Commission provided guidance for MYRPs in its MYRP Order, which, in part, requires that MYRPs be "designed to recover the cost of specific, clearly identified capital projects and, as appropriate, non-capital costs."[281]

159. Consistent with the Commission's MYRP Order, the Company's MYRP "seeks to recover costs related to specific capital projects and a limited number of noncapital expenses associated with capital investments."[282] Specifically, the Company proposed to include in the 2015 Step: a limited number of capital additions; certain capital additions originating in Northern States Power Company-Wisconsin (NSPW); and operations and maintenance items directly tied to these capital additions such as pollution control chemical costs, property taxes, and other minor costs and credits.[283]

160. To develop the proposed revenue requirement for the 2015 Step, the Company utilized the same methodology it uses to calculate revenue requirements for a regular test year, except such calculations were limited to only the 2015 Step capital additions and related O&M. This includes carrying forward "ongoing monthly balances…for the various components of rate base including plant in-service,

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[281] *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multi Year Rate Plans under Minn. Stat. § 216B.16, subd. 19*, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTI YEAR RATE PLANS, Docket No. E,G-999/M-12-587 (June 17, 2013) ("MYRP Order").
[282] Ex. 99, Clark Direct at 10.
[283] Ex. 95, Robinson Direct at 3.

Construction Work In Progress (CWIP), accumulated depreciation provision, and accumulated deferred taxes."[284]

161. During discovery, the Department issued information request No. 2113, which sought to quantify a passage of time adjustment by requesting that the Company provide: "the rate base, income statement and revenue requirement effect of updating depreciation expense and accumulated depreciation reserve to reflect the passage of time for 2015 (except for the 2015 Step projects already reflected in the 2015 Step)."[285]

162. The Company inadvertently responded to this request by summarizing the impact in 2015 of rolling the average depreciation reserve forward one year, while excluding both projects already considered in the 2015 Step and all other 2015 additions to plant-in-service and arrived at an amount of $17.53 million.[286] The Company did not include a rate of return on the annualized rate base effect of the capital projects placed into service in 2014 in this analysis, nor did it include annualization of depreciation expense for all non-Step plant placed into service in 2014.[287]

2. Department's Position

163. Based on the Company's response to information request No. 2113, the Department proposed adjustments to the 2015 revenue requirement to reflect: (1) 2015 capital retirements of transmission and distribution facilities; and (2) accumulated depreciation changes due to the passage of time from 2014 to 2015 for all projects not already incorporated in the Step.[288]

164. The Department stated that the basis for its recommendation was that it would be inequitable to allow the Company to add $68.865 million in plant additions

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[284] Ex. 95, Robinson Direct at 5.
[285] Ex. 430, Campbell Direct at Schedule 32.
[286] Ex. 430, Campbell Direct at Schedule 32; Ex. 94, Perkett Rebuttal at 5-6.
[287] Ex. 94, Perkett Rebuttal at 5-6.
[288] Ex. 429, Campbell Direct at 158.

for the 36 Step year projects and to increase related property taxes, without reflecting reduced depreciation expense and related accumulated depreciation for existing plant in rate base for the passage of time from 2014 to 2015 and without capturing 2015 plant retirements.[289]

165. The Department recommended a $535,552 reduction to the revenue requirements for the 2015 Step to account for forecasted 2015 transmission and distribution plant retirements.[290] The Department recommended a $17.53 million reduction in the revenue requirements for the 2015 Step to account for updates to the depreciation expense and accumulated depreciation reserve for all plant in rate base for 2015.[291]

166. In its initial brief, the Department altered its methodology for calculating a passage of time adjustment such that only changes to accumulated depreciation reserve need to be included. Specifically, "Ms. Campbell determined that it was not necessary to update depreciation [expense] for the passage of time for [the non-2015 Step] capital projects were in service by the end of 2014…."[292] This was because the Company's 2015 Step accounted for the revenue requirements of 81.3 percent of the Company's total increase in 2015 rate base.[293]

3. Company's Position

167. The Company argued that the Department's proposed adjustment is based on an incorrect calculation in response to the Department's information request no. 2113 as the Company's answer only provided the increase in depreciation reserve without providing the offsetting increase in depreciation expense in its response.[294] The Company stated that its error is not a reasonable basis for an adjustment.

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289 Ex. 429, Campbell Direct at 158.
290 Ex. 442, Lusti Surrebuttal at 39-40.
291 Ex. 442, Lusti Surrebuttal at 39-40.
292 Department Initial Brief at 233.
293 *See* Department Initial Brief at 233; Ex. 435, Campbell Surrebuttal at p. 119.
294 *See* Ex. 430, Campbell Direct at Schedule 32 (only providing roll forward of accumulated depreciation reserve).

168. The Company also contended that a passage of time adjustment is neither appropriate nor reasonable. The Company explained that passage of time adjustments may be appropriate in some limited circumstances, such as when additions to rate base outpace the growth of the utility's depreciation expense, but this is not the case in this proceeding. The Company provided evidence that the Company's depreciation expense in 2015 outpaces its additions to rate base and adjusting for the passage of time would increase the Company's 2015 Step request.[295]

169. The Company further stated that a passage of time adjustment would discourage utilities from proposing multi-year rate plans. This is because utilities will be incentivized to: (1) forgo the use of a multi-year rate plan in favor of a traditional rate case in which they can ask for their entire revenue deficiency without the risk of a passage of time adjustment; or (2) request their entire deficiency in every year of a multi-year rate plan, which may be inconsistent with the Commission's objectives expressed in its MYRP Order.[296]

170. The Company also argued that the Department's proposed passage of time adjustment is unbalanced and asymmetrical. The Department's proposal seeks to roll forward depreciation reserve and expense for the entirety of the Company's 2014 rate base but the Company's 2015 Step request is limited to only 36 capital projects.[297] For the passage of time adjustment to be symmetrical, the Company argued that it must include "the actual increase in plant from the same group of projects, which increases rate base… [and] the annualization of depreciation expense for these projects. Any analysis of whether or not a passage of time adjustment should

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[295] Ex. 94, Perkett Rebuttal at 4-7.

[296] *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multi Year Rate Plans under Minn. Stat. § 216B.16, subd. 19*, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTI YEAR RATE PLANS, Docket No. E,G-999/M-12-587 (June 17, 2013) ("MYRP Order").

[297] Ex. 429, Campbell Direct at 162 ("it is not fair to update for 36 new plant additions … and not recognize the net decrease in depreciation, due to the passage of time, for all other plant in rate base"); Ex. 100, Clark Rebuttal at 33-34; Ex. 94, Perkett Rebuttal at 3-7.

be made needs to include the full revenue requirement impacts of the plant that is being annualized."[298]

171. The Company also challenged the Department's calculation of the $17.5 million adjustment as inconsistent with the Department's proposal to carry forward both the depreciation reserve and expense on the entirety of the Company's 2014 rate base. Specifically, the $17.5 million downward adjustment reflects only the rolling forward of the depreciation reserve, and fails to consider the associated $18,478,528 increase in depreciation expense.[299] Netting these two items together would result in the correct passage of time upward adjustment of $949,609.[300]

4. Conclusion

172. The Department's proposed passage of time adjustment should not be adopted as it is inconsistent with the Company's adherence to the Commission's MYRP Order that limited the scope of the Step to specific capital projects. The Department's proposed passage of time adjustment is also contrary to the concept of symmetrical ratemaking. This is because the Department's proposed adjustment expands the scope of the 2015 Step to solely recognize depreciation for non-Step projects.

173. Moreover, when the "passage of time" adjustment is calculated symmetrically to include both accumulated depreciation reserve and depreciation expense, the adjustment would increase the Company's Step revenue requirement by $949,609, rather than decrease it by approximately $17.5 million as proposed by the Department.

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[298] Ex. 94, Perkett Rebuttal at 6.
[299] *See* Ex. 94, Perkett Rebuttal at Schedule 2, page 5 (calculating both the roll forward of depreciation reserve and expenses).
[300] Company Initial Brief at 52.

D. Qualified Pension – Discount Rate (2014) and Market Loss (2014) (Issues # 4 and 5)

1. Introduction and Overview of Pension Expense Calculations

174. Like other utilities, the Company offers its employees not only current cash compensation, but also retirement benefits, including a defined benefit qualified pension plan.[301] The pension benefit (also referred to as the "qualified pension") is part of the Company's overall compensation program.[302]

175. The Company has two pension plans: the pension for the Xcel Energy Service employees (the XES Plan), and the pension plan for NSPM employees (the NSPM Plan).[303]

176. The Company uses two different methods to determine the pension expense (i.e., the accrual for future pension liabilities). For the NSPM Plan, the Company uses the aggregate cost method (ACM), and for the XES Plan, the Company uses the Statement of Financial Accounting Method (FAS) 87 method.[304] Both are actuarially approved methods of calculating, and recovering over the course of an employee's career, the amount of money necessary to satisfy the Company's pension expense to that employee.[305] Both rely on the Company's experience from prior years to determine the current pension expense.[306]

a. ACM Calculation

177. The Company calculates pension expense under the ACM by comparing the market value of the NSPM Plan assets to the present value of future benefits (PVFB).[307] The difference between those amounts, if any, is the unfunded liability,

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301 Ex. 82, Moeller Direct at 11-12.
302 Ex. 82, Moeller Direct at 11.
303 Ex. 82, Moeller Direct at 15.
304 Ex. 82, Moeller Direct at 15-16.
305 Ex. 82, Moeller Direct at 16.
306 Ex. 82, Moeller Direct at 16.
307 Ex. 82, Moeller Direct at 32-33.

and that unfunded liability must be funded over the future working lives of current employees.[308]

178. "Asset gains" or "asset losses" arise when the actual returns on the NSPM Plan assets are greater or lesser than the expected returns.[309] "Liability gains" or "liability losses" occur when the other components of pension expense differ from expectations.[310]

179. Prior-period asset gains or losses are "phased in" to an amortization pool over a five-year period.[311] They are then amortized over the remaining service lives of the employees.[312] Thus, only a fraction of the prior-period asset gain or loss is incorporated into the qualified pension expense calculation in a given year. For example, although the remaining net unamortized asset losses from 2008 for the NSPM Plan total $95.5 million, only $6.2 million is being included in the test year qualified pension expense as a result not only of the phase-in and amortization, but also of the offsets from other prior-period gains.[313]

b. FAS 87 Calculation

180. The method for calculating qualified pension expense under FAS 87 differs somewhat from the ACM method, but the ultimate goal is the same – "to measure the value of the pension assets today, to compare those values to a future liability, and to inform us as to the unfunded liability that must be funded so that we can meet that future obligation."[314]

181. FAS 87 requires the utility to measure pension expense based on five individual components: service cost, interest cost, expected return on assets (EROA),

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308 Ex. 82, Moeller Direct at 33.
309 Ex. 82, Moeller Direct at 19-20.
310 Ex. 82, Moeller Direct at 20.
311 Ex. 82, Moeller Direct at 22.
312 Ex. 82, Moeller Direct at 26-27.
313 Ex. 82, Moeller Direct at 29-30 and Schedule 5.
314 Ex. 83, Schrubbe Rebuttal at 17; *see also* Ex. 82, Moeller Direct at 16.

prior service cost, and the net gain or loss from prior years.[315] Net asset gain or loss from prior years occurs when EROA in a prior year was different from the actual return in that year.[316]

182. The asset gains or losses are phased in on a five-year schedule, and then they are netted not only with any liability gains or losses from the previous year but also with unamortized gains and losses from prior years; if the resulting cumulative gains and losses are more than 10 percent of the projected benefit obligation (PBO) or of the assets' market value, then the excess amount of those gains and losses is amortized over the average expected remaining years of service of the Company's employees.[317] Thus, analogous to the calculation of asset values under the ACM calculation, the net gain or loss under the FAS 87 includes the netting of many pre-2008 gains, the 2008 Market Loss, and post-2008 gains and losses.[318] That net number, and the four other elements of pension expense identified above, are used to determine the test year qualified pension expense under FAS 87.[319]

c. Discount Rate

183. Under both the ACM method and the FAS 87 method, calculation of the qualified pension expense requires the use of a discount rate.[320] Under the ACM, the discount rate is a longer-term rate and is set to equal the rate of return.[321] FAS 87 uses a discount rate based on a bond-matching approach, which is recalculated each year to most accurately value the liability at a point in time using current period information.[322]

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315 Ex. 82, Moeller Direct at 36.
316 Ex. 82, Moeller Direct at 38; Ex. 83, Schrubbe Rebuttal at 21.
317 Ex. 82, Moeller Direct at 38-39.
318 Ex. 83, Schrubbe Rebuttal at 21.
319 Ex. 82, Moeller Direct, at 36, 41.
320 Ex. 82, Moeller Direct at 41, 75.
321 Ex. 82, Moeller Direct at 42.
322 Ex. 82, Moeller Direct at 42.

2. Summary of Recommendations

184. In the Company's 2013 rate case, the Commission required the Company to provide substantial information in its future rate case filings relating to its qualified pension plans.[323] In this case, the Company provided all of the requested information.[324]

185. The Company provided a very detailed explanation of how its qualified pension expense is calculated for ratemaking purposes.[325] In Direct Testimony, the Company proposed recovery of $19.9 million for qualified pension expense for the test year of 2014.[326]

186. In Rebuttal Testimony, the Company provided updated information on various factors that are part of the calculation of the qualified pension expense, and the Company's final requested recovery for qualified pension expense for the test year was $20.9 million.[327]

187. The Company's requested recovery for qualified pension expense includes recovery for the after-effects of the 2008 Market Loss, consistent with its historical practices of pension accounting.[328] The Company's requested recovery also assumes that the discount rate used for the FAS 87 calculation should be 4.74 percent, which is the updated rate as of December 31, 2013.[329]

188. The only intervenor to provide testimony on qualified pension expense was the Department. The Department and the Company agreed on several assumptions related to the calculation of pension and benefit expense.[330] The

[323] Ex. 82, Moeller Direct at 2-3.
[324] Ex. 82, Moeller Direct at 13-14, 20-21, 46-49, 55-64, 104-121, Schedules 2, 5; Ex. 78, Figoli Direct at 2, 70-73; Ex. 84, Wickes Direct at 2, 4-33.
[325] Ex. 82, Moeller Direct, *passim*.
[326] Ex. 82, Moeller Direct at 9, 12, 49, 74-78.
[327] Ex. 83, Schrubbe Rebuttal at 9, 60-61.
[328] Ex. 82, Moeller Direct at 44-64; Ex. 83, Schrubbe Rebuttal at 15-29.
[329] Ex. 83, Schrubbe Rebuttal at 39-47.
[330] Ex. 83, Schrubbe Rebuttal at 2-3. One of the issues on which the Department and Company agreed was the measurement date for the pension calculations (Issue # 18).

Department disagreed with the Company's qualified pension expense calculation as to two issues: (1) the Department recommended that the discount rate for the calculation of pension expense under the FAS 87 method be increased from 4.74 percent to 7.25 percent; and (2) the Department recommended that half of the 2008 Market Loss be eliminated from the calculation of qualified pension expense in the 2014 test year.[331]

3. FAS 87 Discount Rate

189. In Direct Testimony, the Company explained that when it calculated 2014 qualified pension expense, it originally used a discount rate of 4.03 percent in the FAS 87 methodology that is used with the XES Plan.[332]

190. The primary source for the discount rate is a bond-matching study that is performed as of December 31 of each year.[333] The study includes a matching bond for each of the individual projected payout durations within the plan based on projected actuarial experience.[334] The bonds used in the study must meet certain well-established criteria,[335] and the Company employs numerous tests to validate the reasonableness of the discount rate produced by the bond-matching study.[336]

191. The Company has consistently used this bond-matching study approach because it provides the most accurate discount rate available from the alternatives that meet the standards of FAS 87.[337]

192. In Rebuttal Testimony, the Company noted that the 4.03 percent figure was based on information from December 31, 2012, and thus was now outdated.[338] Accordingly, the Company updated its proposed discount rate for use in the XES

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331 Ex. 431, Campbell Direct at 134.
332 Ex. 82, Moeller Direct at 80.
333 Ex. 82, Moeller Direct at 82.
334 Ex. 82, Moeller Direct at 82.
335 Ex. 82, Moeller Direct at 82.
336 Ex. 82, Moeller Direct at 82-84.
337 Ex. 82, Moeller Direct at 83.
338 Ex. 83, Schrubbe Rebuttal at 8.

Plan pension expense calculation, based on the same methodology but based on information as of December 31, 2013, to 4.74 percent.[339] The Company argued that this rate is reasonable because it is consistent with the discount rate used by utilities and other large companies and because customers have benefitted from the lower interest rates reflected in that discount rate.[340]

193. The Department recommended setting the XES Plan discount rate at 7.25 percent, which is the EROA used in the XES Plan.[341] The Company opposed the Department's recommendations regarding the XES Plan discount rate, for a number of reasons.

194. One of the bases for the Department's argument that the EROA should be used as the discount rate for purposes of calculating FAS 87 pension expense was the Department's belief that use of the EROA was required by the federal Employee Retirement Income Security Act (ERISA); the Department relied on a 2004 document to support this proposition.[342] In response, the Company pointed out that in 2006, ERISA was amended to require the discount rate used for purposes of pension funding to be established using a corporate bond yield curve, not EROA.[343]

195. The Department asserted that in the Company's previous rate case, the Commission approved the method of using the same discount rate and EROA for the XES Plan.[344] The Company responded that the Commission's decision in the prior rate case was limited to the facts of that case.[345] Moreover, in the recent CenterPoint

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339 Ex. 83, Schrubbe Rebuttal at 39.
340 Company Initial Brief at 65-66.
341 Ex. 431, Campbell Direct at 110, 118.
342 Department Initial Brief at 99-100 *citing* "Fundamentals of Current Pension Funding and Accounting for Private Sector Pension Plans."
343 *See* 29 U.S.C. § 1083 (h)(2)(C).
344 Ex. 431, Campbell Direct at 117-18.
345 Ex. 83, Schrubbe Rebuttal at 42.

case, the Commission did not accept the Department's proposal (and the ALJ's recommendation) that the discount rate must match the EROA.[346]

196. The Department also believed that there is no reason to use a discount rate that is lower than the EROA, and that doing so artificially overstates pension expense for ratemaking purposes and is therefore unreasonable.[347] The Company responded that use of a discount rate derived from the bond-matching study, rather than a discount rate identical to the EROA, does not artificially overstate pension expense for ratemaking purposes. Rather, FAS 87 is an accounting standard that specifies standards upon which the discount rate should be based.[348] Use of the EROA as the basis for the discount rate would be inconsistent with FAS 87's requirements, and thus would be a departure from GAAP.[349] The Company urged that the Commission should adhere to GAAP in order to avoid creating a disparity between regulatory books and accounting books – "an artificial divorce between our actual costs and what we recover in rates."[350] The Department argued that rates need not be set according to accounting standards, but the Company noted that the Department provided no persuasive basis to vary from accounting standards in calculating the pension expense.

197. The EROA is an offset to the service cost and the interest cost components of the FAS 87 calculation.[351] The Company noted that its use of an EROA higher than the discount rate actually reduces pension expense: if the discount rate had been equal to the EROA since the inception of the XES Plan, customers would have paid more in pension expense through the years because the service cost

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346 Schrubbe Rebuttal at 42-43 (quoting *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, Docket No. GR-13-316 (June 9, 2014).
347 Ex. 431, Campbell Direct at 116.
348 Ex. 83, Schrubbe Rebuttal at 43.
349 Ex. 83, Schrubbe Rebuttal at 40, 43; Ex. 82, Moeller Direct at 86-87.
350 Tr. Vol. 2 at 22 (Schrubbe); Ex. 82, Moeller Direct at 89.
351 Ex. 82, Moeller Direct at 37.

and interest cost elements of the FAS 87 calculation would have been higher.[352] "[R]equiring the use of the EROA to set the discount rate would lead to an artificial liability gain."[353]

198. The Company noted that its customers are benefiting from a higher discount rate relative to other utilities' discount rates. Specifically, approximately 73% of the Company's pension cost is attributable to the NSPM Plan, and the Company uses the EROA as the discount rate for the calculation of pension expense for that plan.[354] In contrast, in the recent CenterPoint case, the Commission approved the use of a five-year average of discount rates to calculate CenterPoint's qualified pension expense, instead of using the EROA. That five-year average was 5.35 percent, although CenterPoint's EROA was 7.25 percent.[355] Thus, the Commission-approved discount rate was 190 basis points lower than the EROA for CenterPoint's entire qualified pension expense balance, whereas the difference between the Company's FAS 87 discount rate and the EROA affects only 27 percent of the Company's qualified pension balance.

199. The Company also stated that the discount rate used by the Company is not "artificially low," as the Department contended.[356] Instead, the discount rate used by the Company is consistent with the discount rates used by utilities and other large companies: a Towers Watson study showed that the average discount rate used for qualified pension expense at December 31, 2013 was 4.87 percent for 151 Towers Watson clients in the Fortune 1000, and the Citigroup benchmark on that date was 4.95 percent.[357]

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352 Ex. 82, Moeller Direct at 89.
353 Tr. Vol. 2 at 29 (Schrubbe).
354 Ex. 83, Schrubbe Rebuttal at 45.
355 Ex. 83, Schrubbe Rebuttal at 46.
356 Ex. 429, Campbell Direct at 116.
357 Ex. 83, Schrubbe Rebuttal at 44.

200. The Department further argued that the XES Plan discount rate used by the Company is not independently established.[358] The Company explained that contrary to the Department's assertion, the FAS 87 discount rate is based on independent information: objective bond-yield studies that are validated by reference to third-party benchmarks, such as the Citigroup Benchmark and the Citigroup Above Median Benchmark, and with further confirmation by review of general survey data provided by Towers Watson and the Edison Electric Institute.[359] Moreover, the Company's selection of pension plan assumptions is subject to significant oversight by outside entities and the Company's own auditor.[360]

201. The Department also asserted that the Company's discount rate of 4.74 percent is artificially low compared to the EROA of 7.25 percent because it relies on a point-in-time measurement.[361] Although the bond-matching study is made at a point in time, it reflects long-term yields for bonds over the entire expected payout range of the pension plan.[362] Accordingly, the Company stated that the discount rate derived from this methodology reflects the market's current best estimate of future bond yields.[363]

202. The Company's proposed calculation of the FAS 87 discount rate closely reflects market interest rates.[364] Rates commensurate with current levels have been in effect for more than half a decade.[365] The discount rate used in the Company's calculation of FAS 87 pension expense is based on actual bond rates, and customers are benefiting from those bond rates through reduced borrowing costs.[366] Most

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358 Ex. 431, Campbell Direct at 113.
359 Ex. 83, Schrubbe Rebuttal at 7.
360 Ex. 85, Wickes Rebuttal at 3-7; Ex. 83, Schrubbe Rebuttal at 8.
361 Ex. 431, Campbell Direct at 116.
362 Ex. 82, Moeller Direct at 86.
363 Ex. 82, Moeller Direct at 86.
364 Ex. 31, Tyson Rebuttal at 21.
365 Ex. 83, Schrubbe Rebuttal at 45; Ex. 31, Tyson Rebuttal at 22; Tr. Vol. 5 at 70 (Campbell) (admitting that 10-year treasury bill rates have not exceeded 7 percent since 2000).
366 Ex. 83, Schrubbe Rebuttal at 45.

recently in May 2014, NSPM issued $300 million of 30-year first mortgage bonds at a rate of 4.125 percent, and customers will benefit from that favorable cost of debt over the entire lives of the bonds.[367]

203. The Company argued that the Department's proposed 7.25 percent discount rate is not representative of current rates as it is higher than any ten-year treasury rate in the last decade.[368] The Company argued that it would be contrary to sound ratemaking principles to give customers the benefit of low bond rates where debt rates are concerned but to substitute a higher rate for purposes of calculating qualified pension expense.[369] As a result, it would be highly inconsistent for the Company's actual low costs of short-term debt and long-term debt to be used to determine its overall ROR and cost of service while the low interest rate environment that supports those low actual costs of short-term debt and long-term debt is not reflected in the Company's pension expense calculation.[370]

4. 2008 Market Loss

204. The Company provided an exhaustive description of how prior years' gains and losses are accounted for in the calculation of pension expense.[371] The Company recognized that the treatment of the 2008 Market Loss was disputed in the prior rate case, and provided detailed information relating to questions and issues from that case, to clarify its position and minimize confusion.[372] It further provided a thorough explanation of why the 2008 Market Loss should be included in the pension expense for this case.[373]

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367 Ex. 83, Schrubbe Rebuttal at 45; *see also* Ex. 82, Moeller Direct at 10.
368 Ex. 31, Tyson Rebuttal at 3, Schedule 1.
369 Ex. 83, Schrubbe Rebuttal at 45; Ex. 82, Moeller Direct at 11.
370 Ex. 31, Tyson Rebuttal at 22-23.
371 Ex. 82, Moeller Direct at 18-32.
372 Ex. 82, Moeller Direct at 44-49.
373 Ex. 82, Moeller Direct at 55-64.

a. The Company's Position

205. The Company outlined several reasons why qualified pension expense, including the effects of the 2008 Market Loss, should be included in rates.

206. First, the Company notes that both the Company and the Department agree that retirement benefits are a legitimate cost of service, and that the Company should be allowed to recover the reasonable costs attributable to those retirement benefits.[374]

207. Second, the Company pointed out that for decades the Company has been using a symmetrical method of including both gains and losses from prior years in its qualified pension expense.[375] For many years the Company had significant gains because of its pension plan investment strategy, and customers reaped the benefits through market gains that exceeded the EROA.[376] Because the customers received the benefits in the high-return years before 2008 (as well as after due to phase-in of losses), and because customers have received the benefit of high-return years since 2008, it is reasonable to include the effects of prior years' gain and loss experience in current pension expense.[377]

208. Third, the Company noted that the Company's consistent practice of symmetrically including both gains and losses has provided customers with very substantial benefits over time.[378] From 2000 to 2014, the cumulative benefit to customers has been approximately $332 million on a Minnesota jurisdictional basis.[379] From 2000 to 2011, the qualified pension expense was at or below zero because of asset gains or liability gains.[380] Thus, the Company stated that it would be neither equitable nor reasonable for the Company to pass along all gains to customers while

[374] Ex. 82, Moeller Direct at 56; Ex. 431, Campbell Direct at 99.
[375] Ex. 82, Moeller Direct at 56-57.
[376] Ex. 82, Moeller Direct at 57.
[377] Ex. 82, Moeller Direct at 57-58.
[378] Ex. 82, Moeller Direct at 56, 58-61.
[379] Ex. 82, Moeller Direct at 60.
[380] Ex. 82, Moeller Direct at 60.

absorbing all losses.[381] Even in 2009 and 2010, prior-period gains from years before 2008 offset the portions of the 2008 Market Loss that were being phased-in and amortized under the ACM and FAS 87 approaches.[382] Only in 2011 did the phased-in and amortized portions of the 2008 Market Loss grow large enough that they could not be completely offset by the prior period gains, but even then the pension expense was lower than it would have been without the offsets of prior-period gains.[383]

209. Fourth, the Company argued that shareholders and employees receive no benefit from gains on pension assets – federal law prohibits the withdrawal of money from a qualified pension trust fund except to pay earned benefits.[384] Rather, the gain benefits customers because it reduces the pension expense in the Company's revenue requirement.[385]

210. Finally, the Company stated that the Company's calculation of qualified pension expense is consistent with "normal ratemaking."[386] The Company argued that if the Commission disallowed recovery of the 2008 Market Loss as the Department has requested, that would create regulatory uncertainty and might require the Company to report a financial impairment (*i.e.*, a reduction in the net of the unrecognized gains and losses) that could have a dramatic effect on the Company's earnings.[387]

211. For these reasons, the Company asked the Commission to authorize recovery of an amount of pension expense that will incorporate the phased-in and amortized portions of the 2008 Market Loss, consistent with its historical practice.[388] $12.0 million of the Company's total 2014 test year qualified pension expense is

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381 Ex. 82, Moeller Direct at 61.
382 Ex. 82, Moeller Direct at 6.
383 Ex. 82, Moeller Direct at 61.
384 Ex. 82, Moeller Direct at 62.
385 Ex. 82, Moeller Direct at 62.
386 Ex. 83, Schrubbe Rebuttal at 24.
387 Ex. 82, Moeller Direct at 63.
388 Ex. 82, Moeller Direct at 62.

associated with the 2008 Market Loss ($8.5 million from the NSPM Plan and $3.5 million from the XES Plan).[389]

b. The Department's Position

212. The Department opposed the inclusion of the 2008 Market Loss component of the pension expense.[390] The Department stated that the 2008 Market Loss is $12.1 million, but the Company noted that this number does not include any of the asset gains or losses since 2008; when those are considered, the asset loss used in calculation of test year pension expense is $9.6 million.[391]

213. The Department's position concerning the Market Loss, as asserted in its Direct Testimony, was that it would be more "reasonable" for ratepayers to "pay for 50 percent" of the 2008 Market Loss.[392] The basis for the Department's recommendation was to make the Company's pension expense more "fair."[393]

214. The Department's assertions were based in part on the assumption that the Company compares the value of the pension plan assets to the future liabilities, takes the difference, and then adds the 2008 Market Loss to that difference and amortizes the sum of the two amounts.[394] The Company mathematically demonstrated that it did not make any such separate adjustment for the 2008 Market Loss.[395] The Department recognized this in Surrebuttal Testimony.[396]

215. The Department's position was also based on the belief that "the Company's accounting for FAS 87…leads Xcel to continue to propose an extra adjustment to current rates for the 2008 market loss."[397] In response, the Company countered that it only uses the FAS 87 approach for calculation of the pension

389 Ex. 82, Moeller Direct at 49, 53.
390 Ex. 431, Campbell Direct at 134-135.
391 Ex. 82, Moeller Direct, Schedule 5 at 1.
392 Ex. 431, Campbell Direct at 134-135.
393 Ex. 431, Campbell Direct at 135.
394 Ex. 431, Campbell Direct at 129.
395 Ex. 83, Schrubbe Rebuttal at 19-22; Ex. 85, Wickes Rebuttal at 9-11.
396 Ex. 437, Campbell Surrebuttal at 78, 92.
397 Ex. 431, Campbell Direct at 129.

expense for the XES Plan.[398] The Company uses the ACM approach for calculation of the pension expense for the NSPM Plan, which accounts for about 73% of the Company's pension expense.[399] And, as described above, there is no "extra adjustment."[400]

216. In surrebuttal, the Department presented several new arguments against inclusion of the 2008 Market Loss, and continued to recommend that only 50 percent of the 2008 Market Loss be included in the pension expense.[401]

217. The Department expressed concern about the Company's "generosity to its employees," and asserted that "requiring ratepayers to pay for all pension expenses is especially troubling in light of the additional 401K plan…."[402]

218. The Company countered that to retain important and skilled personnel, as well as to hire new employees, the Company must provide a competitive level of benefits.[403] The Company noted that its employee benefits programs are in line with its peers, and its benefits for new employees are lower than most of its peers.[404] To ensure that its retirement benefits strike a fair balance between the interests of employees and the Company's customers, the Company has made several design changes over the last decade that reduced the qualified pension benefit levels for new employees.[405] As a result of those changes, the retirement program that the Company offers to new hires ranks in the lowest quartile when compared to those of peer utility companies.[406] As required by the Commission in the previous rate case, the Company has explored freezing or amending prior pension benefits, but the Company has concluded that doing so would create risks, including the risk that skilled retirement-

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398 Ex. 83, Schrubbe Rebuttal at 23.
399 Ex. 83, Schrubbe Rebuttal at 23.
400 Ex. 83, Schrubbe Rebuttal at 23.
401 Ex. 436, Campbell Surrebuttal at 89-95.
402 Ex. 436, Campbell Surrebuttal at 91.
403 Ex. 78, Figoli Direct at 4-15.
404 Ex. 82, Moeller Direct at 56; Ex. 78, Figoli Direct at 67-70.
405 Ex. 82, Moeller Direct at 101; Ex. 78, Figoli Direct at 68-69.
406 Ex. 78, Figoli Direct at 24.

age employees would leave.[407] The five percent Cash Balance program, which is the defined benefit retirement program available to newly hired employees, provides only an 8 percent income replacement level, incommensurate with the Department's proposed 50 percent adjustment.[408]

219. The Department also expressed concern that the Company included over 60 percent of the 2008 Market Loss in the 2014 pension expense, suggesting that "the Company may not have reasonably managed its pension assets."[409]

220. The Company pointed out that the Company's pension trust portfolio is highly diversified with holdings in, among other things, U.S. and international public equities; private equity, real estate and commodities positions; and fixed income securities.[410] The Company stated that it holds a diversified portfolio because it needs to: (1) balance the opportunity for financial market growth, which can result in improving our pension funding status, with its obligations to maintain minimum funding requirements established by law; (2) pay monthly cash benefits to retirees; and (3) sustain its fiduciary duty to the beneficiaries, namely our union and non-union employees, of our pension trust.[411] Individual investors who do not have these obligations, or who do not have current cash flow funding requirements from their portfolios, may try to obtain better returns in a given year, but that usually means accepting greater financial market risk than the Company can accept.[412] Nevertheless, each asset class in the Company's pension trust performed consistent with market returns last year, including the Company's U.S. equities position, which earned 33.3

[407] Ex. 78, Figoli Direct at 70-72.
[408] Ex. 82, Moeller Direct at 70-71, 80.
[409] Ex. 436, Campbell Surrebuttal at 93.
[410] Ex. 116, Tyson Opening Statement at 2.
[411] Ex. 31, Tyson Rebuttal at 17; Ex. 116, Tyson Opening Statement at 3.
[412] Ex. 116, Tyson Opening Statement at 3.

percent.[413] This demonstrates that the Company's management of its pension trust is prudent and reasonable.[414]

221. The Department's assertions were also based in part on the assumption that "the turnaround time for full recovery is estimated to be just a few years in the future," suggesting that the Company's qualified pension expense will be zero in a few years.[415] The Company pointed out that contrary to the Department's assumptions, there will continue to be pension expense for the next few years, because the Company has contributed substantially more than it has recognized in pension expense since the 2008 market collapse.[416]

222. The essence of the Department's opposition to the inclusion of the entirety of the 2008 Market Loss in the Company's pension expense continued to be that the Department considered the Company's position to be "unreasonable."[417] The Company recognized that the magnitude of the 2008 Market Loss makes it seem as if the Company has changed its accounting and ratemaking practices, but explained that the opposite is true: the proposed $12.0 million for 2008 Market Loss in the Company's calculated pension expense is the result of consistently applying the ACM and FAS 87 pension accounting methods.[418]

> "Even though our pension expense did increase, this is not due to any changes in how we calculate our pension obligations nor manage our pension trust. Rather, we have used the same Commission-approved accounting methodologies to determine our pension expense each and every year, both before the 2008 market loss and after. The test year merely represents the current product of the same

[413] Ex. 116, Tyson Opening Statement at 2.
[414] Ex. 116, Tyson Opening Statement at 3.
[415] Ex. 431, Campbell Direct at 133.
[416] Ex. 83, Schrubbe Rebuttal at 26-27.
[417] Ex. 436, Campbell Surrebuttal at 94.
[418] Ex. 83, Schrubbe Rebuttal at 28.

> formula and is representative of what our actual expense will be in 2014."[419]

223. Accordingly, the Company has shown that its proposed inclusion of 2008 Market Loss in its pension expense is amply reasonable.

5. Alternative Proposals

224. To provide a mechanism that will "normalize" the Company's qualified pension expense, and therefore provide greater predictability and certainty, the Company proposed alternative approaches to determination of the pension expense.[420]

225. First, the Company noted that in its prior rate case, it had proposed to cap the XES Plan expense at the 2011 levels, and to extend the amortization period for prior-period gains and losses from 10 years to 20 years for the NSPM Plan.[421]

226. The Company offered two additional proposals to further moderate the rate offset of the 2008 Market Loss.[422]

227. The first proposal compares a five-year average, normalized qualified pension expense to the Company's actual qualified pension expense each year, with the difference being deferred each year until the normalized amount is revisited in 2017 or 2018, at which time the deferred amount will be amortized over a period of time approved by the Commission.[423]

228. The second proposal would also use the five-year average from 2014 through 2018, which is $18,246,925, but instead of deferring the difference between the Company's actual pension expense and the normalized expense, the Company would defer the difference between the normalized amount and the lesser of the actual qualified pension expense amount each year, or the currently forecasted

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[419] Ex. 126, Schrubbe Opening Statement at 1.
[420] Ex. 83, Schrubbe Rebuttal at 30.
[421] Ex. 83, Schrubbe Rebuttal at 31.
[422] Ex. 83, Schrubbe Rebuttal at 31.
[423] Ex. 83, Schrubbe Rebuttal at 31-34.

expenses for each year during this time period (i.e., 2014-2018).[424] In both alternatives, the Company would provide annual compliance filings.[425]

229. The Company explained that these alternative proposals result in a reduction that is equal to or greater than the reduction proposed by the Department with regard to the discount rate for the FAS 87 pension expense.[426] If the Commission is inclined to adopt some mechanism to moderate the qualified pension expense, the Company recommended that the Commission should adopt one of these alternative proposals instead of changing the discount rate for the XES Plan, which would create an artificial liability gain and depart from GAAP accounting.[427]

230. The Department opposed both of the Company's proposed mechanisms to moderate pension expense, but it found the second one to be "least objectionable."[428] The Department will support the Company's second alternative normalization proposal, with four additional modification recommendations.[429]

231. The Department first requests that the Company not be allowed to earn a return on any deferred amounts. The Department contends that the Company "already receives a return on the prepaid pension asset" and that allowing the Company to earn a return would provide "an inappropriate incentive to make poor investment choices for pension assets."[430]

232. The Company opposed this first modification noting that the prepaid pension asset consists of amounts in the pension trust fund that have not yet been recognized as expense.[431] The Company properly receives a return on those amounts because shareholders have essentially paid the pension expense before it is due, either

424 Ex. 83, Schrubbe Rebuttal at 34-38.
425 Ex. 83, Schrubbe Rebuttal at 32, 35.
426 Ex. 83, Schrubbe Rebuttal at 38-39.
427 Ex. 83, Schrubbe Rebuttal at 39.
428 Department Initial Brief at 115.
429 Ex. 435, Campbell Surrebuttal at 101-102; Ex. 450, Campbell Opening Statement at 7-8.
430 Department Initial Brief at 116 (quoting Ex. 435, Campbell Surrebuttal at 101).
431 Ex. 82, Moeller Direct at 122.

through contributions or asset returns that cannot be removed from the trust. In contrast, the deferred amount that would accrue under the Company's second mitigation mechanism consists of pension expense that *has* come due, but has not been paid by customers. Thus, it too is being funded by shareholders, and those shareholders should earn a return on that amount in addition to the return on the prepaid pension asset.

233. The Company also countered the Department's contention that the Company would have incentive to make poor investment decisions but pointing out that the Company's proposal allows recovery of the *lesser of* actual pension expense or currently forecasted amounts.[432] If the Company changed its allocation to drive up actual expense, it would still be capped at the forecasted amount. Thus, the Company has no incentive to make poor investment decisions.

234. The Department's second proposed modification is that the "overall normalization proposal from the last rate case should impact the new alternative normalization proposals," such that "the $1,054,357 deferral for 2013 XES cap that the Commission decided in Xcel's 2012 rate case should be allowed continued deferral."[433] The Company proposed that feature as part of its rebuttal testimony.[434]

235. The Department's third proposed modification is that the Company "be required to make a case for why the Company should be allowed to amortize any unfunded balances in the future."[435] The deferred amounts will consist of the Company's actual pension expense, which the Department admits is a legitimate cost of service. The Company opposed this modification because the deferral is for the benefit of customers, not the Company, there is no reason to require the Company to bear the burden of proving its right to recover the deferred amounts in future cases.

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432 Ex. 83, Schrubbe Rebuttal at 35.
433 Department Initial Brief at 116.
434 Ex. 83, Schrubbe Rebuttal at 37 ("[A]kin to our first proposal, we believe it would be reasonable to continue deferring the XES Plan cap amounts until the normalization period ends.").
435 Department Initial Brief at 116 (quoting Ex. 435, Campbell Surrebuttal at 101).

236. The Department's fourth proposed modification is that the Company be required to calculate the allowed pension expense in each year using a discount rate equal to the EROA.[436] The Company opposed this modification for the same reasons set forth above.

6. Recommendations for the Next Rate Case

237. The Department recommended that the Commission require the Company, in its next rate case, to address the reasonableness of the Company's target asset allocation for the pension fund, including ages of retirees and employees.

238. The Company accepted this recommendation.[437] The Company will also provide information addressing its investment strategies and target asset allocations since 2007.[438]

E. Retiree Medical Expenses (FAS 106) – Discount Rate and 2008 Market Loss (2014) (Issues #6 and #19)

239. The Company requested recovery of $4.10 million in test year O&M expenses, and $1.16 million in test year capital costs related to post-retirement medical expenses, under FAS 106 for certain employees who retired prior to 2000.[439] The post-retirement medical benefits provided under FAS 106 are paid to retired employees for health care costs such as medical, dental, vision, and life insurance.[440]

240. The Company accounts for its post-retirement medical benefits under FAS 106 as follows: "The components and calculations of FAS 106 are identical to FAS 87, with one exception. Unlike FAS 87, FAS 106 asset gains or losses are not phased in before they are amortized, but instead the total gain or loss amount is simply amortized over the average years to retirement for active employees. But

[436] Department Initial Brief at 116 (quoting Ex. 435, Campbell Surrebuttal at 101).
[437] Ex. 116, Tyson Opening Statement at 2.
[438] Ex. 116, Tyson Opening Statement at 2.
[439] Ex. 81, Moeller Direct at 115.
[440] Ex. 423, Byrne Direct at 37.

otherwise, the FAS 106 benefits are calculated based on assumptions regarding the discount rate, the [expected return on assets], and the salary or wage levels."[441]

241. The Company used four assumptions to calculate its FAS 106 test-year O&M expense: (1) an expected rate of return (EROA) of 7.25 percent for the bargaining employee plan, and an EROA of 6.25 percent for the non-bargaining employee plan; and (2) a measurement date of December 31, 2012; (3) inclusion of 2008 market losses; and (4) a discount rate of 4.08 percent.[442]

1. Expected Rates of Return

242. The Department agreed that the Company's two proposed EROAs of 7.25 and 6.25 percent were reasonable.[443]

2. FAS 106 – Measurement Date Update (2014)

243. The Company and the Department agreed to update the measurement date for FAS 106 to December 31, 2013.[444]

244. This results in a decrease of $666,522 (both O&M and capital) in the test year revenue requirements.[445]

3. 2008 Market Loss

245. The Department recommended that the Commission reduce FAS 106 expenses by $88,500 to reflect a disallowance of half the 2008 Market Loss.[446] The Department explained that its reason for this recommendation was to treat the 2008 market loss costs for FAS 106 consistent with the treatment of 2008 Market Loss for the qualified pension.[447]

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441 Ex. 423, Byrne Direct at 37-38 citing Ex. 81, Moeller Direct at 114.
442 Ex. 81, Moeller Direct at 115; Ex. 423, Byrne Direct at 41.
443 Ex. 423, Byrne Direct 39; Department Initial Brief at 56.
444 Ex. 83, Schrubbe Rebuttal at 8-11.
445 Ex. 90, Heuer Rebuttal at 22.
446 Ex. 423, Byrne Direct at 29.
447 Ex. 423, Byrne Direct at 41.

246. The Company did not agree with the Department's proposed disallowance for the 2008 market loss for FAS 106 for the same reasons it opposed the Department's disallowance for the 2008 Market Loss for qualified pension.[448]

247. The Company's proposed inclusion of the 2008 Market Loss in its FAS 106 is reasonable and consistent with the Company's practice of including both market gains and losses in its calculation of this expense.

4. Discount Rate

248. The Department recommended that the discount rate for FAS 106 should match the respective EROA percentages, consistent with the Department's recommendation for qualified pension expense.[449] The Department's recommendation proposed a discount rate of 7.25 percent for the bargaining employees' plan and a rate of 6.25 percent for the non-bargaining employees' plan, for a weighted average discount rate of 7.11 percent.[450]

249. The Department recommended that the FAS 106 discount rate be increased for the same reasons it recommended increasing the FAS 87 discount rate.[451]

250. The Company disagreed with the Department's recommendation related to the FAS 106 discount rate for the same reasons it opposed the Department's recommendation for the qualified pension discount rate.[452]

251. As the Department's proposal to increase the discount rate is inappropriate for the reasons set forth above related to the FAS 87 discount rate, the Commission should decline to adopt the Department's recommendation.

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[448] Ex. 83, Schrubbe Rebuttal at 29.
[449] Ex. 423, Byrne Direct at 42.
[450] Ex. 423, Byrne Direct at 42.
[451] *See* Tr. Vol. 5 at 13 (Byrne).
[452] Ex. 83, Schrubbe Rebuttal at 47.

F. Paid Leave / Total Labor (2014) (Issue #7)

252. In its initial filing, the Company requested recovery of $49.906 million in paid leave costs.

253. The Department initially proposed an adjustment to the Company's test year to address a claimed historic over recovery of paid leave costs.[453] In response, the Company explained its paid leave costs are a component of total labor costs, and even if all budgeted amounts for paid leave were not utilized by the Company's employees, the Company still incurred equivalent costs as part of its total labor expenditures.[454] Thus, on an overall basis, the Company's total labor costs were representative of its cost of service.

254. Upon this showing, the Department withdrew its proposed paid leave adjustment;[455] but, then proposed an overall adjustment to the Company's total labor costs of $5.6 million on a Minnesota jurisdictional basis. The Department's proposed total labor adjustment was based on a historical trending of the Company's 2012 actual labor costs and a statement that total labor increases must be capped at three percent per year.[456]

255. Specifically, the Department concluded that by looking at 2011 to 2012 actuals, the total labor cost increase was three percent and that 2013 was an unusual year for labor costs.[457] The Department stated that the Company's 2013 actual labor costs were abnormally high due to nuclear plant outages and the unusually high number of storms.[458] The Department then calculated 2014 total labor costs by increasing 2012 actuals by three percent to calculate a "normalized" 2013 total labor cost. The Department then increased this "normalized" 2013 total labor cost by three

[453] Ex. 429, Campbell Direct at 95-98.
[454] Ex. 87, Stitt Rebuttal at 3-9.
[455] Ex. 435 Campbell Surrebuttal at 74; Tr. Vol. 5 at 33 (Campbell).
[456] Ex. 435, Campbell Surrebuttal at 72-74.
[457] Ex. 435, Campbell Surrebuttal at 72-73.
[458] Ex. 435, Campbell Surrebuttal at 72.

percent to determine 2014 total labor costs. The Department utilized a three percent growth factor because Department witness Nancy Campbell stated that "an increase of 2 to 3 percent over the costs of a normal year is generally a reasonable increase for labor."[459] The Department's proposed adjustment reflects the difference between the Company's requested 2014 total labor costs and the Department's calculated 2014 total labor costs.[460]

256. The Company stated that the drivers of the Company's labor costs above the Department's proposed three percent cap are due to increases in total labor costs of the Company's Nuclear and Business Systems Business units.[461]

257. With respect to labor costs for the Nuclear Business area, Company witness Mr. O'Connor testified:

> These cost increases have been primarily driven by the cost increases for our internal labor for three following reasons: (1) was have added employees to meet regulatory and safety requirements, (2) we have increased compensation in order to attract and retain in-house expertise, and (3) we have increased our overall headcount in order to drive the performance excellence that will allow for long-term efficiency and sustainability.[462]

258. Mr. O'Connor's testimony provided a detailed explanation supporting the need for these increased labor costs for 2014.[463]

259. With respect to Business Systems labor costs, Company witness Mr. David C. Harkness identified the need for the increased labor spend within the Business Systems Business Area, identifying increases in headcount[464] and an increase

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459 Ex. 435, Campbell Surrebuttal at 72-73.
460 Ex. 435, Campbell Surrebuttal at 73-74.
461 Ex. 129, Stitt Opening Statement at 2; Tr. Vol. 2 at 38– 39 (Stitt).
462 Ex. 51, O'Connor Direct at 83.
463 Ex. 51, O'Connor Direct at 83-90.
464 Ex. 62, Harkness Direct at 76.

in contract labor for a variety of support needs.[465] Mr. Harkness also provided considerable support and justification for these increases.[466]

260. Company witness Ms. Amy L. Stitt concluded that "[w]hen taken together, our uncontested increases in Nuclear and Business Systems total labor costs account for virtually all of the Department's proposed total labor cost adjustment. Consequently, the Company has accounted for, and justified, its overall total labor costs and the Department's proposed adjustment should be rejected."[467]

261. The Company also disagreed with the Department's proposed adjustment because it will deny the Company recovery of its representative labor costs.[468]

262. The Company stated that, consistent with the test year concept, the Company has forecasted its cost of service for the 2014 test year and has proposed a total labor budget reflecting this cost of service.

263. The Company also pointed out that there is no discernible overall trend in the Company's total labor costs; rather, different activities in a particular year drive certain increases or decreases in labor costs.[469] The Company further stated that the Department's own analysis indicates that that the Company's total labor costs increased three percent from 2011 to 2012 and then increased approximately 12 percent from 2012 to 2013 and are expected to decrease approximately four percent from 2013 to 2014.[470] Therefore, the Company argued that the total labor costs in the

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465 Ex. 62, Harkness Direct at 78.
466 Ex. 62 Harkness Direct at 76.
467 Ex. 129, Stitt Opening Statement at 2.
468 Company Initial Brief at 71.
469 Ex. 87, Stitt Rebuttal at 6-7 (discussing the drivers of the different total labor costs for the different years presented).
470 Ex. 435, Campbell Surrebuttal at 72.

2014 test year should be judged on the merits of the forecasted cost of service during the test year, rather than historical comparisons suggested by the Department.[471]

264. As the Company has demonstrated that its total labor costs for the 2014 test year is representative and reasonable, the Department's proposed adjustment should not be adopted.

III. OTHER DISPUTED REVENUE REQUIREMENT ISSUES

A. Prairie Island Cancelled EPU Project (2014) (Issue #3)[472]

1. Background

265. The Prairie Island EPU project was proposed by the Company to meet growing energy needs forecasted over the course of several resource plans.[473] The Prairie Island EPU Project sought to increase the capacity of the Company's two Prairie Island nuclear generation units by 164 MW to meet this growing demand.[474] The Company sought Certificate of Need approval from the Commission for the EPU project and this approval was granted in December 2009.[475]

266. The Company undertook Prairie Island EPU Project activities based on this need and the projected benefits of the project.[476]

267. On March 30, 2012, the Company filed with the Commission a Notice of Changed Circumstances proposing to delay the implementation date and to reduce the capacity of the uprate to 135 MW.[477] The Notice of Changed Circumstances was

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[471] *See, e.g. Petition of Interstate Power Company, 416 N.W.2d 800, 810 (1987) (citing* Minn. Stat. § 216B.16, subd. 6 for the proposition that "only costs which are reasonable may receive rate base treatment") (affirming ALJ rejection of certain expenses as historic and outside of the test year).

[472] The issue of AFUDC related to the Prairie Island EPU Project is addressed Section III(B).

[473] Ex. 48, Alders Direct at 7-9; *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, INITIAL FILING, Docket No. E002/CN-08-509 (May 16, 2008).

[474] Ex. 49, McCall Direct at 10.

[475] Ex. 48, Alders Direct at 9.

[476] Ex. 49, McCall Direct at 40.

[477] Ex. 48, Alders Direct at 17-18.

based on changes to the federal licensing process, construction risk, the slower pace of projected economic growth, and decreasing natural gas prices.[478]

268. After receiving Commission approval for the uprate Certificate of Need in late 2009, the Company applied for approval from the NRC to begin using new fuel and fuel assemblies prior to uprate project work.[479] After receiving NRC approval and installing the new fuel, the Company assessed the likely future refueling schedule if the Prairie Island EPU Project was cancelled.[480] The Company determined that without the Prairie Island EPU Project, the installation of new fuel assemblies allowed the Company to extend periods between outages by six-month to twenty four-month cycles for each unit.[481] This eliminated two refueling outages for each unit over the remaining life of the plant, at an estimated customer savings of $75 million on a present value basis.[482] The Company's analysis indicated that the total benefits of the uprate declined to $10 million net present value of revenue requirement (PVRR) compared to the $50 million estimated in the Notice of Changed Circumstance.[483]

269. In response to the Notice of Changed Circumstance, the Department stated that preliminary results showed the Prairie Island EPU Project was cost-effective despite delays in timing and updated assumptions.[484]

270. The Company submitted a supplemental set of comments to the Commission on October 22, 2012.[485] The Company informed the Commission of its evolving analysis and its conclusion that the outstanding risks of delay and increased

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478 Ex. 48, Alders Direct at 18.
479 Ex. 48, Alders Direct at 19.
480 Ex. 48, Alders Direct at 20.
481 Ex. 48, Alders Direct at 20.
482 Ex. 48, Alders Direct at 20.
483 Ex. 48, Alders Direct at 20.
484 *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, DEPARTMENT INITIAL COMMENTS, Docket No. E002/CN-08-509 (May 30, 2012).
485 Ex. 48, Alders Direct at 20.

cost outweighed the small benefit calculation remaining, and rendering further investment in the Prairie Island EPU Project, beyond the investments incurred to date, imprudent.[486]

271. On November 7, 2012, the Commission issued an Order to Show Cause, asking interested persons to present arguments as to why the Commission should not terminate the Certificate of Need for the Prairie Island EPU Project.[487]

272. On December 20, 2012, the Commission voted to terminate the Certificate of Need for the Prairie Island EPU Project prospectively.[488] In its February 2013 Order, the Commission concluded that it was in the public interest to discontinue the Project and that no party had shown cause to continue the Project.[489]

273. In the 2013 rate case, there was discussion and testimony as to whether Prairie Island EPU Project cost recovery should have been sought in the course of that rate proceeding.[490] Ultimately, the Commission's 2013 Rate Case Order determined that the matter was not yet ripe for decision and required that "[i]n the initial filing in its next rate case, Xcel shall provide a complete justification for any rate recovery or deferral of its Prairie Island extended power uprate costs."[491]

274. The Company's initial filing in this proceeding included the required justification of rate recovery.[492]

275. In the initial filing in the current proceeding the Company sought recovery of $66.1 million for the Prairie Island EPU Project, which is the total amount of the expenditures to carry out the Prairie Island EPU Project, plus accrued

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486 Ex. 48, Alders Direct at 20.
487 *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY at 1, Docket No. E002/CN-08-509 (Feb. 27, 2013).
488 *Id.* at 4.
489 *Id.*
490 ALJ REPORT IN 2013 RATE CASE at 86-91.
491 2013 RATE CASE ORDER at Order Point 51.
492 Ex. 99, Clark Direct; Ex. 100, Clark Rebuttal; Ex. 49, McCall Direct; Ex. 48, Alders Direct; Ex. 45, Weatherby Direct; Ex. 47, Weatherby Rebuttal.

AFUDC of $12.8 million.[493] The Company proposed to amortize cost recovery over 12 years while earning a return on the asset, or six years if no return is permitted.[494]

276. Several Parties (the Department, MCC, ICI Group, and OAG) recommended that any recoverable costs should be amortized over a longer period – most commonly over the remaining life of the facility (approximately 20 years) with no return on the asset.[495] In Surrebuttal Testimony and at hearing, the Company and the Department each testified that recovery of Prairie Island EPU Project costs over the remaining life of the facility with a debt-only return of 2.42 percent would be acceptable.[496]

277. The OAG suggested that the Company should be precluded from recovering $10.1 million in Prairie Island EPU Project costs, any return on the costs, and any AFUDC because (i) the Company took a pretax charge of $10.1 million in late 2012 to reflect the uncertainty of earning a return on the asset; and (ii) the Company may have been able to avoid some level of Prairie Island EPU Project costs by cancelling earlier or providing the Commission with earlier updates about evolving circumstances.[497]

278. The ICI group suggested that the Company should not recover any portion of Project costs because the Prairie Island EPU was never "used and useful."[498]

2. Cost Recovery Standard

279. The Commission has addressed several cancelled and abandoned projects in recent years, and has established a clear standard for recovery of cancelled project costs. In particular, the Commission "has consistently treated the issue of

[493] Ex. 99, Clark Direct at 31.
[494] Ex. 99, Clark Direct at 31.
[495] Ex. 437, Lusti Direct at 12-18; Ex. 340, Schedin Direct at 10-11; Ex. 250, Glahn Direct at 10-12.
[496] Ex. 134, Clark Opening Statement at 1; Ex. 373, Lusti Surrebuttal at 17-24
[497] Ex. 370, Lindell Direct at 35-44.
[498] Ex. 250, Glahn Direct at 10-12.

abandoned plant costs as turning on the unique facts and circumstances surrounding each rate case and each plant."[499] The Commission has determined that the appropriate test for cost recovery is whether the costs were "prudently incurred in good-faith" not the "used and useful" test recommended by ICI:

> The Commission concludes that there is no public interest or regulatory benefit to be gained by disallowing costs prudently incurred in good-faith to meet future need. And there is much to be lost by potentially chilling a utility's diligence in developing resources and in promptly withdrawing from projects when experience shows that they will no longer serve ratepayers' best interests.[500]

280. The "prudently incurred in good faith" standard is the correct standard to apply to a cancelled project because if a "used and useful" test were applied, no project that was cancelled before it was placed in service could be eligible for cost recovery.[501]

281. The ICI Group's adjustment relies on the "used and useful" standard as opposed to the correct "prudently incurred in good faith" and therefore, the proposed adjustment should not be adopted.

3. Cost Recovery for Prairie Island EPU Project Costs

282. First, the OAG argued that cost recovery for the Prairie Island EPU Project costs is barred in this rate proceeding because the Company sought neither cost recovery nor deferred accounting in its previous rate case.[502]

283. The Company noted that this issue was addressed in the Company's previous rate case, and the Commission concluded that the Company should provide a complete justification of cost recovery or deferred accounting in the next rate case,

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[499] *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, FINDINGS OF FACT CONCLUSIONS AND ORDER, Docket No. E001/GR-10-276 (Aug. 12, 2011) (*hereinafter* E001/GR-10-276 ORDER).
[500] E001/GR-10-276 ORDER.
[501] Ex. 99, Clark Direct at 34.
[502] Ex. 370, Lindell Direct at 40.

i.e., the current proceeding.[503] The Company complied with the Commission's directive by providing the requisite justification in the direct and rebuttal testimony from four Company witnesses.[504]

284. Second, the OAG suggested the Company could have brought a Notice of Changed Circumstances earlier and thereby avoided certain Prairie Island EPU Project costs, but the OAG does not specify which costs could have been avoided.[505]

285. The Company argued that the record demonstrates that given the changing circumstances experienced throughout 2011-2012, the Company's actions were appropriate. At the time of the Company's March 2012 Notice of Changed Circumstances filing, the Company continued to identify PVRR benefits for the Prairie Island EPU Project,[506] and the Department and other parties independently concluded at that time that the Prairie Island EPU Project should proceed.[507] In addition, the Company had both effectively suspended the Prairie Island EPU Project by the end of 2011 and provided extensive changed circumstance information in its December 2011 update to its 2010 Resource Plan.[508] Given that it was not clear even a year later, in late 2012, that the Prairie Island EPU Project should be cancelled,[509] the timing of the Company's Notice of Changed Circumstances filing and Company's actions were prudent and suspension had virtually no impact on Prairie Island EPU Project costs.

503 ORDER IN 2013 RATE CASE at 54.
504 *See* Ex. 99, Clark Direct; Ex. 100, Clark Rebuttal; Ex. 48, Alders Direct; Ex. 49, McCall Direct; Ex. 45, Weatherby Direct, Ex. 47, Weatherby Rebuttal.
505 Ex. 370, Lindell Direct at 38.
506 Ex. 48, Alders Direct at 16, 18.
507 Ex. 48, Alders Direct at 19; *see also In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE – DIVISION OF ENERGY RESOURCES, Docket No. E002/CN-08-509 (June 12, 2012).
508 Ex. 48, Alders at 16.
509 Ex. 48, Alders at 20-21.

286. Third, the OAG argued that the Company could not have created a regulatory asset consistent with FERC rules and generally accepted accounting principles (GAAP) unless it had a specific Commission order permitting deferral.[510]

287. Regulated companies must close their books at the end of their fiscal year, and utilize regulatory assets to account for the likelihood a regulatory body will decide rate recovery of accumulated costs in a future period.[511] The creation of a regulatory asset does not govern future rate recovery decisions, but rather recognizes that rate recovery has yet not been resolved.[512]

288. Here, the Company accounted for the accumulated Prairie Island EPU Project costs at the end of 2012 in a manner consistent with GAAP and FERC accounting rules, after consultation with independent external auditors.[513] The Company reassessed the situation at the end of 2013 and again concluded rate recovery would be decided in a future year.[514] In each instance, the Company's external auditors did not take exception to either the Company's GAAP-basis or FERC-basis financial statements.[515]

289. Because establishing a regulatory asset for financial accounting purposes does not dictate the Commission's ability to decide rate recovery matters, the OAG's argument does not affect cost recovery for the Prairie Island EPU Project costs in this proceeding.

290. Finally, the OAG argued the Company should be required to permanently write off \$10.1 million of Prairie Island EPU Project costs because the Company recorded a regulatory asset at the end of 2012 (when the Company needed to close its books for financial accounting purposes) and took a \$10.1 million pretax

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510 Ex. 370, Lindell Direct at 41.
511 Tr. Vol. 1 at 181 (Weatherby).
512 Tr. Vol. 1 at 181 (Weatherby).
513 Tr. Vol. 1 at 181 (Weatherby).
514 Tr. Vol. 1 at 181 (Weatherby).
515 Tr. Vol. 1 at 181 (Weatherby); Ex. 47, Weatherby Rebuttal at 4.

charge to reflect uncertainty whether the Company would earn a return on the Prairie Island EPU asset.[516] Thus, the OAG suggests the Company cannot recover these dollars for ratemaking purposes because it already "wrote them off" for financial accounting purposes.

291. The Company explained that the $10.1 million pretax charge does not represent a "write off" of actual Prairie Island EPU Project costs; rather, under GAAP it accounted for cost recovery over at least 12 years without earning a return.[517] The $10.1 million pretax charge "reflects that we would essentially lose some of the value of our investment by delaying rate recovery into a future period without earning a carrying charge on the asset."[518]

292. The OAG's recommendation should not be accepted because a disallowance of a $10.1 million portion of total Prairie Island EPU Project costs plus no earn a return on the asset would mean that the Company would take a $10.1 million impairment charge in addition to the $10.1 million pretax charge.[519] This result is inconsistent with the Company's prudent project management and reasonable project costs.

4. Amortization of Cancelled Project Costs

293. In the initial filing, the Company proposed to amortize the costs of the Prairie Island EPU Project over 12 years with a return on the asset, or, in the alternative, to amortize the project costs (with AFUDC) over six years without earning a return on the asset.[520]

294. The Company stated that its proposals to recover Prairie Island EPU Project costs over 12 years with a return on the asset, or over 6 years with no return, are consistent with Commission precedent. The Company noted that amortization

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[516] Ex. 370, Lindell Direct at 41-44.
[517] Ex. 47, Weatherby Rebuttal at 6; Tr. Vol. 1 at 182 (Weatherby).
[518] Tr. Vol. 1 at 182 (Weatherby).
[519] Tr. Vol. 1 at 182 (Weatherby).
[520] Ex. 99, Clark Direct at 41.

over 12 years is a longer amortization schedule than the Commission approved in 2006 for costs associated with the Company's cancelled Private Fuel Storage project,[521] and longer than the amortization period for the costs of the cancelled portion of Otter Tail Power's Big Stone II project.[522]

295. In surrebuttal, the Department indicated that amortization of Prairie Island EPU Project costs over the life of the plant with a debt-only return would be acceptable if the Commission determines a debt-only return would be preferable, and that the appropriate debt return percentage would be 2.24 percent.[523]

296. During the evidentiary hearing, the Company accepted the Department's proposal in the interest of resolving this issue and for the further benefit of our customers.[524] The Company stated, however, that if the Department's proposal is not accepted, the Company believes that recovery of the full Prairie Island EPU Project costs over 12 years with a return on the asset would be appropriate.[525]

5. Conclusion

297. Amortizing Prairie Island EPU Project costs over the remaining life of the Plant with a 2.24 percent debt return appropriately balances stakeholder interests without discouraging utilities' willingness to propose cancellation of a project.

298. The OAG's and ICI's additional adjustments are not warranted in light of the applicable cost recovery standard, the reasonableness of the costs, and the Company's prudent management of the Prairie Island EPU Project.

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521 *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, Docket No. E-002/GR-05-1428 (Sept. 1, 2006).
522 *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 11, Docket No. E-017/GR-10-239 (Apr. 25, 2011).
523 Ex. 442, Lusti Surrebuttal at 6-7.
524 Tr. Vol. 2 at 112 (Clark).
525 Company Initial Brief at 78.

B. CWIP and AFUDC (Issue #63)

1. Background

299. CWIP and AFUDC are used to account for and recover the cost of capital during construction. CWIP represents the accumulation of costs for projects under construction that will be capitalized and then depreciated over time once the projects are put in service.[526] AFUDC represents funds that the utility uses to finance construction projects.[527]

300. In the Company's last rate case, the OAG raised certain issues related to the Company's accounting for CWIP and AFUDC – namely, that "the Company has not provided any justification for short term projects to be included in CWIP" and "the Company has not complied with the FERC accounting rules regarding the inclusion of CWIP in rate base and the calculation of AFUDC."[528] The Commercial Group similarly contested the Company's accounting for CWIP.[529] After reviewing the arguments of the Parties, the ALJ made the following findings:

> 626. The Company responded that its treatment of CWIP and AFUDC conform to the Commission's established policies. The Company also maintained that its treatment of these items is consistent with FERC's Uniform System of Accounts. The Company noted that CWIP and AFUDC are authorized by statute, commonly included in rates, and audited by FERC. The Company asserts that the methods it uses for CWIP and AFUDC are fair to both the Company and its customers.
>
> **ii. Conclusion**
>
> 627. The Company has shown that its proposed inclusion of CWIP and AFUDC is consistent with FERC accounting requirements and past Commission practice. None of the other parties have demonstrated that any change to the

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526 Ex. 370, Lindell Direct at 17.
527 Ex. 370, Lindell Direct at 17.
528 ALJ REPORT IN 2013 RATE CASE at 129.
529 ALJ REPORT IN 2013 RATE CASE at 129.

> Company's accounting for CWIP and AFUDC is necessary to meet applicable legal requirements. Including CWIP in the rate base and providing AFUDC in the manner proposed by the Company is an appropriate exercise of the Commission's discretion under Minn. Stat. § 216B.16, subds. 6 and 6a.[530]

301. Upon review of these recommendations, the Commission concluded that it would permit inclusion of CWIP and AFUDC in that case but would require "a more detailed explanation of the Company's CWIP and AFUDC practices in its next rate case."[531] The Commission therefore ordered that:

> 52. In the initial filing in its next rate case, Xcel shall provide evidence of FERC's accounting requirements for CWIP/AFUDC and demonstrate that it has met the FERC requirements. It shall also address whether a minimum dollar level should be set for projects in CWIP.[532]

302. In this proceeding, the Company offered detailed testimony through Company witness Ms. Lisa Perkett as well as AFUDC and FERC accounting expert Mr. James Guest, explaining (i) the Company's AFUDC and CWIP accounting practices, (ii) how the Company complies with FERC accounting requirements, Minnesota statutes, and Commission precedent regarding AFUDC and CWIP; (iii) why it is neither necessary nor appropriate to establish a minimum dollar level for projects for which CWIP is included in rate base.[533]

303. Ms. Perkett explained that the Company's inclusion of CWIP in rate base is subject to a revenue requirement offset of AFUDC incurred in the year, which effectively eliminates the cost of financing construction from the revenue requirement during the construction period.[534] The utility is then allowed to include AFUDC in

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[530] ALJ REPORT IN 2013 RATE CASE at 130.
[531] ORDER IN 2013 RATE CASE at 10.
[532] ORDER IN 2013 RATE CASE at 54.
[533] Ex. 92, Perkett Direct at 51-63; Ex. 91, Guest Direct *passim*.
[534] Ex. 92, Perkett Direct at 53.

the final cost of the asset at the end of construction.[535] As a result, these costs are deferred and amortized over the life of the asset after being placed in service.

2. OAG's and the Commercial Group's Position

304. The OAG contends that the Company's accounting for CWIP and AFUDC violates FERC requirements because FERC limits CWIP to 50 percent in rate base, allows either CWIP or AFUDC in rate base but not both, and disallows AFUDC during project interruptions.[536]

305. The OAG also argued that the purpose of AFUDC is to recognize the need for external funding, yet the Company accrues AFUDC on virtually all CWIP projects despite the fact that it has substantial internal funding available and all projects do not require external financing.[537]

306. The OAG recommended: (1) CWIP should not be included in rate base with an AFUDC offset to the income statement, but AFUDC should be deferred for recovery once the asset goes in service; (2) AFUDC should only be allowed on capital projects costing more than $25 million; (3) the AFUDC rate should not be set in accordance with FERC requirements (which recognize the cost of short-term debt first and then a weighted average of long-term debt and equity); rather, the AFUDC rate should be based on a simple average of the cost of short term debt and long term debt; and (4) AFUDC should be disallowed for the Prairie Island EPU Project for 2011 and 2012.[538]

307. The Commercial Group also recommended excluding CWIP from rate base, arguing the inclusion of CWIP charges ratepayers for assets during construction

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[535] Ex. 92, Perkett Direct at 54.
[536] Ex. 370, Lindell Direct at 16-29.
[537] Ex. 370, Lindell Direct at 23-24.
[538] Ex. 320, Lindell Surrebuttal at 22. In Direct Testimony, Mr. Lindell argued that AFUDC should not be permitted at all for the Prairie Island EPU, for the Monticello LCM/EPU project during the period the EPU portion was not in service, or for Sherco 3 during the period of its extended outage. It appears that Mr. Lindell modified that position in his Rebuttal Testimony, which only discusses a more limited disallowance of AFUDC during 2011 and 2012 for the Prairie Island EPU Project.

that are not yet used and useful.[539] The Commercial Group noted that CWIP shifts to ratepayers risks that are traditionally assumed by utility investors, and if a project is delayed or not completed, ratepayers have no resource for recovering what they have paid in rates for CWIP.[540] The Commercial Group did not address the reduction in net income resulting from the AFUDC offset but it is assumed that the Commercial Group is proposing the elimination of both CWIP and the AFUDC offset.[541]

3. Company's Position

a. Company's CWIP/AFUDC Accounting Complies with FERC

308. In detailed Direct Testimony, the Company explained its treatment of AFUDC and CWIP as consistent with FERC accounting standards. The fundamental process is consistent with Minnesota statutes and the FERC Uniform System of Accounts, and involves inclusion of CWIP in rate base subject to an offset by AFUDC.[542] The purpose of combining the AFUDC offset with the accumulation and capitalization of AFUDC is to avoid the cost of a current return on CWIP that would occur if CWIP was included in rate base without the AFUDC offset, and at the same time include these financing costs in the total cost of the project.[543] The Company explained that offsetting AFUDC combined with capitalization of these costs is not only consistent with FERC and long-standing state methodology, but also serves to defer and amortize these costs over the life of the asset through the recording of book depreciation expense after the asset is placed in service.[544]

309. FERC mandates the appropriate accounting in the Uniform System of Accounts (USofA), which the Commission adopted in Rule 7825.0300 as the basis for the financial data that is the foundation for rate making. The Minnesota treatment of

539 Ex. 225, Chriss Direct at 10-11.
540 Ex. 225, Chriss Direct at 10-11.
541 Ex. 225, Chriss Direct at 10-11; Ex. 94, Perkett Rebuttal at 14-38.
542 Ex. 92, Perkett Direct at 54-55.
543 Ex. 92, Perkett Direct at 56.
544 Ex. 92, Perkett Direct at 56.

AFUDC in ratemaking is in line with the USofA.[545] Moreover, while FERC typically does not allow CWIP in rate base, it also does not use an AFUDC offset and allows a higher rate of return over the life of the asset.[546]

310. The difference between the FERC method and the Company's longstanding treatment of AFUDC and CWIP is, in general, solely related to timing of the recovery.[547] The Company noted, however, that utilizing the longstanding Minnesota method in this proceeding in a manner consistent with FERC's AFUDC rate would increase the revenue requirement in 2014 by $8.5 million, and would increase the revenue requirement in 2015 by $12.4 million.[548] Based on this fact, the Company concluded that Minnesota method not only encompasses a balanced approach of applying the Company's full cost of capital to all investments while allowing full recovery of financing costs consistent with the FERC method, it also reduces the revenue requirement in this proceeding as compared to the FERC method.[549]

b. Proposed Minimum for Projects in CWIP

311. The OAG recommended that only projects in excess of $25 million should accrue AFUDC because "smaller projects would be financed with cash from operations and would not require external financing."[550]

312. In Direct Testimony, the Company explained that:

> The standard in Minnesota has been to include all investment in CWIP in rate base but to exclude less costly, short duration projects from the AFUDC offset and, consequently, from accumulating and capitalizing AFUDC. This practice provides a balanced approach that properly includes all investment in rate base while eliminating the

[545] Ex. 94, Perkett Rebuttal at 19.
[546] Ex. 94, Perkett Rebuttal at 17-18, 25.
[547] Ex. 94, Perkett Rebuttal at 25.
[548] Ex. 94, Perkett Rebuttal at 25.
[549] Company Initial Brief at 86.
[550] Ex. 320, Lindell Direct at 28; Ex. 323, Lindell Surrebuttal at 2.

> additional cost of accumulated AFUDC for projects that should be considered in service almost immediately.[551]

313. The Company also countered that the OAG's recommendation ignores that the Company first uses short-term debt to finance construction and then uses a mix of long-term debt and equity to provide capital.[552] It also ignores that retail rates are set such that revenues equal costs, including depreciation and a return on equity, and retail revenues cannot be used as a replacement for capital.[553]

314. The Company further stated that the effect of the OAG's recommendation would be to exclude 62 percent of CWIP investment, or approximately $441 million in capital costs during construction.[554] This exclusion would occur notwithstanding FERC's past findings that "carrying costs on the investment are as much a legitimate expense of the project as are the more tangible costs such as parts and materials."[555] Because the Company is entitled to recover its costs of capital in rates and maintain a fair opportunity to earn a reasonable return, the OAG's threshold proposal is inappropriate.

c. OAG's Method to Calculate AFUDC Rate

315. The OAG recommends that equity not be used in the calculation of the AFUDC rate.[556] Rather, the OAG suggests that a blended short-term debt and long-term debt rate, weighted at 50 percent each, which produces a rate of 2.62 percent, should be used.[557]

316. The Company opposed the OAG's AFUDC rate because it would depart from long-standing Commission precedent, it would be inconsistent with

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[551] Ex. 92, Perkett Direct at 64.
[552] Ex. 94, Perkett Rebuttal at 30.
[553] Ex. 94, Perkett Rebuttal at 31.
[554] Ex. 92, Perkett Direct at 29.
[555] In *Northern States Power Co.*, 17 FERC ¶ 61,196, at 61,382-83 (1981) (Opinion No. 134).
[556] Ex. 370, Lindell Direct at 28.
[557] Ex. 370, Lindell Direct at 28.

FERC policy and practice, and would also substantially lower the Company's AFUDC rate of 6.792 percent.[558]

317. The Company supported its methodology for calculating AFUDC by noting that the Company's methodology to calculate AFUDC is the same as used in every rate case since 1977 and that the Company's calculation of the AFUDC rate has always been calculated "in conformance with FERC Order 561 issued February 2, 1977."[559]

d. AFUDC for Prairie Island EPU Project

318. In response to the OAG's claim that the Company should not have accumulated AFUDC for the Prairie Island EPU Project for 2011 or 2012, the Company argues that the OAG misconstrues both FERC accounting rules and the timing of the cancellation.[560]

319. The Company noted that relevant precedent establishes that AFUDC accrual is appropriate through project cancellation, even where there is a period of interruption.[561]

320. The Company also explained that the OAG's recommendation assumes that the Prairie Island EPU Project was cancelled in 2011 when that was not the case. The Company clarified that activities furthering the Prairie Island EPU Project continued in 2011 and 2012 for two primary reasons: (1) The Prairie Island EPU Project remained viable, and in fact there was no time at which it was clear it should be cancelled;[562] and (2) It was more prudent to continue the third-party contract and receive the final deliverables – especially if the Prairie Island EPU Project continued

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558 Ex. 92, Perkett Direct at 57.
559 Ex. 92, Perkett Direct at 57 (citing E002/GR-81-342, FINDINGS OF FACT CONCLUSIONS OF LAW AND ORDER, dated June 25, 1982, at 25; 75 P.U.R. 4th 538 at p. 15, ORDER dated June 2, 1986; Tr. Vol. 2 at 191 (Perkett)).
560 Company Initial Brief at 94.
561 Ex. 94, Perkett Rebuttal at 34; *See* Company Initial Brief at 94-95.
562 Ex. 48, Alders Direct at 18, 20-21; Ex. 100. Even in October 2012, when the Company filed its Supplemental filing in the Prairie Island EPU changed circumstances proceeding, the PVRR benefits of the Program remained marginally positive. Ex. 48, Alders Direct at 20-21.

as expected – than to cancel the contract, pay a termination fee, and receive no deliverables.[563] Finally, the Prairie Island EPU Project was not formally cancelled until February 2013, when the Commission its Order Terminating the Certificate of Need Prospectively.[564] By that time, the Company had already terminated AFUDC accrual consistent with the Commission's vote on the matter in December 2012.[565]

4. Conclusion

321. The record does not support the recommendations of the OAG or the Commercial Group related to CWIP and AFUDC.

322. The Company accounts for CWIP and AFUDC appropriately, consistent with FERC accounting requirements, Minnesota statutes, and longstanding Commission-approved practice. The Company's inclusion of CWIP in rate base with an AFUDC offset is balanced and appropriate for all stakeholders, while ensuring the Company recovers its full financing costs. The Company's AFUDC rate is likewise consistent with FERC rules and is reasonable, and the Company's AFUDC accounting for the Prairie Island EPU Project is consistent with both FERC requirements and the circumstances surrounding the cancellation.

C. MYRP: Rate Moderation Proposal – TDG Theoretical Depreciation Reserve Surplus (2014 and 2015 Step)[566] (Issue #9)

323. In the Company's last rate case, the Commission required amortization over eight years of the difference between the Company's recorded book depreciation reserve compared to a theoretical book reserve for the Company's transmission, distribution, and general (TDG) assets.[567] As a result, the Company began amortizing the reserve surplus of approximately $261 million over eight years beginning in

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[563] Ex. 49, McCall Direct at 33-34, 38.

[564] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY, Docket No. E002/CN-08-509 (Feb. 27, 2013) (emphasis added).

[565] Ex. 45, Weatherby Direct at 5.

[566] The rate moderation proposal regarding DOE Settlement Funds is discussed under issue # 34 and Nuclear Theoretical Depreciation Reserve is discussed under issue # 75.

[567] Ex. 99, Clark Direct at 27.

2013.[568] At the beginning of 2014 there is $228.5 million remaining to be amortized over the next seven years.[569]

324. To moderate the impact of rate increases on its customers as part of its MYRP, the Company proposed to accelerate return of the depreciation reserve surplus to customers over the next three years: 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016.[570] The Company stated that this amortization pattern is intended to result in stable and predictable rate increases for its customers.[571]

325. The Department proposed an alternative 50 percent, 40 percent, and 10 percent amortization schedule to accelerate the benefits to the years at issue in this case.[572] The Department, however, acknowledged that the Company's initial 50 percent, 30 percent, and 20 percent proposal would also be reasonable.[573]

326. The Company also provided as an illustrative example a 50-0-50 percent schedule.[574]

327. The OAG recommended that the Commission deny the Company's proposed change in the amortization of the depreciation reserve surplus. The OAG stated that the Company's proposal does not reduce customers' rates but simply shifts costs recovery to the future.[575] The OAG also opposed the Company's proposal because it argued that it was inconsistent with the Company's position in prior rate cases.[576]

328. The Company disagreed with the OAG's recommendation stating that: (1) rate moderation tools can be utilized to provide more predictable year-over-year rates, enhance regulatory efficiency, and reduce the impacts of our current investment

568 Ex. 99, Clark Direct at 27.
569 Ex. 99, Clark Direct at 27.
570 Ex. 99, Clark Direct at 28.
571 Ex. 25, Sparby Direct at 28.
572 Ex. 431, Campbell Direct at 94.
573 Ex. 431, Campbell Direct at 94.
574 Company Initial Brief at 98.
575 Ex. 370, Lindell Direct at 13.
576 Ex. 370, Lindell Direct at 13-16.

cycle on our customers and (2) that the Company has supported accelerated amortization options in prior rate cases.[577]

329. The Commission has the discretion to direct the use of the rate moderation tools in the manner it deems most appropriate, once final rates are determined. These rate moderation tools include ordering a specific theoretical reserve consumption pattern that it determines best moderates rates once the outcome of the key disputed revenue requirement issues are resolved. The Commission may also conclude there is no need to refund the 2015 DOE settlement credits to customers after resolving the disputed revenue requirement issues. The Commission could also consider other solutions such as moving rate recovery of the Border and Pleasant Valley wind projects from the 2015 Step to the RES rider.

D. Nuclear Theoretical Depreciation Reserve (2014) (Issue #75)

1. Background

330. The depreciation a utility accrues over the course of an asset's life is to cover the cost of the asset plus retirement costs. Depreciation is based on the expected useful life of an asset and the estimated net salvage value.

331. Depreciation is defined in the Commission's rules as "the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance."[578]

332. "Depreciation accounting" is a "system of accounting which aims to distribute cost or other basic value of tangible capital assets, less salvage, if any, over the estimated useful life of the unit, which may be a group of assets, in a systematic and rational manner. It is a process of allocation, not valuation."[579]

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[577] Ex. 100, Clark Rebuttal at 39-40.
[578] Minn. R. 7825.0500, subp. 6.
[579] Minn. R. 7825.0500, subp. 7.

333. At any point in time, the current expected useful life and estimated net salvage can be used to estimate where the reserve would be assuming this current information was used to calculate depreciation throughout time. The resulting calculated reserve is the "theoretical reserve."[580]

334. When a utility's actual reserve is greater than the theoretical reserve, this difference is referred to as a surplus. A surplus does not immediately mean that the utility recovered more depreciation from customers than was necessary or prudent at the time because the actual reserve is based on the estimated useful life and net salvage at the time it was accrued rather than the current estimated useful life and net salvage. Nor does a surplus indicate that excess funds may exist as it would be rare for actual depreciation to match the theoretical reserve. As a result it is not always clear when or to what extent a surplus depreciation reserve is "real."

335. In the Company's prior rate case, XLI and the MCC (i) argued that the Company had a surplus of $265 million for Transmission, Distribution, and General plant (TDG) and $219 million for nuclear production plant; and (ii) proposed that the Company amortize these funds over a five-year period.

336. The ALJ and Commission concurred that a TDG surplus reserve did exist, noting that (as in the current rate proceeding) "[r]egarding Xcel's transmission, distribution, and general plant, no party disputes that Xcel has accrued a depreciation surplus or that the surplus should be amortized."[581]

337. The Commission, however, rejected XLI's proposal with respect to nuclear generating plants.[582] The Commission observed "the preponderance of the evidence indicates that these reserves appropriately reflect the cost of production

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[580] ORDER IN 2013 RATE CASE at 26.
[581] ORDER IN 2013 RATE CASE at 28.
[582] ORDER IN 2013 RATE CASE at 29.

plant retirements, including interim retirements, as explained by Xcel and the Department."[583]

338. In addition, the Commission concurred with the ALJ that it was "prudent to avoid accelerating the depletion of the production plant depreciation reserves when Xcel has just made large investments in its nuclear generators, increasing the amount of production plant it has to depreciate."[584]

339. Finally, the Commission noted that the nuclear production plant decision was not intended to preclude "continued monitoring and analysis," and directed the parties to explore the matter more fully in this case.[585]

340. In this proceeding, the Company calculated a nuclear depreciation reserve of $72.5 million (Minnesota jurisdiction) but noted that the existence and amount of the calculation depends of several current assumptions including remaining life, interim retirements and removal, and net salvage.[586]

2. XLI's Position

341. XLI claims that the Company miscalculated the nuclear theoretical depreciation reserve such that the figure is not $72.5 million (Minnesota jurisdiction) but is instead $208 million (Minnesota jurisdiction).[587] XLI's calculation of theoretical reserve excludes interim capital additions and uses vintage accounting.[588]

342. XLI's proposed to reduce the Company's revenue requirement by accelerating amortization of its calculated theoretical nuclear depreciation reserve surplus of $208 million to a five-year term.[589]

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583 ORDER IN 2013 RATE CASE at 29.
584 ORDER IN 2013 RATE CASE at 27, 29.
585 ORDER IN 2013 RATE CASE at 29.
586 Tr. Vol. 2 at 66-68 (Perkett); Perkett Direct at 50-51.
587 Ex. 264, Pollack Opening Statement at 1.
588 Ex. 264, Pollack Opening Statement at 1.
589 Ex. 260, Pollack Direct at 9-19.

343. The Company and the Department both disagree with XLI's proposal based on XLI's assumptions about the existence of a surplus, its calculation methods, and XLI's recommendation to implement a five-year amortization period.

3. Department's Position

344. The Department opposed expansion of the use of amortization of theoretical depreciation reserve surplus beyond the Commission's action in the Company's prior rate case, which excluded nuclear plant depreciation reserve.[590] Specifically, Department witness Ms. Nancy Campbell testified that "this short-term rate reduction would be short sighted and would result in higher rates for ratepayers in the long run."[591] The Department urged the Commission to calculate the useful life of nuclear facilities based on: (1) the annual and five-year depreciation studies and (2) the integrated resource plan and not to recalculate the remaining life in this case based on theoretical information.[592]

345. The Department also contended that the XLI's claim of overpayment is incomplete and incorrect because it does not consider what is occurring during the current rate case in the 2014 test year and the 2015 Step year and what is expected over the remaining lives of the nuclear assets. The Department stated that is it not reasonable to conclude that there is a surplus in nuclear depreciation reserve, particularly in light of the Company's request for recovery of costs related to the cancelled Prairie Island EPU and the Monticello LCM/EPU Program.[593]

4. Company's Position

346. The Company disagreed with XLI's assumptions used to calculate the alleged surplus. The Company contended that XLI's use of vintages to determine depreciation expense for nuclear facilities is inappropriate. Company witness, Ms.

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[590] Ex. 434, Campbell Rebuttal at 2-4.
[591] Ex. 434, Campbell Rebuttal at 2.
[592] Ex. 434, Campbell Rebuttal at 2-4.
[593] Ex. 434, Campbell Rebuttal at 3.

Perkett explained that the vintage method works well where there are a large number of essentially identical assets such that a reliable average life can be determined for each vintage of asset type.[594] The vintage method also works well for assets that are being replaced at the end of their life with a like kind of asset with similar life expectations.[595]

347. In contrast, the remaining life for assets in nuclear facilities is determined more by the license life for the unit in which the asset is used than the standalone life of the asset.[596] As Ms. Perkett explained that "a pump with an individual life expectation of 40 years would not have this same expectation if it is installed 15 years before the nuclear unit's license expires. In that example, the pump would have a 15-year life expectation."[597] Consequently, it is more accurate to base nuclear reserve calculations on reasonable assumptions about remaining operating license lives, where possible, than to use the vintage method to develop a surplus calculation and propose accelerated amortization based on asset life regardless of licensing life.[598]

348. Company also stated that it would not be prudent to accelerate amortization of the nuclear costs when the Company has recently "made large investments in its nuclear generators, increasing the amount of production plant it has to depreciate."

349. The Company acknowledged that there is another way to reduce the current amount of depreciation without harming future customers.[599] The Company explained that the method, which would require approval to deviate from the Generally Accepted Accounting Principles (GAAP), would employ regulatory

594 Ex. 94, Perkett Rebuttal at 8-9.
595 Ex. 94, Perkett Rebuttal at 9.
596 Ex. 94, Perkett Rebuttal at 9.
597 Ex. 94, Perkett Rebuttal at 9.
598 Ex. 94, Perkett Rebuttal at 9.
599 Ex. 94, Perkett Rebuttal at 13-14.

accounting to depreciate nuclear units over a remaining life longer than the license life.[600] No other party expressed interest in this proposal.

5. Conclusion

350. The Company has established by a preponderance of the evidence that there is no surplus depreciation reserve for nuclear assets because the existing reserve is needed to account for interim plant retirements and interim salvage of nuclear assets. Moreover, the Company will be making significant investments in its nuclear assets in the near future and these expenses will require additional depreciation expense. As a result, the Commission should decline to accept XLI's proposal to amortize the claimed nuclear depreciation reserve over five years.

E. Changes to In-Service Dates for Capital Projects (2014 and 2015 Step)(Issue #11)

1. Department's Position

351. In Direct Testimony, the Department proposed a downward adjustment to the Company's revenue requirement to reflect capital projects with updated in-service dates that moved outside the test year, or Step year, as applicable.

352. These projects included $67.3 million in capital additions that moved outside the 2014 test year, and disallowance of those projects would result in a $2.18 million reduction to the 2014 revenue requirement.[601]In addition, in-service date changes for seven of the 2014 projects also impact the 2015 Step, and two additional projects have a revised in-service date outside the 2015 Step year.[602]These projects total an additional $3.8 million in capital additions, and disallowance would result in a $2.05 million revenue requirement reduction for 2015.[603]

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600 Ex. 94, Perkett Rebuttal at 13-14.
601 Ex. 429, Campbell Direct at 153 and Schedule 28 at 3.
602 Ex. 429, Campbell Direct at 153 and Schedule 28 at 3.
603 Ex. 429, Campbell Direct at 153 and Schedule 28 at 3.

2. Company's Position

353. The Company objected to the Department's proposed reductions stating that it is inconsistent with the representative test year concept.

354. The Company cited that the Commission has previously accepted such changes to in-service dates as part of the test year concept:

> [T]he Commission has noted that isolated changes in test year data can skew the rate case process for or against the Company, for or against ratepayers. '…the test year method by which rates are set rests on the assumption that changes in the Company's financial status during the test year will be roughly symmetrical – some favoring the Company, others not. Not adjusting for either type of change maintains this symmetry and maintains the integrity of the test year process. Anomalies are likely to exist in and beyond any test year.'[604]

355. Company witness Mr. Christopher B. Clark testified that the shift of specific capital projects out of the 2014 test year and the 2015 Step does not reflect a significant percentage of capital projects or capital expenditures, and the capital expenditures that have been shifted out of the 2014 test year and 2015 Step have been offset by other capital projects that are being shifted into the 2014 test year and 2015 Step.[605]

356. The Company stated that changes to in-service dates are part of the dynamic nature of the utility business which can be unpredictable due to condition of equipment, severe weather events, changes to business or customer priorities, or emerging regulatory requirements and that any one of these types of changes can

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604 *In the Matter of the Complaint by Myer Shark et al Regarding Xcel Energy's Income Taxes,* ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 4, Docket No. E,G002/C-03-1871 (Oct. 1, 2004) (quoting *In the Matter of the Petition of Minnesota Power & Light Company, d/b/a Minnesota Power, for Authority to Changes its Schedule of Rates for Retail Electric Service in the State of Minnesota,* ORDER AFTER RECONSIDERATION AND REHEARING, Docket No. E-015/GR-87-223 (May 16, 1988)).
605 Ex. 100, Clark Rebuttal at 16-18.

impact the timing of capital project completion (either through delay or acceleration).[606]

357. The Company also provided detailed support illustrating when planned project in-service dates change, the Company allocates the capital budget to fund like-kind replacements (work similar in scope, timing, and cost to the original project); emergent work (work that was not originally planned but becomes necessary to complete); and normal business changes (reallocations based on normal changes in project priorities due to changing circumstances).[607]

358. The Company also noted that for capital projects in the 2015 Step, no adjustment is needed because of the refund mechanism applicable to these projects in the event a Step project is delayed or cancelled.[608] The Company further stated that the 2015 Step projects represent a limited percentage of total 2015 costs and do not reflect all of the Company's capital additions in that year.[609]

359. The Company also argued that to the extent the Commission considers changes in in-service dates, the Company should be allowed to add new capital projects that have moved into the test year or Step year. The Department did not accept this proposal claiming that allowing additional capital projects into the case would unfairly burden parties and would not be in the public interest.[610]

3. Conclusion

360. The Company's capital revenue requirement is representative of the capital projects that will go into service during the 2014 test year and the 2015 Step year and therefore the Department's proposed revenue requirement reductions should not be adopted.

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[606] Ex. 94, Perkett Rebuttal at 38-39.
[607] Ex. 94, Perkett Rebuttal at 39-42.
[608] Ex. 100, Clark Rebuttal at 18-19.
[609] Ex. 100, Clark Rebuttal at 18-19.
[610] Ex. 429, Campbell Direct at 153; Ex. 450, Campbell Opening Statement at 8.

F. Interest Rate on Interim Rate Refund (Issue #66)

361. Minn. Rule 7825.3300 establishes the interest rate required to be paid on an interim rate refund. The rule states in part:

> Any increase in rates or part thereof determined by the commission to be unreasonable shall be refunded to customers or credited to customers' accounts within 90 days from the effective date of the commission order and determined in a manner prescribed by the commission including interest at the average prime interest rate computed from the effective date of the proposed rates through the date of refund or credit.

The rule requires the utility to refund the amount by which interim rates exceed final rates, plus interest, to reflect the fact that the Company, in effect, borrowed money from its customers during pendency of the interim rate period.

362. Minn. R. 7829.3200 allows the Commission to vary its rules when the following requirements are met: (A) enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule; (B) granting the variance would not adversely affect the public interest; and (C) granting the variance would not conflict with the standards imposed by law.

363. Based on the Commission's decision in the Company's last rate case, the OAG recommends the Commission vary its rule and increase the interest rate based on the Company's full weighted cost of capital (*i.e.*, the Company's overall rate of return).[611]

364. The Company argued that the present case is distinguishable from the prior rate case and that the requirements for varying the Commission's rule have not been met. The Company pointed out several differences.

365. First, the Company took a conservative approach with interim rates when compared to interim rate calculations provided under Minnesota law. The

[611] Ex. 370, Lindell Direct at 58-59.

Company took steps to ensure that its interim rates would be approximately half of its requested rate increase for the test year. Also, the Company did not seek an interim rate increase for the 2015 Step year.

366. Second, from a cost-of-service perspective, revenues from interim rates are equivalent to, and a trade-off for, short-term borrowing.[612] In the absence of the added revenues from interim rates, the Company would increase short term borrowing by the amount of those revenues on a dollar for dollar basis.[613]The Company's cost of short term borrowing, is 0.62 percent.[614] The Prime Rate, which is the rate the Company will pay on interim rate refunds pursuant to Commission rule, is 3.25 percent.[615] Thus, under the Commission Rule, the Company will pay far more in interest on interim rate refunds (3.25 percent) than it would cost for replacement short term borrowing (0.62 percent).[616]

367. Third, application of the Company's ROR to the entire refund would be inappropriate. The interim rate refund is based on the difference between (i) the Company's interim rate revenue requirement; and (ii) the final Commission-approved annual test year revenue requirement.[617] If the approved test year revenue requirement is reduced as a result of a reduction in the Company's allowed return on investment (ROR x rate base), the entire reduction in the Company's allowed return, including the ROR, is refunded to customers.[618] As a result, any refund to customers already reflects application of the Company's ROR for any reduction in allowed return.[619] The interest on the interim rate refund is in addition to the refund of any excess return (ROR x rate base).[620] The Company obtains recovery of its current

[612] Ex. 31, Tyson Rebuttal at 23-24.
[613] Ex. 31, Tyson Rebuttal at 23-24.
[614] Ex. 31, Tyson Rebuttal at 24.
[615] Minn. R. 7825.3300
[616] Ex. 31, Tyson Rebuttal at 24.
[617] Ex. 90, Heuer Direct at 38.
[618] Ex. 90, Heuer Direct at 38.
[619] Ex. 90, Heuer Direct at 38.
[620] Ex. 90, Heuer Direct at 38.

expenses but does not earn a return on current expenses.[621] The OAG's recommendation would, however, apply a level of interest to the current expenses that is equal to the Company's ROR.[622]

368. As the present case is distinguishable from the Company's prior rate case and the requirements of Minn. R. 7829.3200 have not been met, the Commission should not grant the variance.

G. Fuel Cost Recovery Reform (Issue #67)

369. XLI and MCC have raised the need for reforms of the Company's Fuel Clause Adjustment (FCA) mechanism.[623] The Department has also identified an interest in reforms to the FCA.[624] Since the FCA is separate rate mechanism from the base rates which are the subject of the instant rate case, the Company and the Department agree that the appropriate proceeding in which to address FCA matters is in the Annual Automatic Adjustment (AAA) proceeding.[625]

370. Because the Company did not include replacement fuel costs in this rate case and because the issue involves other investor-owned utilities, the AAA docket is a better forum to address reforms to the Company's FCA mechanism.

H. Sherco Unit 3 Outage-Replacement Fuel Costs (Issue #68)

371. MCC proposed that the replacement fuel costs for Sherco 3 be capitalized and recovered over the life of the respective plant.[626]

372. Both the Company and the Department agreed that these issues are most appropriately addressed in AAA proceedings.[627]

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621 Ex. 90, Heuer Direct at 38.
622 Ex. 90, Heuer Direct at 38.
623 Ex. 260, Pollack Direct at 25-32; Ex. 343, Maini Direct at 41-43.
624 *See* Ex. 412, Ouanes Rebuttal at 16.
625 Ex. 100, Clark Rebuttal at 43; Ex. 412, Ouanes Rebuttal at 15.
626 Ex. 340, Schedin Direct at 9, 13-14.
627 Ex. 94, Perkett Rebuttal at. 54- 55; *See* Ex. 437, Lusti Direct at 68 (discussing the Sherco 3 replacement power costs are being addressed in the Company's current open AAA Docket).

373. The Company noted that these fuel costs were not included in the calculation of base rates in this case.[628]

374. The Company also stated that such costs should not be capitalized because the cost of replacement power should be covered by those customers who used the power during the outage rather than future customers.[629]

375. As replacement fuel costs were not included in the Company's initial filing, this is issue is more appropriately addressed in the AAA proceeding.

I. Corporate Aviation Costs (Issue #65)

376. The Company requested recovery of $954,425 for corporate aviation costs in its 2014 test year.[630] This amount represents half of the approximately $1.9 million that the Company has budgeted for corporate aviation in 2014.[631] The Company argued that its request to include 50 percent of the corporate aviation costs is reasonable and consistent with Commission precedent.[632]

377. The Company asserts that it obtains the following benefits from using corporate aviation costs: travel expense savings, employee time savings, increased in-flight productivity, scheduling convenience, reduced stress and post-trip fatigue, and personal security.[633]

378. To confirm these benefits, the Company commissioned a third-party cost-benefit analysis for corporate aircraft usage from January 2012 through June 2013.[634] The study showed that corporate aviation resulted in higher productivity since employees reach their destinations faster allowing them to maximize their work

[628] Ex. 100, Clark Rebuttal at 44; Ex. 97, Robinson Rebuttal at 25.
[629] Ex. 100, Clark Rebuttal at 44.
[630] Ex. 75, O'Hara Direct at 28.
[631] Ex. 75, O'Hara Direct at 28.
[632] Ex. 75, O'Hara Direct at 28-29; *see also* ALJ REPORT IN 2013 RATE CASE at findings. 593-598 (finding the Company has demonstrated the reasonableness of including fifty percent of corporate aviation costs in the 2013 test year budget and that the request is consistent with Commission precedent).
[633] Ex. 75, O'Hara Direct at 29.
[634] Ex. 75, O'Hara Direct at 29.

days and that employees are getting more work accomplished in transit.[635] The cost-benefit analysis concluded that on average, 68 percent of the Company's corporate aviation expenses from January 2012 to June 2013 were justified compared to commercial aviation services.[636]

379. The OAG raised three main concerns regarding the Company's corporate aviation costs: (i) the Company's cost per flight was excessive; (ii) many of the flights scheduled did not provide ratepayer benefits; and (iii) most of the flights recorded did not include a sufficient business purpose to determine whether the flight was necessary and prudent to provide utility service.[637]

380. Based on these reasons and a review of the Company's flight logs, the OAG recommended disallowing the majority of the corporate aviation costs and allowing recovery of $34,143.[638] The OAG's adjustment was calculated based on $300 per flight multiplied by the number of passengers per flight.[639] The OAG also proposed additional adjustments for personal travel, flights coded as business area travel, and costs for investor relations and aviation use.[640]

381. The Company countered that the OAG's calculation of aviation expenses does not take into account practical issues that affect ticket prices, different time periods between reservations and travel, and fees related to ticket changes and cancellations[641] nor does it account for increased productivity, time savings, avoided hotel charges, and any other benefit of corporate aviation.[642] In addition, the Company noted that the OAG's $300 per flight approach has been previously reviewed and rejected by the Commission.[643]

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[635] Ex. 75, O'Hara Direct at 30.
[636] Ex. 75, O'Hara Direct at 30-31.
[637] Ex. 370, Lindell Direct at 50.
[638] Ex. 370, Lindell Direct at 56-58.
[639] *See* Ex. 370, Lindell Direct at 52.
[640] *See* Ex. 370, Lindell Direct at 57-58.
[641] Ex. 77, O'Hara Rebuttal at 7.
[642] Ex. 77, O'Hara Rebuttal at 7.
[643] 2013 RATE CASE ORDER at 10-11.

382. The Company further argued that the OAG's disallowance for personal travel, flights coded as business area travel, and costs for investor relations and aviation use are also not well supported.

383. The Company stated that the flight logs show that the aircraft have the appropriate passengers on board and travel mostly between company locations. The Company acknowledged that "personal travel" is rare and it is only used when spouses of Company executive employees or members of the Xcel Energy Board of Directors accompany their employed spouses to business functions.[644]

384. With respect to the OAG's proposal to disallow the costs of 42 flights for which the business purpose was listed as "Aviation Use,"[645] the Company noted that these flights "are necessary to maintain the functionality of the aircraft and provide corporate aviation services."[646]

385. The Company noted that with respect to business area, executive travel, director travel, and manager travel, a valid business purpose is required for use of any of the corporate aircraft.[647]

386. The Company has demonstrated that it is reasonable to include $954,425 for corporate aviation costs in the 2014 test year. The Company's request is based on a detailed cost-benefit analysis and is consistent with Commission precedent.

J. Rate Case and Monticello Prudency Review Expense Amortization (2014) (Issue #8)

387. The Company's test year includes expenses totaling approximately $950,000 to account for the cost of conducting the Monticello Prudence Investigation proceeding (Docket No. E002/CI-13-754), as well as approximately $2.7 million in rate case expenses for this case.[648]

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[644] Ex. 77, O'Hara Rebuttal at 8.
[645] OAG Initial Brief at p. 24.
[646] Ex. 77, O'Hara Rebuttal at p. 11.
[647] Ex. 77, O'Hara Rebuttal at 12.
[648] Ex. 90, Heuer Rebuttal at 23; Ex. 438, Lusti Direct at 28.

388. The Company proposed to amortize the Monticello Prudence Investigation costs and rate case costs over two years, consistent with the likelihood the Company will file its next rate case in late 2015, using a 2016 test year.[649]

389. The Department agreed with the amount and the two-year amortization of rate case expenses.[650]

390. The Department agreed with the amount of Monticello Prudence Investigation expense included in the test year. [651]

391. However, the Department proposed to amortize Monticello Prudence Investigation costs over the remaining life of the Monticello facility (16.8 years) without a return, on the grounds that the prudence investigation pertains to the overall facility and will have ramifications over the life of the facility.[652]

392. The Department's recommendation decreases teat year rate case amortization expense by $418,452.[653]

393. The Company supported its proposed two-year amortization for the costs for the Monticello Prudence Investigation by noting that these costs are similar to rate case costs as they are relatively small in amount and pertain to a one-time investigation.[654] Thus while a rate case proceeding may also have long-term financial effects on a utility, amortization of rate case costs is typically limited to shorter periods to reflect the primary period affected by the proceeding.[655]

394. The Company argued that prudence investigation expenses should not be treated like capital costs, as these expenses do not affect plant operations and have no bearing on the remaining useful life of the facility.[656]

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649 Ex. 90, Heuer Rebuttal at 24.
650 Ex. 438, Lusti Direct at 28-29.
651 Ex. 438, Lusti Direct at 28-29.
652 Ex. 90, Heuer Rebuttal at 24; Ex. 442, Lusti Surrebuttal at 17-18.
653 Ex. 437, Lusti Direct at 29.
654 Ex. 90, Heuer Rebuttal at 25.
655 Ex. 90, Heuer Rebuttal at 24.
656 Ex. 90, Heuer Rebuttal at 24.

395. Finally, the Company claimed it would be inappropriate to require the Company to bear the Prudence Investigation costs over the life of the facility without providing a carrying charge to account for the time that the Company must wait before recovering the costs.[657]

396. Given the similarities between rate case costs and the Monticello Prudence Investigation costs, it is reasonable to amortize both costs over a two-year period.

K. Nuclear Refueling Outage Costs (Issue #64 and #27)

1. Accounting Methodology (Issue #64)

397. The Company supported continued use of the deferral and amortization method for nuclear refueling outage expenses as a means to promote stability, predictability, and fairness for ratepayers.[658] The Company stated that this methodology, which has been used since 2008, moderates rate increases by phasing them in over a longer period of time, moderates year-over-year variations, and matches the outage costs to the period during which the benefits from the outage occur.[659]

398. The OAG's primary concern is that the Company should not be allowed to earn a return on a normal expense, and that providing such a return gives the Company incentives to increase the scope of nuclear outage expenses.[660]

399. The OAG also objected to the Company's continued use of the deferral and amortization method for nuclear refueling outage costs as the OAG believes that the normalization method would be superior.[661] However, the OAG recommended that the Company be allowed to continue use of the deferral and amortization method

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[657] Ex. 90, Heuer Rebuttal at 24.
[658] Ex. 97, Robinson Rebuttal at 22.
[659] Ex. 97, Robinson Rebuttal at 22.
[660] Ex. 370, Lindell Direct at 45-47.
[661] Ex. 370, Lindell Direct at 47.

to set rates but that the Company not be allowed to earn a return on nuclear refueling outage costs.[662]

400. The Company responded that it is appropriate to allow return on these expenses under fundamental ratemaking principals.[663] The Company stated that when it uses funds to cover nuclear refueling outage costs prior to receiving funds from customers, standard ratemaking contemplate that the Company is entitled to earn a return on the unamortized balance net of accumulated deferred income tax.[664]

401. The Company also pointed out that it has an ongoing obligation by way of its May 1 Electric Jurisdictional Annual Report, to demonstrate that the nuclear refueling outage costs are reasonable and accurate.[665]

402. The Company has demonstrated that it is reasonable to include a carrying charge on the unamortized deferred balance of nuclear refueling outage costs as it represents the appropriate time-cost of money.

2. Cost Amortization (Issue #27)

403. The Company included $89.3 million in test year amortization expenses for nuclear refueling outages.[666] During discovery, the Company provided additional information related to the 2015 Step year nuclear outage amortization expenses.[667] This information showed that the amortization expenses for nuclear refueling outages decreased from 2014 to 2015. Based on this information, the Department recommended a $5.5 million reduction in revenue requirements for the 2015 Step.[668]

404. In Rebuttal Testimony, the Company disagreed with the Department's proposal, explaining that the Company included only a limited number of capital

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662 Ex. 370, Lindell Direct at 47.
663 Ex. 97, Robinson Rebuttal at 23-24.
664 Ex. 97, Robinson Rebuttal at 23-24.
665 Ex. 97, Robinson Rebuttal at 24.
666 Ex. 52, O'Connor Direct at 119 and Sch. 16.
667 Ex. 431, Campbell Direct at 63 and Sch. 12.
668 Ex. 431, Campbell Direct at 67, 169-170.

projects.[669] The Company noted that the Department's proposal would expand the scope of the 2015 Step to include decreasing rate base components and expenses without including increasing rate base components and expenses.[670] The OAG disagreed with the Company's characterization of the 2015 Step and supported the Department's proposed $5.5 million adjustment.[671]

405. In Surrebuttal Testimony, the Department agreed with the Company and noted that the nuclear outage costs are separate O&M expenses not directly related to any of the 2015 Step capital project, and therefore no longer recommended the $5.5 million adjustment.[672]

406. In the evidentiary hearing, the Department noted that this issue is resolved between the Department and the Company.[673] The issue is unresolved between the OAG and the Company.[674] The OAG supports the Department's original recommendation of a $5.5 million revenue requirement reduction for 2015 Step.[675]

407. Nuclear amortization expense is a separate O&M item, which is not directly related to any of the 2015 Step capital projects. As a result, projected decrease in these expenses does not warrant the OAG's proposed adjustment to the 2015 Step revenue requirements.

L. Black Dog-Unit 2 and 5 Outage Costs (2014) (Issue #76)

408. Units 2 and 5 of the Black Dog Generating Plant experienced a three month outage ("Black Dog 5/2").[676]The outage lasted from late 2012 to early 2013

669 Ex. 26, Sparby Direct at 11-12.
670 Ex. 26, Sparby Direct at 12; Ex. 100, Clark Direct at 35.
671 Ex. 322, Lindell Rebuttal at 6.
672 Ex. 435, Campbell Surrebuttal at 14-16; Ex. 442, Lusti Surrebuttal at 43.
673 Ex. 450, Campbell Opening Statement at 1.
674 Ex. 141, Lindell Opening Statement at 2.
675 Ex. 141, Lindell Opening Statement at 2; Tr. Vol. 3 at 194-195 (Lindell).
676 Ex 58, Mills Direct at 54.

due to a bowed rotor, which occurred when the rotor was removed from its turning gear while hot due to human error.[677]

409. Since the outage was the result of human error, XLI proposed disallowing investment of $24,104 and operating costs of $1.838 million.[678]

410. The Company pointed out that the $1.838 million of additional operating costs were incurred in 2013 and that these costs were not included in the 2014 test year.[679]The Company clarified that the $24,104 of capital addition is merely embedded within the rate base for the 2014 test year since that capital addition was incurred during the 2012-2013 outage.[680] As a result, the Company argued "[r]eopening NSP's past rate cases to readjust rates to account for [XLI's proposed disallowance] would violate the long-standing and well-supported Commission policy against retroactive ratemaking."[681]

411. XLI's proposed adjustment relates to both O&M costs as well as capital costs. Even though these costs are of a different nature, the Commission's standard to determine if inclusion of these costs in rates is just and reasonable is the same: prudence.[682] The general prudence standard calls for determining whether the utility action was reasonable at the time it was taken under all relevant circumstances.[683]

412. The Company urged that its conduct should be reviewed based on its response to any human error that occurred. With respect to Black Dog 5/2, since the

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677 Ex. 58, Mills Direct at 54.
678 Ex. 260, Pollack Direct at 24.
679 Ex. 90, Heuer Rebuttal at 35.
680 Ex. 60, Mills Rebuttal at 17.
681 *In the Matter of Northern States Power Company's Petition for Deferred Accounting Treatment for Settlement Payments from SMMPA*, ORDER ALLOWING WITHDRAWAL OF PETITION, Docket No. E-002/M-96-1623 (Sept. 17 1997).
682 *In the Matter of the Petition of Northern States Power Company for Authority to Change Its Schedule of Gas Rates for Retail Customers Within the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER, Docket No. E-002/GR-85-108, 73 P.U.R.4th 395 (Dec. 30, 1985) ("[t]he standard for allowing recovery of a utility expense is that it is reasonable and prudent and related to the provision of the utility service").
683 *See* Charles F. Philips, Jr., THE REGULATION OF PUBLIC UTILITIES – THEORY AND PRACTICE at 292 (Public Utility Reports 1988); *see also* David J. Muchow, William A. Mogel, ENERGY LAW AND TRANSACTIONS at § 4.02[3][b] (2009).

Units came back on-line, "the plant has been operating well, and all of our performance indicators are improving and positive."[684] In fact, "[t]he project year-end equivalent availability factor…for 2014 is better than the previous 12 years."[685] The Company stated that its response to an unfortunate human error event resulted in improved performance based on the Company's prudent management of the plant.[686]

413. XLI's recommended disallowance imposes a standard of perfection, not prudence, on the Company and constitutes in retroactive ratemaking. Consequently, XLI's proposed adjustment for the 2012-2013 outage at Black Dog 5/2 should not be adopted.

414. Further, XLI recommended that any replacement fuel costs should also be disallowed in the AAA proceeding.[687] The Company stated that the AAA proceeding is the appropriate forum to address replacement power costs for this outage and the Sherco 3 outage.[688]

M. Capital Structure and Cost of Debt (2014 and 2015 Step) (Issue # 12)

415. One of the components in determining the rate of return for the Company is the capital structure, *i.e.*, whether the Company's proportion of long-term debt, short-term debt, preferred stock and common equity is reasonable. A related component is the cost of the short-term debt and of the long-term debt.

1. Capital Structure

416. A utility's capital structure provides the long-term structural foundation for the financing necessary to support its operations and capital investments.[689] The Commission generally uses a reasonableness standard to evaluate a utility's capital structure.[690] The Commission considers how a utility's debt and equity ratios

[684] Ex. 60, Mills Rebuttal at 16.
[685] Ex. 60, Mills Rebuttal at 16.
[686] Ex. 60, Mills Rebuttal at 18.
[687] Ex. 260, Pollack Direct at 24.
[688] Ex. 100, Clark Rebuttal at 44.
[689] Ex. 30, Tyson Direct at 7.
[690] Ex. 30, Tyson Direct at 7-8.

compare to those of similarly situated utilities; whether the utility's capital structure is an actual capital structure based on market forces or is instead an internal accounting structure; whether the utility's capital structure supports long-term credit quality; and whether the utility's capital structure provides long-term cost benefits to customers.[691]

417. The Company initially proposed a capital structure for the 2014 test year of 52.50 percent common equity, 45.61 percent long-term debt, and 1.89 percent short-term debt, and for Step year 2015 of 52.50 percent common equity, 45.63 percent long-term debt, and 1.87 percent short-term debt.[692] The Department agreed that this capital structure was appropriate and reasonable, subject to the caveat that the capital structure calculations should be updated in the Company's rebuttal testimony.[693]

418. In Rebuttal Testimony, the Company proposed the following capital structure based on updated calculations: for the 2014 test year, 52.50 percent common equity, 45.60 percent long-term debt, and 1.90 percent short-term debt; and for Step year 2015, 52.50 percent common equity, 45.61 percent long-term debt, and 1.89 percent short-term debt.[694] This updated proposed capital structure is very close to the originally proposed capital structure. The Department agreed that this updated proposed capital structure was appropriate and reasonable.[695]

419. The Company's proposed capital structure is reasonable. First, the Company's capital structure is consistent with the capital structures of other utilities, both at the operating company level as analyzed by Mr. Hevert,[696] and at the parent company level as analyzed by Dr. Amit.[697] To the extent that the Company's equity ratio is slightly higher than the averages of the groups analyzed, that is justified by the

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691 Ex. 30, Tyson Direct at 8; Ex. 400, Amit Direct at 44-45.
692 Ex. 30, Tyson Direct at 4.
693 Ex. 400, Amit Direct at 46-47, 51.
694 Ex. 31, Tyson Rebuttal at Schedules 3 and 7.
695 Ex. 403, Amit Surrebuttal at 10; Ex. 443, Amit Opening Statement at 4.
696 Ex. 27, Hevert Direct at 53-54 and Schedule 11.
697 Ex. 400, Amit Direct at 48; Ex. 28, Hevert Rebuttal at 9-17.

Company's significant capital expenditures of approximately $7.6 billion in its combined gas and electric utility business from 2005 to 2012.[698]

420. Second, NSPM's capital structure is an actual and market-based capital structure.[699] NSPM is a legally separate Minnesota corporation, issues its own debt securities, reports its capital structure in its own separate SEC filings, and credit ratings agencies assign credit ratings to NSPM as its own corporate entity.[700]

421. Third, when issuing long-term debt and targeting an equity ratio, the Company properly considers credit rating evaluations, its anticipated capital investments, the long-term stability of the capital structure in relation to the long life of its assets, the macroeconomic outlook, and the need to manage the maturities of long-term debt.[701]

422. Fourth, the Company's proposed capital structure has an effect on its financial integrity, which in turn benefits customers.[702] The Company's capital structure has allowed it simultaneously finance its considerable capital investments, achieve upgrades of its credit ratings, and reduce its cost of long-term debt.[703] The resulting financial strength ensures that the Company has consistent access to capital markets that will enable it to raise the future capital required to complete its capital investment plan.[704]

423. Finally, the components of the proposed capital structure (long-term debt, short-term debt, and common equity capital) were each calculated in a manner consistent with how those components were calculated in the Company's previous rate case.[705] Not only is the methodology consistent, but the actual capital structure

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698 Ex. 31, Tyson Rebuttal at 9.
699 Ex. 30, Tyson Direct at 9; Ex. 400, Amit Direct at 45; Ex. 31, Tyson Rebuttal at 5.
700 Ex. 30, Tyson Direct at 9; Ex. 400, Amit Direct at 45.
701 Ex. 30, Tyson Direct at 9-12; Ex. 31, Tyson Rebuttal at 6-8.
702 Ex. 30, Tyson Direct at 13; Ex. 31, Tyson Rebuttal at 5-6, 9-10.
703 Ex. 30, Tyson Direct at 13.
704 Ex. 30, Tyson Direct at 13; Ex. 31, Tyson Rebuttal at 9.
705 Ex. 400, Amit Direct at 46-47; Ex. 30, Tyson Direct at 27-30, 34-38.

the Company proposed for 2014 is very similar to the capital structure of 52.56 percent equity, 45.30 percent long-term debt, and 2.14 percent short-term debt approved by the Commission in the prior rate case.[706]

424. The ICI Group recommended that the Commission limit the amount of common equity that the Company could include in its capital structure to the amount of common equity employed by Xcel Energy, Inc as projected by Value Line: 47.5 percent in 2014 and 49.0 percent in 2015.[707]

425. This recommendation should not be adopted, because it fails to recognize that the Company's capital structure is separate from that of its parent company, Xcel Energy, Inc.[708]

426. Mr. Glahn testified on behalf of the ICI Group that the Company is nothing but an "accounting fiction, an entry on the books of Xcel Energy."[709] His testimony is incorrect, because the Company reports its actual capital structure in its own SEC filings and because S&P, Moody's, and Fitch assign credit ratings to the Company and to each of the Company's bonds.[710]

427. Utility operating companies, not holding companies, are the appropriate basis by which to analyze capital structure.[711] The Company does not finance its capital investments based on Value Line's projections, and Value Line does not include short-term debt in its projections.[712]

428. Modifying the Company's equity ratio, as the ICI Group recommended, would be seen as a significant adverse change in the Company's regulatory

706 Ex. 30, Tyson Direct at 27.
707 Ex. 250, Glahn Direct at 26.
708 Ex. 402, Amit Rebuttal at 14-15.
709 Ex. 251, Glahn Surrebuttal at 6.
710 Ex. 31, Tyson Rebuttal at 5.
711 Ex. 28, Hevert Rebuttal at 42.
712 Ex. 28, Hevert Rebuttal at 42.

environment and thus would likely lead to a change in the credit outlook for the Company, potentially resulting in a credit downgrade.[713]

429. The Company's proposed capital structure of 52.50 percent common equity, 45.60 percent long-term debt, and 1.90 percent short-term debt for the 2014 test year, and 52.50 percent common equity, 45.61 percent long-term debt, and 1.89 percent short-term debt for Step year 2015, is reasonable and appropriate.

2. Cost of Debt

430. The Company initially recommended that for the 2014 test year, its cost of short-term debt should be 0.67 percent and its cost of long-term debt should be 4.93 percent, and for the 2015 Step year, its cost of short-term debt should be 1.12 percent and its cost of long-term debt should be 4.97 percent.[714]

431. In Rebuttal Testimony, the Company updated its cost of debt, resulting in a final recommendation that for the 2014 test year, the cost of short-term debt should be 0.62 percent and the cost of long-term debt should be 4.90 percent, and for the 2015 Step year, the cost of short-term debt should be 1.12 percent and the cost of long-term debt should be 4.94 percent.[715]

432. The Company's proposed cost of long-term debt for 2014 is lower than in the previous rate case, and is much lower than the 6.09 percent cost in Docket E-002/GR-10-971.[716]

433. The cost of long-term debt was calculated based on the coupon rate on all of the Company's bonds expected to be outstanding for each month of 2014, plus related expenses such as amortization expense for debt issuance costs, discounts or

[713] Ex. 31, Tyson Rebuttal at 11.
[714] Ex. 30, Tyson Direct at 4.
[715] Ex. 31, Tyson Rebuttal at 26-27 and 29, and Schedules 3 and 7.
[716] Ex. 30, Tyson Direct at 5.

premiums, and losses on reacquired debt.[717] This calculation methodology is consistent with the calculations of the cost of long-term debt in prior rate cases.[718]

434. The cost of short-term debt includes the interest expense for commercial paper and the monthly financing fees associated with maintaining a credit facility to provide back-up liquidity.[719]

435. The Department agreed with the Company's proposed cost of debt.[720] No other party commented on the cost of debt.

3. Rate of Return

436. The overall rate of return (ROR) reflects the common equity, LTD, and STD in the capital structure along with the costs of common equity, LTD and STD. The Company proposes a 7.62 percent ROR for 2014 test year and a 7.65 percent ROR for the 2015 Step.[721]

N. FERC Cost Comparison Study – KPI Benchmarks (Issue #70)

437. The Company conducts an annual Electric FERC Cost Comparison Study (Benchmarking Study) which compares Xcel Energy and its four operating companies to peer companies, investor-owned utilities in the Edison Electric Institute (EEI) Index.[722] The Study focuses on retail revenues, fuel and purchased power costs, and non-fuel O&M costs including Production, Transmission, Distribution, Customer Care, and Administrative & General.[723]

438. MCC recommended that in the instances where NSPM appears in the bottom two quartiles of any metric in the 2013 Benchmarking Study, the Company use those measures as key performance indicators to help improve the efficiency of

[717] Ex. 30, Tyson Direct at 28, 36.
[718] Ex. 30, Tyson Direct at 28, 36.
[719] Ex. 30, Tyson Direct at 30-31, 37.
[720] Ex. 400, Amit Direct at 52; Ex. 403, Amit Surrebuttal at 10.
[721] Ex. 31, Tyson Rebuttal at 27-28; Ex. 116 Tyson Opening Statement at 1-2.
[722] Ex. 67, Kline Rebuttal at 37.
[723] Ex. 100, Clark Rebuttal at 45.

Xcel Energy's operations.[724] In the 2013 Benchmarking Study, NSPM is trending below its peer companies with respect to (i) non-fuel O&M benchmarks (percent of retail revenue by total, per customer, per retail MWh sales, and per MWh generated) and (ii) transmission O&M benchmarks (transmission O&M per line mile and transmission O&M per MWh throughput).[725]

439. The Department agreed with MCC's recommendation to use benchmarks from the Benchmarking Study to improve the efficiency of the Company's operations.[726]

440. For non-fuel O&M costs, the Company has already implemented a KPI related to non-fuel O&M growth management for 2014.[727] The Company noted that unlike the Benchmarking Study, this KPI is tied to recoverable costs and takes into account the variation that may occur between cost categories and thus appropriately addresses O&M growth.[728]

441. With respect to the transmission O&M benchmarks, the Company pointed out that five of the top ten utilities with the lowest transmission O&M costs per MWh throughput have sold the vast majority of their transmission assets to a transmission company.[729] Higher ranking utilities have large retail loads and high MWh throughput but very small transmission systems and low O&M costs. Such factors have a large impact on their high ranking.[730] Conversely, the utilities in the bottom two quartiles tend to be large transmission-owning utilities that are members of a Regional Transmission Organization (RTO).[731] The MWh throughput calculations in the 2013 Benchmarking Study fail to capture the increased throughput

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[724] Ex. 343, Maini Direct at 43-45.
[725] Ex. 343, Maini Direct at 43-44.
[726] Ex. 412, Ouanes Rebuttal at 16.
[727] Ex. 100, Clark Rebuttal at 46.
[728] Ex. 100, Clark Rebuttal at 46.
[729] Ex. 67, Kline Rebuttal at 40-41.
[730] Ex. 67, Kline Rebuttal at 40-41.
[731] Ex. 67, Kline Rebuttal at 40-41.

associated with the wheeling of power for others when an RTO member's transmission system is controlled and coordinated by the RTO due to the regional sharing of the transmission systems within the RTO.[732]

442. With respect to the transmission O&M line-mile calculation, utilities that have high transmission O&M costs per transmission line mile often provide service in some of the largest cities in the United States.[733] Transmission lines in very large cities tend to be underground or in areas that are difficult to access for maintenance. Customer density (the number of customers per mile) is also higher.[734] Both factors will increase transmission O&M costs per line mile.[735]

443. The 2013 Benchmarking Study does not control for comparability of data, different tracking and reporting systems, relative size of a utility's transmission system, or other variations among utilities and as a result it is not appropriate to use the study's non-fuel and transmission O&M benchmarks as KPIs.

O. Transmission Business Area Cost Controls (Issue #69)

444. MCC raised concerns about cost controls for the transmission business unit.[736] MCC recommended that each transmission project requiring a certificate of need should have a firm cost cap which cannot be exceeded for ratemaking purposes without Commission approval.[737]

445. The Company argued that a firm cost cap for transmission projects based on the cost estimates provided at the certificate of need stage is inappropriate. The Company pointed out that at the certificate of need stage there are a significant number of uncertainties that can impact the final cost of a project that will not be resolved until the final route is determined.[738]

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[732] Ex. 67, Kline Rebuttal at 40-41.
[733] Ex. 67, Kline Rebuttal at 41.
[734] Ex. 67, Kline Rebuttal at 41.
[735] Ex. 67, Kline Rebuttal at 41.
[736] Ex. 340, Schedin Direct at 15-21.
[737] Ex. 340, Schedin Direct at 17.
[738] Ex. 67, Kline Rebuttal at 20-29.

446. In addition, imposing a cost cap based on certificate of need cost estimates is inconsistent with the purpose of the certificate of need proceeding which is to determine system needs and the most appropriate way to meet that need through a comparison of reasonable alternatives.[739]

447. The Company also noted that there are ample opportunities for parties to review and challenge the prudence of transmission project costs. For certificate of need projects, parties can challenge prudence during rate case proceedings or in the Transmission Cost Recovery Rider.

448. For projects that do not require a certificate of need, MCC recommended that the Company and other MISO transmission owners set up a reasonable cost control mechanism at MISO that would be approved by FERC.[740]

449. The Company stated that processes are already in place at MISO to control costs. The Company pointed out that MISO and interested stakeholders have the power under the MISO tariff and the formula rate protocols to request, review and monitor transmission owner cost data.[741] This provides our stakeholders an opportunity to challenge the Company's transmission costs.[742] Second, MISO has a robust stakeholder process in which many entities actively participate.[743] Through this process, employees from the Company participated in MISO's regional planning effort o ensure that transmission expansion plans are fully vetted and appropriately sized.[744] The Company also noted that MISO is likely to develop additional cost control mechanisms in light of FERC Order No. 1000 but that development of these additional mechanisms may take time.[745]

[739] Ex. 67, Kline Rebuttal 19.
[740] Ex. 340, Schedin Direct at 17.
[741] Ex. 67, Kline Direct at 36.
[742] Ex. 67, Kline Direct at 36.
[743] Ex. 67, Kline Direct at 36.
[744] Ex. 67, Kline Direct at 36.
[745] Ex. 67, Kline Direct at 36.

450. The Company has demonstrated that its transmission business unit has rigorous cost controls in place and that relevant personnel are held accountable for bringing transmission projects on time and on budget.

P. MYRP in General (Issue #79)

451. The ICI Group opposed the Company's MYRP proposal for several reasons: (1) the 2015 Step will get less scrutiny and lower-level review than a regular one-year rate case; (2) the 2015 Step will move the Company from regulatory lag to regulatory lead and may allow the Company to over-earn if the U.S. economy improves; (3) the inclusion of only Company-selected items in the 2015 Step tilts the playing field against customers who will not have access to the Company's entire 2015 financial data; and (4) the process and reporting requirements for setting the 2015 Step rates are extremely complicated.[746]

452. The ICI Group believed that even with the risk of annual, consecutive rate cases, customers benefit from the transparency of having all revenue and expenses examined at one time in one proceeding.[747] The ICI Group recommended that the Company's MYRP will be denied and the rates set in this proceeding based on 2014 test year costs and assets.[748]

453. The Company opposed the ICI Group's recommendation and urged the Commission to accept the MYRP as proposed and modified by the Company during this proceeding.

454. The Company stated that it proposed a MYRP as the best regulatory fit to reflect the current environment of significant investments the Company is undertaking to support its ability to provide reliable and safe electric service to its customers.[749]

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746 Ex. 250, Glahn Direct at 6-9.
747 Ex. 250, Glahn Direct at 6-9.
748 Ex. 250, Glahn Direct at 6-9.
749 Ex. 100, Clark Rebuttal at 4.

455. The Company noted that the MYRP offers several benefits to stakeholders including: greater rate predictability for customers, opportunities for rate moderation, regulatory efficiency, and long-term view of Company financials.[750] The Company noted that MYRP provides additional benefits for customers, because the 2015 Step does not reflect the Company's full revenue requirement for 2015.[751]

456. The Company believes that MYRP will also provide benefits into 2016, as long as it is implemented in a manner that balances the interests of all Company stakeholders.[752]

IV. RATE DESIGN AND CLASS COST OF SERVICE STUDY

A. Background

457. Rate design occurs after the Commission establishes the Company's revenue requirement. The rate design process is a zero-sum game: a reduction in one rate necessarily results in an equal and offsetting increase in one or more other rates.[753]

458. Under Minnesota law, the rates that result from the rate design process must be just and reasonable and may not be unreasonably preferential, unreasonably prejudicial, or discriminatory.[754] Rates design must also consider issues of conservation and affordability.[755] Balancing these factors in the rate design process is a quasi-legislative function that largely rests on policy determinations.[756]

459. The Commission considers a variety of factors when designing rates, including: "economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; ability to bear,

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[750] Ex. 100, Clark Rebuttal at 4-5.
[751] Ex. 100, Clark Rebuttal at 4-5.
[752] Ex. 100, Clark Rebuttal at 4-5.
[753] Company Initial Brief at 124.
[754] Minn. Stat. § 216B.03.
[755] Minn. Stat. §§ 216B.03, 216B.2401, 216B.16, subd. 15.
[756] *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n*, 312 Minn. 250, 260, 251 N.W. 2d 350, 357 (1977).

deflect, or otherwise compensate for additional costs; and in particular, the cost of service."[757]

460. The Company uses similar principals when designing rates:

- Produce total revenue equal to test year revenue requirements, thereby providing the Company a reasonable opportunity to earn its authorized return on investment;
- Accurately reflect the resource costs of providing service and, where appropriate, the market value of the service;
- Provide sufficient flexibility in pricing levels and provisions for our electric service to remain competitive in the broader energy market; and
- Provide reasonable pricing by considering the importance of rate continuity, customer understanding, revenue stability, and administrative practicality.[758]

B. Class Cost of Service Study (Issue #51)

461. The Class Cost of Service Study (CCOSS) allocates jurisdictional costs to customer classes using class cost allocation factors. The CCOSS measures the contribution each class makes to the Company's overall cost of service, including calculating inter-class and intra-class cost responsibilities.[759]

462. The Company filed 2014 and 2015 CCOSSs with its Application, as required by Commission Rules and the Commission's Order Establishing Terms, Conditions and procedures for multiyear rate plans in Docket No. E,G999/M-12-587.[760]

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757 *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota,* FINDINGS OF FACT, CONCLUSIONS AND ORDER at 14, Docket No. E002/GR-10-971 (May 14, 2012) (hereinafter E002/GR-10-971 ORDER).
758 Ex. 105, Huso Direct at 4-5.
759 Ex. 102, Peppin Direct at 1-2.
760 Minn. R. 7825.4300; *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19*, Docket No. E,G999/M-12-587, ORDER ESTABLISHING TERMS, CONDITIONS AND

463. The Company revised the 2014 and 2015 CCOSSs in its Rebuttal Testimony to reflect: 1) the Company's Rebuttal revenue requirement; 2) Rebuttal sales and customer forecasts; 3) removal of the Conservation Improvement Program (CIP) Conservation Cost Recovery Charge (CCRC) from the CCOSSs, as recommended by the Department; 4) a reduction in the amount of economic development discounts to actual 2013 levels, as recommended by the Department; and 5) and using actual replacement cost data for Pleasant Valley and Borders in the 2015 CCOSS.[761]

464. The Company's proposed CCOSS incorporates many of the fundamental aspects of previous CCOSSs, including using the Plant Stratification method to classify and allocate fixed production plant and the class definitions used in previous cases.[762] These two aspects of the CCOSS have been used by the Company with Commission approval for several rate cases.[763] The Company's proposed CCOSSs also include two changes approved by the Commission in the Company's 2013 rate case (Docket No. E002/GR-12-961): 1) allocation of capacity-related fixed production plant and transmission plant to classes based on the summer peak; and 2) allocation of economic development discounts to all classes.[764]

465. The Department, OAG, MCC and XLI have all presented different CCOSSs in this case and have taken a variety of positions on CCOSS-related issues.

1. CCOSS Methodology

466. The Company explained that it performs a critical analysis of its CCOSS prior to filing each rate case.[765] According to the Company, these analyses are

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PROCEDURES FOR MULTIYEAR RATE PLANS at Order Point 18 (June 17, 2013). *See* Ex. 13, Vol. 3 (Required Information).

761 Ex. 103, Peppin Rebuttal at 2-3.

762 Ex. 102, Peppin Direct at 11-12.

763 Ex. 102, Peppin Direct at 11-12. *See also In the Matter of the Application of Northern States Power Company for an Increase in its Minnesota Electric Retail Rates*, FINDINGS OF FACT CONCLUSIONS OF LAW AND ORDER at 83-87, Docket E001/GR-92-1185 (Sept. 29, 1993).

764 Ex. 102, Peppin Direct at 11.

765 Ex. 102, Peppin Direct at 11-12; Ex. 103, Peppin Rebuttal at 18.

informed by the outcomes of previous cases, new or renewed studies and changes that have occurred in the Company's business that are relevant to the cost-measurement process.[766] The Company contends that these refinements improve the measurement of cost causation.[767]

467. The Company made five refinements to its CCOSS methodology in this case: 1) classification and allocation of Other Production O&M; 2) classification and allocation of Company-owned wind; 3) separation of distribution lines costs into single-phase and multi-phase categories; 4) direct assignment of costs to the Lighting class; and 5) removal of CIP CCRC costs and revenues from the CCOSS.[768] The refinements related to Other Production O&M and Company-owned wind are contested in this case.

2. Other Production O&M

468. Other Production O&M costs are production plant operations and maintenance expenses "other" than fuel and purchased power.[769]

469. As part of the 2013 rate case, the Commission ordered the Company to perform an analysis of Other Production O&M costs in this case, stating:

> In the initial filing of its next rate case, Xcel shall refine its Class Cost of Service Study cost allocation method by identifying any and all Other Production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators, while allocating the remainder of Other Production O&M costs on the basis of the Production Plant.[770]

[766] Ex. 102, Peppin Direct at 11-12.
[767] Ex. 104, Peppin Surrebuttal at 6-7.
[768] Ex. 102, Peppin Direct at 11, Table 4; Ex. 103, Peppin Rebuttal at 2.
[769] Company Initial Brief at 126.
[770] 2013 RATE CASE ORDER at Order Point 49.

470. In response, the Company examined each of the 117 cost items that make up Other Production O&M.[771] The Company identified chemicals and water use as being costs that vary directly with the amount of energy produced.[772]

471. The Company prepared a compliance CCOSS that classified chemicals and water use costs as energy-related and classified the remaining Other Production O&M costs based on the type of production plant associated with the costs.[773]

472. Using underlying plant type to classify the Other Production O&M costs that do not vary directly with energy output is known as the "location method."[774] The location method is one of the methodologies identified in the National Association of Regulatory Commissioners Electric Utility Cost Allocation Manual (NARUC Manual) used to classify Other Production O&M costs that do not vary directly with energy output.[775] One of the other methodologies identified in the NARUC Manual is known as the "predominant nature" method.[776] Under the predominant nature method, Other Production O&M costs that do not vary directly with energy output are classified "according to [their] 'predominant' – i.e. [capacity]-related or energy-related – character."[777] The two methods result in different energy-related and capacity-related classifications of Other Production O&M costs.

Table 1
Comparison of Other Production O&M Cost Classification Methodologies[778]

Classification Methodology	Capacity-Related	Energy-Related
Location Method	35.0%	65.0%
Predominant Nature Method	78.4%	21.6%

771 Ex. 102, Peppin Direct at 19 and Schedule 7.
772 Ex. 102, Peppin Direct at 19-20.
773 Ex. 102, Peppin Direct at 20 and Schedule 8; Ex. 103, Peppin Rebuttal at 23-25.
774 Ex. 102, Peppin Direct at 22; Ex. 103, Peppin Rebuttal (quoting National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992)).
775 Ex. 103, Peppin Rebuttal (quoting National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992)).
776 Ex. 102, Peppin Direct at 22.
777 Ex. 102, Peppin Direct at 22 (citing National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual, 66 (Jan. 1992)).
778 Ex. 102, Peppin Direct at 24, Table 10.

473. The Company's proposed CCOSSs are based on the predominant nature method. The Company asserted the predominant nature method is superior to the locational method because it is based on an individualized analysis of each cost category and does not rely on plant-type as a proxy for determining the nature of each cost type.[779] According to the Company, using proxies produces a less refined view of the nature of Other Production O&M costs.[780] For example, the Company stated that under the location method, all non-chemicals and non-water Other Production O&M that occurs at peaking plants is treated as capacity-related, even though some of those costs clearly change with the amount of energy produced.[781] The Company also supported the predominant nature method because it is characterized as a "common method" in the NARUC Manual while the location method is deemed "not standard practice".[782]

474. The MCC and XLI supported the use of the predominant nature method.[783]

475. Both the Department and OAG recommend using the location method to classify and allocate Other Production O&M costs that do not vary directly with energy output.[784] Their opposition to the predominant nature method was based upon: 1) the Company's position in previous rate cases; 2) a view that the Commission required use of the location method in this case; and 3) their conclusion that the location method results in reasonable classifications.[785]

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[779] Ex. 103, Peppin Rebuttal at 26.
[780] Ex. 103, Peppin Rebuttal at 26.
[781] Ex. 103, Peppin Rebuttal at 27; Company Initial Brief at 128.
[782] Ex. 103, Peppin Rebuttal at 25-26.
[783] Ex. 343, Maini Direct at 24-25; Ex. 345, Maini Surrebuttal at 17-18; Ex. 262, Pollock Rebuttal at 16-23.
[784] Ex. 408, Ouanes Direct at 35; Ex. 377 Nelson Rebuttal at 18.
[785] Ex. 408, Ouanes Direct at 29-34; Ex. 414, Ouanes Surrebuttal at 7-8; Ex. 377, Nelson Rebuttal at 14-18.

476. The Company and XLI explained that it is common to refine CCOSS methodologies based on new or better information.[786] In this case, the Company stated its evaluation of the 117 different cost items that make up Other Production O&M was a new analysis not previously performed in past cases.[787] Therefore, the Company and XLI concluded the Company's decision to refine its methodology based on new information to be both reasonable and consistent with past practice.[788]

477. The Company and XLI also pointed out that Company's evaluation of different methodologies for classifying Other Production O&M costs was consistent with the broader intent expressed in the Commission's Order in the 2013 rate case.[789] Finally, the Company, XLI and MCC all asserted the detailed examination conducted under the predominant nature method results in more accurate reflection of cost-causation than occurs under the proxy-based location method.[790]

478. Parties appear to agree with the Company's classification of chemicals and water use as being energy-related;[791] this classification is reasonable and should be adopted.

479. The Company's use of the predominant nature method in its proposed CCOSSs is reasonable. The predominant nature method is a refinement of past practice supported by a new analysis. The Company's examination of each of the 117 cost items that make up Other Production O&M avoids the need to rely on proxies in the classification process. The method is also considered "common" practice, while the locational method is "not standard."[792] The Company's proposal is therefore reasonable and should be adopted.

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786 Ex. 104, Peppin Surrebuttal at 6-8; Ex. 262, Pollock Rebuttal at 19.
787 Ex. 104, Peppin Surrebuttal at 8-9.
788 Ex. 103, Peppin Rebuttal at 27; Ex. 262, Pollock Rebuttal at 18-19.
789 Ex. 102, Peppin Direct at 25; Ex. 262, Pollock Rebuttal at 18.
790 Ex. 103, Peppin Rebuttal at 27-28; Ex. 343, Maini Direct at 24-25; Ex. 262, Pollock Rebuttal at 21.
791 Ex. 408, Ouanes Direct at 35; Ex. 377 Nelson Rebuttal at 18; Ex. 343, Maini Direct at 25; Ex. 262, Pollock Rebuttal at 16-23; Tr. Vol. 4 at 100-101 (Ouanes).
792 Ex. 103, Peppin Rebuttal at 25 (quoting page 66 of the National Association of Regulatory Commissioners, Electric Utility Cost Allocation Manual (Jan. 1992)).

3. Customer-Related Distribution Costs

480. The cost of primary lines, secondary lines, secondary transformers and service drops are classified as both demand-related and customer-related costs in the Company's CCOSS.[793] The Commission has explained this classification process as follows:

> Utility distribution plant is installed to extend service to customers and to meet their peak demand requirements. Because this distribution plant serves two purposes, total distribution costs are classified as both customer and demand-related. Imputing a minimum distribution system is a common method for deriving this breakdown. If utilities were concerned with only extending service to customers and meeting their minimum requirements, they would install the smallest possible distribution system. The cost of installing this theoretical minimum system is then classified as customer-related, while remaining distribution costs are classified as demand-related.[794]

481. The Company separates distribution costs into demand-related and customer-related components using the Minimum Distribution System (MDS) method. The Company has used this method in each of its electric rate cases since at least 1985.[795]

482. The OAG recommended a 10 percent adjustment to the Company's classification of distribution costs.[796] The OAG asserted the adjustment is appropriate because the MDS method overestimates customer-related costs and that

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793 Ex. 103, Peppin Rebuttal at 28-29.

794 *In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 74, Docket No. E002/GR-91-1 (Nov. 27, 1991).

795 Ex. 103, Peppin Rebuttal at 28. *See also In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Utility Service for Customers within the State of Minnesota*, ORDER at 28, Docket No. E002/GR-85-558 (June 2, 1986)(indicating the Company's CCOSS was performed using the MDS method)(*hereinafter* E002/GR-85-558 ORDER).

796 Ex. 378, Nelson Surrebuttal at 10; Ex. 142, Nelson Opening Statement at 1.

the zero-intercept method is superior.[797] The OAG also contended an adjustment is appropriate because there is smaller equipment installed on the Company's system and because the Company does not have the original cost data used to develop the assumptions supporting its minimum system study.[798]

483. The Company maintained that its classification of distribution related costs into customer-related and capacity-related components is reasonable for use in this case.[799] According to the Company, both the MDS method and the zero-intercept method are accepted practice.[800] Further, the Company stated the OAG's position that the MDS method overestimates the customer-related portion of distribution costs was not supported in the record.[801] Finally, the Company pointed out that the Commission has identified the MDS method as a "common method" for separating distribution costs into demand-related and customer-related components and has approved or required use of the MDS method for all Minnesota electric utilities.[802]

484. The Company also disagreed that the other reasons cited by the OAG justify an adjustment. The Company explained that the minimum sized equipment used in its minimum system study was established in preparation for the Company's

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797 Ex. 375, Nelson Direct at 16.

798 Ex. 378, Nelson Surrebuttal at 10; Ex. 142, Nelson Opening Statement at 1.

799 Ex. 103, Peppin Rebuttal at 36-37; Company Initial Brief at 131.

800 Ex. 103, Peppin Rebuttal at 29-31; Company Initial Brief at 130 (citing Ex. 143, Excerpts from the National Association of Regulatory Commissioners, <u>Electric Utility Cost Allocation Manual at 9 (page 90 of the manual)</u>).

801 Company Initial Brief at 130.

802 Ex. 103, Peppin Rebuttal at 29-30; Xcel Energy Initial Brief at 130 (citing *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION at ¶ 481, Docket No. E017/GR-10-239 (Feb. 14, 2011)(adopted by FINDINGS OF FACT, CONCLUSIONS AND ORDER at 7 (Apr. 25, 2011)); *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, FINDINGS OF FACT, CONCLUSIONS AND ORDER at Order Point 15.C., Docket No. E001/GR-10-276 (Aug. 12, 2011)(*hereinafter* E001/GR-10-276 ORDER); *In the Matter of the Application of Minnesota Power for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota*, Docket No. E015/GR-94-001, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 51 (Nov. 22, 1994)(indicating Minnesota Power performed a minimum distribution study and requiring further discussion of its methodology in the company's next rate case)).

1992 rate case based the minimum sized equipment being installed at that time.[803] According to the Company's distribution witness, the minimum sized equipment used in the study (based on 1992 standards) reasonably approximates the minimum size equipment being installed today, though some differences do exist.[804] For example, the current minimum sized poles and transformers are larger than what is used in the minimum system study, while the minimum sized single-phase primary underground conductor is smaller than what is used in the minimum system study.[805] All else being equal, the Company stated that the current minimum sized poles and transformers are more expensive than the equipment used in the minimum system study and the current minimum sized single-phase primary underground conductor is less expensive than what is used in the study.[806]

485. The Company concluded that focusing only the current equipment that is smaller than what is in the study and ignoring current equipment that is larger and more expensive than what is in the study leads to an arbitrary adjustment.[807]

486. Regarding the cost data used in the minimum system study, the Company explained that it escalated the original per unit installed cost of the minimum sized equipment using the Handy-Whitman construction cost index.[808] The Company said it used the escalation method because it does not track minimum sized distribution equipment on an installed cost basis.[809] The Company also stated that while it did not have the historical records need to replicate the development of the original per unit installed costs of the minimum sized equipment,[810] the per unit costs and escalation method used in this case were the same as what was used in the

803 Ex. 70, Foss Rebuttal at 2-4.
804 Ex. 70, Foss Rebuttal at 4.
805 Ex. 70, Foss Rebuttal at 4-8.
806 Ex. 70, Foss Rebuttal at 4-8.
807 Company Initial Brief at 131.
808 Ex. 103, Peppin Rebuttal at 33; Ex. 104, Peppin Surrebuttal at 5.
809 Ex. 104, Peppin Surrebuttal at 5.
810 Ex. 377 Nelson Rebuttal at Schedules REN-19 – REN-21.

Company last six rate cases.[811] Finally, the Company explained, and the OAG eventually acknowledged, that the Company appropriately accounts for the minimum load associated with the minimum sized system, which was another justification previously relied upon by the OAG.[812]

487. The Company separated demand related costs into customer-related and demand-related components using the same methodology as it has used in its past six rate cases. There is no evidence in the record supporting the contention that the MDS method automatically over-estimates customer-related costs. Further, the OAG's recommended adjustment is, by the OAG's own admission, arbitrary.[813] Arbitrarily changing a cost classification is not reasonable.[814] The Company's classification of distribution related costs into customer-related and capacity-related components is reasonable for use in this case.

488. Consistent with the OAG's recommendation and the Company's commitment, the Company should fully reexamine all of the assumptions supporting its minimum system study, including the engineering assumptions supporting the minimum sized equipment and the installed cost of the minimum sized equipment.[815] To the extent the Company is able to gather sufficient data, the Company should also include a zero-intercept analysis as part of the initial filing of its' next rate case.

4. Classification of Fixed Production Plant

489. The Company classifies fixed production plant into capacity-related and energy-related sub-functions using the Plant Stratification method.[816] Under this

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811 Ex. 104, Peppin Surrebuttal at 5.
812 Tr. Vol. 3 at 247-248 (Nelson); Ex. 375, Nelson Direct at 24-25.
813 Ex. 375, Nelson Direct at 26; Tr. Vol. 3 at 249-250 (Nelson).
814 E002/GR-85-558 ORDER at 28-29 ("The ALJ rejected the three modifications [to the Company's CCOSS] suggested by the RUD-AG. He rejected the minimum system adjustment because there is no indication in the record that the RUD-AG's proposed solution does anything but produce an arbitrary number for the amount of customer costs…. The Commission agrees in every respect with the findings of the ALJ regarding the class cost of service study and adopts his findings and supporting discussion as its own.")
815 Ex. 103, Peppin Rebuttal at 35; Ex. 104, Peppin Surrebuttal at 6; Ex. 375, Nelson Direct at 26.
816 Ex. 102, Peppin Direct at 12.

method, the capacity-related portion of fixed production plant is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant.[817] The percent of total generation costs that exceed the cost of a comparable peaking plant are classified as energy-related.[818]

490. The Company claimed the advantage of Plant Stratification is that it recognizes the duel benefits associated with baseload and intermediate generation resources.[819] For example, according to the Company, a significant portion of the fixed costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher fixed costs associated with such plants, thereby minimizing total cost.[820] Plant Stratification assigns a portion of the cost of these plants to energy and a portion to capacity.[821]

491. The MCC requested that the Plant Stratification method be replaced by the Straight Fixed-Variable (SFV) method.[822] According to the MCC, fixed production plant is built to serve demand and reserve margin requirements and is therefore appropriately classified as capacity.[823] Under the MCC's SFV method, fuel and other variable costs associated with the throughput derived from fixed production plant investments are classified as energy-related.[824] MCC stated the move to the SFV method would be reasonable because it would send better price signals, would improve load factors and help address the addition of policy-based resources to the system.[825]

492. The Company stated the movement to the SFV method would be a significant departure from past precedent and would lead to a significant shift in inter-

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[817] Ex. 102, Peppin Direct at 12.
[818] Ex. 102, Peppin Direct at 12.
[819] Ex. 102, Peppin Direct at 13-14; Ex. 103, Peppin Rebuttal at 10.
[820] Ex. 102, Peppin Direct at 13-14.
[821] Ex. 102, Peppin Direct at 12-13.
[822] Ex. 343, Maini Direct at 19.
[823] Ex. 343, Maini Direct at 17; Ex. 345, Maini Surrebuttal at 22.
[824] Ex. 343, Maini Direct at 16-21.
[825] Ex. 343, Maini Direct at 17-19; Ex. 345, Maini Surrebuttal at 12-13.

class cost responsibilities.[826] Also, the Company pointed out the SFV method does not reflect the dual nature of baseload and intermediate fixed production plant.[827]

493. As pointed out by the Commission in the Company's previous rate cases,[828] and in several other recent electric rate cases,[829] Plant Stratification recognizes baseload and intermediate generation resources provide both energy and capacity, and that a significant portion of the fixed costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher fixed costs associated with such plants, thereby minimizing total cost. The continued use of the Plant Stratification methodology is therefore reasonable.

494. XLI did not challenge the use of the Plant Stratification method, but instead recommended modifying the Company's Plant Stratification analysis in two ways: 1) replace the current-dollar replacement value of a peaker with the estimated cost of a new peaking plant used by the Company to calculate the Windsource capacity credit and 2) replace current-dollar replacement costs for each plant type with depreciated replacement values.[830]

495. The Company, Department and OAG all opposed the XLI's recommended change to the Plant Stratification methodology.[831] The Company and Department asserted the XLI's stratification analysis was not performed on an apples-to-apples basis, but rather mixed depreciated and undepreciated costs.[832]

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826 Ex. 102, Peppin Direct at 11-12 (stating the Company has used Plant Stratification in its CCOSSs since the 1970's); Ex. 103, Peppin Rebuttal at 10 (identifying an approximately $19.8 million increase in Residential class cost responsibility under the SFV method). *See also* E001/GR-10-276 ORDER at 50; E017/GR-07-1178 ORDER at 69.
827 Ex. 103, Peppin Rebuttal at 10.
828 E002/GR-10-971 ORDER at 20; E002/GR-08-1065 ORDER at 44.
829 E001/GR-10-276 ORDER at 50; *In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E017/GR-07-1178, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 69 (Aug. 1, 2008)(*hereinafter* E017/GR-07-1178 ORDER). Note that plant stratification is referred to as "the equivalent peaker methodology" in the Commission's ORDERS in Docket Nos. E001/GR-10-276 and E017/GR-07-1178.
830 Ex. 260, Pollock Direct at 33, 36.
831 Ex. 103, Peppin Rebuttal at 11-12; Ex. 412, Ouanes Rebuttal at 10-11; Ex. 377, Nelson Rebuttal at 7-10.
832 Ex. 103, Peppin Rebuttal at 11-12; Ex. 412, Ouanes Rebuttal at 10-11.

Table 2
Comparison of Plant Stratification Calculations[833]

Calculation	Company	XLI
Numerator	Current-Dollar CT Replacement Cost	Undepreciated Cost of New CT
Denominator	Current-Dollar Plant Type Replacement Cost	Depreciated Plant Type Replacement Cost

496. The Company and Department stated that when XLI's methodology is corrected to place the numerator and denominator on comparable grounds (by comparing the cost of a new peaker to the cost of new nuclear, fossil and other resources), more fixed production plant is classified as energy-related than is the case under the Company's Plant Stratification methodology.[834]

497. The OAG also showed that the XLI's methodology implies that as generation ages, it begins to meet customers' demand instead of their energy needs.[835]

498. The XLI's methodology is unreasonable and should not be adopted.

5. Company-Owned Wind

499. The Company's CCOSSs include four Company-Owned wind projects: Nobles, Grand Meadow, Borders and Pleasant Valley.[836] Nobles and Grand Meadow are included in both the 2014 and 2015 CCOSSs, while Pleasant Valley and Borders are included in the 2015 CCOSS.[837]

500. The Company classified Pleasant Valley and Borders into capacity-related and energy-related components using the Plant Stratification method, similar to other fixed production plant.[838] The Department and OAG agreed with this

[833] Company Initial Brief at 133.
[834] Ex. 103, Peppin Rebuttal at 11-12; Ex. 412, Ouanes Rebuttal at 11.
[835] Ex. 377 Nelson Rebuttal at 9.
[836] Ex. 103, Peppin Rebuttal at 16.
[837] Ex. 103, Peppin Rebuttal at 16.
[838] Ex. 103, Peppin Rebuttal at 16.

treatment.[839] The MCC did not take a specific position on the classification and allocation of Pleasant Valley and Borders, but rather recommends these projects be recovered through riders.[840]

501. The Company classified Nobles and Grand Meadow as 100 percent capacity-related.[841] The Company asserted the projects should be treated differently from Pleasant Valley and Borders on grounds of cost causation.[842] According to the Company, Nobles and Grand Meadow were acquired to fulfill the Company's Renewable Energy Standard (RES) obligations,[843] while Borders and Pleasant Valley were acquired to minimize system costs, consistent with how other fixed production plant is added to the system.[844]

502. The Department and OAG did not support the Company's proposed treatment of Nobles and Grand Meadow. The Department recommends classifying all Company-owned wind, including Nobles and Grand Meadow, using the Plant

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839 Ex. 408, Ouanes Direct at 27; September 26, 2014 Letter from Ian Dobson, Assistant Attorney General to the Honorable Jeanne Cochran.

840 September 30, 2014 Letter from Richard J. Savelkoul to the Honorable Jeanne M. Cochran.

841 Ex. 103, Peppin Rebuttal at 16.

842 Ex. 102, Peppin Direct at 27; Ex. 103, Peppin Rebuttal at 17.

843 Ex. 102, Peppin Direct at 27-28; Ex. 103, Peppin Rebuttal at 17 and Schedule 5 (citing *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for the Grand Meadow Wind Farm*, Docket No. E002/CN-07-873, ORDER (Dec. 24, 2007); *In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation, for Approval of Investments in Two Wind Power Projects: 200 MW Nobles Wind Project and 150 MW Merricourt Wind Project*, Docket No. E002/M-08-1437, ORDER APPROVING INVESTMENTS AND EXPENDITURES, FINDING THE NOBLES PROJECT EXEMPT FROM OBTAINING A CERTIFICATE OF NEED, AND ADDING REQUIREMENTS (June 10, 2009)).

844 Ex. 103, Peppin Rebuttal at 17 and Schedule 5 (citing *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 600 MW of Wind Generation*, Docket No. E002/M-603, *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 150 MW of Wind Generation*, Docket No. E002/M-13-716, ORDER APPROVING ACQUISITIONS WITH CONDITIONS at 9-10 (Dec. 13, 2013)("In the current dockets, Xcel acquired new facts when it received bids for new wind turbine projects demonstrating that wind power had become more competitive with other sources of electricity. And Xcel adapted. In brief, Xcel concluded that it could operate more efficiently by increasing its reliance on electricity from wind and reducing its reliance on electricity from other sources such as fossil fuels. And Xcel identified the best available new wind resources via a competitive bidding process. Xcel's filings support these assertions, and no party presented evidence challenging either assertion.")).

Stratification method;[845] the OAG recommended classifying Nobles and Grand Meadow as 100 percent energy related.[846]

503. Both the Department and OAG maintained the Company's proposed treatment of Nobles and Grand Meadow conflicted with its position in previous cases and past Commission treatment of the projects.[847] The Department also stated there are theoretical arguments against classifying any generation facility as 100 percent demand-related.[848]

504. The OAG asserted that its recommended treatment was appropriate because the Company's RES obligations are measured on an energy basis, not capacity.[849] The OAG also cited the NARUC manual for the proposition that capital costs that reduce fuel costs should be classified as energy-related and drew the conclusion that Nobles and Grand Meadow were added to reduce fuel consumption.[850]

505. The MCC recommended that all renewable investment be allocated using base revenues.[851] The MCC stated this method implicitly includes both energy and capacity elements and mimics existing rate design.[852]

506. The Company acknowledged that it had supported different classification methodologies for Nobles and Grand Meadow in the past, but asserted that the new information available in this case made the Company's proposed refinement reasonable.[853] Specifically, the Company stated there is a clear difference

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845 Ex. 408, Ouanes Direct at 27.
846 Ex. 375, Nelson Direct at 10. The OAG identifies plant stratification as "an acceptable method," though it supports a 100 percent energy classification as being most appropriate. Ex. 377, Nelson Rebuttal at 13.
847 Ex. 408, Ouanes Direct at 24-26; Ex. 377 Nelson Rebuttal at 11-13.
848 Ex. 408, Ouanes Direct at 22.
849 Ex. 375, Nelson Direct at 8.
850 Ex. 375, Nelson Direct at 9.
851 Ex. 343, Maini Direct at 23. The MCC did not take a specific position on the allocation of Pleasant Valley and Borders, but rather recommends these projects be recovered through riders. *See* September 30, 2014 Letter from Richard J. Savelkoul to the Honorable Jeanne M. Cochran.
852 Ex. 343, Maini Direct at 23.
853 Ex. 103, Peppin Rebuttal at 19-20.

between renewables that were added to minimize system costs (Pleasant Valley and Borders) and those added to fulfill RES obligations.[854] The Company and XLI both indicated that it is common to refine CCOSS methodologies in the face of new or better information.[855]

507. The Company disagreed with the Department's recommendation to apply the Plant Stratification methodology to Nobles and Grand Meadow.[856] According to the Company, Plant Stratification mirrors least-cost planning by recognizing a tradeoff between the lower-capital cost of peaking plants and the fuel savings achieved through intermediate and baseload plants.[857] The Company stated it did not engage in this tradeoff when pursuing Nobles and Grand Meadow, making the Plant Stratification method inappropriate.[858]

508. The Company also disagreed with the OAG's 100 percent energy classification.[859] The Company stated that Nobles and Grand Meadow were acquired to comply with the RES obligation, and that if the Company was only interested in procuring energy, it may have pursued other options.[860]

509. Finally, in response to both the Department and the OAG, the Company contended that the operational characteristics of Nobles and Grand Meadow were not relevant because the projects were not pursued for operational purposes.[861]

510. Pleasant Valley and Borders were added to minimize system costs on the same basis as other production plant. It is therefore reasonable to classify these projects using the Plant Stratification method.

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854 Ex. 103, Peppin Rebuttal at 17-18.
855 Ex. 104, Peppin Surrebuttal at 6-8; Ex. 262, Pollock Rebuttal at 19.
856 Ex. 103, Peppin Rebuttal at 19.
857 Ex. 103, Peppin Rebuttal at 19.
858 Ex. 102, Peppin Direct at 27-28; Ex. 103, Peppin Rebuttal at 19.
859 Ex. 103, Peppin Rebuttal at 19.
860 Ex. 103, Peppin Rebuttal at 19.
861 Ex. 103, Peppin Rebuttal at 18.

511. As for Nobles and Grand Meadow, there are four alternatives before the Commission:

Table 3
Percentage of Nobles and Grand Meadow Costs Allocated to Classes[862]

	Residential	C&I Non-Demand	C&I Demand	Lighting
OAG (100% Energy)	28.91%	3.29%	67.37%	0.43%
Department (Plant Stratification)	29.16%	3.31%	67.12%	0.41%
Company (100% Capacity)	34.52%	3.68%	61.80%	0.00%
MCC (Base Revenues)	39.22%	4.03%	55.57%	1.18%

512. Nobles and Grand Meadow were acquired on a different basis than Pleasant Valley and Borders, meaning a different classification method is appropriate.

513. The cost allocation under the Company's proposal reasonably reflects the policy nature of the Nobles and Grand Meadow projects and is reasonable overall; it should be adopted.

6. Calculation of the D10S Capacity Allocator

514. The D10S capacity allocator is calculated based on each class's load that is coincident with the NSP System peak, as measured by the forecasted test year class hourly load shapes.[863]

515. The OAG asserted the allocator should be calculated using each class's load at the hour of the MISO peak, not the Company's peak.[864]

516. The Company explained that the OAG's proposed calculation would require MISO to publish an hourly forecast that is compatible with the test year, which MISO currently does not do.[865] The Company also noted that there is no way

[862] Ex. 103, Peppin Rebuttal at 22.
[863] Ex. 103, Peppin Rebuttal at 37.
[864] Ex. 375, Nelson Direct at 13; Ex. 378, Nelson Surrebuttal at 13.
[865] Ex. 103, Peppin Rebuttal at 37-38.

of knowing how each class' share of the MISO peak differs from each class' share of the NSP system peak.[866]

517. The OAG responded that the MISO peak occurs earlier in the day than does the NSP peak and residential customers would represent a lower proportion of the MISO peak.[867]

518. XLI asserted that the NSP system peak was the key factor in determining resource need and that the OAG had provided no evidence supporting a different calculation.[868]

519. In order to calculate the D10S allocator based on the MISO peak, MISO would need to publish an hourly forecast that is compatible with the test year. MISO does not publish such a forecast, making the OAG's recommendation unfeasible.

7. Allocation of Economic Development Discounts

520. In the 2013 rate case, the Commission decided that all classes should share in the cost of economic development discounts, but ordered the Company to provide additional information in this case regarding the appropriate cost allocation.[869]

521. In response, the Company evaluated different allocation options in its Direct Testimony;[870] the Department and OAG recommended an additional option.[871]

Table 4
Percentage of Nobles and Grand Meadow Costs Allocated to Classes[872]

Allocation Method	Residential	C&I Non-Demand	C&I Demand	Lighting
100% Energy / Sales (DOC, OAG)	28.1%	3.1%	68.2%	0.6%
Present Revenues (Company, XLI)	35.9%	3.8%	59.4%	0.9%
Present Base Revenues (MCC)	39.2%	4.0%	55.6%	1.2%

866 Ex. 103, Peppin Rebuttal at 38.
867 Ex. 378, Nelson Surrebuttal at 12-13.
868 Ex. 262, Pollock Rebuttal at 24-26.
869 ORDER IN 2013 RATE CASE at Order Points 34 and 57.
870 Ex. 102, Peppin Direct at 18.
871 Ex. 408, Ouanes Direct at 39; Ex. 375, Nelson Direct at 31.
872 Ex. 103, Peppin Rebuttal at 22.

522. The Company, XLI and MCC maintained that the Company's economic development programs are designed to attract and retain large customers.[873] These parties therefore support allocations they claim are consistent with the purpose of the economic development programs.[874]

523. The Department and OAG recommend allocating economic development discounts using an energy-only allocator because the discounts are based on customers' energy usage.[875]

524. The Company's proposed allocation of economic development discounts is more consistent with the purpose of the economic development discount program than is the recommendation of the Department and OAG. The Company's preferred methodology should be adopted.

8. Interruptible Credits

525. The Company's CCOSS process treats interruptible credits as a cost of peaking capacity and, like other supply-side resources, allocates the costs to customer classes based on firm loads.[876]

526. As it has in past cases, the XLI asserted that the Company's treatment of interruptible credits in the CCOSS violates the matching principle.[877] According to the XLI, the CCOSS needs to be adjusted by restated class revenues at otherwise applicable firm rates and then reallocating payments to all classes relative to demand.[878]

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873 Ex. 102, Peppin Direct at 19; Ex. 103, Peppin Rebuttal at 41. Ex. 262, Pollock Rebuttal at 22-23; Ex. 345, Maini Surrebuttal at 19.
874 Ex. 102, Peppin Direct at 19; Ex. 103, Peppin Rebuttal at 41. Ex. 262, Pollock Rebuttal at 22-23; Ex. 345, Maini Surrebuttal at 19.
875 Ex. 408, Ouanes Direct at 39; Ex. 375, Nelson Direct at 31.
876 Ex. 103, Peppin Rebuttal at 13.
877 Ex. 260, Pollock Direct at 46.
878 Ex. 260, Pollock Direct at 46.

527. The Company explained the XLI's cost-causation arguments are not applicable when future avoided costs are higher than average embedded costs, as is the case with the Company's CCOSS.[879] The Company also noted that the Commission has agreed with the Company's treatment of interruptible loads and associated service credits in the Company's last four rate cases.[880]

528. Interruptible credits are power-supply costs and should be treated as such in the CCOSS. The Company's proposed allocation is reasonable and should be approved.

9. Treatment of Capacity Portion of Power Purchase Agreements

529. The OAG initially questioned the Company's proposed classification of the capacity portion of power purchase agreements (PPAs) in the CCOSS.[881] Ultimately, the OAG requested that the Company provide additional information related to PPAs and cost causation in its next rate case filing.[882]

530. The Company's explained that the PPA classification mirrored the classification of other capacity-related costs and that the methodology was used in the 2013 rate case.[883]

531. The Company should include additional discussion of PPAs and cost causation in its next rate case filing.

10. Settled, Resolved or Uncontested CCOSS Issues

a. Separation of Distribution Line Costs

532. The Company changed its allocation of primary distribution line costs based on analysis of data in its Geographic Information System.[884] The MCC agreed with the Company's allocations.[885]

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[879] Ex. 103, Peppin Rebuttal at 14-15. *See also* Company Initial Brief at 138.
[880] Ex. 103, Peppin Rebuttal at 14-15. *See also* Company Initial Brief at 138.
[881] Ex. 375, Nelson Direct at 26.
[882] Ex. 378, Nelson Surrebuttal at 15.
[883] Ex. 103, Peppin Rebuttal at 39.
[884] Ex. 102, Peppin Direct at 25-26.

533. The Company's revision is reasonable and should be adopted.

b. Direct Assignment to Lighting Class

534. Pursuant to Finding 693 from the Administrative Law Judge's report in the Company's 2013 rate case,[886] the Company engaged staff in its Capital Asset Accounting and Distribution Operations areas to identify the specific, Company-owned lighting equipment costs included in each distribution FERC Account.[887] The Company analyzed FERC Accounts 364 (Poles, Towers and Fixtures) and 373 (Street Lighting and Signal Systems).[888] Based on its analysis, the Company directly assigned $54.4 million in 2014 test year FERC Account 373 costs to the Lighting class and $35.2 million in 2014 test year FERC Account 364 costs to the Lighting class, for a total direct assignment of $89.6 million.[889] No other party provided testimony on this topic.

535. The Company's direct assignments are reasonable and should be adopted.

C. Revenue Allocation (Issue # 53)

536. Allocating revenue to customer classes is not formulaic and requires a balancing of several factors.[890] The Commission has stated all of the following are relevant to the rate design process: "economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; ability to bear, deflect, or otherwise compensate for additional costs; and in particular, the cost of service."[891]

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885 Ex. 343, Maini Direct at 26-27.
886 ALJ REPORT IN 2013 RATE CASE at ¶ 693 ("In addition, the Administrative Law Judge recommends that the Company provide a detailed analysis of its street lighting costs, both overhead and underground, as part of its next rate case filing.")
887 Ex. 102, Peppin Direct at 28.
888 Ex. 102, Peppin Direct at 28.
889 Ex. 102, Peppin Direct at 29-30.
890 *St. Paul Area Chamber of Commerce,* 312 Minn. at 260.
891 E002/GR-10-971 ORDER at 14.

537. The Company used four pricing objectives in developing its proposed class revenue allocation:

538. Produce total revenue that matches the revenue requirement for the test year in order to allow the Company a reasonable opportunity to earn its authorized return on investment;

539. Accurately reflect the resource costs of providing service and, where appropriate, the market value of service;

540. Provide sufficient flexibility in pricing levels and provisions for electric service to remain competitive in the broader energy market; and

541. Provide reasonable pricing by considering the importance of rate continuity, customer understanding, revenue stability, and administrative practicality.[892]

542. The Department used similar principles in developing its recommended revenue allocation.[893]

543. In applying their own principles, the Company and Department arrived at slightly different revenue allocations, with the Company recommending a revenue allocation that tracks the cost of service (as measured by the Company's CCOSS) more closely than does the allocation recommended by the Department.[894]

544. The MCC and XLI recommend allocating revenue to fully match cost responsibilities (as measured by their own CCOSSs).[895] The Commercial group recommends moving all classes to cost, but could also accept the Company's recommended revenue allocation if the Company's CCOSS is approved.[896]

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892 Ex. 105, Huso Direct at 6.
893 Ex. 420, Peirce Direct at 2.
894 Ex. 107, Huso Rebuttal at 6-7.
895 Ex. 345, Maini Surrebuttal at 20-21; Ex. 260, Pollock Direct at 37-38, 47.
896 Commercial Group Initial Brief at 11.

545. The OAG recommended no change in the existing revenue apportionment because, according to the OAG's CCOSS, the Residential class is at or very near cost.[897] AARP supports the OAG's recommended revenue allocation.[898]

546. The SRA supports the Company's recommended revenue allocation for the Lighting class.[899]

547. These positions result in the following recommended allocations of the proposed revenue increase in this case.

Table 5
Comparison of Recommended Allocations of Proposed Revenue Increase[900]

2014					
Class	**Company**	**Department**	**OAG**	**MCC**	**XLI**
Residential	7.6%	6.4%	6.2%	10.1%	7.8%
Non-Demand	7.7%	4.8%	6.2%	7.8%	6.6%
C&I Demand	5.4%	6.3%	6.3%	4.2%	5.3%
Lighting	0.0%	0.0%	0.0%	-13.0%	0.0%
Total	6.2%	6.2%	6.2%	6.2%	6.2%
2015					
Class	**Company**	**Department**	**OAG**	**MCC**	**XLI**
Residential	11.3%	9.9%	9.7%	*	*
Non-Demand	11.2%	8.2%	9.7%	*	*
C&I Demand	8.9%	9.8%	9.9%	*	*
Lighting	0.0%	3.1%	1.6%	*	*
Total	9.7%	9.7%	9.7%	*	*

897 Ex. 375, Nelson Direct at 38-39.
898 AARP Initial Brief at 18-19.
899 SRA Initial Brief at 12.
900 Ex. 107, Huso Rebuttal at 5, Tables 3 and 4; Ex. 422, Peirce Surrebuttal at 3-4, Tables 3 and 4; Ex. 375, Nelson Direct at 39, Tables 9 and 10; Ex. 378, Nelson Surrebuttal at 18; Ex. 343, Maini Direct at 20, Table 5; Ex. 345, Maini Surrebuttal at 20-21; Ex. 260, Pollock Direct at 46-47 (indicating XLI's proposed recommendation would move all classes to cost); Ex. 263, Pollock Surrebuttal at 31 and Schedule 22. Note, values for the OAG, MCC and XLI in the above table relate to the Company's proposed Rebuttal Testimony revenue requirement and were adjusted from Direct Testimony positions using the proportional adjustment methodology described on page 13 of Mr. Huso's Direct Testimony. The MCC and XLI did not provide specific allocations for 2015.

548. The Company identified two reasons that justify a moderated, rather than full, movement to cost. First, final rates from the 2013 rate case were implemented on December 1, 2013 and, according to the Company, a moderated movement to cost would maintain rate continuity.[901] Also, the Company proposed to refine its CCOSS as part of this case and the Company stated a moderated movement to cost would allow those changes to be reflected in rates over time.[902]

549. The Department found the Company's proposed revenue allocation would push the Residential class above cost, as measured by the Department's CCOSS.[903] The Department stated its proposed allocation moved all classes closer to cost while moderating the overall rate increases to all classes.[904]

550. The MCC and XLI asserted that cost based rates would help address the competitiveness of the Company's business rates.[905] According to the MCC, uncompetitive business rates ultimately harm all customers through decreased future sales that can produce a need for future rate increases.[906]

551. The Company has demonstrated its recommended revenue allocation is reasonable.

552. The final revenue allocation should be adjusted using the proportional adjustment methodology supported by the Company and the Department.[907]

D. Rate Design Proposals

1. Customer Charge (Issue # 54)

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901 Ex. 105, Huso Direct at 9-10.
902 Ex. 105, Huso Direct at 9-10.
903 Ex. 420, Peirce Direct at 7.
904 Ex. 420, Peirce Direct at 9.
905 Ex. 343, Maini Direct at 30-34; Ex. 260, Pollock Direct at 39-40.
906 Ex. 343, Maini Direct at 33.
907 Ex. 105, Huso Direct at 12-13; Ex. 420, Peirce Direct at 11.

553. The customer charge is intended to recover the fixed cost of serving customers that is not related to energy usage. These fixed costs include metering, service lines, meter reading, and billing.[908]

554. The Company and Department both proposed to increase Residential and Small General Service customer charges.[909] The OAG, CEI, ECC and AARP opposed any increase in customer charges.[910]

Table 6
Comparison of Proposed Customer Charges

Service Category	**Cost of Service**[911]	**Present Charge**[912]	**Company Proposed**[913]	**Department Proposed**[914]
Residential Overhead	$15.70 (Average)	$8.00	$9.25	$8.50
Residential Underground – Standard		$10.00	$11.25	$10.50
Residential Heating – Overhead		$10.00	$11.25	$10.50
Residential Heating – Underground		$12.00	$13.25	$12.50
Small General Service	$16.65	$10.00	$11.50	$10.50

555. The Company and Department both asserted their proposals represent important movements to cost and improve intra-class fairness among the respective customer classes.[915]

556. The Company also stated its proposed customer charges (and associated increases) are comparable to the customer charges recently approved by the Commission in Docket No. G008/GR-13-316.[916] Finally, the Company maintained

908 Ex. 105, Huso Direct at 14.
909 Ex. 105, Huso Direct at 15; Ex. 420, Peirce Direct at 12.
910 Ex. 375, Nelson Direct at 52; Ex. 280, Chernick Direct at 28-29; Ex. 290, Cavanagh Direct at 8; Ex. 234, Colton Direct at 41; Ex. 310, Brockway Direct at 33.
911 Ex. 107, Huso Rebuttal at 29, Table 10.
912 Ex. 107, Huso Rebuttal at 25, Table 9.
913 Ex. 107, Huso Rebuttal at 25, Table 9.
914 Ex. 420, Peirce Direct at 12, Table 6.
915 Ex. 105, Huso Direct at 15; Ex. 420, Peirce Direct at 12.
916 Ex. 107, Huso Rebuttal at 27-28; Company Initial Brief at 142-143.

that its proposed customer charges leave a reasonable amount of customer-related fixed costs in energy charges as a conservation incentive.[917]

557. The Department recommended a smaller increase in the Company's customer charge, based in part, on a comparison to other Minnesota investor-owned electric utilities.[918]

558. The OAG opposed any increase in customer charges.[919] The OAG's opposition was grounded in its view that: 1) the Company's CCOSS overstates customer-related costs;[920] 2) the Company's customer charges have increased four times since 2010;[921] 3) the Company's proposed customer charges would be greater than the customer charges of other investor owned utilities;[922] and 4) the overall magnitude of the increase is too large.[923]

559. CEI claimed customer charges should not be increased because doing so would decrease conservation incentives.[924] CEI also asserted the Company was not calculating customer-related costs correctly and that intra-class equity was not an appropriate rate design consideration.[925]

560. The ECC and AARP both oppose increasing the customer charge on conservation and affordability grounds.[926]

561. The Company's proposed customer charges are reasonable and should be adopted. Increases of $1.25 and $1.50 per month are consistent with the Commission's recent decision in Docket No. G008/GR-13-316. The Company's proposed customer charges help improve intra-class equity, which is an important

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917 Ex. 105, Huso Direct at 16-18; Ex. 107, Huso Rebuttal at 32.
918 Ex. 420, Peirce Direct at 12-13.
919 Ex. 375, Nelson Direct at 52.
920 Ex. 375, Nelson Direct at 42-44; OAG Initial Brief at 77 (citing Ex. 280, Chernick Direct at 28 and Ex. 293, Chernick Rebuttal at 6-8).
921 Ex. 375, Nelson Direct at 40-42.
922 Ex. 378, Nelson Surrebuttal at 23.
923 Ex. 375, Nelson Direct at 40-41, 44-52.
924 Ex. 280, Chernick Direct at 26-27; Ex. 290, Cavanagh Direct at 8-9.
925 Ex. 280, Chernick Direct at 27-29; Ex. 293, Chernick Rebuttal at 4-8, 14-16.
926 Ex. 234, Colton Direct at 35, 40-41; Ex. 310, Brockway Direct at 27, 32-33.

consideration in rate design.[927] Further, both the Company and Department have shown that low-income customers exist throughout the usage spectrum,[928] which raises questions about the prudence of using the customer charge as means of addressing affordability. Finally, the OAG and CEI are incorrect about the calculation of customer-related costs,[929] negating their cost-based arguments.

2. Interruptible Rates (Issue # 52)

562. The Company proposed to increase the level C Performance Factor discounts by six percent, with corresponding increases at the other Performance Factors to maintain the current relationship between tiers and Performance Factors.[930]

Table 7
Present and Company's Proposed Interruptible Discounts
(Average Monthly Discount per kW)

Tier-PF	**2-C**	**2-B**	**2-A**	**1-C**	**1-B**	**1-SN**
Present	$4.30	$3.82	$3.10	$5.05	$4.49	$5.55
Proposed	$4.56	$4.05	$3.15	$5.35	$4.76	$5.85
Increase ($)	*$0.26*	*$0.23*	*$0.05*	*$0.30*	*$0.27*	*$0.30*
Increase (%)	*6.0%*	*6.0%*	*1.6%*	*5.9%*	*6.0%*	*5.4%*

563. The Company contended the proposed increases will improve the its ability to maintain an optimal supply of interruptible load.[931] The Company also stated that its proposed interruptible rate discounts help offset recent and proposed demand charge increases.[932]

564. The Department agreed interruptible rate discounts should be increased, but by a smaller amount than proposed by the Company.[933] The Department stated a

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927 *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 52 (June 9, 2014)(*hereinafter* G008/GR-13-316 ORDER).
928 Ex. 105, Huso Direct at 18-19; Ex. 107, Huso Rebuttal at 31-33; Ex. 420, Peirce Direct at 14-21; Ex. 422, Peirce Surrebuttal at 4-12.
929 Ex. 103, Peppin Rebuttal at 28-37; Ex. 104, Peppin Surrebuttal at 2-6, Schedule 1.
930 Ex. 105, Huso Direct at 26-28.
931 Ex. 105, Huso Direct at 27.
932 Ex. 105, Huso Direct at 27.
933 Ex. 420, Peirce Direct at 26.

smaller increase in interruptible rate discounts is appropriate given the limited number of interruptions over the last several years and the Company's statement that it has sufficient levels of interruptible load.[934]

565. The MCC and XLI both supported larger increases in interruptible rate discounts. The MCC recommended increasing interruptible rate discounts to $77.24/kW-year for Tier 1, Performance Factor C.[935] The MCC based its proposed interruptible discounts on an avoided cost analysis.[936] XLI advocated for setting Short Notice Demand credits at $6.76 per kW.[937] XLI also relied on avoided cost analysis.[938]

566. The Company stated that avoided cost is a useful reference point for assessing the value of interruptible service, but asserted that avoided cost cannot be used to directly set interruptible rate interruptible rate discounts.[939]

567. The Company, MCC and XLI each stated the value of interruptible service stems from the option to interrupt, not necessarily the number of interruptions.[940]

568. Interruptible load has decreased since the Company's last rate case.[941] In the face of such declines, increasing interruptible rate discounts should help the Company maintain an optimal supply of interruptible load.[942] However, the discounts proposed by the MCC and XLI are based on avoided cost, which cannot be directly applied to embedded cost rates. The levels proposed by the Company are reasonable and should be adopted.

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[934] Ex. 420, Peirce Direct at 26.
[935] Ex. 343, Maini Direct at 41; MCC Initial Brief at 27.
[936] Ex. 343, Maini Direct at 38; Ex. 340, Schedin Direct at 23-24.
[937] Ex. 260, Pollock Direct at 55.
[938] Ex. 260, Pollock Direct at 53-55.
[939] Ex. 107, Huso Rebuttal at 36-37.
[940] Ex. 107, Huso Rebuttal at 35-36; Ex. 345, Maini Surrebuttal at 22; Ex. 263, Pollock Surrebuttal at 36.
[941] Ex. 345, Maini Surrebuttal at 24; Ex. 145, Mani Opening Statement at 1 and Attachment A (Company response to MCC-157).
[942] Ex. 105, Huso Direct at 27.

3. Inclining Block Rates (Issue # 80)

569. CEI and ECC initially recommended the Company implement a four-block inclining block rate (IBR) rate structure to promote conservation and affordability.[943]

570. The Company questioned whether an IBR could effectively deliver conservation and asserted an IBR could lead to adverse customer impacts.[944] The Company also raised concerns regarding the administration of an IBR.[945] Finally, the Company cautioned that an IBR should not be implemented in this case without further examination of important issues, including ways to mitigate impacts on certain customers and how the IBR would be implemented.[946]

571. The Department initially recommended further study of IBR and the implementation of a parallel billing for one year.[947]

572. The Company, CEI, ECC, and the Suburban Rate Authority entered into a Stipulation Agreement on Inclining Block Rates during the Evidentiary Hearing.[948] The parties to the Stipulation requested that the Commission open a new docket in which the Company would file a proposal for an IBR rate structure, in a form of compliance filing, 120 days after the Commission issues its final order in this proceeding.[949] The Stipulation also asks that all the evidence and arguments regarding the IBR from this case be incorporated into the new docket.[950]

573. The Department agreed that the IBR structure can be considered and implemented outside of a general rate case and noted that it no longer supported a requirement related to parallel billing.[951] The Department also agreed to convene

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[943] Ex. 280, Chernick Direct at 3; Ex. 234, Colton Direct at 4.
[944] Ex. 107, Huso Rebuttal at 10-21.
[945] Ex. 107, Huso Rebuttal at 21-23.
[946] Ex. 74, Gersack Surrebutal at 2-5; Ex. 108, Huso Surrebuttal at 2-6.
[947] Ex. 416, Grant Rebuttal at 5-6.
[948] Ex. 135, Stipulation on Inclining Block Rates.
[949] Ex. 135, Stipulation on Inclining Block Rates.
[950] Ex. 135, Stipulation on Inclining Block Rates.
[951] Ex. 446, Grant Opening Statement at 1-2.

stakeholder meetings and review the Company's IBR proposal, as stated in the Stipulation Agreement, if the Commission so orders.[952]

574. The OAG concluded the CEI IBR was not adequately developed and could not be implemented in this case.[953] The OAG also did not support the Stipulation because, in the opinion of the OAG, the evaluation process described in the Stipulation is too limited.[954]

575. IBR is not sufficiently developed to be adopted in this case. The Stipulation describes a process for additional review and development; it should be adopted. To the extent the process described in the Stipulation should be expanded or modified to address the concerns of the OAG, the Commission may do so in its final Order in this case.

E. Settled, Resolved or Uncontested Rate Design Issues

1. Low-Income Discount Program (Issue # 55)

576. The Company's Low-Income Discount Program provides eligible customers with bill payment assistance and/or discounts for their electric service; the program includes two components: the Discount Program and PowerOn.[955] The Department initially recommended expanding the Discount Program to include customers eligible for LIHEAP assistance, whether or not they are receiving such funds.[956] The Company and ECC questioned whether the expansion could be accomplished under current Minnesota law.[957] The Company also stated expansion

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952 Ex. 446, Grant Opening Statement at 1-2.
953 Ex. 377, Nelson Rebuttal at 23.
954 OAG Initial Brief at 75.
955 *See In the Matter of a Petition by Northern States Power d/b/a Xcel Energy for Approval of its Electric Lower Income Program Meter Surcharge*, Docket No. E002/M-10-854, ORDER APPROVING INCREASE IN COST RECOVERY FOR ELECTRIC LOW INCOME ENERGY PROGRAM at 2 (Jan. 28, 2011).
956 Ex. 416, Grant Rebuttal at 6.
957 Ex. 74, Gersack Surrebuttal at 11; Ex. 240, Marshall Surrebuttal at 8-9.

would also require additional administrative resources.[958] The Department eventually withdrew its proposal.[959]

2. Level of Economic Development Discounts (Issue # 56)

577. The Department recommended setting the 2014 and 2015 Competitive Response Rider (CRR) economic development discounts at 2013 levels.[960] The Company agreed to the Department's proposal for this case.[961]

578. The 2014 and 2015 Competitive Response Rider (CRR) economic development discounts should be set equal to the actual 2013 economic development discounts.

3. FCA Rider / Base Cost of Energy – Nuclear Disposal Fees (2014) (Issue # 57)

579. The Department noted that the Company collects the DOE spent nuclear disposal fees through the FCA and that the Company received notification from the DOE that the disposal fee was reduced to zero effective May 16, 2014.[962]

580. The Company responded that the spent nuclear fuel disposal fee is included in the 2014 test year as a component of the cost of fuel as well as fuel revenue (making it cost neutral), therefore the test year revenue deficiency is not materially affected by the removal of the disposal fee from the test year.[963] The Company recommended that the base cost of energy be adjusted to reflect the removal of the disposal fee in compliance at the conclusion of this case.[964]

581. The Company's proposal to reflect the removal of the disposal fee in compliance at the conclusion of this case is reasonable and should be adopted.

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958 Ex. 74, Gersack Surrebuttal at 10-11 (discussing the additional verification process required under the Department's proposal and the funding cap and fixed discounts implemented as part of 2014 Minn. Laws Ch. 254, § 8 (amending 216B.16, subd. 14)).
959 Department of Commerce September 30, 2014 Comments on Issues Matrix at 51.
960 Ex. 408, Ouanes Direct at 41-44.
961 Ex. 107, Huso Rebuttal at 38-39.
962 Ex. 408, Ouanes Direct at 14-18.
963 Ex. 90, Heuer Rebuttal at 14.
964 Ex. 90, Heuer Rebuttal at 14.

4. CIP Rider: CCRC and CAF (Issue # 58)

582. The Company proposed to zero out and remove Conservation Cost Recovery Charge (CCRC) from base rates and recover all CIP program costs through the CIP Adjustment Factor (CAF).[965] The Company agreed that the CCRC be zeroed out when final rates are implemented and agreed to submit an updated Conservation Cost Recovery Adjustment (CCRA) filing 90 days before final rates are estimated to go into effect.[966]

583. The Department supported the Company's proposal.[967]

584. The Company's proposal is reasonable and should be adopted.

5. Windsource Rider (Issue # 59)

585. The Department recommended that the Company identify and justify any changes to historical data in future Windsource and FCA filings and that the Company use consistent terminology in these filings.[968] The Company accepted the Department's recommendation.[969]

586. The Department's proposal is reasonable and should be adopted.

6. Time-of-Day Energy Charges / Energy Charge Credit (Issue # 60)

587. The Department recommended the Commission approve the Company's proposed TOD Energy Charge methodology and the proposed increase in the energy charge credit.[970]

588. The Company's proposal is reasonable and should be adopted.

7. Firm Service Demand Charges (Issue # 61)

589. The Company proposed to increase firm service demand charges.[971] No other party provided testimony on this issue.

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965 Ex. 102, Peppin Direct at 33.
966 Ex. 90, Heuer Rebuttal at 10-11; Ex. 103, Peppin Rebuttal at 42.
967 Ex. 417, Davis Direct at 3-7.
968 Ex. 408, Ouanes Direct at 6-13.
969 Ex. 102, Peppin Direct at 31-32.
970 Ex. 105, Huso Direct at 21-25; Ex. 420, Peirce Direct at 22-24.

590. The Company's proposal is reasonable and should be adopted.

8. Voltage Discounts (Issue # 62)

591. The Company proposed to increase the demand charge discounts for the Transmission voltage level.[972] No other party provided testimony on this issue.

592. The Company's proposal is reasonable and should be adopted.

9. Base Energy Charges for the C&I Demand Class (Issue # 62A)

593. The Department accepted the Company's base energy charges because they appeared to be consistent with the results of the Department's modified CCOSS.[973]

594. The Company's proposal is reasonable and should be adopted.

V. TARIFF PROPOSALS

A. Coincident Peak Billing (Issue # 71)

595. The MCC proposed to amend the Company's service rules to facilitate coincident peak billing.[974]

596. The Company estimated coincident peak billing would impact at most, nine customers.[975] The Company also asserted the MCC proposal is not consistent with established rate design and that it is inappropriate for distribution capacity costs.[976] While customers may be willing to pay the additional metering costs associated with the program,[977] the Company stated that the MCC did not address cost recovery for the associated billing process changes.[978] Finally, the Company

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[971] Ex. 105, Huso Direct at 25-26.
[972] Ex. 105, Huso Direct at 28.
[973] Ex. 105, Huso Direct at 21; Ex. 420, Peirce Direct at 22.
[974] Ex. 340, Schedin Direct at 24-26; Ex. 342, Schedin Surrebuttal at 13-14.
[975] Ex. 107, Huso Rebuttal at 43.
[976] Ex. 107, Huso Rebuttal at 44.
[977] Ex. 340, Schedin Direct at 25.
[978] Ex. 107, Huso Rebuttal at 44.

maintained that if the nine customers truly are interested in being billed on a coincident peak basis, they can modify their wiring configurations accordingly.[979]

597. The MCC proposal is estimated to impact at most nine customers. At the same time, significant questions remain regarding the benefits associated with this change and the costs to implement the program. The MCC's proposal should not be adopted.

B. Definition of Contiguous (Issue # 72)

598. The MCC raised the issue of the definition of the term "contiguous" in three areas: 1) coincident peak billing; 2) solar projects and tax credits; and 3) Section No. 6, 2nd Revised Sheet No. 19.3 of the Company's Electric Rate Book.[980]

599. The Company contends no definition of "contiguous" is needed in the context of coincident peak billing because that proposal is unreasonable.[981] Next, the Company stated that Minnesota law already addresses the definition of contiguous in the context of solar projects, and that the issue is being explored in Docket No. E999/R-13-729.[982] Finally, the Company provided its interpretation of the term contiguous as it appears in its tariff.[983]

600. The MCC has not demonstrated its recommended change is needed at this time.

C. Definition of Peak Period for Time of Day Rates (Issue # 78)

601. The Company's on-peak period is currently defined as the weekday hours of 9:00 am though 9:00 pm except for seven specific holidays.[984] XLI proposed to limit the on-peak period to summer months.[985]

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979 Ex. 107, Huso Rebuttal at 43; Company Initial Brief at 145.
980 Ex. 340, Schedin Direct at 26; Ex. 342, Schedin Surrebuttal at 14-15.
981 Company Initial Brief at 145-146.
982 Minn. Stat. § 216B.164, subd. 2a (e); Ex. 136, Company response to MCC-251.
983 Ex. 136, Company response to MCC-251.
984 Es. 107, Huso Rebuttal at 44.
985 Ex. 260, Pollock Direct at 58; Ex. 263, Pollock Surrebuttal at 39-42.

602. The Company disagreed with the XLI's proposal. The Company stated its current seasonal demand charges reflect the cost difference associated with system seasonal peak capacity differentials, meaning no change is necessary.[986] The Company also claimed the seasonal peak capacity differential identified by the XLI does not impact the intra-day price differential between on- and off-peak periods.[987]

603. The XLI's proposal is unreasonable and should not be adopted.

D. Settled, Resolved or Uncontested Tariff Proposals

1. Standby Service Tariff – Manner of Service (Issue # 73)

604. MCC requested that its testimony regarding standby rates be included in Docket No. E002/M-13-315.[988] The Company agreed that the testimony could be included in the docket, though the Company did indicate it disagreed with the substance of the MCC's positions.[989]

605. The Commission may, at its option, take notice of the MCC's testimony from this case in Docket No. E002/M-13-315.

2. DG Tariff Change (Issue # 74)

606. MCC requested that the Company file changes certain changes to the DG tariff in a miscellaneous docket.[990] The Company responded that it was under the impression that the Company and MCC had agreed to work through the advisory group Rulemaking to incorporate the DG tariff change.[991] The Company agreed to file the tariff change as a miscellaneous filing.[992]

607. The Company made the DG tariff filing in Docket No. E002/M-14-648 on July 31, 2014, making this item moot.

E. Renewable Energy Purchase Tariff (Renew-a-Source) (Issue # 77)

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[986] Ex. 107, Huso Rebuttal at 45.
[987] Ex. 107, Huso Rebuttal at 45.
[988] Ex. 340, Schedin Direct at 26-30.
[989] Ex. 107, Huso Rebuttal at 40-42.
[990] Ex. 340, Schedin Direct at 22-23.
[991] Ex. 107, Huso Rebuttal at 40.
[992] Ex. 107, Huso Rebuttal at 40.

608. XLI recommended that to match around-the-clock high load customers with renewable energy resources, the Company should develop a specific tariff under which the Company can purchase and sell renewable energy directly to qualifying high load factor customers.[993] The Company would have the leverage of negotiating better prices and matching the output of defined portfolio of renewable resources with the customers' load shapes.[994] XLI recommended that the Commission order the Company to work with interested Parties and develop such a new tariff, to be filed no later than the Company's next rate case.[995] XLI also proposed guidelines for the tariff and recommended that discussions on the tariff should commence within 60 days after the final Order is issued in this case.[996]

609. The Company confirmed its commitment to begin discussions with XLI and other interested stakeholders on developing a program that addresses XLI interests, however, the Company recommended against a particular deadline for commencing discussions or making a specific tariff proposal.[997]

VI. DECOUPLING (ISSUE # 50)

A. Introduction

610. Decoupling is a "regulatory tool designed to separate a utility's revenue from changes in energy sales."[998] Its purpose "is to reduce a utility's disincentive to promote energy efficiency."[999] The Commission has previously approved three different decoupling mechanisms for natural gas utilities.[1000] The Company's proposal is the first electric utility decoupling proposal in this State.[1001]

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993 Ex. 260, Pollack Direct at 60-61.
994 Ex. 260, Pollack Direct at 61.
995 Ex. 260, Pollack Direct at 62.
996 Ex. 260, Pollack Direct at 62.
997 Ex. 100, Clark Rebuttal at 47-48.
998 Minn. Stat. § 216B.2412, subd. 1.
999 Minn. Stat. § 216B.2412, subd. 1.
1000 G008/GR-13-316 ORDER at Order Point 3. *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G007, G011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at Order Point 11 (July 13, 2012)[*hereinafter* G007,

B. The Company's Proposal

611. The Company proposed to implement a partial revenue decoupling mechanism ("RDM") for its Residential and C&I Non-Demand customers.[1002]The Company's proposed RDM is a "partial" decoupling mechanism because it excludes weather effects.[1003]

612. The Company's RDM is a per-customer model.[1004] Specifically, the revenue requirement recovered through the non-fuel energy charge, on a per-customer basis, would become the revenue baseline for calculating the decoupling deferrals under the RDM.[1005] Each month, the RDM deferral would be calculated as the difference between the monthly baseline revenue and the weather-normalized revenue collected under the volumetric rates from those customers.[1006]

613. Under the Company's proposal, monthly deferrals would be calculated as follows:

$$\text{Deferral}_{c,t} = (\text{FRC}_c \times C_{c,t}) - (\text{FEC}_c \times \text{kWh}_{c,t}^{\text{Billed,WN}})$$

where

$Deferral_{c,t}$ is the RDM deferral for customer group c in month t;

FRC_c is the fixed revenue per customer for customer group c;

$C_{c,t}$ is the number of customers in customer group c during month t;

G011/GR-10-977 ORDER]; *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at Order Point 3 (Jan. 11, 2010) (*hereinafter* G008/GR-08-1075 ORDER).

1001 Ex. 110, Hansen Rebuttal at 13; Xcel Energy Initial Brief at 146.

1002 Ex. 109, Hansen Direct at 2, 9-19. The RDM will apply to the following customer groups: residential non-space heating (customers served on rate codes A01, A02, A03, A04, A05, and A06); residential space heating (customers served on rate codes A00, A01, A02, A03, A04, A05, and A06); and small C&I customers that do not pay a demand charge (customers served on rate codes A05, A06 1S, A06 3S, A06 P, A09, A10, A11, A12, A16, A18, and A22). Ex. 109, Hansen Direct at 10.

1003 Ex. 109, Hansen Direct at 2.

1004 Ex. 109, Hansen Direct at 9.

1005 Ex. 109, Hansen Direct at 10.

1006 Ex. 109, Hansen Direct at 10.

FEC_c is the non-fuel energy rate for customer group c, expressed in \$/kWh; and

$kWh_{c,t}^{Billed,WN}$ is the weather-normalized billed sales to customer group c in month t.[1007]

614. The Company proposed to incorporate the cumulative deferral for each customer group into customer rates every twelve months for the following year by dividing the deferral amount by the forecast of sales to the customer group.[1008] A positive cumulative deferral would result in a rate increase; a negative cumulative deferral will result in a rate decrease.[1009]

615. Under the Company's proposal, the weather-normalized billed sales to customer group c in month t ($kWh_{c,t}^{Billed,WN}$) would be calculated as billed sales to customer group c in month t, adjusted to account for deviations from normal weather conditions.[1010] Sales would be weather normalized using the same methods used to develop test year sales.[1011]

616. The fixed revenue per customer for customer group c (FRC_c) and the non-fuel energy rate for customer group c, expressed in \$/kWh (FEC_c) would be calculated for each month of the test year, using test year revenues, numbers of customers, and sales.[1012] FRC_c would be calculated as the fixed-cost revenue requirement (described below) divided by the number of customers forecast for each month in the 2015 test year.[1013] FEC_c would be calculated as the fixed-cost revenue requirement divided by the sales forecast for each month of the 2015 test year.[1014] According to the Company, using month-specific values for these parameters, rather

[1007] Ex. 109, Hansen Direct at 10.
[1008] Ex. 109, Hansen Direct at 10-11.
[1009] Ex. 109, Hansen Direct at 11.
[1010] Ex. 109, Hansen Direct at 11.
[1011] Ex. 109, Hansen Direct at 11.
[1012] Ex. 109, Hansen Direct at 11.
[1013] Ex. 109, Hansen Direct at 11.
[1014] Ex. 109, Hansen Direct at 11.

than a single value that is constant across months, helps minimize month-to-month deferrals.[1015]

617. The total fixed revenue used in the Company's RDM would be calculated using the test year energy charges, less the CIP component, multiplied by test year sales for the corresponding customers.[1016] Separate values would be calculated for each month of the test year.[1017] The calculations would be conducted at the rate code level, with revenues aggregated up to the customer group level for purposes of the FRC_c and FEC_c calculations.[1018] Customer charge revenue would be excluded from the RDM because it is already decoupled from customer sales.[1019]

618. According to the Company, adjustments for the residential non-space heating, residential space heating, and small C&I non-demand customer groups would be calculated separately.[1020] The Company did not propose to apply a carrying charge on deferrals.[1021] At the end of a 12-month period, the total deferral for each customer group would be divided by the forecast of sales to that group for the coming year.[1022] The resulting charge would be added to or subtracted from the customer group's volumetric rate for the following 12 months.[1023] The forecast of sales for each group would be developed using the Company's normal forecasting methods.[1024]

619. The Company proposed to implement RDM rate adjustments once per year; the adjustments would remain in effect for 12 months.[1025] The Company proposed to begin calculating deferrals in the month after the Commission's final

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1015 Ex. 109, Hansen Direct at 11-12.
1016 Ex. 109, Hansen Direct at 12.
1017 Ex. 109, Hansen Direct at 12.
1018 Ex. 109, Hansen Direct at 12.
1019 Ex. 109, Hansen Direct at 12.
1020 Ex. 109, Hansen Direct at 14.
1021 Ex. 109, Hansen Direct at 14.
1022 Ex. 109, Hansen Direct at 14.
1023 Ex. 109, Hansen Direct at 14.
1024 Ex. 109, Hansen Direct at 14.
1025 Ex. 109, Hansen Direct at 14-15.

Order in this proceeding.[1026] The RDM deferrals would be calculated each month through December, after which the RDM rate adjustment will be calculated and put into effect on April 1 for the following 12 months.[1027] The RDM rate adjustment would include deferrals for January through December, though, under the Company's proposal, the first year of the RDM adjustment may include less than 12 monthly deferrals due to implementation timing.[1028]

620. The Company agreed with the recommendations of the Department and OAG that the RDM should be implemented as a three-year pilot program.[1029]

621. The Company proposed to implement a five percent soft cap on its RDM.[1030] Under a soft cap, deferral amounts in excess of the cap are carried over in the deferral account for recovery in subsequent years; in contrast, under a hard cap, the deferral amount in excess of the cap is never recovered.[1031]

622. Under the Company's RDM, there is no downward limit on RDM adjustments.[1032]

623. The Company's five percent soft cap would be measured against base revenue, excluding fuel and all applicable riders.[1033] If the Commission orders the Company to implement full decoupling, then the Company requested the RDM include a 10 percent soft cap, measured against base revenue, excluding fuel and all applicable riders.[1034]

624. The Company proposed to list the RDM rate adjustment as a separate line item on customers' bills.[1035]

[1026] Ex. 109, Hansen Direct at 14-15.
[1027] Ex. 109, Hansen Direct at 14-15.
[1028] Ex. 109, Hansen Direct at 14-15.
[1029] Ex. 110, Hansen Rebuttal at 2-3; Ex. 417, Davis Direct at 40; Ex. 375, Nelson Direct at 61.
[1030] Ex. 109, Hansen Direct at 15; Ex. 110, Hansen Rebuttal at 9-10.
[1031] Ex. 110, Hansen Rebuttal at 10.
[1032] Ex. 109, Hansen Direct at 15.
[1033] Ex. 110, Hansen Rebuttal at 9.
[1034] Ex. 110, Hansen Rebuttal at 9.
[1035] Ex. 109, Hansen Direct at 16.

625. The Company offered to submit annual RDM reports to the Commission that would include the following items: (1) total over or under collection of allowed revenues by class; (2) total collection of prior deferred revenue; (3) calculations of the RDM deferral amounts; (4) the number of customer complaints; (5) the amount of revenues stabilized and how the stabilization impacted the Company's overall risk profile; and (6) a comparison of how revenues under traditional regulation would have differed from those collected under partial and full decoupling.[1036]

626. Finally, the Company agreed to forgo any RDM surcharges in the year following a year that it fails to achieve energy savings equal to 1.2 percent of retail sales.[1037]

627. For the reasons discussed below, the Company's RDM is reasonable and should be adopted.

C. Decoupling Policy

628. The OAG and AARP asserted no decoupling mechanism should be adopted in this case.[1038] Both the OAG and AARP based their opposition upon their view that the Company already has significant conservation incentives, making decoupling unnecessary.[1039] The OAG also stated the Company has not explained or quantified any benefits associated with the RDM and that the RDM would have adverse consequences for customers.[1040] AARP claimed the RDM unfairly shifts risks to customers, is prone to cross-subsidization, and reduces the economic benefit associated with customers' conservation efforts.[1041]

1036 Ex. 109, Hansen Direct at 18-19; Ex. 110, Hansen Rebuttal at 4; Ex. 417, Davis Direct at 22-23.
1037 Ex. 110, Hansen Rebuttal at 2-3; Ex. 417, Davis Direct at 12-14.
1038 Ex. 142, Nelson Opening Statement at 1; Ex. 310, Brockway Direct at 4.
1039 Ex. 142, Nelson Opening Statement at 1; Ex. 310, Brockway Direct at 9-12.
1040 OAG Initial Brief at 68-69.
1041 Ex. 310, Brockway Direct at 18, 22; Ex. 311, Brockway Rebuttal at 6

629. The Company disagreed with the premise that decoupling and conservation incentives should be treated as substitutes.[1042] According to the Company, the purpose of decoupling is to remove a utility's financial disincentive to promote conservation.[1043] The Company stated the legislature has expressly authorized incentive mechanisms "to encourage the vigorous and effective implementation of utility conservation programs."[1044] The Company interpreted the statutory structure as treating decoupling and incentive mechanisms as complements, not substitutes.[1045]

630. The Company also noted that the Commission appears to treat decoupling and conservation incentives to be compliments through the approval of decoupling for natural gas utilities with conservation incentive programs in place.[1046] The Company stated that Commissions in other states have taken a similar approach.[1047] Finally, the Company claimed its proposal fits within the State's overall policy for pursuing energy savings.[1048]

631. Regarding assertions by the OAG and AARP that decoupling increases costs without measurable benefits,[1049] the Company contended similar arguments have been raised in the past and have been rejected.[1050] The Company disagreed with the contentions of the OAG and AARP that the RDM will adversely impact customers because the Company will ultimately only collect the revenue per customer authorized in this case.[1051] The Company also claimed the level of potential RDM

1042 Company Initial Brief at 147.
1043 Company Initial Brief at 147 (citing Minn. Stat. § 216B.2412, subd. 1).
1044 Company Initial Brief at 147 (citing Minn. Stat. § 216B.16, subd. 6c).
1045 Company Initial Brief at 147. CEI appears to take a similar view. *See* Ex. 294, Cavanagh Rebuttal at 3-4.
1046 Company Initial Brief at 147.
1047 Ex. 109, Hansen Direct at 17 and Schedule 2.
1048 Company Initial Brief at 147.
1049 Ex. 142, Nelson Opening Statement at 1; Ex. 310, Brockway Direct at 9-11, 19-20.
1050 Company Initial Brief at 148 (citing G008/GR-08-1075 ORDER at 25 ("While no pilot program can guarantee a particular result in advance, the Decoupling Statute does not require such a guarantee as a precondition for approving a pilot project.").
1051 Ex. 109, Hansen Direct at 9-11.

adjustments would be mild, that customers can offset upward RDM adjustments through less than average conservation, that percentage of bill increases are smaller for low-use customers, and that at lower usage levels, the maximum adjustment can be offset by replacing a single light bulb.[1052]

632. Finally, the Company stated it included customer protection mechanisms that will mitigate potential harm associated with the RDM. These protections include using caps as a means of limiting volatility associated with the RDM, structuring the program as a pilot, and agreeing to provide annual RDM reports.[1053]

633. CEI supported the Company's decoupling proposal.[1054] CEI asserted that it, the Company and the Department have all shown the Company's proposed decoupling mechanism would reduce the Company's disincentive to promote energy efficiency.[1055] Regarding the relationship between decoupling and conservation, CEI identified examples from both Minnesota and nationally that CEI claimed establish a link between decoupling and energy efficiency.[1056]

634. CEI acknowledged the Company's statements that compliance will be more difficult in coming years,[1057] but also recommended adopting decoupling as a means of insuring continued excellence in energy efficiency, not merely compliance.[1058]

635. CEI disagreed that decoupling leads to adverse customer impacts. First, CEI stated that decoupling would not affect the underlying, Commission-approved revenue requirement established in this case and that the Company would collect no

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1052 Ex. 109, Hansen Direct at 13 and Schedule 6; Ex. 110, Hansen Rebuttal at 6-11.
1053 Ex. 109, Hansen Direct at 15; Ex. 110, Hansen Rebuttal at 2-4, 9.
1054 CEI Initial Brief at 16.
1055 CEI Initial Brief at 17 (citing Ex. 109, Hansen Direct at 2-9; Ex. 42, Sundin Rebuttal at 3-5; Ex. 290, Cavanagh Direct at 7-8; Ex. 294, Cavanagh Rebuttal at 3-4; Ex. 417, Davis Direct at 18; and Tr. Vol. 4 at 140-141 (Davis)).
1056 Ex. 290, Cavanagh Direct at 11; CEI Initial Brief at 22-24.
1057 CEI Initial Brief at 24-25.
1058 Tr. Vol. 3 at 80 (Cavanagh).

more and no less than what is approved.[1059] Second, CEI cited a national study for the proposition that decoupling adjustments are generally very modest and do not affect benefits associated with conservation.[1060] CEI also cited the Company's analysis showing low-use customers would see smaller bill impacts (in terms of percent) and that low-use customers can conserve enough to offset the highest allowed RDM adjustment.[1061] Finally, CEI maintained the record does not establish that decoupling causes customer confusion.[1062]

636. The statutory structure of this State treats decoupling and incentive mechanisms as complements, not substitutes. The Commission apparently agrees, having approved decoupling for natural gas utilities with conservation incentive programs in place.[1063] Other states similarly treat decoupling and incentive mechanisms as different tools.[1064] Arguments that decoupling does not deliver measurable benefits have been raised and rejected in the past.[1065] Finally, the RDM would be limited to the per-customer revenues approved in this case, which, by definition, will be just and reasonable.[1066] Decoupling itself therefore does not result in adverse customer-impacts. As a matter of policy, the Company's proposal is reasonable.

1059 Tr. Vol. 3 at 83-84 (Cavanagh); CEI Initial Brief at 26.
1060 Ex. 291, Cavanagh Direct Exhibit A at 3-4.
1061 CEI Initial Brief at 26-27 (citing Ex. 111, Hansen Surrebuttal at 5-10).
1062 CEI Initial Brief at 28-29 (citing, in part, Ex. 110, Hansen Rebuttal at 16-17).
1063 G008/GR-13-316 ORDER at Order Point 3; G007, G011/GR-10-977 ORDER at Order Point 11; G008/GR-08-1075 ORDER at Order Point 3. Both CenterPoint and MERC have conservation incentive programs in place. *See e.g.*, *In the Matter of Commission Review of Utility Performance Incentives for Energy Conservation Pursuant to Minn. Stat. § 216B.241, Subd. 2c*, Docket No. E, G999/CI-08-133, ORDER ADOPTING MODIFICATIONS TO SHARED SAVINGS DEMAND SIDE MANAGEMENT FINANCIAL INCENTIVE (Dec. 20, 2012).
1064 Ex. 109, Hansen Direct at 17 and Schedule 2.
1065 *See* G008/GR-08-1075 ORDER at 25 ("While no pilot program can guarantee a particular result in advance, the Decoupling Statute does not require such a guarantee as a precondition for approving a pilot project.")
1066 Minn. Stat. § 216B.03.

D. RDM Design

637. The Department, OAG and AARP all disagree with certain design elements of the Company's proposed RDM.[1067] Each design element is discussed below.

1. Full or Partial Decoupling

638. The Department and OAG both maintained the decoupling mechanism should be a full decoupling mechanism that includes the effects of weather.[1068] The Department calculated that over the 2009-2013 and 2004-2013 periods, customers would have paid less under full decoupling than under partial decoupling.[1069] The Department and OAG both relied on this analysis to support their recommendations in favor of full decoupling.[1070]

639. The Company responded that the inclusion or exclusion of weather in the RDM has no impact on meeting the statutory purpose of decoupling, which is to reduce the disincentive to promote energy efficiency.[1071]

640. The Company also asserted that the Department's analysis was dependent on the pilot period sharing weather and economic conditions with the recent past – something that is not guaranteed.[1072] The Company provided examples showing that shifts in weather or economic assumptions would lessen or reverse the difference between partial and full decoupling identified by the Department.[1073] Further, the Company stated there is no guaranty that weather and non-weather effects will offset each other.[1074]

[1067] The OAG and AARP do not support decoupling, but if the Commission were to approve a decoupling mechanism, both indicate the design should be different from the Company's proposal. *See* OAG Initial Brief at 70-71; AARP Initial Brief at 16-18.
[1068] Ex. 417, Davis Direct at 40; Ex. 375, Nelson Direct at 60.
[1069] Ex. 417, Davis Direct at 27-29; Ex. 419, Davis Surrebuttal at 13-14.
[1070] Ex. 417, Davis Direct at 31-32; Ex. 419 Davis Surrebuttal at 14-15; Ex. 375, Nelson Direct at 55-56, 60.
[1071] Ex. 109, Hansen Direct at 12; Ex. 110, Hansen Rebuttal at 9.
[1072] Ex. 110, Hansen Rebuttal at 5.
[1073] Ex. 110, Hansen Rebuttal at 5-8.
[1074] Ex. 110, Hansen Rebuttal at 8.

641. Finally, the Company claimed that partial decoupling is consistent with its preference for a gradual approach.[1075]

642. The Company, CEI, and Department all agree that the Company's partial decoupling proposal fulfills the statutory purpose of decoupling.[1076] The Commission has approved both full and partial decoupling in the past, an indicator both may be acceptable.[1077] Partial decoupling also aligns the RDM with the Company's desire for a gradual approach, which, according to CEI, can help increase the overall efficacy of decoupling.[1078] For these reasons, it is the Company's proposal to structure its RDM as a partial decoupling mechanism should be adopted.

2. Hard or Soft Cap

643. The Department, OAG, and AARP all support a hard cap on potential RDM surcharges.[1079] All contend that a soft cap is not an actual cap because amounts above the cap are deferred for future recovery.[1080]

644. The Company supports a soft cap as a means of addressing the variability of RDM adjustments.[1081] According to the Company and CEI, a hard cap reintroduces a disincentive to promote energy efficiency and therefore undermines the purpose of decoupling.[1082] The Company also stated that most electric decoupling

[1075] Ex. 110, Hansen Rebuttal at 9.
[1076] Ex. 109, Hansen Direct at 12; Ex. 417, Davis Direct at 18; Ex. 290, Cavanagh Direct at 7; Tr. Vol. 4 at 141-142 (Davis).
[1077] G008/GR-13-316 ORDER at 48 ("The Commission has previously approved two decoupling pilot programs. One partial decoupling program was implemented by the Company from 2010 to 2013. The other, a full decoupling program implemented by Minnesota Energy Resources Corporation is just now underway. The Commission concludes that the modified full decoupling proposal in this proceeding is an appropriate addition to the list of pilot programs intended to aid the Commission in assessing rate decoupling's merits as a regulatory tool.")
[1078] Ex. 294, Cavanagh Rebuttal at 6.
[1079] Ex. 417, Davis Direct at 38; Ex. 377, Nelson Rebuttal at 39; Ex. 311, Brockway Rebuttal at 3.
[1080] Ex. 417, Davis Direct at 33; Ex. 310, Brockway Direct at 21; OAG Initial Brief at 70.
[1081] Ex. 111, Hansen Rebuttal at 11.
[1082] Ex. 110, Hansen Rebuttal at 10; Ex. 294, Cavanagh Rebuttal at 4-5.

mechanisms have soft caps or no caps at all.[1083] Finally, the Company maintained the RDM is subject to a true cap – the revenue per customer established in this case.[1084]

645. The Department disagreed that a hard cap reintroduces a disincentive to promote energy efficiency.[1085] According to the Department's analysis, the Company "can make far more money by saving a marginal unit of energy than by making additional sales."[1086]

646. The Company's proposed soft cap is a reasonable means of managing the variability of RDM adjustments from year to year and should be adopted. A hard cap reintroduces a disincentive to promote energy efficiency, thereby undermining the purpose of decoupling. Further, the Department's reliance on the DSM financial incentive conflates two programs the legislature has deemed to be separate. And the Department itself has said that it plans to recommend changing DSM financial incentives in the future.[1087]

3. Cap Level and Cap Basis

647. The Company, Department, OAG and AARP all presented different cap levels and ways to measure the cap.

Table 8
Comparison of Recommended RDM Cap Level and Cap Basis[1088]

	Company	Department	OAG	AARP
Cap Level	5%	3%	1%	2%
Cap Basis	Base Revenue Excluding Fuel and Applicable Riders	Base Revenue Including Fuel and Applicable Riders	Base Revenue Excluding Fuel and Applicable Riders	Base Revenue Excluding Fuel and Applicable Riders

1083 Ex. 110, Hansen Rebuttal at 10 (citing Ex. 109, Hansen Direct, Schedule 2).
1084 Ex. 417, Davis Direct at 33; Ex. 109, Hansen Direct at 9-12.
1085 Ex. 419, Davis Surrebuttal at 3.
1086 Department Initial Brief at 210 (citing Ex. 419, Davis Surrebuttal at 3).
1087 Department Initial Brief at 209-210, 215.
1088 Ex. 110, Hansen Rebuttal at 9; Ex. 419, Davis Surrebuttal at 9; Ex. 375, Nelson Direct at 58; Ex. 377, Nelson Rebuttal at 38-39; Ex. 310, Brockway Direct at 21; Ex. 311, Brockway Rebuttal at 3.

648. If the Commission adopts full decoupling, then the Company requested a soft cap of 10 percent of base revenue, excluding fuel and all applicable riders.[1089]

649. The Department, OAG and AARP all asserted their proposed caps would limit customers' exposure to potentially large surcharges.[1090] Further, the Department presented an analysis showing its proposed cap would be triggered rarely.[1091]

650. The Company stated that its five percent cap was lower than the typical caps seen across the country.[1092] For example, the Company stated that caps measured according to base revenues are typically set at 10 percent.[1093] The Company also stated that most decoupling mechanisms have no caps at all.[1094]

651. The cap level and measurement proposed by the Company is consistent with national practice and should be adopted.

4. Measurement of RDM Adjustments

652. ECC supported the Company's RDM,[1095] but recommended RDM adjustments be measured on a percent of bill basis.[1096] ECC asserted the percent of bill basis is more equitable to low-income customers.[1097] AARP made a similar recommendation.[1098]

653. The Company explained RDM adjustments are applied to the variable portion of customer bills, meaning low-use customers receive smaller percentage increases than to average or higher-use customers.[1099]

1089 Ex. 110, Hansen Rebuttal at 9.
1090 Ex. 419, Davis Surrebuttal at 9; Ex. 375, Nelson Direct at 58; Ex. 377, Nelson Rebuttal at 38-39; Ex. 310, Brockway Direct at 21; Ex. 311, Brockway Rebuttal at 3.
1091 Ex. 419, Davis Surrebuttal at 8-9.
1092 Ex. 110, Hansen Rebuttal at 12.
1093 Ex. 110, Hansen Rebuttal at 12 (citing Ex. 109, Hansen Direct at Schedule 2).
1094 Ex. 110, Hansen Rebuttal at 12.
1095 ECC Initial Brief at 23.
1096 Ex. 234, Colton Direct at 35.
1097 Ex. 234, Colton Direct at 35; ECC Initial Brief at 24-25.
1098 AARP Initial Brief at 18.
1099 Ex. 111, Hansen Surrebuttal at 10; CEI Initial Brief at 27.

654. The Company's proposal to calculate RDM adjustments on a per kWh basis is reasonable and should be adopted.

5. Other RDM Design Proposals

655. In addition to design elements discussed above, the AARP recommended any decoupling mechanism include several additional design elements, including: 1) a strong and increased commitment by the Company to provide cost-effective demand-side programs and measures; 2) limit the frequency of RDM rate adjustments to more than an annual basis; 3) prevent cross-subsidization; and 4) review the basis for the weather normalization component of the RDM.[1100]

656. The Company has reaffirmed its commitment to pursuing cost-effective energy savings opportunities at numerous points in this case,[1101] eliminating the need to adopt the AARP's first recommendation. Further, the AARP's first recommendation incorrectly conflates decoupling with the State's energy savings incentive program. The Company's proposal calls for annual adjustments, meaning the AARP's second adjustment is also unnecessary. The Company has explained that its RDM is not susceptible to cross subsidization and reasonably explained why the RDM is initially limited to Residential and C&I Non-Demand customers.[1102] Finally, the Company is proposing to use the same weather normalization techniques in calculating the RDM adjustments as will be used to establish the sales forecast in this case.[1103] This means the RDM will be calculated consistent with baseline revenue per customer.

657. The AARP recommendations should not be adopted.

[1100] Ex. 310, Brockway Direct at 18; AARP Initial Brief at 17-18.

[1101] Ex. 42, Sundin Rebuttal at 3-5; Ex. 109, Hansen Direct at 6-8; Tr. Vol. 1 at 156-161 (Sundin); Tr. Vol. 3 at 94-95 (Hansen).

[1102] Ex. 109, Hansen Direct at 13-14; Ex. 110, Hansen Rebuttal at 12-13, 21-22.

[1103] Ex. 109, Hansen Direct at 11, 14.

VII. RESOLVED REVENUE REQUIREMENTS ISSUES

658. The issues in this section have been resolved, settled, or are undisputed. These matters have been reasonably resolved in the public interest and the Commission should adopt the stated resolution.

A. Sales Forecast (2014 and 2015 Step) (Issue # 13)

1. Actual Sales

659. Accurately forecasting sales is important to ensure that the Company recovers its costs, no more and no less.[1104] If the forecast overestimates sales, rates will be set too low and the Company will not be able to recover the full cost of service.[1105]

660. The Company's sales forecast was a contested issue in the prior rate case: the Department challenged the Company's forecast as being too low based on customer count, future energy prices, loss of large industrial consumers, and treatment of Demand Side Management (DSM).[1106] In the 2013 rate case, the ALJ recommended that the Commission adopt the Department's proposals and the Department's alternative of using a four-year average to calculate embedded DSM.[1107] The Commission adopted the Department's proposals but did not adopt the four-year average approach to DSM.[1108]

661. In its Direct Testimony in this case, the Company endeavored to address the concerns raised in the prior rate case,[1109] in part by utilizing a different methodology to account for future DSM.[1110] The Department disagreed with several

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1104 Ex. 39, Marks Direct at 4; Ex. 405, Shah Direct at 2.
1105 Ex. 43, Hyde Direct at 2.
1106 Ex. 43, Hyde Direct at 4.
1107 Ex. 43, Hyde Direct at 4.
1108 Ex. 43, Hyde Direct at 4; Ex. 405, Shah Direct at 18.
1109 Ex. 43, Hyde Direct at 4.
1110 Ex. 39, Marks Direct at 31.

aspects of the Company's sales forecast, particularly the Company's use of DSM and its customer counts.[1111]

662. The MCC also expressed concern about the Company's sales forecasts, arguing that because the historical data on DSM achievements is derived from energy savings in the CIP plan, the Company was being compensated for energy efficiency twice – once through the CIP incentive and then again in lower sales caused by energy efficiency.[1112]

663. In rebuttal, the Company proposed that the sales forecast be based on weather-normalized actual data for the test year.[1113] This alternative methodology rendered a decision on the DSM adjustment issue and the customer count issues unnecessary.[1114] The use of this methodology is possible because it is expected that the parties will have the benefit of a full year of actual sales data for the 2014 test year before the Commission issues its decision in this proceeding in 2015.[1115] The actual sales data must be weather-normalized to be representative of sales in future years.[1116]

664. The Company committed to include weather-normalized actual sales data for the remainder of 2014 in a compliance filing.[1117] The Company agreed to use the Department's coefficients for the calculation of the weather-normalization.[1118] The Company committed to submit its weather-normalized actual electric sales data for the first eleven months of 2014 on December 16, 2014, and then to submit the December 2014 actual sales data by January 16, 2015.[1119] The Company committed to work with the Department to ensure that the calculations are correct,[1120] and also

1111 Ex. 405, Shah Direct at 8-25.
1112 Ex. 343, Maini Direct at 7-14.
1113 Ex. 44, Hyde Rebuttal at 1.
1114 Ex. 44, Hyde Rebuttal at 1; Ex. 407, Shah Surrebuttal at 9, 11.
1115 Ex. 44, Hyde Rebuttal at 5.
1116 Ex. 44, Hyde Rebuttal at 5.
1117 Ex. 44, Hyde Rebuttal at 6.
1118 Ex. 119, Hyde Opening Statement at 1.
1119 Ex. 140, Heuer Opening Statement at 5-6.
1120 Ex. 140, Heuer Opening Statement at 5.

agreed to work with the Department and other stakeholders in the future on the use of the price variable or other aspects of the sales forecast model.[1121]

665. The Department agreed with the Company's proposal to use weather-normalized actual data for the test year.[1122]

666. The MCC accepted the proposal by the Company and the Department to use the weather-normalized 2014 actual sales.[1123] No other party commented on the sales forecast.

667. As explained by Company witness Ms. Jannell Marks, weather-normalized actual 2013 sales were significantly lower than the forecast approved by the Commission in the last case.[1124] Weather-normalized actual 2013 sales were 0.3% higher than the Company's forecast.[1125] In this case, to avoid the significant underrecovery of a forecast set to high, or an overrecovery if the forecast were set too low, the parties have agreed to use weather-normalized actual sales. Thus, it is reasonable to adopt the sales forecast proposal agreed to by the Company, the Department, and MCC.

668. If the Commission does not adopt the recommendation to use actual sales, the Commission should apply the Company's rebuttal sales forecast for purposes of setting rates. The Company's sales forecast is supported by the evidence in the record and produces results shown to be reasonable.

2. The Company's Sales Forecast

669. The Company provided an updated forecast in the Rebuttal Testimony of Company witness Ms. Marks reflecting the use of actual data through the end of May 2014. [1126]

1121 Ex. 40, Marks Rebuttal at 17.
1122 Ex. 444, Shah Opening Statement at 1; Tr. Vol. 4 at 54 (Shah).
1123 Ex. 145, Maini Opening Statement; Tr. Vol. 4 at 13 (Maini).
1124 Ex. 38, Marks Direct at 18.
1125 Ex. 40 Marks Rebuttal at 8.
1126 Ex. 40, Marks Rebuttal.

a. DSM adjustment

670. DSM achievements have contributed to lower sales growth over the last several years.[1127] As reflected in Ms. Marks' testimony, the continued impact of embedded DSM is significantly lower than the impact of future DSM savings.[1128]

671. In response to the issues raised in the Company's last rate case, and recognizing that energy efficiency savings continue to impact the sales forecast in this case, the Company proposed a new, more transparent methodology to account for future DSM in the forecast.[1129]

672. The Company collected monthly historical data on actual DSM achievements, added the historical achievements to historical actual monthly sales to derive a time series of data excluding any DSM impacts, and used the restated time series as the input data to the regression model. The Company then reduced the forecast of sales excluding DSM by the amount of future DSM related to both historical achievements with continued impacts and planned future new programs.[1130]

673. The Department's sales forecast did not make an adjustment for DSM impacts in the test year. The Department stated that DSM savings and spending are not increasing and therefore no adjustment is necessary.[1131]

674. The Company contends that the failure to make this adjustment results in unreasonable results which are particularly pronounced when looking at the Department's forecast sales for the Large C&I class for 2014.[1132]

675. The Company also stated that the Department failed to address how DSM savings are reflected in the model and the difference between historical DSM, existing DSM and future DSM affecting sales in the test year.

[1127] Ex. 38, Marks Direct at 33-34 and Figure 8.
[1128] Ex. 38, Marks Direct at 8, Figure 1.
[1129] Ex. 38, Marks Direct at 33.
[1130] Ex. 38, Marks Direct at 33.
[1131] Department Initial Brief at 174.
[1132] Ex. 40, Marks Rebuttal at 20.

676. In her Direct Testimony, Ms. Marks demonstrates the difference between actual, historical DSM embedded in the forecast and forecast DSM impacting the test year.[1133]

677. Further, as Company witness Ms. Deb Sundin described, the effects of historical DSM, existing DSM and future DSM are accounted for in the model.[1134] The DSM adjustment adjusts historical sales to generate a forecast that removes the impact of all past DSM achievements, allowing the Company to project future sales independent of DSM.[1135] The continuing impacts of existing DSM (actual achievements with remaining life in the test year after subtracting the life included in historical DSM) are included, as well as new DSM achievements occurring in the forecast period.[1136] New DSM is primarily offsetting the effect of expiring measures from prior CIP program years. The Company stated that it is appropriate to include the full DSM achievements as to disqualify part or all of the adjustment would cause the sales forecast to increase artificially.[1137]

b. Verification of DSM savings

678. The Department additionally raised concerns that the DSM savings are estimates.[1138]

679. Company witness Ms. Sundin explained that these savings are subject to rigorous review.[1139] The energy savings and equipment lifetimes are calculated by the Company's engineering team applying standard industry practices and these calculations are reviewed by the Department itself.[1140]

1133 Ex. 38, Marks Direct at 32, Figure 1.
1134 Ex. 42, Sundin Rebuttal at 9.
1135 Ex. 42, Sundin Rebuttal at 10.
1136 Ex. 42, Sundin Rebuttal at 11.
1137 Ex. 42, Sundin Rebuttal at 11.
1138 Department Initial Brief at 170.
1139 Ex. 42, Sundin Rebuttal at 12.
1140 Ex. 42, Sundin Rebuttal at 12.

680. The forecast savings for these measures are built based on project and customer type for baseline and efficient equipment options, and the engineering analysis applied is built off of external industry resources and, if available, historical program results.[1141] These savings calculations are thereafter subject to a rigorous measurement and verification process.[1142] The Company then applies the savings calculations approved by the Department.[1143]

c. Impacts on forecast for small C&I

681. The Company also contends that the Department inaccurately attributes the difference between the forecast for July – December 2013 and actual results for the small commercial and industrial class to DSM.[1144]

682. As explained by Company witness, Ms. Marks, the difference between the initial forecast for the last 6 months of 2013 and actual results is not attributable to accounting for DSM savings.[1145] The Company stated that without the DSM adjustment, sales would have been overforecast for the last half of 2013 for all classes.[1146] The Company argues that the key driver of the underforecasting in the small C&I class was the underforecasting of households and total employment, not DSM.[1147]

d. Price variable

683. The Department raised concerns with the use of the price variable but recognized that to exclude the price variable would produce an unreasonable result. The Company concurred that the use of the variable improves the overall results and

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1141 Ex. 42, Sundin Rebuttal at 12.
1142 Ex. 42, Sundin Rebuttal at 13.
1143 Ex. 42, Sundin Rebuttal at 12-13.
1144 Department Initial Brief at 172.
1145 Ex. 40, Marks Rebuttal at 13.
1146 Ex. 40, Marks Rebuttal at 13-14 and Table 4.
1147 Ex. 40, Marks Rebuttal at 6-7, 13.

is appropriate for inclusion.[1148] The Company agreed to work with the Department to see if improvements may be made.[1149]

e. Customer counts

684. The Company continued to support its customer count in this case. As Company witness Ms. Marks testified, the key driver for the change was updated economic data.[1150] It is standard practice for both the household information and the employment information to be revised annually as new estimates are released.[1151] Further, while the updated data resulted in some changes, the Company noted that its 2013 forecast overall was very close to actuals in total.[1152]

685. In addition, the Company's updated forecast is based on the most up-to-date information available at the time rebuttal testimony was filed. It is appropriate to include this updated data in the sales forecast model in this case.

f. Large C&I Class

686. The Large C&I class has continued to decline for the last several years. Despite evidence of this decline, the Department's forecast for this class was 3.3 percent higher than the Company's initial forecast, 3.9 percent higher than the Company's updated forecast and 3.8 percent higher than actual sales to this class in 2013.[1153]

687. However, actual sales to the Large C&I class were 33,430 MWh lower than the Company's initial forecast and continued declines are expected.[1154] The Department's forecast would result in a base revenue adjustment of $11.6 million when the evidence supports that sales to these customers has declined.[1155]

1148 Ex. 40, Marks Rebuttal at 17.
1149 Ex. 40, Marks Rebuttal at 17.
1150 Ex. 40, Marks Rebuttal at 6-7.
1151 Ex. 40, Marks Rebuttal at 8.
1152 Ex. 40, Marks Rebuttal at 7.
1153 Ex. 40, Marks Rebuttal at 5 and 20.
1154 Ex. 40, Marks Rebuttal at 5.
1155 Ex. 40, Marks Rebuttal at 20.

3. Conclusion

688. While the record supports the use of the Company's sales forecast in this case, the Company, the Department, and the MCC agree that the use of weather-normalized 2014 sales is the preferred solution in the case. If the Commission declines to adopt this proposal, the Commission should adopt the Company's forecast as supported by the evidence in the record and accurately forecasting test year sales taking into account updated economic data, the impact of energy efficiency efforts, and the continued decline in sales for the Company's large C&I customers.

B. Property Tax Amount (2014) (Issue # 14)

689. Minnesota property taxes represent a significant expense to the Company. In Direct Testimony, the Company provided a detailed explanation of the methodology by which the Company forecasts its 2014 property taxes.[1156] The Company noted that its Minnesota property taxes, which represent almost 97 percent of its total property tax expense,[1157] have increased rapidly over the last ten years.[1158] The Company forecasted its 2014 electric and natural gas property taxes (including Minnesota, North Dakota, and South Dakota) to be $206 million on an NSPM total Company basis,[1159] resulting in property taxes attributable to Minnesota electric operations for purposes of ratemaking to be $149.2 million.[1160]

690. The Department, arguing that the Company had over-recovered its allowed and/or forecasted property taxes in past years by an average of 9 percent, recommended that the 2014 property tax expense be reduced by 9 percent, or 13.5 million, to $135.7 million.[1161]

1156 Ex. 33, Duevel Direct at 1-18.
1157 Ex. 33, Duevel Direct at 2.
1158 Ex. 33, Duevel Direct at 18-23.
1159 Ex. 33, Duevel Direct at 1.
1160 Ex. 33, Duevel Direct at 1-2, Schedule 10; *see also* Ex. 14 at Tab A-58.
1161 Ex. 439, Lusti Direct at 36.

691. In Rebuttal Testimony, the Company used additional information it had received from the Department of Revenue (DOR) to validate its original forecast.[1162] Using the additional information, the Company showed the total 2014 electric and natural gas property taxes would be $200.1 million.[1163] This resulted in property tax expenses attributable to Minnesota electric operations, for purposes of ratemaking, of $145 million.[1164]

692. In Surrebuttal Testimony, the Department acknowledged that its prior analysis had been flawed.[1165] The Department noted, though, that during the five-year period from 2009 through 2013, the Company's Minnesota property tax expenses had increased an average of 10.72 percent, and thus argued that the Company's 2014 property tax expense for ratemaking should be $136 million, a 10.72% increase over the actual 2013 figure.[1166]

693. In the alternative, the Department proposed a reduction of $9.0 million from the Company's original $150 million figure, based on the percent difference between the Company's initial 2014 test year forecast presented in the Company's Direct Testimony and the validated 2014 property tax presented in the Company's Rebuttal Testimony, as well as a further adjustment based on the difference between the Company's June 2013 forecast of 2013 property taxes and actual 2013 property taxes.[1167] The result of the Department's alternative proposal was a property tax expense for ratemaking purposes of $141 million, a $9 million reduction from the Company's initial proposal.[1168]

1162 Ex. 34, Duevel Rebuttal at 3.
1163 Ex. 34, Duevel Rebuttal at 3.
1164 Tr. Vol. 4 at 138 (Duevel).
1165 Ex. 442, Lusti Surrebuttal at 25-26.
1166 Ex. 442, Lusti Surrebuttal at 29.
1167 Ex. 442, Lusti Surrebuttal at 30.
1168 Ex. 442, Lusti Surrebuttal at 30.

694. The MCC did not object to the validated figures presented in the Company's Rebuttal Testimony, but also did not object to the Department's alternative proposal of $141 million.[1169]

695. The Company agreed to the Department's alternative proposal to reduce the 2014 property tax expense to $141 million, subject to a true-up for the actual 2014 property taxes.[1170] Under the true-up, the total 2014 test year property tax expense would be capped at the Company's $145 million figure; there is no downward limit on the true-up.[1171] The Department and the MCC agreed to the Company's true-up proposal.[1172] No other party commented on 2014 property taxes.

696. The Company and the Department agreed on a procedure for the property tax true-up. The Company will file its actual year-end 2014 property tax expense with the Commission on January 16, 2015, based on Truth-in-Taxation Notices received in November and December of 2014.[1173] The Company and the Department recommended that the Commission reflect the 2014 year-end property tax expense in its determination of the Company's 2014 revenue requirement and the 2014 year-end property tax expense would be reflected in final rates in this case, up to a cap of $145.0 million (Minnesota electric jurisdiction).[1174]

697. The Company will also make a compliance filing on June 30, 2015 detailing the final 2014 property tax expense reflected on property tax statements received in the spring of 2015.[1175] If the actual 2014 property taxes reflected on those statements is less than the year-end 2014 property tax expense (*i.e.*, the 2014 test year

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[1169] Ex. 342, Schedin Surrebuttal at 12.
[1170] Ex. 117, Duevel Opening Statement at 1; Ex. 140, Heuer Opening Statement at 2.
[1171] Ex. 117, Duevel Opening Statement at 1; Tr. Vol. 1 at 137-39 (Duevel); Ex. 451, Lusti Opening Statement at 2 ("no downward bound").
[1172] Ex. 451, Lusti Opening Statement at 2; Tr. Vol. 1 at 137 (Duevel).
[1173] Ex. 451, Lusti Opening Statement at 2.
[1174] Ex. 451, Lusti Opening Statement at 2; Tr. Vol. 3 at 161-164, 168-69 (Heuer).
[1175] Ex. 451, Lusti Opening Statement at 2.

property tax expense), the Company agreed to make ongoing annual refunds of the difference until the Company files the next rate case.[1176]

698. The resolution reached by the Company and the Department is reasonable and should be adopted.

699. If the Commission does not accept the resolution reached by the Company and the Department, then 2014 test year property taxes should be set at $145 million for the Minnesota electric jurisdiction, as calculated in Mr. Duevel's Rebuttal Testimony.[1177] The expense calculation included in Mr. Duevel's Rebuttal Testimony reflected actual information that will be used to determine the Company's actual 2014 property taxes. This leads to a more accurate and reasonable result than any of the forecasts presented by the Department.

700. If no actual information related to the Company's 2014 property taxes is to be reflected in the determination of the 2014 test year expense, then the Company's Direct Testimony forecast of $150 million on a Minnesota electric jurisdiction basis is the most reasonable option and should be adopted.

C. Emissions Control Chemical Costs (2014) (Issue # 15)

701. One of the components in the Company's Energy Supply Operations and Maintenance budget is the cost of chemicals (sometimes referred to as "base commodities") used to reduce emissions.[1178] The Company provided a detailed explanation of the factors affecting the costs for these chemicals, such as plant operations and efficiencies, commodity costs, the Company's purchasing process, and the addition of emissions control equipment.[1179] The Company requested recovery of approximately $10.305 million for emissions control chemical costs for the 2014 test year.[1180] The Company noted that its request was based on a new methodology that

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[1176] Ex. 451, Lusti Opening Statement at 2.
[1177] Ex. 34, Duevel Rebuttal at 3.
[1178] Ex. 59, Mills Direct at 2, 8-9, 16-18.
[1179] Ex. 59, Mills Direct at 18-29.
[1180] Ex. 59, Mills Direct at Sch. 4.

was developed in response to comments in the prior rate case,[1181] and explained that various differences between the current request and costs incurred during previous years were the result of Sherco 3 coming back on-line and other various factors.[1182]

702. The Department observed that the Company had generally over-recovered for emissions chemical costs each year since 2009.[1183] The Department recommended using a three-year historical average of the Company's actual emissions control chemical costs, adjusted for the Sherco 3 outage and for anticipated chemical use at Sherco 1 and 2.[1184] Based on this approach, the Department recommended a downward adjustment of $2.265 million ($1.876 million for other than Sherco chemical costs, and $0.389 million for Sherco chemical costs) to the Company's request, i.e., that the 2014 test year emissions control chemical costs for ratemaking purposes should be $8.040 million.[1185]

703. At the evidentiary hearing, the Company accepted the Department's recommended downward adjustment.[1186] No other parties presented evidence on this issue.

D. Insurance – Surplus Distributions from Industry Mutual Insurance Pools (2014) (Issue # 16)

704. The Company's insurance for certain difficult-to-place risks is provided through industry mutual insurance pools such as Energy Insurance Mutual (EIM) and Nuclear Electric Insurance Limited (NEIL).[1187] From time to time, these insurance pools return excess premiums to the Company, in the form of surplus distributions or continuity credits.[1188]

1181 Ex. 59, Mills Direct at 20-21.
1182 Ex. 59, Mills Direct at 24-26; Ex. 60, Mills Rebuttal at 3-10.
1183 Ex. 431, Campbell Direct at 15-25; Campbell Surrebuttal at 23-24.
1184 Ex. 431, Campbell Direct at 25-26; Campbell Surrebuttal at 24-26.
1185 Ex. 431, Campbell Direct at 26; Ex. 439, Lusti Direct at 40; Ex. 442, Lusti Surrebuttal at 32.
1186 Ex. 140, Heuer Opening Statement at 1; Ex. 125, Mills Opening Statement at 1; Ex. 450, Campbell Opening Statement at 2.
1187 Ex. 36, Anderson Direct at 14-15, 17, 42.
1188 Ex. 425, Byrne Direct at 24.

705. The Department noted that the Company had included certain continuity credits in its 2014 test year budget (which reduced test year insurance costs), but had not included anticipated surplus distributions from NEIL and EIM in the 2014 test year budget.[1189]

706. The Company explained that unlike the continuity credits, which occur regularly, the anticipated NEIL and EIM surplus distributions had not been included in the 2014 test year budget because they were irregular: each was only the second such distribution since the economic downturn in 2008.[1190]

707. The Department recommended that the anticipated NEIL and EIM surplus distributions, a total of $1,662,299, should be included in the 2014 test year budget so that Minnesota ratepayers could receive the benefit of the distributions.[1191]

708. In Rebuttal Testimony, the Company agreed to include the anticipated surplus distributions from NEIL and EIM in the 2014 test year budget, because even though the distributions occur irregularly, they were received prior to the closing of the record in the rate case.[1192]

709. As a result, the Department considered this issue resolved.[1193] No other party commented on the issue of surplus distributions from industry mutual insurance pools.

E. Treatment of Capitalized Pension and Related Benefit Costs –Rate Based Factor Method (Issue #17)

710. The Company proposed to use the "rate base factor" method developed in the Company's last rate case (Docket No. E002/GR-12-961) to determine pension and related benefit O&M expenses. This method applies a rate base factor to the

[1189] Ex. 425, Byrne Direct at 24.
[1190] Ex. 425, Byrne Direct at 24-25.
[1191] Ex. 425, Byrne Direct at 25-27; Ex. 439, Lusti Direct at 39.
[1192] Ex. 37, Anderson Rebuttal at 3; Ex. 90, Heuer Rebuttal at 12-13.
[1193] Ex. 428, Byrne Surrebuttal at 11.

beginning-of-year/end-of-year average of the capitalized portion of costs and thus converts the capital adjustments to revenue requirements.[1194]

711. The Department accepted the Company's proposal.[1195]

F. Qualified Pension- Measurement Date (Issue #18)

712. The Company proposed that the same measurement date be used to calculate all pension and benefit expenses, including qualified pension.[1196] The Company recommended using December 31, 2013 as the measurement date because it provides the most current information available and results in an adjustment that favors customers.[1197]

713. The Department did not initially accept the Company's proposal to update the measurement date for the qualified pension because the update increased the pension expense and because the Department had concerns about the financial performance of the pension assets.[1198]

714. In Surrebuttal Testimony, the Department accepted the Company's proposal to update the measurement date for the qualified pension to December 31, 2013.[1199]

715. This results in an increase of $1,011,492 (both O&M and capital) in the test year revenue requirements.[1200]

G. Non-Qualified Pension-Restoration Plan (2014) (Issue #20)

716. The Company's non-qualified pension restoration plan provides supplemental benefits to those employees whose wages exceed the IRS-determined

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[1194] Ex. 90, Heuer Rebuttal at 18-20.
[1195] Ex. 435, Campbell Surrebuttal at 74-75.
[1196] Ex. 83, Schrubbe Rebuttal at 11.
[1197] Ex. 83, Schrubbe Rebuttal at 11.
[1198] Ex. 435, Campbell Surrebuttal at 87.
[1199] Ex. 435, Campbell Surrebuttal at 88.
[1200] Ex. 90, Heuer Rebuttal at 20; Ex. 450, Campbell Opening Statement at 5.

compensation limits to give them equal level of benefits than those employees who can participate in qualified pension plans.[1201]

717. The Department recommended disallowance of all non-qualified pension restoration plan costs because it is not reasonable for ratepayers to finance these benefits.[1202] In Rebuttal Testimony, the Company accepted the Department's recommendation to exclude non-qualified pension restoration plan costs in this case.[1203]

718. This results in a reduction of $704,000 in test year revenue requirements (both O&M and capital).[1204]

H. Post-Employment Benefits- Long-term Disability and Workers' Compensation (Issue #21)

719. The Company requested recovery of $3.79 million in O&M expenses and $190,152 in capital costs related to post-employment benefits (primarily long-term disability and workers' compensation) for former or inactive employees after employment but before retirement.[1205] The Company used a measurement date of December 31, 2012 and a discount rate of 3.74 to calculated the test year expenses.[1206]

720. The Department agreed that the Company's 3.74 discount rate was reasonable.[1207] The Department recommended using the most recent information available and updating the measurement date to December 31, 2013.[1208] The Department provided an adjustment that reduced post-employment FAS 112 O&M expenses by $412,498 of the test year.[1209]

1201 Ex. 81, Moeller Direct at 11; Ex. 78, Figoli Direct at 73-76.
1202 Ex. 429, Campbell Direct at 141-144.
1203 Ex. 80, Figoli Rebuttal at 17.
1204 Ex. 90, Heuer Rebuttal at 21.
1205 Ex. 81, Moeller Direct at 119.
1206 Ex. 423, Byrne Direct at 45.
1207 Ex. 423, Byrne Direct at 46.
1208 Ex. 423, Byrne Direct at 43-47.
1209 Ex. 423, Byrne Direct at 46-47.

721. The Department proposed a corresponding proportional (52 percent) reduction to FAS 112 capital costs of $99,172 reduction.[1210]

722. The Company agreed with the Department's recommendations and proposed to combine the O&M and capital adjustments into one revenue requirement reduction of $421,463 (both O&M and capital).[1211] The Department accepted the Company's calculated adjustment.[1212]

I. Active Health Care and Welfare Costs (2014) (Issue #22)

723. The Company requested recovery of $33,264,053 in active health care costs and a total of $36,443,475 in combined active health and welfare costs for the test year.[1213] The Company calculated the test year amount by utilizing actual active health care costs from 2011 (weighted at 20 percent) and 2012 (weighted at 80 percent), making adjustments for changes in plan design, regulation, administrative fees, etc., and then trending the data forward to 2014 using a 7.0 percent inflation factor.[1214]

724. The Department recommended that the 2014 active health case O&M costs be based on a three-year historical average of $33,136,458, resulting in a downward adjustment of $3,307,017.[1215]

725. The Department recommended use of an inflation factor of 2.85 percent over 2013 claims expenses as this is an average of the annual percentage increases in claims expenses in 2012 and 2013.[1216] This results in a reduction to the Company's requested test year active health care O&M expense of $1,056,493.[1217] The

[1210] Ex. 423, Byrne Direct at 23; Ex. 427, Byrne Surrebuttal at 13.
[1211] Ex. 90, Heuer Rebuttal at 23; Ex. 83, Schrubbe Rebuttal at 60;
[1212] Ex. 427, Byrne Surrebuttal at 13.
[1213] Ex. 80, Moeller Direct at 129.
[1214] Ex. 80, Moeller Direct at 130-131.
[1215] Ex. 427, Byrne Surrebuttal at 13-14.
[1216] Ex. 427, Byrne Surrebuttal at 20-21.
[1217] Ex. 427, Byrne Surrebuttal at 20-21.

Department recommended a proportional adjustment to the active health care capital costs of $225,480.[1218]

726. The Company agreed to the Department's recommended reduction in active health care costs of $1.082 million (O&M and capital) to the test year revenue requirements.[1219]

J. Nuclear Cash-Based Retention Program (2014) (Issue #23)

727. The Company proposed recovery of $516,466[1220] in costs for one component of its Nuclear Retention Program, the Nuclear Cash-Based Retention agreements.[1221] The Company's Nuclear Retention Program is a compensation tool to help attract and retain employees that are qualified to work in nuclear plants.[1222]

728. The Department stated it is reasonable to conclude that the Nuclear Retention Program was created in 2012 to provide some of the Company's nuclear employees additional compensation and to replace the amounts they would otherwise have received through the AIP.[1223] The Department recommended removing all the costs associated with the Nuclear Retention Program from the test year.[1224]

729. During the evidentiary hearing, the Company accepted the Department's proposal to remove all the costs associated with the Nuclear Retention Program from the test year.[1225]

730. This results in a $516,466 reduction in test year revenue requirements.[1226]

1218 Ex. 427, Byrne Surrebuttal at 20-21.
1219 Ex. 140, Heuer Opening Statement at 2.
1220 The Company's proposed recovery is based on a Total Company number of $694,736 of nuclear retention program expenses. The Minnesota jurisdictional amount is $516,466 after applying a 74.34 percent allocation factor. Ex. 437, Lusti Direct at 31.
1221 Ex. 78, Figoli Direct at 51-52.
1222 Ex. 78, Figoli Direct at 51.
1223 Ex. 437, Lusti Direct at 35.
1224 Ex. 437, Lusti Direct at 35.
1225 Ex. 140, Heuer Opening Statement at 2.
1226 Ex. 140, Heuer Opening Statement at 2.

K. Customer Care O&M Expenses - Miscellaneous O&M Credits (Issue # 24)

731. The Company requested Customer Care O&M Expenses that included forecasted Miscellaneous O&M Credits.[1227] The Miscellaneous O&M Credits offset O&M expenses related to Meter Reading and Field Collections.[1228]

732. In Direct Testimony, the Department noted the Company has over-recovered Customer Care O&M expenses by $3.2 million from 2011 to 2013 and that much of the over-recovery is attributed to higher than forecasted Miscellaneous O&M Credits.[1229] The Department recommended that the Company's 2014 test year Miscellaneous O&M Credits to be set at the amount of the average Miscellaneous O&M Credits from 2010 through 2013, at $1.216 million.[1230]

733. In Rebuttal Testimony, the Company agreed with the Department's proposed adjustment to the forecasted Miscellaneous O&M Credits, but disagreed with the Department's use historical averages.[1231] The Company noted that the Department's recommendation closely correlates with the Company's current budget forecast for 2014 Miscellaneous O&M Credits, which was $1.218 million.[1232] The Company also noted that the Department's proposal to set the 2014 Miscellaneous O&M Credits at $1.216 million results in a decrease in test year revenue requirement of $503,142.[1233]

734. In Surrebuttal Testimony, the Department noted the Company and Department continue to disagree on the rationale of the Miscellaneous O&M Credit

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1227 Ex. 71, Gersack Direct at 16 and Schedule 2.
1228 Ex. 71, Gersack Direct at 16.
1229 Ex. 425, Byrne Direct at 11-13.
1230 Ex. 423, Byrne Direct at 49; Ex. 437, Lusti Direct at 38.
1231 Ex. 73, Gersack Rebuttal at 2-3.
1232 Ex. 73, Gersack Rebuttal at 5-6.
1233 Ex. 90, Heuer Rebuttal at 12.

adjustment, but agree on the amount to be included, which effectively resolved the issue.[1234]

L. Nuclear Fees (Issue # 25)

735. The Company requested recovered recovery of the Minnesota jurisdictional portion of $35.2 million for nuclear fees in the test year.[1235] The Department recommended the Company recover $23.75 million, which results in a $0.25 million or 1.1 percent increase from the Department's calculated actual nuclear fees costs from 2013, resulting in a decrease in test year power production expense by $1.9 million.[1236]

736. In Rebuttal Testimony, the Company disagreed with the Departments recommendation to allow only a 1.1 percent increase in nuclear fees from 2013, because the Department relied on the abnormally low 2013 Nuclear Regulatory Commission (NRC) actual fees for the starting point and because all nuclear fees other than the NRC fees increased by at least 10 percent from 2011 to 2013.[1237] The Company also noted that a recent update to NRC pre-reactor portions of NRC's 2014 Annual Fee is 19 percent higher than in 2013, which justifies the Company's test year 2014 nuclear fee amount.[1238]

737. In Surrebuttal Testimony, the Department noted the justification for NRC Fees and recommended the amount of $15.00 million for the Minnesota jurisdiction.[1239] The Department continued to disagree with the Company's 2014 test year amounts for other nuclear fees and recommended a $1.00 million downward adjustment to revenue requirements.[1240]

1234 Ex. 427, Byrne Surrebuttal at 7.
1235 Ex. 52, O'Connor Direct at 112.
1236 Ex. 429, Campbell Direct at 74-75; Ex. 437, Lusti Direct at 42 and Sch. 7.
1237 Ex. 54, O'Connor Rebuttal at 31-35.
1238 Ex. 54, O'Connor Rebuttal at 35-37.
1239 Ex. 435, Campbell Surrebuttal at 61-62.
1240 Ex. 435, Campbell Surrebuttal at 62-65; Ex. 442, Lusti Surrebuttal at 32.

738. During the evidentiary hearing, the Company accepted the Department's final recommended $1.00 million reduction to revenue requirement.[1241] The Department recognized the issue as resolved.[1242]

M. Investor Relations Costs (Issue # 26)

739. The Company requested recovery of 50 percent of investor relations costs with the exception of requesting recovery of all stock registration fees for the Minnesota electric jurisdiction, resulting in a decrease in test year revenue requirement of $385,000.[1243] In Direct Testimony, the Company presented information supporting its request,[1244] and noted that the Company believed this adjustment was consistent with the prior rate cases.[1245]

740. In Direct Testimony, the Department disagreed with the Company's exception for stock registration fees, and recommended that the 50 percent of all investor relations costs, including the stock registration fees, be removed from the test year.[1246] The Department's proposal would decrease the test year revenue requirement by an additional $78,140.[1247]

741. In Rebuttal Testimony, the Company accepted the Department's proposal.[1248]

742. In Surrebuttal Testimony, the Department confirmed the agreed upon adjustment.[1249]

1241 Ex. 140, Heuer Opening Statement at 2; Tr. Vol. 1 at 218 (Heuer); Tr. Vol. 3 at 140 (Heuer).
1242 Ex. 450, Campbell Opening Statement at 2.
1243 Ex. 88, Heuer Direct at 138-139; Ex. 30, Tyson Direct at 44.
1244 Ex. 30, Tyson Direct at 38-44.
1245 Ex. 86, Stitt Direct at 60-61; Ex. 88, Heuer Direct at 138-139.
1246 Ex. 423, Byrne Direct at 7-10.
1247 Ex. 423, Byrne Direct at 10, 48-49; Ex. 437, Lusti Direct at 38.
1248 Ex. 90, Heuer Rebuttal at 13; Ex. 31, Tyson Rebuttal at 30.
1249 Ex. 427, Byrne Surrebuttal at 4-5; Ex. 442, Lusti Surrebuttal at 31.

N. Business Systems General Ledger System (Issue # 28)

743. In Direct Testimony, the Company included $27.721 million in capital costs in the 2015 Step related to the Business Systems' General Ledger System project, scheduled to go in-service during the fourth quarter of 2015.[1250]

744. In Direct Testimony, the Department proposed an adjustment to remove all General Ledger System project costs from the 2015 Step, because the Department did not find that the Company had shown that the system will be used and useful for Minnesota ratepayers until January 1, 2016.[1251] The Department's proposal would reduce the test-year rate base by $8.8 million and remove the Minnesota Jurisdictional portion of $27.721 million in capital costs from the 2015 Step.[1252]

745. The Company disagreed with the Department's proposal.[1253] In Rebuttal Testimony, the Company noted that running the new general ledger system parallel to the old system does not mean the system is not used and useful.[1254] The Company further clarified that the new general ledger testing period would begin in April 2015, and be fully operational on November 1, 2015, so as to align with the Company's financial year-end date.[1255]

746. In Surrebuttal Testimony, the Department agreed that the General Ledger System project would be in-service on December 31, 2015 and no longer recommended the adjustment.[1256]

1250 Ex. 62, Harkness Direct at 48-52 and Sch. 2; Ex. 18, May 7, 2014 Errata to the Application, Direct Testimony and Schedules, Errata Summary at 6.
1251 Ex. 423, Byrne Direct at 21-22.
1252 Ex. 427, Lusti Direct at 47, Ex. 423; Byrne Direct at 21-22.
1253 Ex. 64, Robinson Rebuttal at 8; Ex. 94, Perkett Rebuttal at 51; Ex. 64, Harkness Rebuttal at 3.
1254 Ex. 94, Perkett at 50-51; *See* Ex. 64, Harkness Rebuttal at 1-12.
1255 Ex. 64, Harkness Rebuttal at 5, 7-8.
1256 Ex. 427, Byrne Surrebuttal at 9-10; Ex. 442, Lusti Surrebuttal at 38.

O. Prairie Island Administration Building (Issue # 29)

747. In Direct Testimony, the Company included $22.6 million for project costs associated with the Prairie Island Administration Building.[1257] In Direct Testimony, Department challenged the reasonableness of the Company's scheduled in-service date of December 31, 2014 and recommended an in-service date of March 1, 2015.[1258] The Departments proposal would have the effect of decreasing the test year rate base by $1.8 million, and decreasing the 2015 Step by $1.1 million.[1259]

748. The Company provided further explanation for the costs in Rebuttal Testimony and provided additional explanation regarding the December 2014 in-service date.[1260] The Company did not agree with the Department's proposed modification of the in-service date.[1261]

749. In Surrebuttal Testimony, the Department agreed with the Company, and no longer recommended the change to the in-service date or the corresponding downward capital adjustment.[1262]

P. Pleasant Valley Wind and Borders Wind (2015 Step) (Issue #30)

750. The Company proposed to include the capital costs for two wind projects, Pleasant Valley Wind and Borders Wind, in the 2015 Step.[1263]

751. The Company accepted the Department's recommendation to include estimated Production Tax Credits (PTC) ($11.093 million) in base rates along with project costs, subject to a true-up of the PTCs in the Renewable Energy Standard ("RES") Rider.[1264] However, the Company was also open to MCC's recommendation

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1257 Ex. 52, O'Connor Direct at 69-70.
1258 Ex. $31, Campbell Direct at 154-156.
1259 Ex. 437, Lusti Direct at 22, 49.
1260 Ex. 54, O'Connor Rebuttal at 42-44; Ex. 94, Perkett Rebuttal at 48-50.
1261 Ex. 54, O'Connor Rebuttal at 42-44; Ex. 94, Perkett Rebuttal at 48-50.
1262 Ex. 436, Campbell Surrebuttal at 17-20; Ex. 442, Lusti Surrebuttal at 10, 41.
1263 Ex. 58, Mills Direct at 61-66.
1264 Ex. 429, Campbell Direct at 40-41; Ex. 100, Clark Rebuttal at 28.

to include both the capital costs and associated PTCs for Pleasant Valley and Border Winds in the RES Rider.[1265]

752. The Department originally stated that the Company has not shown why it is reasonable to recover capital costs for the Pleasant Valley and Border Winds projects in excess of the amounts that were approved in the Wind Acquisition Dockets and believed that the project costs were overstated in the 2015 Step.[1266] In Surrebuttal, the Department accepted the Company's explanation of discrepancies between the capital costs included in Mr. Mills' and Mr. Robinson's Direct Testimonies was due to AFUDC and no longer proposed a downward adjustment of $5,672,482 for capital project costs.[1267]

753. The OAG supported the recommendations made by the Department in its Direct Testimony, including the downward adjustment of $5,672,482 and inclusion of the PTC for these wind projects in base rates.[1268]

754. Based on their late 2015 in-service dates, MCC initially recommended removing all the capital costs related to these two wind projects from the 2015 Step, or alternatively, MCC recommended using a 13-month average rate base methodology.[1269] The Company stated that MCC's proposal does not reflect how rate base is calculated using beginning of year/end of year averages.[1270] In addition, the methodology used should be consistent for all capital additions calculations.[1271] In Surrebuttal Testimony, MCC recommended that the Company should recover the costs for the two wind projects through the RES Rider.[1272]

[1265] Ex. 100, Clark Rebuttal at 28.
[1266] Ex. 429, Campbell Direct at 38-39.
[1267] Ex. 435, Campbell Surrebuttal at 4-5.
[1268] Ex. 372, Lindell Rebuttal at 3-5.
[1269] Ex. 343, Maini Direct at 3-4.
[1270] Ex. 94, Perkett Rebuttal at 52-53.
[1271] Ex. 94, Perkett Rebuttal at 52-53.
[1272] Ex. 345, Maini Rebuttal at 3-4.

755. Inclusion of the costs for two wind projects in the 2015 Step is reasonable as is recovery of these costs in the RES Rider. The OAG's recommended adjustment is not supported by the record.

Q. Ratepayer Protection Mechanism for Company-Owned Wind Farm (Issue #31)

756. MCC recommended that a "ratepayer protection mechanism" be imposed for Company-owned wind projects.[1273]

757. Given the limited time in the present proceeding, the Company stated that this case is not the best forum to develop a ratepayer protection mechanism for Company-owned wind farm costs, and proposed to work with MCC and other Parties prior to January 1, 2015 and report results in the RES Rider Docket.[1274]

758. The MCC agreed to the Company's proposal.[1275]

R. Property Tax Amount (2015 Step) (Issue # 32)

759. In Direct Testimony, the Company provided a detailed explanation of its forecast that its total 2015 property taxes would be $221.4 million, resulting in property tax expense for 2015 for the Minnesota electric jurisdiction of $156.5 million.[1276] The Company also explained how the forecasted 2015 property tax expense was properly included in the calculations for the 2015 Step revenue requirement analysis.[1277]

760. The Department recommended reducing the 2015 Step property tax expense by nine percent to reflect a nine percent cumulative over-recovery for the period from 2001 through 2013.[1278]

761. In Rebuttal Testimony, the Company defended its property tax calculation and instead proposed to include in the 2015 Step only those property tax

[1273] Ex. 343, Maini Direct at 2-6.
[1274] Ex. 100, Clark Rebuttal at 29.
[1275] Ex. 345, Maini Surrebuttal at 4
[1276] Ex. 33, Duevel Direct at 3-4, 15-18; Ex. 89, Heuer Direct at 152; *see also* Ex. 14 at Tab A-58.
[1277] Ex. 96, Robinson Direct at 23-25.
[1278] Ex. 439, Lusti Direct at 54.

expenses that were directly associated with the capital projects in the 2015 Step year.[1279] This resulted in a $3.309 million reduction in the 2015 Step revenue requirement.[1280]

762. The Department accepted the $3.309 million reduction in the 2015 Step revenue requirements proposed by the Company.[1281] No other party commented on the issue of property taxes for the 2015 Step year.

S. Emissions Control Chemical Costs (2015 Step) (Issue # 33)

763. For O&M costs for 2015 Step as part of its MYRP, the Company requested an increase over the 2014 budget of $5.959 million for the Minnesota electric jurisdiction, to capture increased mercury sorbent costs due to the addition of emission control equipment at Sherco 1 and 2 in 2014.[1282] The Company's budget was based on the best information available, but the Company acknowledged some uncertainty inherent in estimating the amount of mercury sorbent to be used.[1283]

764. The Department recommended that the Company's proposed increase be reduced by half, to $2.98 for the Minnesota electric jurisdiction, because of the Company's prior over-estimating of the amount of emissions control chemicals and because the chemicals costs at A.S. King and Sherco 3 are not directly tied to new capital upgrades in 2015.[1284]

765. In rebuttal, the Company agreed that non-capital costs in the 2015 Step should be directly related to capital projects and agreed to remove chemical costs associated with A.S. King and Sherco Unit 3 from the 2015 Step (an $180,000 decrease).[1285]

[1279] Ex. 34, Duevel Rebuttal at 12-13; Ex. 98, Robinson Rebuttal at 10; Ex. 100, Clark Rebuttal at 7, 9, 30-32.
[1280] Ex. 98, Robinson Rebuttal at 10.
[1281] Ex. 442, Lusti Surrebuttal at 45.
[1282] Ex. 59, Mills Direct at 39-40; Ex. 96, Robinson Direct at 27-28; Ex. 99, Clark Direct at 16-17.
[1283] Ex. 59, Mills Direct at 40; Ex. 61, Mills Rebuttal at 10.
[1284] Ex. 431, Campbell Direct at 31.
[1285] Ex. 61, Mills Rebuttal at 9-10; Ex. 98, Robinson Rebuttal at 9-10; Ex. 100, Clark Rebuttal at 32; Sparby Rebuttal at 20-21.

766. In response to the Department's continued concern that the budget for mercury sorbent was still too high,[1286] the Company agreed at the evidentiary hearing to further reduce the budgeted amount by $1.4 million, resulting in a total downward adjustment of $1.58 million in revenue requirements.[1287] The Department agreed with this adjustment.[1288] No other parties commented on this issue.

T. MYRP: Rate Moderation Proposal-DOE Settlement Funds (2015 Step) (Issue #34)

767. One of the rate moderation proposals from the Company was to utilize settlement funds[1289] received from the Department of Energy in 2013 and 2014 in excess of the annual decommissioning accrual amount (totaling approximately $35.8 million) to reduce the 2015 Step revenue requirement.[1290]

768. The Department did not oppose use of the DOE settlement funds for rate mitigation in the 2015 Step as these amounts are in excess of the currently approved decommissioning accrual.[1291]

769. The OAG recommended that the Commission carefully consider whether the Company's moderation proposal was reasonable and in the public interest.[1292] The OAG stated that the Company's use of DOE settlement funds does not provide any ratepayer benefit as these are funds owed to ratepayers in any event.[1293]

770. The Commercial Group agreed with the proposal to use excess DOE payments for rate moderation but instead of assigning the entire amount to the 2015 Step, the Commercial Group recommended using the funds received in 2013 to

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1286 Ex. 436, Campbell Surrebuttal at 28-31.
1287 Ex. 140, Heuer Opening Statement. at 7.
1288 Ex. 450, Campbell Opening Statement at 2.
1289 The Company receives settlement payments from the DOE as a result of litigation regarding the DOE's contractual obligation to take spent nuclear fuel. Ex. 95, Robinson Direct at 33.
1290 Ex. 99, Clark Direct at 28-29.
1291 Ex. 429, Campbell Direct at 90.
1292 Ex. 370, Lindell Direct at 16.
1293 Ex. 370, Lindell Direct at 16.

reduce rates in the 2014 Test Year and the funds received in 2014 to reduce rates in 2015.[1294] If the Commission does not approve the 2015 Step, the Commercial Group recommended use of the entire amount to moderate rates in the 2014 Test Year.[1295]

771. During discovery, the Company noted that DOE payments are expected to be $10.1 million lower than projected in the initial filing or $25.737 million.[1296] The Company provided support for this expected reduction to the DOE payments.[1297]

772. During the evidentiary hearing, the Company agreed to true-up and refund to customers any DOE payments received in excess of the amount reflected in the Commission's final Order for the 2015 Step.[1298]

773. Also during the evidentiary hearing, the Department agreed that the current placeholder for DOE payments is now $25.737 million, since the Company had provided support for $10.1 million reduction. The Department stated that this adjustment results in a net $12.633 million increase in revenue in 2015.[1299]

U. MYRP: Refund Mechanism Due to Postponed or Cancelled Capital Projects (Issue #35)

774. During the evidentiary hearing, the Company and the Department agreed to a refund mechanism for capital projects that are postponed or cancelled for the 2014 test year and the 2015 Step.[1300]

775. For the 2014 test year, the refund mechanism will start with the Commission approved 2014 test year plant related base revenue, but exclude the 2014 plant additions for the Monticello LCM/EPU project or 2015 Step projects (Adjusted Test Year 2014 Plant Related Revenue Requirements).[1301] The refund mechanism would then compare the Adjusted Test Year 2014 Plant Related Revenue

1294 Ex. 255, Chriss Direct at 12.
1295 Ex. 255, Chriss Direct at 12.
1296 Ex. 429, Campbell Direct at 86; Ex. 97, Robinson Rebuttal at 13-14.
1297 Ex. 130, Perkett Opening Statement at 1; Ex. 450, Campbell Opening Statement at 3-4.
1298 Ex. 140, Heuer Opening Statement at 7.
1299 Ex. 450, Campbell Opening Statement at 3-4.
1300 Ex. 130, Perkett Opening Statement at 1-2.
1301 Ex. 140, Heuer Opening Statement at 3-4.

Requirements to the actual plant related base rate revenue requirements, again excluding the 2014 plant additions for the Monticello LCM/EPU project or 2015 Step projects (Adjusted Actual 2014 Plant Related Revenue Requirements).[1302] If the Adjusted Actual 2014 Plant Related Revenue Requirements is lower than the Adjusted Test Year 2014 Plant Related Revenue Requirements, the Company will include the amount in the interim rate refund and the calculation of final rates in 2015.[1303]

776. The Company will submit a compliance filing prior to the implementation of final 2014 rates that: (i) calculates the Adjusted Actual 2014 Plant Related Revenue Requirements and compares it to the Adjusted Test Year 2014 Plant Related Revenue Requirements; (ii) compares the 2014 test year to the 2014 actual capital additions, and (iii) provides an explanation for all project capital additions that were included in actual rate base but not part of the 2014 test year.[1304]

777. A similar process will be used in 2015, except it would be limited to only the current proposed 34 Step projects.[1305]

V. MYRP: Compliance for 2015 Step Projects (Issue #36)

778. During the evidentiary hearing, the Company proposed to submit compliance reports to abide by the terms of the Commission's MYRP Order.[1306]

779. The Company agreed to provide quarterly compliance reporting during 2015 (April, August, November) to the Commission comparing the most current forecast of each 2015 Step project to the amount included in the 2015 Step.[1307]

780. By April 1, 2016, the Company will submit its final compliance report which will include: (i) the actual 2015 Step revenue requirement for each project, specifically 2014 actual, 2015 actual and the difference (2015 Step); (ii) the revenue

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[1302] Ex. 140, Heuer Opening Statement at 3-4.
[1303] Ex. 140, Heuer Opening Statement at 3-4.
[1304] Ex. 140, Heuer Opening Statement at 3-4.
[1305] Tr. Vol. 2 at 55-56 (Perkett).
[1306] Ex. 140, Heuer Opening Statement at 6-7.
[1307] Ex. 140, Heuer Opening Statement at 6-7.

requirement difference for each 2015 Step project between the 2015 Step actual and 2015 Step test year; (iii) explanations for project additions that are greater than included in the 2015 Step; (iv) in the event the total actual 2015 Step revenue requirement is lower than the total test year 2015 Step revenue requirement, the Company will include in its compliance filing a proposal for rate refund; and (v) in the event the Company becomes aware of a 2015 Step project cancellation or postponement, the Company will provide 30 day notice including a refund plan.[1308]

W. Service Agreement between NSP and Xcel Energy Services, Inc. (Issue # 37)

781. On March 4, 2014, after the filing of this rate case, the Company filed a petition in a separate docket (Docket No. E,G002/AI-14-234) seeking a second amendment to the Commission-approved service agreement that specifies the methods by which the costs of services provided by Xcel Energy Services, Inc. (XES) are allocated to various accounting function at the Company and to other entities.[1309]

782. The Company and the Department agree that any changes that result from the Commission's order in the service agreement amendment docket will be incorporated into this case as appropriate.[1310]

X. Withdrawal of Hollydale Transmission Project (Issue # 38)

783. The Company noted in discovery that it no longer anticipates that the Hollydale transmission project will be placed in-service during the 2014 test year and proposed to remove the associated capital costs amounting to $388,000 from the rate base.[1311]

1308 Ex. 140, Heuer Opening Statement at 6-7.
1309 Ex. 425, Byrne Direct at 3-4.
1310 Ex. 87, Stitt Rebuttal at 13-14; Ex. 425, Byrne Direct at 4; Ex. 428, Byrne Surrebuttal at 2-3; Ex. 449, Byrne Opening Statement at 1.
1311 Ex. 437, Lusti Direct at 19-20 and Sch. 31.

784. In Direct Testimony, the Department agreed with the Company's proposal and noted that the proposal results in a $43,025 reduction in revenue requirement.[1312]

785. In Rebuttal Testimony, the Company confirmed withdrawal of the Company's Certificate of Need and Route Permit applications for the Hollydale transmission project and proposed to exclude the associated costs from the 2014 test year, with an associated reduction in revenue requirement of $43,000.[1313]

786. The Department accepted the proposal in Surrebuttal Testimony.[1314]

Y. Prairie Island EPU/LCM Split Correction (Issue # 39)

787. In Direct Testimony, the Company noted results of a recently completed transactional assessment of the Prairie Island EPU/LCM project costs, and indicated had made adjustments to the interim rates and the Company would make the necessary adjustments to the cost allocations in Rebuttal Testimony.[1315]

788. In Direct Testimony, the Department noted the need for this adjustment and indicated preliminary approval based on the Company's adjustment in the Interim Rate Petition.[1316]

789. In Rebuttal Testimony, the Company proposed an adjustment removing $2.157 million from the LCM project costs and reallocating the costs to the EPU portion of the project costs.[1317]

790. The Company's proposed adjustment reduces test year rate base by $1.418 million and decreases test year revenue requirements by $158,000.[1318]

1312 *Id.*
1313 Ex. 100, Clark Rebuttal at 26; Ex. 90, Heuer Rebuttal at 11-12 and Sch. 6A.
1314 Ex. 442, Lusti Surrebuttal at 7-8.
1315 Ex. 88, Heuer Direct at 79; Ex. 12, Notice and Petition for Interim Rates at 9; Interim Rate Petition Supporting Schedules, Schedule B, Part 2, page 5, column 4.
1316 Ex. 437, Lusti Direct at 18-19.
1317 Ex. 90, Heuer Rebuttal at 9.
1318 Ex. 90, Heuer Rebuttal at 9.

791. In Surrebuttal Testimony, the Department agreed to the Company's proposed adjustment.[1319]

Z. Xcel Energy Foundation Administration Cost Correction (Issue # 40)

792. In Direct Testimony, the Company included a reduction to test year rate base of $281,000 to reflect disallowance of all administrative costs of the Xcel Energy Foundation.[1320]

793. In Information Request DOC-1186, the Company identified an error in the original Foundation Administration Cost adjustment and indicated the Foundation Administration Cost adjustment should have included an additional $114,622 reduction in test year revenue requirement related to non-labor Foundation Administration Costs.[1321]

794. The Company proposed the $114,622 reduction in test year revenue requirement in Rebuttal Testimony, and it was accepted by the Department in its Surrebuttal Testimony.[1322]

AA. Big Stone Brookings Cost Correction (Issue # 41)

795. In Direct Testimony, the Company noted that subsequent its original filing, a forecasted update was made to a component of the Big Stone Brookings transmission project, with an effect of lowering the associated test year operating costs.[1323] The Company's initial filing adjusted the interim revenue requirement to reflect the lower operating costs, but did not incorporate the change into the test year revenue requirement.[1324]

[1319] Ex 442, Lusti Surrebuttal at 2-3.
[1320] Ex. 88, Heuer Direct at 10 and 138.
[1321] Ex. 423, Byrne Direct at 6.
[1322] Ex. 90, Heuer Rebuttal at 10; Ex. 427, Byrne Surrebuttal at 3-4; Ex. 442, Lusti Surrebuttal at 31.
[1323] Ex. 88, Heuer Direct at 80.
[1324] Ex. 12, Notice and Petition for Interim Rates at 9; Interim Rate Petition Supporting Schedules, Schedule B, Part 2, page 5, column 5.

796. In Rebuttal Testimony, the Company proposed an adjustment to the test year to reflect the forecasted update.[1325] The Company's proposed adjustment increases test year rate base by $299,000, and decreases test year revenue requirement by $145,000.[1326]

797. In Surrebuttal Testimony, the Department accepted the Company's Big Stone Brookings cost correction.[1327]

BB. Bargaining Unit Wage Increase Correction (2014) (Issue #42)

798. The Company's 2014 test year included a 3.0 percent wage increase for bargaining unit employees.[1328]

799. After the initial filing on November 4, 2013, the union ratified a new agreement with a 2.6 percent wage increase.[1329] To account for this change, the Company proposed a $405,000 reduction to the test year revenue requirements.[1330]

800. In surrebuttal, the Department agreed to the adjustment proposed by the Company.[1331]

CC. Theoretical Reserve for Intangible Plant Correction (Issue # 43)

801. In Direct Testimony, the Company provided a detailed explanation of its amortization of the surplus reserve margin for transmission, distribution, and general assets.[1332]

802. In Rebuttal Testimony, the Company pointed out that in its initial calculations, it had amortized all of the theoretical reserve surplus for intangible plant over eight years, but instead should have amortized the theoretical reserve surplus for electric and common intangible plant accounts over the average remaining lives of

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1325 Ex. 90, Heuer Rebuttal at 40.
1326 Ex. 90, Heuer Rebuttal at 40.
1327 Ex. 442, Lusti Surrebuttal at 12-13.
1328 Ex. 90, Heuer Rebuttal at 41.
1329 Ex. 90, Heuer Rebuttal at 41.
1330 Ex. 90, Heuer Rebuttal at 41.
1331 Ex. 442, Lusti Surrebuttal at 31.
1332 Ex. 89, Heuer Direct at 82-83.

those accounts.[1333] The Company proposed an additional adjustment to fix this error.[1334] The adjustment resulted in a $77,000 decrease in the 2014 rate base and a $28,000 increase in the 2014 revenue requirements.[1335]

803. The Department agreed with the adjustment.[1336] No other party commented on this issue.

DD. Net Operating Loss Correction (2014) (Issue # 44)

804. In its initial filing, the Company provided detailed information about the Net Operating Loss (NOL) in the COSS.[1337]

805. In rebuttal, the Company pointed out that it had inadvertently excluded state tax credits from its initial NOL calculation in the COSS.[1338] The Company proposed additional adjustments to the NOL to fix this inadvertent error.[1339] The adjustments result in a $190,000 increase to the 2014 rate base and a $366,000 reduction in the 2014 revenue requirements.[1340]

806. The Department agreed with the Company's correction relating to the error in NOL.[1341] No other party commented on this issue.

EE. Monticello Cyber Security Correction (Issue # 45)

807. The Company's initial filing included costs associated with the Monticello Cyber Security project, which was scheduled to go in-service during the 2014 test year.[1342]

808. In Direct Testimony, the Company's updated forecasts suggested the Monticello Cyber Security project would be delayed until 2015, and indicated that the

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1333 Ex. 90, Heuer Rebuttal at 41.
1334 Ex. 90, Heuer Rebuttal at 42.
1335 Ex. 90, Heuer Rebuttal at 42.
1336 Ex. 442, Lusti Surrebuttal at 13.
1337 Ex. 89, Heuer Direct at 110-116.
1338 Ex. 90, Heuer Rebuttal at 42-43.
1339 Ex. 90, Heuer Rebuttal at 43.
1340 Ex. 90, Heuer Rebuttal at 43.
1341 Ex. 442, Lusti Surrebuttal at 14.
1342 Ex. 88, Heuer Direct at 80.

Company would make the necessary reductions in test year costs in Rebuttal Testimony.[1343]

809. In Rebuttal Testimony, the Company's updated forecasts projected that the Monticello Cyber Security project will go in service during the 2014 test year, as a result, no adjustments are necessary.[1344]

810. No party other than the Company provided testimony on this issue.

FF. Alliant Wholesale Billing Revenues (Issue # 46)

811. In Rebuttal Testimony, the Company noted that it anticipates receiving a refund from Alliant for transmission expenses paid, which will include $561,616 that will be accounted for in 2014 Other Revenues.[1345] The Company notes no adjustment is necessary because the initial filing includes an adjustment to capture unbudgeted Other Revenues using a three-year historical average and the revenue associated with the Alliant refund will be included in the three-year historical average of Other Revenues in a future rate case.[1346]

812. No party other than the Company provided testimony on this issue.

GG. Cost of Capital Impact (2014 and 2015 Step) (Issue # 47)

813. The cost of capital adjustment is the effect of the change in cost of capital for all other adjustments made to the unadjusted test year.[1347] It is a secondary calculation that cannot be completed until other issues, such as capital structure, cost of debt, return and equity, and overall rate of return are decided.[1348]

814. The Company will update its calculation of the cost of capital to reflect the Commission's final decisions regarding capital structure, cost of debt, return on equity, and overall rate of return in this case.[1349]

1343 Ex. 88, Heuer Direct at 80.
1344 Ex. 90, Heuer Rebuttal at 43.
1345 Ex. 90, Heuer Rebuttal at 44.
1346 Ex. 90, Heuer Rebuttal at 44; *see also* Ex. 88, Heuer Direct at 134.
1347 Ex. 89, Heuer Direct at 145.
1348 Ex. 89, Heuer Direct at 94; Ex. 90, Heuer Rebuttal at 44-45.
1349 [cite needed]; *see also* Ex. 140, Heuer Opening Statement at 3.

HH. Net Operating Loss Impact (2014 and 2015 Step) (Issue # 48)

815. The NSPM income tax determination has been in a net operating loss (NOL) position since 2010.[1350] This means that more deductions exist in the current period than is needed to bring current taxable income to zero.[1351] Excess deductions and unused credits were deferred and tracked for use in future periods.[1352] The Company and the Department developed a process for reporting these deferred balances and returning to customers the revenue requirement reduction associated with the utilization of these deferred balances in the form of a refund or as a reduction to base rates.[1353]

816. Determination of the Company's NOL position is a secondary calculation that cannot be completed until all other adjustments are decided.[1354] In Rebuttal Testimony, the Company analyzed the extent to which various adjustments recommended by the Department, as well as various adjustments recommended by the Company in rebuttal, would reduce taxable income, resulting in less use of the deferred tax asset (and thus increasing the rate base).[1355]

817. The Company agreed that once disputed issues are resolved via issuance of the Commission's final order, the Company will, in a compliance filing, recalculate the NOL to be included in final rates.[1356] The Department agreed that NOL will need to be recalculated.[1357] No other party commented on NOL.

II. Cash Working Capital Impact (2014 and 2015 Step) (Issue # 49)

818. Cash working capital (CWC) refers to the amount of cash a utility needs to have on hand to conduct its business.[1358] A lead/lag study is necessary to

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1350 Ex. 89, Heuer Direct at 110-11, 144.
1351 Ex. 89, Heuer Direct at 110-11, 144.
1352 Ex. 89, Heuer Direct at 144.
1353 Ex. 89, Heuer Direct at 144.
1354 Ex. 89, Heuer Direct at 94; Ex. 90, Heuer Rebuttal at 44.
1355 Ex. 90, Heuer Rebuttal at 44.
1356 Ex. 89, Heuer Direct at 94; *see also* Ex. 140, Heuer Opening Statement at 3.
1357 Ex. 442, Lusti Surrebuttal at 14.

determine the amount of CWC that a company must reserve.[1359] Lead time is the number of days between the utility's receipt and payment of invoices it receives.[1360] Lag time is the average number of days between the utility's billing of its customers and its receipt of payment.[1361] In Direct Testimony, the Company calculated its initial CWC requirement.[1362]

819. The Department agreed that the lead/lag factors used by the Company were reasonable.[1363] No other party commented on this issue.

820. Because the CWC calculation is based on the test year O&M expenses and test year rate base, it needs to be recalculated after disputed issues are resolved via issuance of the Commission's final order. In Rebuttal Testimony, the Company calculated the CWC requirement for 2014 based on the various adjustments recommended by the Company at that time.[1364] In Surrebuttal Testimony, the Department calculated the CWC requirement for 2014 and the 2015 Step based on the various adjustments recommended by the Department at that time.[1365]

821. The Company and the Department agreed that CWC will need to be recalculated as part of the final compliance filing based on the revenue requirement approved in this case.[1366]

JJ. Low-Income Renter Conservation Program (Issue #81)

822. The ECC recommended that the Company should implement a low-income conservation program for renters who live in smaller housing units.[1367] ECC stated that there is substantial need and opportunity for promoting energy efficiency

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[1358] Ex. 439, Lusti Direct at 24.
[1359] Ex. 439, Lusti Direct at 24.
[1360] Ex. 439, Lusti Direct at 24.
[1361] Ex. 439, Lusti Direct at 24.
[1362] Ex. 439, Lusti Direct at 24; Ex. 89, Heuer Direct at 145.
[1363] Ex. 439, Lusti Direct at 24.
[1364] Ex. 90, Heuer Rebuttal at 46.
[1365] Ex. 442, Lusti Surrebuttal at 15, 42.
[1366] Ex. 140, Heuer Opening Statement at 3.
[1367] Ex. 235, Marshall Direct at 1-31.

in low-income, one- to four-unit rental dwellings, and low-income renters are unable to invest in energy efficiency measures without financial assistance.

823. The OAG agreed with the ECC that low-income renters are one of the groups at most risk being negatively impacted by inclining block rates and would also provide the largest marginal efficiency gains with respect to conservation investment.[1368]

824. The Company noted that it currently offers CIP programs that are also available for low-income renters in smaller housing units through Home Energy Savings Program (HESP) and Multi-Family Energy Savings Program (MESP). The Company is also currently evaluating and redefining its conservation programs and design options for the multi-family segment in the CIP process.[1369] The Company explained that this evaluation will also include addressing the need for program modifications or new programs for one- to four-unit rental properties. The Company agreed to modify its CIP plan once the new program is fully developed.[1370]

825. The Department stated that to the extent that the Company's current programs are available to low-income renters, they should be evaluated and utilized first before creating a new program.[1371] If a need is found to develop an additional CIP program for low-income renters who live in smaller housing units, the Department recommended ordering the Company to work with the Department CIP staff to develop such a program.[1372]

826. In surrebuttal, ECC agreed that the standard CIP process is appropriate for developing and implementing the low-income renter conservation program.[1373]

[1368] Ex. 377, Nelson Rebuttal at 31.
[1369] Ex. 42, Sundin Rebuttal at 16-18.
[1370] Ex. 42, Sundin Rebuttal at 16-18.
[1371] Ex. 416, Grant Rebuttal at 7.
[1372] Ex. 422, Pierce Surrebuttal at 13.
[1373] Ex. 240, Marshall Surrebuttal at 1-3.

Based on these Findings of Fact,[1374] the Administrative Law Judge makes the following:

VIII. CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. §§ 14.50 and 216B.08.

2. The public and parties received proper and timely notice of the hearing and the Applicant complied with all procedural requirements of statute, rule, and the MYRP Order.

3. Every rate set by the Commission shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of Minn. Stat. §§ 216B.164, 216B.241, and 216C.05.

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.

5. The record supports the resolution of the settled, resolved, and uncontested matters set forth in the above Findings. These matters have been resolved in the public interest and are supported by substantial evidence.

6. Rates set in accordance with this Report would be just and reasonable.

7. The final rates ordered by the Commission should be compared to the interim rates set by the Commission and a refund ordered to the extent that the interim rate exceeds the final rate, subject to any true-up that is ordered.

8. Any Findings of Fact more properly designated as Conclusions are hereby adopted as such.

[1374] Citations to the transcript or hearing exhibits in these Findings of Fact are not inclusive of all applicable evidentiary support in the record.

Based on these Conclusions, the Administrative Law Judge makes the following:

IX. RECOMMENDATIONS

1. The Company is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. The Commission incorporate the agreements made by the Parties in the course of this proceeding into its Order.

3. The Commission adopt the recommendations set forth in the Findings above.

4. The Company make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated on ____________________ ____________________________________

Jeanne M. Cochran
Administrative Law Judge

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 15 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.

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota;

xx by e-mail; or

xx electronic filing.

OAH Docket No. 68-2500-31182

MPUC Docket No. E002/GR-13-868

Dated this 14th day of October 2014

/s/

____

SaGonna Thompson

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