OAH 68-2500-31182
PUC E-002/GR-13-868

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

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

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STATE OF MINNESOTA
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In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota	**FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS**

An evidentiary hearing was held before Administrative Law Judge Jeanne M. Cochran on August 11-15, 2014 at the Public Utilities Commission, St. Paul, Minnesota, in the above-captioned matter. Public hearings were held in Minneapolis, St. Paul, Woodbury, Mankato, Eden Prairie, and St. Cloud between June 23, 2014 and June 27, 2014. Written public comments were received until July 7, 2014.

Post-hearing briefs were filed by the parties on September 23, 2014. Responsive briefs were filed on October 14, 2014. The hearing record closed on October 14, 2014, with the filing of the last responsive brief.

Appearances:

Aakash H. Chandarana, Lead Regulatory Attorney-North, Kari L. Valley, Assistant General Counsel, James R. Denniston, Assistant General Counsel, and Stephen E. Fogel, Assistant General Counsel, all of Xcel Energy Services Inc., and Richard J. Johnson and Patrick T. Zomer, Moss and Barnett, appeared on behalf of Northern States Power Company (NSP or the Company).

Andrew P. Moratzka and Sarah Johnson Phillips, Stoel Rives, LLP, appeared on behalf of the Xcel Large Industrials (XLI).

Richard Savelkoul, Martin & Squires, appeared on behalf of the Minnesota Chamber of Commerce (MCC).

Alan R. Jenkins, Jenkins at Law, LLC, appeared on behalf of the Commercial Group (JC Penney Corporation Inc.; Macy's Inc.; Sam's West Inc.; and Wal-Mart Stores Inc.).

Pam Marshall, Executive Director, appeared on behalf of the Energy CENTS Coalition (ECC).

James Strommen, Kennedy & Graven, appeared on behalf of the Suburban Rate Authority (SRA).

Peder A. Larson and Conner T. McNellis, Larkin Hoffman Daly & Lindgren Ltd., appeared on behalf of the ICI Group.

Kevin Reuther, Attorney at Law; and Samantha Williams, Attorney at Law; appeared on behalf of Fresh Energy, Izaak Walton League – Midwest Office, Minnesota Center for Environmental Advocacy, Natural Resources Defense Council, and Sierra Club (Clean Energy Intervenors or CEI).

John B. Coffman, Attorney at Law, appeared on behalf of AARP.

Ian M. Dobson and Ryan P. Barlow, Assistant Attorneys General, appeared on behalf of the Office of the Attorney General – Antitrust and Utilities Division (OAG).

Julia E. Anderson, Linda S. Jensen, and Peter E. Madsen, Assistant Attorneys General, appeared on behalf of the Minnesota Department of Commerce, Division of Energy Resources (Department).

Robert Harding, Jorge Alonso, Jerry Dasinger, Clark Kaml, Ganesh Krishnan, Susan Mackenzie, Dorothy Morrissey, Sean Stalpes, and Andrew Twite, staff of the Public Utilities Commission (PUC or Commission), also attended the hearing.

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 multiyear rate plan (MYRP) pursuant to Minn. Stat. § 216B.16, subds. 1, 19 (2014). 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 (2015 Step) limited to specific capital additions and related costs.[1] The Company asked to increase its retail electric rates in 2014 by approximately $192.7 million, or 6.9 percent, and by an additional $98.5 million, or 3.5 percent, in 2015. Combined, these proposals would increase the Company's Minnesota electric revenues by approximately 10.4 percent based on present revenues.[2]

2. On January 2, 2014, the Commission issued its 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 by the parties:

[1] Exhibit (Ex.) 12 at 1 (Filing Letter). 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).
[2] Ex. 12 at 1 (Filing Letter).

a. Is the test year revenue increase sought by the Company reasonable or will it result in unreasonable and excessive earnings?

b. Is the rate design proposed by the Company reasonable?

c. Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?

d. Has the Company fully complied with past Commission orders?

e. 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?

f. 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's rates?

g. What will be the short-term and long-term consequences of the rate mitigation strategy proposed by the Company?[3]

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

FINDINGS OF FACT

I. 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.[4]

2. The Company has proposed that the revenue requirement for the 2014 test year be calculated in the traditional manner, and that the revenue increase for the 2015 Step be calculated utilizing the same methodology as it uses to calculate revenue requirements for a regular test year, except such calculations be limited to only the 2015 Step capital additions and related Operations and Maintenance (O&M).[5]

[3] NOTICE AND ORDER FOR HEARING (January 2, 2014).
[4] Ex. 88 at 1 (Heurer Direct).
[5] *Id.* at 6-1, 41-47; Ex. 95 at 5, 7 (Robinson Direct); *see also* Ex. 88, Schedule 25 (Heuer Direct).

3. 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]

4. Over the course of the proceeding, a number of the financial and rate design issues were resolved among the parties. The Company also updated its cost of service as new information became available.

5. In Rebuttal Testimony, the Company modified 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.[7]

6. 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.[8]

7. 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.[9]

8. The issues affecting the Company's 2014 and 2015 Step revenue requirements that were fully resolved by the parties are listed in Attachment A. Also listed in Attachment A are undisputed corrections made by the Company.[10]

II. The Parties

9. Northern States Power Company is a Minnesota corporation serving Minnesota customers. NSP 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.

10. The Commercial Group is an association of large commercial operators of retail facilities and distribution centers in Minnesota, many of which are served by the Company. The Commercial Group is concerned with any rate increase to its commercial customers.

11. The Energy CENTS Coalition is a non-profit organization which 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.

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[6] Ex. 99 at 26-30 (Clark Direct).
[7] Ex. 90 at 1-2 (Heuer Rebuttal).
[8] Ex. 140 at 8 (Heuer Opening Statement).
[9] Final Issues List (Oct. 7, 2014) (eDockets No. 201410-103651-01).
[10] *See also* Final Issues List.

12. The Suburban Rate Authority is a joint powers association. Its members are suburban municipalities within the Twin Cities metropolitan area. Most of the SRA member municipalities are served by the Company.

13. The ICI Group is comprised of U.S. Energy Services and its industrial, commercial, and institutional customers that receive electric service from the Company in Minnesota. The ICI Group is concerned about the financial impact of the proposed rate increases.

14. The Xcel Large Industrials include Flint Hills Resources, Gerdau Ameristeel US Inc., USG Interiors, and Unimin Corporation, some of the Company's largest retail electric customers in Minnesota. A rate increase could significantly impact the costs of production for these large industrial companies.

15. The Minnesota Chamber of Commerce represents over 2,400 businesses throughout the state of Minnesota. Many of its members are within the Company's service territory. The MCC is involved in policy issues that affect business, including energy policy, on behalf of its members.

16. The Clean Energy Intervenors include state, regional, and national environmental groups with an interest in advancing resource choices and rate decisions that minimize pollutant emissions and maximize energy efficiency and conservation.

17. AARP is a nonprofit organization that advocates for people who are 50 years of age or older. AARP has approximately 652,000 members in Minnesota, many of whom are residential customers of the Company. AARP intervened in the proceeding to ensure that any increase in the Company's rates is just and reasonable.

18. The OAG represents the interests of residential and small business customers in proceedings before the Commission. The OAG staff reviews the testimony and schedules filed by the Company and other parties and files testimony and argument intended to protect those interests.

19. The Department represents the public interest in rate proceedings. Department staff reviews the testimony and schedules filed by the Company and other parties to assure their accuracy and completeness, and files testimony and argument addressing the reasonableness of the elements of the rate request.

III. Procedural Background[11]

20. 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] That data was to be provided 30 days in advance of the filing of the Company's subsequent rate case.[13]

21. On November 4, 2013, the Company filed its application to increase its electric rates in Minnesota.[14] In its application, the Company requested approval of an interim rate increase of 4.57 percent beginning January 3, 2014.[15]

22. The Commission issued its NOTICE AND ORDER FOR HEARING on January 2, 2014. On that same date, it issued two other orders, one finding the rate case filing was substantially complete,[16] and one setting an interim rate schedule for the duration of this proceeding.[17]

23. On January 2, 2014, at the time the Commission issued its NOTICE AND ORDER FOR HEARING, the only parties to this proceeding were the Company, the Department, and the OAG.[18]

24. On January 28, 2014, a Prehearing Conference was held at the Public Utilities Commission. The 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 petitions to intervene of the Commercial Group, ECC, SRA, the ICI Group, and XLI.[19]

25. On March 5, 2014, the petitions to intervene of MCC and the Clean Energy Intervenors were granted.[20]

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[11] All Documents referred to in this section are filed with the eDocket 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=eDocketsResult&userType=public#{2CA4EF2B-C7DE-4C7B-8EE0-C548750D8B59}.

[12] *In the Matter of the Application of Northern States Power Co. for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 18 (Sept. 3, 2013) (12-961 ORDER); Exs. 1-2 (Pre-filing Sales Forecast Data).

[13] *Id*.

[14] Exs. 12-18.

[15] Ex. 12 at 1 (Filing Letter).

[16] ORDER ACCEPTING FILING AND SUSPENDING RATES (January 2, 2014).

[17] ORDER SETTING INTERIM RATES (January 2, 2014).

[18] NOTICE AND ORDER FOR HEARING (January 2, 2014).

[19] FIRST PREHEARING ORDER (February 14, 2014).

[20] 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 MINNESOTA CENTER FOR ENVIRONMENTAL ADVOCACY (March 5, 2014).

26. On March 14, 2014, AARP's petition to intervene was granted with limited party status. AARP's participation was limited to issues of rate design and decoupling, as well as to issues affecting service quality.[21]

27. Also on March 14, 2014, an order was issued denying Minnesota Power's petition to intervene, but allowing Minnesota Power to file an *amicus curiae* brief.[22]

28. On June 5 and 6, 2014, the Intervenors filed Direct Testimony.

29. On June 6, 2014, the Department filed a motion to extend the time for the filing of Direct Testimony from June 5 to June 6 due to computer problems with the eDockets system on June 5, 2014.

30. On June 25, 2014, an order was issued granting the Department's motion and extending the deadline for the filing of Intervenor Direct Testimony from June 5, 2014 to June 6, 2014.[23]

31. Public hearings were held according to the following schedule:

June 23, 2014, Earle Brown Heritage Center, and Sabathani Community Center, Minneapolis;

June 24, 2014, West Minnehaha Recreation Center, St. Paul;

June 24, 2014, Woodbury Central Park, Woodbury;

June 25, 2014, Civic Center, Mankato;

June 26, 2014, Eden Prairie City Center; and

June 27, 2014, Lake George Municipal Complex, St. Cloud.

32. The parties filed Rebuttal Testimony on July 7, 2014.

33. A Prehearing Conference was held on July 16, 2014 to address how to coordinate the handling of issues related to the Monticello Nuclear Generating Plant in this docket and MPUC Docket No. E002/CI-13-754 (the Monticello CI docket). The Prehearing Conference was held jointly with Administrative Law Judge Steve Mihalchick and the parties to the Monticello CI docket. [24]

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[21] ORDER GRANTING PETITION TO INTERVENE OF AARP WITH LIMITATIONS (March 15, 2014).
[22] ORDER REGARDING PETITION TO INTERVENE OF MINNESOTA POWER (March 14, 2014). While the order allowed Minnesota Power to file an amicus curiae brief, Minnesota Power decided not to file a brief in this docket.
[23] SECOND PREHEARING ORDER AND ORDER GRANTING MOTION FOR EXTENSION OF TIME (JUNE 25, 2014).
[24] JOINT PREHEARING ORDER (JULY 17, 2014).

34. On July 17, 2014, Administrative Law Judge Cochran and Administrative Law Judge Mihalchick issued an order specifying that:

a. The issue of whether the Extended Power Uprate should be considered "used and useful" during 2014 will be addressed in this docket;

b. The issue of the recovery and amortization of expenses from the Monticello CI docket will be addressed in this docket;

c. The issue of the reasonableness and prudence of the costs for the Life Cycle Management and Extended Power Uprate at the Monticello Nuclear Generating Plant will be addressed in the Monticello CI docket; and

d. The issue of cost allocation between the Extended Power Uprate and Life Cycle Management will be addressed in the Monticello CI docket.[25]

35. On August 4, 2014, the parties filed Surrebuttal Testimony.

36. On August 8, 2014, a Prehearing Conference was held at the Public Utilities Commission to discuss efforts towards resolving issues prior to the evidentiary hearing and to address procedural matters relating to the evidentiary hearing.[26]

37. The evidentiary hearing was held on August 11-15, 2014 at the Public Utilities Commission 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 resolved and which issues remained in dispute.[27] The same day, the Company also filed a Financial Adjustment Summary.[28]

39. On September 23, 2014, the parties filed Initial Briefs.

40. On September 30, 2014, the parties filed comments on the Company's Issues List.

[25] *Id.*
[26] Transcript of April 15, 2013 Status Conference.
[27] Company Draft Issues List and Financial Summary (Sept. 10, 2014) (eDockets Doc. No. 20149-102963-01).
[28] *Id.*

41. On October 7, 2014, the Company filed an updated version of the Issues List, incorporating comments from the other parties. [29]

42. On October 14, 2014, the parties filed Reply Briefs and Proposed Findings of Fact.

IV. Summary of Public Comments

43. Over 900 written public comments were filed by the July 7, 2014 deadline. In addition, over 90 individuals provided oral comments at the seven public hearings held in June 2014 across the Company's service territory. The vast majority of the public comments were from residential customers of the Company, although some business customers also provided comments as did some member organizations. A full summary of the public comments is included as Attachment B to this report.

44. While the public raised a variety of specific concerns, there was widespread concern about the size of the proposed rate increases. Residential customers with fixed and low-incomes expressed concern about their ability to pay for an increase of more than ten percent over two years when they are experiencing little or no increase in their incomes. A large number of seniors commented that the proposed rate increases are not affordable and will result in real hardship. In addition, a number of customers felt that the increased conservation efforts of customers should not result in increased rates. Some customers expressed concern that the Company had not been controlling its costs sufficiently. There were also specific objections to the Company's executive compensation and use of corporate aircraft. Business customers expressed a concern that higher rates would adversely affect their ability to compete or remain profitable. A small number of individuals along with a few local Chambers of Commerce expressed support for the proposed rate increases.

45. A significant number of customers also commented on the rate design proposals in the rate case. These customers raised a variety of perspectives on the following rate design topics: revenue apportionment; decoupling; the customer charge; and Inclining Block Rates (IBR). The public also provided input regarding the Company's generation resources. Some members of the public expressed support for greater use of renewable energy and conservation, and other members of the public stated that they favor greater use of coal and nuclear resources.

V. Legal Standards

46. The Commission must set rates that are just and reasonable, balancing the interests of the utility and its customers.[30] 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. Minnesota law recognizes this principle when it

[29] Final Issues List (Oct. 7, 2014) (eDockets Doc. No. 201410-103651-01).
[30] Minn. Stat. § 216B.03 (2014).

defines a fair rate of return as the rate which, when multiplied by the rate base, will give a utility a reasonable return on its total investment.[31]

47. The utility seeking an increase in its rates has the burden of proving by a preponderance of the evidence that its proposed change will result in just and reasonable rates.[32] This standard applies both in a traditional rate case and when a utility has proposed a multiyear rate plan.[33]

48. In the context of a rate proceeding, the "preponderance of the evidence" is defined as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory duty to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[34] Any doubt as to reasonableness of the proposed rates is to be resolved in favor of the consumer.[35]

49. The Commission acts in both a quasi-judicial and quasi-legislative capacity in setting rates. On purely factual issues, the Commission acts in its quasi-judicial capacity. On issues involving policy judgment, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.[36]

VI. Disputed Revenue Requirement Issues

50. In a traditional rate case, the revenue requirement portion of a rate case seeks to determine what additional revenue is required to meet the utility's required operating income, based upon a "test year" of operations. The required operating income is derived from determining the amount of investments in the rate base that have been made by a utility's shareholders, and multiplying the approved rate base times the rate of return that is determined to be appropriate for the Company.

51. After determining the required operating income, the Company's test year expenses and revenues are evaluated to determine the current operating income for the test year (in this case, 2014). The difference between the required operating income and the test year operating income is the income deficiency. The income deficiency is converted into a gross revenue deficiency amount.[37]

[31] Minn. Stat. § 216B.16, subd. 6 (2014).
[32] Minn. Stat. § 216B.16, subds. 4, 19(a) (2014).
[33] *Id.*
[34] *In re Northern States Power Co.,* 416 N.W.2d 719, 722 (Minn. 1987).
[35] Minn. Stat. § 216B.03.
[36] *St. Paul Chamber of Commerce v. Minnesota Pub. Utilities Comm'n*, 251 N.W.2d 350, 356-57 (Minn. 1977).
[37] This is portrayed in the revenue requirements summary exhibits of both the Company and the Department. *See e.g.* Ex. 88, Schedule 3 (Heuer Direct) and Ex. 442, DLV-S-2 (Lusti Surrebuttal Attachments).

52. In this case, the Company has filed a multiyear rate plan, which requires evaluation not only of a traditional test year (in this case the 2014 test year) but also of the proposed revenue in 2015.

53. During the course of the proceeding, the parties resolved some of the revenue requirement issues for 2014 and the 2015 Step. The resolved issues are listed in Attachment A to this report.

54. The revenue requirement issues that remain disputed among the parties are addressed in this section of the report. The seven most controversial revenue requirement issues are addressed first, in the following order:

- Monticello Life Cycle Management/Extended Power Uprate (LCM/EPU);
- Qualified Pension – discount rate and 2008 Market Loss; [38]
- Retiree Medical Expenses;
- Paid Leave/Total Labor;
- Depreciation and Plant Retirements in the 2015 Step; and
- Return on Equity.

The other disputed revenue requirement issues follow, generally in the order that they appear on the Final Issues List filed by the Company on October 7, 2014.

A. Monticello LCM/EPU (2014 and/or 2015 Step)[39]

55. The Company included costs for the LCM/EPU project at its Monticello nuclear power plant in the rate base for the 2014 test year.[40] The Company also included depreciation expenses for the LCM/EPU project in its test year revenue requirement.[41]

56. In accordance with the Commission's decision in the last rate case, a review of the reasonableness of the underlying costs of the Monticello LCM/EPU project is being conducted in the Monticello CI docket.[42] The question of allocation of costs

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[38] This bullet point encompasses two issues, Issues 4 and 5. As a result, seven issues are covered in the six sections listed in these bullet points. *See* Final Issues List (October 7, 2014) (eDockets Doc. No. 201410-103651-01) (listing each disputed issue).
[39] Issue 2, Final Issues List (Edocket No. 201410-103651-01) (hereinafter only the issue number will be provided).
[40] Ex. 51 at 17, note 2 (O'Connor Direct).
[41] *See* Ex. 88 at 84 (Heuer Direct); Ex. 90 at 25 (Heuer Rebuttal).
[42] 12-961 ORDER at 19-20.

between EPU and the LCM portions of the project is also being considered in that docket.[43]

57. The issue to be addressed in this docket is whether the EPU portion of the project should be considered "used and useful" for purposes of setting rates.[44]

58. The Company maintained that the EPU should be considered "used and useful" for the 2014 test year. The Department, XLI, and MCC disagreed, and each proposed adjustments to the Company's proposed revenue requirement on that basis.

i. Background

59. The Monticello nuclear power generating plant (Monticello) has been in operation since 1971. The plant was originally licensed until 2010. In 2006, the Company obtained a license extension from the Nuclear Regulatory Commission (NRC), allowing the plant to operate until 2030.[45]

60. The Life Cycle Management portion of the project was initiated in conjunction with the license extension received from the NRC in 2006. The LCM involves the work undertaken so that the plant can operate safely and reliably under its longer license.[46]

61. The Extended Power Uprate portion of the project is designed to add approximately 71 MW of additional capacity at the plant. 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.[47] The Company was not required to obtain a Certificate of Need for the LCM related-work.[48]

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[43] JOINT PREHEARING ORDER at 2 (July 17, 2014). The Joint Prehearing Order also provides that the question of how expenses from the Monticello CI docket should be recovered and amortized will be addressed in this docket. That question is addressed separately below in Issue 8.
[44] *Id.*
[45] Ex. 51 at 16 (O'Connor Direct).
[46] *Id.*
[47] *Id.* at 15 (O'Connor Direct); *In the Matter of the Application of Northern States Power Co., a Minnesota Corp., for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate,* Docket No. E002/CN-08-185, PETITION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE MONTICELLO NUCLEAR GENERATING PLANT FOR EXTENDED POWER UPRATE (Feb. 14, 2008).
[48] *See* Minn. Stat. §§ 216B.2421, .243 (2014).

62. In January 2009, the Commission approved the Certificate of Need for the EPU.[49]

ii. Project Implementation and Current Status

63. The LCM/EPU implementation started in 2009, approximately two months after the Company received the Certificate of Need for the EPU.[50] While the LCM and EPU were managed as a single project, the EPU required equipment specifically designed to allow the plant to operate at the higher EPU capacity level. Certain equipment had to be replaced, designed differently, or increased in size to accommodate the EPU portion of the project.[51] The Company completed its installation of equipment for the LCM/EPU project in 2013.[52]

64. Due to unanticipated delays in the NRC license review process, the Company did not receive NRC approval of the EPU license amendment until December 2013.[53] In March 2014, the Company received the MELLLA+[54] license amendment from the NRC, which was required to achieve uprate above 640 MW.[55] The NRC license amendment process took approximately four times longer than expected.[56]

65. Even after the Company received the license amendments, the Company could not immediately operate the Monticello plant at the new 671 MW power level. Per NRC requirements, the Company must first complete a power ascension process that is subject to NRC oversight and approval.[57] The power ascension process involves prescribed testing to evaluate nuclear plant operations and output during the power uprate startup phase. The testing starts with the plant operating at its previously licensed level, and then, over time, power is increased by small increments during which data is collected and verified by the Company's vendors against licensed parameters. When the plant reaches predefined power levels, data is sent to the NRC for review. During the NRC review, the plant will not further ascend without NRC concurrence and approval. The power ascension process includes three power levels

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[49] *In the Matter of the Application of Northern States Power Co., a Minnesota Corp., for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, Docket No. E0002/CN-08-185, ORDER GRANTING CERTIFICATE OF NEED AND ACCEPTING ENVIRONMENTAL ASSESSMENT (January 8, 2009).
[50] Ex. 51 at 15, 17 (O'Connor Direct).
[51] *In the Matter of the Application of Northern States Power Co. for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND RECOMMENDATIONS at 12, ¶ 61 (July 5, 2013) (12-961 REPORT).
[52] 12-961 REPORT at 11, ¶ 57; Ex. 51 at 17 (O'Connor Direct).
[53] Ex. 51 at 20 (O'Connor Direct); Ex. 53 at 4 (O'Connor Rebuttal).
[54] "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 at 20 (O'Connor Direct).
[55] Ex. 53 at 4 (O'Connor Rebuttal).
[56] Ex. 51 at 20 (O'Connor Direct).
[57] Ex. 53 at 4-7 (O'Connor Rebuttal); Transcript (Tr.) Volume (Vol.) 1 at 228, 231 (O'Connor).

where NRC review and approval is required. The process is designed to ensure the safe, reliable operation of the plant at the higher power levels.[58]

66. After receiving the EPU license amendment on December 9, 2013, the Company began the first part of the ascension process. On March 11, 2014, the plant reached the first NRC data collection power level, which was approximately 640 MW.[59] After reviewing the data, the Company discovered an anomaly with the steam dryer data. As a result, and to comply with its license, the Company returned the plant to its pre-EPU level of approximately 600 MW on March 27, 2014.[60]

67. During its review of the steam dryer data, the Company's vendor discovered that a programming error was made during the initial setup for data collection. Because of this error, the Company conducted additional review analyses on the entire data set. In the course of that review, the Company also discovered a configuration issue associated with wiring to the strain gauges on one of the main steam lines located in the Drywell. The upper and lower wires were mislabeled, which resulted in the Company incorrectly connecting them at the data Collection Panel outside of the Drywell. After the misconfiguration was corrected, the vendor re-ran the stress model with the correct configurations. Following completion of the additional data set runs, the Company reviewed the results with its vendor.[61]

68. On July 22, 2014, the Company submitted the data to the NRC for review.[62] After conducting its initial review of the data, the NRC asked for a new data comparison. This new data comparison identified two outliers in the data set. As a result, the NRC has asked the Company follow-up questions regarding the data.[63] As of August 11, 2014, the time of the evidentiary hearing, the NRC had not yet completed its review and the Monticello plant was continuing to operate at pre-EPU levels.[64] As noted above, the Company cannot resume power ascension testing until the NRC completes its review and authorizes the Company to proceed.[65] As of August 2014, the Company did not know when it would receive NRC approval to restart the process.[66]

[58] Ex. 53 at 6 (O'Connor Rebuttal); Tr. Vol. 1 at 241-242 (O'Connor).
[59] Ex. 53 at 10 (O'Connor Rebuttal). From a financial reporting perspective, the Company considers the EPU license amendment to be in-service once the plant operates for 24 continuous hours under the new license. With this 24-hour requirement, the plant need not operate at the maximum power level, 671 MW in this case. Ex. 94 at 44-45 (Perkett Rebuttal).
[60] Ex. 53 at 4, 10-12 (O'Connor Rebuttal); Tr. Vol. 1 at 231 (O'Connor Rebuttal).
[61] Ex. 53 at 10-12 (O'Connor Rebuttal).
[62] Ex. 21 at 5 (Errata); Ex. 55 at 4 (O'Connor Surrebuttal).
[63] Ex. 55 at 4-5 (O'Connor Surrebuttal); Ex. 123 (O'Connor Opening Statement).
[64] Ex. 123 (O'Connor Opening Statement); Tr. Vol. 1 at 239 (O'Connor).
[65] Ex. 53 at 12 (O'Connor Rebuttal).
[66] *See* Ex. 101 at 7 (Clark Surrebuttal) (stating "[a]t this point we do not know the extent of additional time that will be required" to resolve the data issues with the NRC).

69. The Company believes that it will be able to complete the ascension process before the end of 2014.[67] Back in May 2014, the Company estimated that it would take until December 2014 to complete the power ascension process. That schedule assumed the Company would have NRC approval to restart the process in July, and that it would re-enter the ascension process in August.[68] The Company has not explained how it will be able to maintain its schedule given that as of mid-August 2014 the Company had not received approval to restart the ascension process.[69]

70. At the time of the August 2014 evidentiary hearing, the equipment installed for the LCM/EPU project was being used, but only at pre-EPU levels.[70]

iii. "Used and Useful" Standard

71. Minnesota Statutes section 216B.16, subdivision 6, provides that in setting "just and reasonable rates" the Commission is required to:

> give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property *used and useful* in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.[71]

72. By the terms of this statute, a utility is allowed to earn a fair and reasonable return on capital projects that are "used and useful" in providing service to its customers.[72]

73. The Minnesota Supreme Court has held that utility property is "used and useful" when it: (1) is "in service"; and (2) is "reasonably necessary to the efficient and reliable provision of utility service."[73] The determination of whether property is "used

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[67] Tr. Vol. 1 at 235 (O'Connor) (stating on August 11, 2014 that the plant would likely achieve full ascension to 671 MW in three to four months).
[68] *See* Ex. 430 at NAC-8 (Xcel Response to DOC IR 115)(Campbell Direct Attachments); Ex. 429 at 52-53 (Campbell Direct).
[69] Tr. Vol. 1 at 235 (O'Connor) (stating on August 11, 2014 that the plant would likely achieve full ascension to 671 MW in three to four months); *see also* Ex. 53 at 13 (O'Connor Rebuttal) (including condensed schedule with no explanation for shorter time frames); Ex. 55 at 3-5 (O'Connor Surrebuttal) (stating that schedule would be pushed back "somewhat"); Ex. 434 at 50-51 (Campbell Surrebuttal).
[70] Ex. 53 at 14 (O'Connor Rebuttal); Tr. Vol. 1 at 239 (O'Connor).
[71] Minn. Stat. § 216B.16, subd. 6 (emphasis added).
[72] *Id.*
[73] *Senior Citizens Coalition of Northern Minnesota v. Minnesota Pub. Utilities Comm'n*, 355 N.W.2d 295, 301 (Minn. 1984).

and useful" for ratemaking purposes depends on the facts of each case and involves consideration of what is reasonable from a policy perspective.[74]

74. In the last rate case, which was decided in September 2013, the Commission and Administrative Law Judge both concluded that the Monticello LCM/EPU capital project was "in service" **but only** for LCM purposes because the equipment installed as part of the LCM/EPU project was being used to generate electricity at existing levels, not at the higher EPU level.[75]

75. More specifically, the Administrative Law Judge (and the Commission) concluded that the EPU portion of the project was not "in service" at that time because the Company did not have the NRC license amendments required to operate at the uprated 671 MW EPU level and the Company was not reasonably expected to obtain the license amendments during the test year. Because the plant had not operated at its increased EPU level, the Administrative Law Judge (and Commission) determined that the EPU-related equipment was not being used for its intended purpose and was not benefitting ratepayers at that time.[76] As a result, the Commission denied recovery of EPU-related costs in the last rate case.[77]

iv. Objections of the Department, XLI, and MCC

76. In this case, the Department argued that the Company has again failed to demonstrate that the EPU is "used and useful." In support of its position, the Department noted that the EPU has not yet achieved operation at 671 MW, the level at which it is intended to operate. The Department also stated that the plant has been operating at the pre-EPU level of approximately 600 MW since March 2014 due to problems satisfying NRC testing protocol. The Department maintained that the EPU will not be available for most, if not all, of the 2014 test year because the NRC has not authorized the Company to resume the ascension process and has not provided the Company a timeframe as to when it may be allowed to resume the process. The Department asserted that human performance errors appear to have contributed to the problems with the EPU ascension process.[78] As a result, the Department argued that the EPU should not be considered used and useful "at least until the NRC allows the [Company] to operate the plant at the full 671 MWe level."[79] The Department asserted that it would not be reasonable for ratepayers to pay for the EPU in the 2014 test year

[74] *In re Request of Interstate Power for Authority to Change its Rates for Gas Service in Minnesota*, 559 N.W.2d 130, 133-34 (Minn. 1997); *In re Connecticut Light & Power Co*., 183 P.U.R.4th 187, 194 (*Connecticut Light & Power Decision*) (citing *Pennsylvania Public Utility Comm'n v. Metro. Edison Co*., 37 PUR4th 77, 86 (1979)).
[75] 12-961 ORDER at 19.
[76] *Id.*; Ex. 97 at 16 (Robinson Rebuttal).
[77] 12-961 ORDER at 19.
[78] Ex. 435 at 43-44 (Campbell Surrebuttal); Initial Post-Hearing Brief of the Department (Department Initial Brief (Br.)) at 75-76, 84-90.
[79] Ex. 435 at 43 (Campbell Surrebuttal).

because they will not receive the benefit of the additional 71 MW that the EPU is intended to provide.[80]

77. Based on its position, the Department recommended that the Commission exclude the Monticello EPU depreciation expense and rate base treatment from the 2014 test year. With regard to the 2015 Step, the Department recommended that the Monticello EPU project be placed back into rate base in 2015 subject to refund through the MYRP refund mechanism if the plant does not operate successfully at the 671 MW level by January 2015.[81]

78. Similar to the Department, XLI contended that the Company has failed to meet its burden to demonstrate that the Monticello EPU is "used and useful" in rendering service to the public.[82] XLI noted that at the time of the evidentiary hearings the Monticello plant was operating at pre-EPU levels. XLI also pointed out that the original power ascension schedule was delayed as a result of data issues, and those issues still had not been resolved as of the time of the evidentiary hearings.[83] In addition, the Company could not identify with certainty when the plant would receive NRC approval to operate at full uprate levels. Because the Company is not able to operate the EPU project at the full 671 MW on an on-going basis, XLI asserted that there is no meaningful difference between the status of the Monticello EPU in this case and the status of the EPU at the time of the last rate case.[84] As a result, XLI recommended that any EPU costs be excluded from rate base.[85]

79. MCC agreed with the Department and XLI that the Monticello EPU is not currently "used and useful."[86] MCC, however, did not recommend that the EPU costs be excluded from the rate base. Instead, MCC proposed that the Commission treat the Monticello EPU in a manner consistent with the Commission's 2013 decision regarding Sherco Unit 3 in the last rate case, based on MCC's view that the delay in ascending to 671 MW is similar to a mechanical failure.[87] Under MCC's proposal, the Company would be allowed to leave the EPU costs in rate base, but would remove the 2014 depreciation expense and recover it over the remaining life of the plant.[88] MCC also recommended that the increased fuel costs resulting from the delay in the power ascension process be returned to current ratepayers and instead be collected from ratepayers over the life of the plant.[89] MCC asserted that it is reasonable to recover the

[80] Ex. 450 (Campbell Opening Statement); Department Initial Br. at 76.
[81] Ex. 450 (Campbell Opening Statement); Department Initial Br. at 93. The Department and the Company agreed to a refund mechanism for capital projects that are postponed or canceled. Ex. 130 at 1-2 (Perkett Opening Statement); Ex. 140 at 3-4 (Heuer Opening Statement) (describing agreement).
[82] Initial Post-Hearing Brief of XLI (XLI Initial Br.) at 8-10.
[83] *Id.* at 9.
[84] *Id.* at 9-10.
[85] *Id.* at 10.
[86] Initial Post-Hearing Brief of the MCC (MCC Initial Br.) at 4-5; Ex. 340 at 9 (Schedin Direct).
[87] Ex. 340 at 9 (Schedin Direct).
[88] *Id*.
[89] *Id.*

increased fuel costs over the life of the plant because the increased fuel costs are a "risk and cost of construction … [which] should be accumulated and recovered from ratepayers that benefit from the plant during its useful life."[90] Finally, MCC recommended that the Commission require the Company to provide status updates on the ascension process.[91]

80. During the evidentiary hearing, the Company accepted MCC's proposal.[92] The Company contended that MCC's approach reasonably reflects the current status of the Monticello plant and balances the interests of all stakeholders by recognizing that the equipment installed for the LCM/EPU project is being used to generate power at pre-uprate levels even though the plant has not yet operated at its full EPU capacity.[93]

81. If MCC's proposal is not accepted by the Commission, the Company maintained that the entire Monticello LCM/EPU should be considered "used and useful" in 2014 and the Company should be allowed to recover its reasonable, prudently incurred costs for the project. In support of its position, the Company asserted that several important facts have changed since the last rate case. First, the Company has received all necessary NRC license amendments to operate at EPU levels. Second, the LCM/EPU equipment is currently being used to produce power, which results in higher safety margins and more efficient operations. Third, the plant has achieved a partial uprate, ascending to 640 MW for approximately 20 days.[94]

82. The Company also asserted that the Commission should expect that less than full performance of the plant would occur as systems are checked and validated.[95] The Company maintained that completion of the ascension process is not a prerequisite to the LCM/EPU being "in service," as the capital investment for the entire project has been dedicated to public use.[96] In support of its position, the Company cited decisions from other jurisdictions.[97] For these reasons, the Company argued that the EPU, along with the LCM, should be considered "used and useful" in 2014.

v. Analysis

83. In the last rate case, the Commission provided that the "Company may be allowed to recover [EPU-related] 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."[98] Based on a careful review of the record in

[90] MCC Initial Br. at 20.
[91] Ex. 340 at 9 (Schedin Direct).
[92] Ex. 134 at 1 (Clark Opening Statement); Ex. 140 at 2 (Heuer Opening Statement).
[93] Ex. 134 at 1 (Clark Opening Statement); Xcel Initial Br. at 36.
[94] Xcel Initial Br. at 42.
[95] *Id.* at 38-39.
[96] *Id.* 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 Pub. Serv. Co. v. Fraas,* 627 N.W.2d 882, 889 (Mo. Ct. App. 1982)).
[97] Xcel Initial Br. at 39-40.
[98] 12-961 ORDER at 19 (emphasis added).

this case, the Administrative Law Judge concludes that the Company has failed to demonstrate that the EPU is currently "in service" and "used and useful," or that the EPU is likely to be during the 2014 test year.

84. The EPU portion of the LCM/EPU project is not "in service" because the Company does not have the authorizations from the NRC that are required before the Company can generate the additional 71 MW that the EPU was intended to provide.[99] While the Company has received the necessary license amendments from the NRC for the EPU, the Company is required to go through a multi-step power ascension process that is subject to NRC oversight and approval before it can operate the plant at its EPU power level of 671 MW.[100] The Company has not yet completed that process, and in fact has been operating the plant at its pre-EPU level of approximately 600 MW since March 2014 due to unresolved data problems encountered during the ascension process.[101] Until the Company completes the EPU ascension process, the ratepayers will not be able to receive the benefit of the additional 71 MW of power that the EPU was intended to provide, and the EPU will not be "in service" or "used and useful."

85. In addition, it is not reasonable to expect that the Company will receive approval from the NRC to operate the plant at the 671 MW level during the 2014 test year. In May 2014, the Company expected to complete the multi-step ascension process by December 2014, but that estimate was made before the NRC requested additional data for further review.[102] As of August 2014, the Company did not know when the NRC was likely to allow it to resume the ascension process. Given that the Company's original December 2014 estimate for completion of the ascension process did not account for the delays in the NRC's review of data, the Administrative Law Judge concludes the Company has failed to demonstrate that it will be able to complete the ascension process and be authorized to operate at the 671 MW level before the end of 2014.

86. Moreover, the fact that the equipment installed at the plant as part of the LCM/EPU project is currently being used to produce power at the pre-uprate level of approximately 600 MW does not demonstrate that the EPU is "in service" or "used and useful" as the Company asserts. Similarly, the fact that the plant operated at 640 MW briefly during the ascension process does not show that the EPU is "used or useful." To be "in service" and "used and useful," the EPU capital investment needs to be in use for its intended purpose.[103]

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[99] Ex. 53 at 5-12 (O'Connor Rebuttal); Ex. 55 at 4 (O'Connor Surrebuttal); Ex. 123 (O'Connor Opening Statement); Tr. Vol. 1 at 239 (O'Connor).
[100] Ex. 53 at 5-7 (O'Connor Rebuttal); Tr. Vol. 1 at 228, 231 (O'Connor).
[101] Ex. 123 (O'Connor Opening); Tr. Vol. 1 at 239 (O'Connor).
[102] *See* Ex. 430 at NAC-8 (Xcel Response to DOC IR 115) (Campbell Direct Attachments); Ex. 429 at 52-53 (Campbell Direct); Ex. 55 at 4 (O'Connor Surrebuttal).
[103] *See* 12-961 ORDER at 19 (incorporating by reference 12-961 REPORT at ¶¶ 49-85); *see also* Post-Hearing Reply Brief of the Company (Xcel Reply Br.) at 30 (stating "Property is considered used and useful when it is dedicated to public use for the purposes intended….").

87. The two "common facility" cases relied on by the Company to argue that the EPU should be considered "used and useful" because the LCM/EPU equipment is being used to produce power at pre-uprate levels are both distinguishable on their facts.[104] Both cases address the question of whether common facilities, such as switching stations, parking lots, and administration buildings, are properly included in rate base where the facilities are intended to support multiple generation units but only one unit is in-service.[105] In those cases, recovery was allowed.[106] The issue in this case, however, does not involve the recovery of costs for common facilities, like a parking lot, necessary for the operation of one or more nuclear units. Rather, this case involves the costs associated with equipment designed to increase the plant's generating capacity that is not being used as intended.[107] Moreover, the Commission already concluded in the last rate case that the EPU was not "in service" or "used and useful" even though the LCM/EPU project equipment was being used to generate electricity at pre-EPU levels at that time.[108]

88. In summary, the facts in this case demonstrate that the EPU is not "used and useful" because the EPU is not being used for its intended purpose. To require ratepayers to pay for the cost of the EPU before they receive the benefit of the additional 71 MW of power that the EPU is designed to provide would result in unreasonable rates.

89. In reaching this conclusion, the Administrative Law Judge is not suggesting that the plant must operate continuously at 671 MW once the Company receives NRC approval to operate at that level in order for the EPU be "used and useful." The Administrative Law Judge recognizes that the plant may operate at a lower level at times for operational reasons or because of a planned outage. However, until the Company receives authorization from the NRC to operate at the 671 MW level, the

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[104] Xcel Initial Br. at 39-41 (citing *State ex rel. Utilities Comm'n v. Eddleman*, 358 S.E.2d 339 (N.C. 1987) and *State ex rel. Missouri v. Fraas*, 627 S.W.2d 882 (Mo. Ct. App. 1982)).

[105] In *State ex rel. Missouri Pub. Serv. Comm'n v. Fraas*, 627 S.W.2d 882, (Mo. Ct. App. 1982), the Court examined whether the Commission properly included only 25% of the cost of common facilities where only one of four nuclear units was in service. The Court reversed the Commission, and determined that the full cost should have been included because the record demonstrated that the common facilities were in use for the first unit and there was no evidence that the facilities were overbuilt or enlarged beyond what was needed for the first unit. Similarly, in *State ex rel. Utilities Comm'n v. Eddleman*, 358 S.E.2d 339, 362-63 (N.C. 1987), the Court concluded that the common costs were properly included in the rate base where the common facilities were necessary for the operation of a nuclear unit, which was the first of two to be built.

[106] *Id.*

[107] 12-961 ORDER at 19; *see also* 12-961 REPORT at ¶¶ 49-85 (incorporated by reference into the 12-961 ORDER).

[108] 12-961 ORDER at 19; *see also* 12-961 REPORT at ¶ 82 (incorporated by reference into the 12-961 ORDER). The Company's reliance on cases from other states where cost recovery was allowed before the facility operated at full capacity is misplaced. *See* Xcel Reply Br. at 31. Those cases are distinguishable on their facts. As the Company itself has recognized, the determination of whether a facility is "used and useful," however, depends on the facts of each case and involves policy considerations. Xcel Initial Br. at 35.

plant is not able to provide the 71 MW of additional cost-effective power that the EPU was intended to provide when the Commission approved the Certificate of Need.

90. Because the Company has failed to demonstrate that the EPU is "used and useful," the Administrative Law Judge agrees with the Department that the EPU portion of the LCM/EPU project should be removed from the 2014 rate base and the associated depreciation expense should be removed from the test year as well. With regard to the 2015 Step, the Administrative Law Judge agrees with the Department that the Company should be allowed to include the EPU costs in the 2015 Step subject to refund as part of the MYRP refund process.[109]

91. Finally, the Administrative Law Judge concludes that MCC's proposed treatment of the Monticello costs is not reasonable. MCC's proposal, which leaves the EPU costs in rate base but defers recovery of the 2014 depreciation expense, is inconsistent with the Administrative Law Judge's conclusion that the EPU is not yet "used and useful." In addition, MCC's suggestion that the delay in the use of the EPU should be viewed as an unplanned outage, like at Sherco Unit 3, lacks support in the record because the EPU has not yet been authorized by the NRC to operate as intended. It is not reasonable to characterize the current situation as a temporary outage when the EPU has not yet been placed in service. For these reasons, the Administrative Law Judge recommends that the Commission reject MCC's proposed treatment of the EPU capital-related costs.

92. Likewise, the Administrative Law Judge recommends that the Commission reject MCC's proposal to recover increased fuel costs, arising from the delay in the EPU power ascension process, over the life of the Monticello plant. This proposal is not reasonable because the increased fuel costs are for energy used by current customers. It would not be fair or reasonable to recover these energy costs from future customers over the life of the plant. Therefore, these costs should not be addressed in this rate case but rather are properly considered with other fuel costs in the Annual Automatic Adjustment (AAA) proceeding.

B. Qualified Pension Expense – Discount Rate (2014) and 2008 Market Loss (2014)[110]

93. The Company included recovery of its qualified pension expense in the 2014 test year. The Department challenged one of the discount rate assumptions used by the Company in calculating the expense, and also disagreed with the Company's treatment of the 2008 stock market losses (2008 Market Loss) in determining the

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[109] In Surrebuttal Testimony, the Department suggested a refund should be required if the Monticello plant is not approved to operate, and does not operate, at the 671 MWe level by January 2015. Ex. 450 (Campbell Opening Statement). At the hearing, however, Ms. Campbell clarified that if approval and operation at 671 MWe was obtained later in 2015, the refund should be adjusted accordingly. Tr. Vol. 5 at 58 (Campbell); *see also* Ex. 140 at 6-7 (Heuer Opening) (describing the MYRP refund process).
[110] Issues 4 and 5.

expense.[111] On these grounds, the Department objected to the Company's qualified pension expense.

i. Background

94. As part of its overall compensation package, the Company provides a defined benefit pension. This pension benefit is known as a "qualified pension."[112] The Company's employees can also contribute to a 401(k) plan, for which there is a Company match. The qualified pension and the 401(k) plan together provide retirement income to employees.[113]

95. The Company's retirement program provides moderate benefits compared to that of its peers. The Company's "legacy retirement program would benchmark slightly lower than [its] peer companies median retirement programs" and its retirement program for new hires "ranks as one of the lowest" among peer companies.[114]

96. The Company's test year qualified pension expense includes costs for employees of NSP-Minnesota and costs for employees of Xcel Energy Services (XES), NSP-Minnesota's service company owned by its parent, Xcel Energy Inc. Employees of NSP-Minnesota are covered by the NSPM Plan and employees of XES are covered by the XES Plan.[115] Approximately 73 percent of the Company's test year qualified pension costs relate to the NSPM Plan, and 27 percent relate to the XES Plan.[116]

97. Because the XES Plan was created after the NSPM Plan and accounting standards changed in the interim, the Company uses two different accounting methods to determine its total qualified pension expense. Pension costs under the NSPM Plan are determined under the Aggregate Cost Method (ACM). For the XES Plan, pension costs are determined in accordance with Financial Accounting Standard (FAS) 87.[117]

98. Both ACM and FAS 87 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.[118] The calculation of the expense under the two accounting methods differs somewhat but the ultimate goal is the same – "to measure the value of the pension assets today, to

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[111] *See* Department Initial Br. at 96.
[112] Ex. 81 at 11-12 (Moeller Direct).
[113] *Id.*; *see also* Ex. 78 at 65-80 (detailed discussion of the design of the Company's retirement programs and a discussion of the issues raised in Order Point 25 from the 12-961 ORDER regarding its pension plans).
[114] Ex. 78 at 24-25 (Figoli Direct).
[115] Ex. 81 at 15 (Moeller Direct).
[116] Ex. 83 at 45 (Schrubbe Rebuttal).
[117] Ex. 81 at 15-16, 32 (Moeller Direct); Tr. Vol. 2 at 28 (Schubbe).
[118] Ex. 81 at 16 (Moeller Direct).

compare those values to a future liability, and to inform [the Company] as to the unfunded liability…."[119]

a. ACM Pension Expense Calculation

99. Under the ACM, the pension cost is the normalized amount that would need to be paid into the pension fund each year to fund earned benefits. Based on specific actuarial assumptions such as the discount rate, projected salary levels, and mortality, the present value of future benefits (PVFB) is calculated. The PVFB is then compared to the market value of the NSPM Plan assets, which includes a phase-in of prior period asset gains and losses. The difference between the PVFB and the market value of the assets, if any, is the unfunded liability that must be funded over the future working lives of current employees.[120]

100. As noted above, in determining the current pension expense, the ACM considers prior gains and losses.[121] "Asset gains" or "asset losses" arise when the actual returns on the NSPM Plan assets are greater or lesser than the expected returns. "Liability gains" or "liability losses" occur when the other components of pension expense, such as mortality rates, differ from expectations.[122]

101. Under the ACM method, prior-period asset gains and losses are phased-in over a five year period and then amortized over the remaining service lives of the employees.[123] Thus, only a portion of the prior-period asset gain or loss is incorporated into the qualified pension expense calculation in a given year. Liability gains and losses are not phased-in. Rather, if there is a liability gain or loss from a prior year, the PVFB is adjusted by that amount when calculating the annual pension expense for the NSPM Plan in a given year.[124] Generally, if there is an asset or liability gain, it reduces the NSPM pension expense in the following years. Conversely, if there is an asset or liability loss, it increases the NSPM pension expense in following years.[125]

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[119] Ex. 83 at 17 (Schrubbe Rebuttal); *see also* Ex. 81 at 41 (Moeller Direct).
[120] Ex. 81 at 32-33, Schedule 3 (Moeller Direct).
[121] *Id.* at 16.
[122] *Id.* at 19-20.
[123] *Id.* at 19, 22, 26-27, 33-35. As explained by Mr. Moeller, the term "amoritization" is something of a misnomer in so far as the ACM is concerned because the Company recalculates the amount each year and sets the expense to recover the newly calculated amount. Ex. 81 at 26-27 (Moeller Direct).
[124] Ex. 81 at 19-20, 22, 33-34 (Moeller Direct).
[125] *Id.* at 22.

b. FAS 87 Pension Expense Calculation

102. Under FAS 87, the XES Plan pension expense is made up of five components: (1) the Service Cost, which is the present value of benefits being provided in the current year; (2) the Interest Cost, which is reflected in the discount rate; (3) the earned return on assets (EROA), which is what the pension asset is expected to earn during the year; (4) amortization of unrecognized prior service cost, which includes adjustments to benefit levels; and (5) recognition of prior period gains or losses.[126] Prior period asset gains or losses occur because the EROA in a prior year was different from the actual return in that year. Similarly, liability gains and losses occur when the actual values experienced in a prior year, such as the discount rate and wage assumptions, were different from what was expected.[127]

103. Under FAS 87, 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 net unamortized gains or 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.[128] 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.[129]

c. Differences and Similarities between the ACM and FAS 87

104. At a high level, both the ACM and FAS 87 attempt to determine the present value of future benefits and estimated earnings in the pension trust that have accumulated to determine the unfunded obligation. The present value of this unfunded obligation and the current-period earned value are the basis for determining the current-period pension expense accrual. Thus, both the ACM and FAS 87 are affected by the discount rate and rate-of-return assumptions. In addition, as discussed above, both methods provide for a smoothed recognition of unrealized gains and losses in plan asset earnings, such that the level of expense will change more gradually.[130]

105. The two key differences between the ACM and FAS 87 are: (1) the calculation of the discount rate; and (2) whether there is a negative expense recorded when the plan is overfunded. With regard to the first difference, under the ACM, the discount rate is set to equal the EROA whereas under FAS 87, the discount rate is based on a bond-matching approach. With regard to the second difference, under FAS

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[126] *Id.* at 36-37.
[127] *Id.* at 39.
[128] *Id.* at 39.
[129] *Id.* at 41.
[130] *Id.* at 41.

87, the fund can have a negative expense whereas under the ACM, the level of expense is zero when the plan is overfunded.[131] Over time, both methods will converge toward actual cash contributions and will equal the amount of contributions during the life of the plan.[132]

ii. The Parties' Overall Positions

106. The Company initially proposed recovery of approximately $19.9 million in qualified pension expenses for the 2014 test year.[133] In determining the amount of the pension expense, the Company used the same accounting methodologies as it has used in past rate cases. The amount the Company requested in this case is based on detailed testimony, which includes all of the information requested by the Commission in its 12-961 ORDER.[134]

107. The Company's calculation of its pension expense was based on the following primary assumptions: discount rate; EROA; and wage rate. The assumptions used in the Company's initial calculation are set forth in the table below. The assumptions were calculated with a measurement date of December 31, 2012.[135]

Table 1

2014 Test Year Pension Assumptions			
Company - Accounting Method	**Discount Rate**	**Wage Increase**	**EROA**
NSPM - Aggregate Cost Method (ACM)	7.25%	3.75%	7.25%
XES – FAS 87 (ASC 715)	4.03%	3.75%	7.25%

108. In Rebuttal Testimony, the Company provided updated information as of December 31, 2013. This updated information increased the FAS 87 discount rate from 4.03 percent to 4.74 percent.[136]

109. While an increase in discount rate would normally decrease the total pension expense, the Company's total expense increased due to a variety of other factors such as: a lower return than expected on assets in the NSPM Plan; higher

[131] While fund does not show a negative balance, any excess gains are carried forward to future years under the ACM. Ex. 81 at 22, 62 (Moeller Direct).
[132] Ex. 81 at 42 (Moeller Direct).
[133] *Id.* at 9, 53.
[134] *See* 12-961 ORDER at 51-53; Ex. 81 at 13-14, 20-21, 46-49, 55-64, 104-121, Schedules 2, 5 (Moeller Direct); Ex. 78 at 2, 70-73 (Figoli Direct); Ex. 84 at 2, 4-33 (Wickes Direct); Ex. 126 at 1 (Schrubbe Opening Statement).
[135] Ex. 81 at 80 (Moeller Direct).
[136] Ex. 83 at 10-11 (Schrubbe Rebuttal).

payments to retirees than expected; and unfavorable demographics.[137] As a result of updating the relevant information, the Company's final requested recovery for its qualified pension expense in the 2014 test year is $20.9 million.

110. The Company's calculation of its 2014 qualified pension expense includes recovery of an amortized and phased-in portion of the 2008 Market Loss, consistent with its longstanding practice of recognizing both asset gains and losses.[138] Of the $20.9 million test year expense, approximately $12 million is related to the 2008 Market Loss.[139]

111. The Department was the only other party to file testimony on the qualified pension expense issue. The Department agreed with the updating of information to December 31, 2013 and agreed with most of the assumptions used by the Company. The Department disagreed, however, with the Company's discount rate assumption for the XES Plan and recommended instead that it match the EROA. In addition, the Department maintained that the amount the Company included for the 2008 Market Loss in its qualified pension expense calculation is unreasonable.[140] The specific reasons for the Department's objections are discussed in detail below.

112. To address these concerns, the Department recommended that: (1) the discount rate used for the XES Plan be increased from 4.74 percent to 7.25 percent to match the EROA assumption for the plan; and (2) half of the 2008 Market Loss be excluded from the calculation of the qualified pension expense in the 2014 test year.[141] Adoption of the Department's recommendation regarding the discount rate assumption for the XES Plan would decrease the qualified pension expense by approximately $1.77 million because the discount rate has an inverse relationship to pension cost.[142] The Department's recommendation to exclude a portion of the expense related to the 2008 Market Loss would further decrease the 2014 qualified pension expense by approximately $6.17 million.[143]

iii. Discount Rate Assumption for the XES Plan[144]

113. The Company's calculation of the pension expense for the XES Plan uses the discount rate provided by FAS 87, the accounting method prescribed for the XES Plan.[145] The primary source for the discount rate is a bond-matching study that is performed as of December 31 of each year.[146] The study includes a matching bond for

[137] *Id.* at 9, 12-14.
[138] Ex. 81 at 44-64 (Moeller Direct); Ex. 83 at 15-29 (Schrubbe Rebuttal).
[139] Ex. 81 at 53 (Moller Direct); Ex. 83 at 61 (Schrubbe Rebuttal).
[140] Department Initial Br. at 96-115.
[141] *See* Ex. 450 at 4-7 (Campbell Opening Statement); Department Initial Br. at 96.
[142] *See* Ex. 429 at 119 (Campbell Direct); Ex. 450 at 5 (Campbell Opening Statement).
[143] Ex. 450 at 5 (Campbell Opening Statement).
[144] Issue 4.
[145] Ex. 81 at 80-82 (Moeller Direct); Ex. 83 at 11 (Schrubbe Rebuttal).
[146] Ex. 81 at 82 (Moeller Direct).

each of the individual projected payout durations within the plan based on projected actuarial experience.[147] The bonds used in the study must meet certain well-established criteria,[148] and the Company employs numerous tests to validate the reasonableness of the discount rate produced by the bond-matching study.[149]

114. The Company argued that this discount rate is reasonable to use in calculating the XES Plan expense because it is consistent with the discount rates used by other utilities and large companies, and because customers have benefitted from the lower interest rates reflected in this discount rate.[150]

a. Department's Position on the Discount Rate

115. The Department raised a number of concerns with the Company's use of the FAS 87 discount rate to calculate the XES Plan expense.[151] First, the Department asserted that the discount rate calculated by the Company using FAS 87 is "artificially low" because it is based on the measurement of bond rates at a single point in time that is not necessarily representative of the long term. The Department recommended that the discount rate for the XES Plan be set to match the higher EROA rate. The Department maintained that its recommended approach ensures that the discount rate, which is used to measure the time value of money, is consistent with the level of expected return on assets. According to the Department, if the two do not match, then the pension obligation will be overstated for ratemaking purposes.[152]

116. The Department also noted that the Company set the discount rate for the NSPM Plan to match the EROA under the ACM, and asserted the same should be done for the XES Plan even though that XES Plan is subject to FAS 87 not ACM. The Department stated that the Commission is not required to follow accounting standards in determining the pension expense for ratemaking purposes. The Department also maintained that reliance on FAS 87 is not reasonable for ratemaking purposes because actuaries are primarily concerned with ensuring the pension expense is not understated, whereas ratemaking is concerned with making sure the pension expense is not overstated. Moreover, the Department questioned whether the Company's calculation of its XES pension expense is accurate given that the assumptions used in the calculation were selected by the Company. The Department claimed that its recommendation to set the discount rate equal to the EROA is consistent with pension funding requirements under the Employee Retirement Income Security Act (ERISA).[153]

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[147] *Id.* at 82.
[148] *Id*.
[149] *Id.* at 82-84.
[150] Xcel Initial Br. at 65-66.
[151] Ex. 450 at 5-6 (Campbell Opening Statement); Department Initial Br. at 96-108.
[152] Ex. 429 at 116-118 (Campbell Direct); Ex. 450 at 5 (Campbell Opening Statement).
[153] Ex. 429 at 112-114, 118 (Campbell Direct); Ex. 435 at 83-84 (Campbell Surrebuttal); Ex. 450 at 5-6 (Campbell Opening Statement); Department Initial Br. at 98-102.

117. Finally, the Department pointed out that, in the last rate case, both the Administrative Law Judge and the Commission agreed with the Department's view that the discount rate should match the EROA rate for both the XES Plan and the NSPM Plan.[154]

b. The Company's Response on the Discount Rate Issue

118. The Company disagreed with the Department's view that the XES Plan discount rate calculated in accordance with FAS 87 is "artificially low." The Company responded that FAS 87 is an accounting standard that specifies standards upon which the discount rate should be based.[155] The Company noted that the FAS 87 bond matching study includes a matching bond for each of the individual projected payout durations within the plan based on projected actuarial experience.[156] The Company asserted that the bond rates are commensurate with levels that have been in effect for more than a decade.[157] The Company also reiterated that the FAS 87 discount rate used for the XES Plan is consistent with the discount rates used by utilities and other large companies.[158]

119. The Company acknowledged that the Commission is not required to follow accounting standards in setting rates but asserted that there is no valid reason to deviate from FAS 87 when establishing the pension expense for the XES Plan in this rate case. The Company maintained that the FAS 87 expense represents its actual cost for the XES Plan. The Company maintained that it would not be reasonable to set the discount rate for the XES Plan at the EROA simply because the NSPM Plan uses the EROA for the discount rate. Doing so would ignore the fact that the NSPM Plan uses a different accounting method (the ACM, not FAS 87) to determine its pension expense. While both FAS 87 and the ACM are intended to assure accurate reporting of pension expense, each approaches the funding goal from a differing perspective. For that reason, if the discount rate for the XES Plan is set at the EROA level for ratemaking purposes, as the Department suggests, the Company would experience a permanent under-recovery of pension costs for the XES Plan.[159] The Company also pointed out that 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 and interest cost elements of the FAS 87 calculation would have been higher.[160]

[154] Ex. 429 at 117 (Campbell Direct); Ex. 450 at 5 (Campbell Opening Statement); Department Initial Br. at 104.
[155] Ex. 83, Schrubbe Rebuttal at 43.
[156] Ex. 81 at 82 (Moeller Direct).
[157] Ex. 83 at 41, 45 (Schrubbe Rebuttal).
[158] *Id.* at 44.
[159] Ex. 81 at 86-87 (Moeller Direct); Ex. 129 (Schrubbe Opening Statement).
[160] Ex. 81 at 89 (Moeller Direct); Ex. 126 (Schrubbe Opening Statement).

120. In addition, the Company objected to the Department's claim that the FAS 87 discount rate used in calculating the XES Plan expense is not independent. The Company explained that the FAS 87 discount rate is based on 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 are subject to further confirmation by review of general survey data provided by Towers Watson and the Edison Electric Institute.[161]

121. The Company also disagreed with the Department's claim that use of the EROA for the discount rate is consistent with ERISA funding requirements. The Company pointed out that the Department relied on a 2004 document in support of its characterization of ERISA.[162] In response, the Company noted that in 2006, ERISA was amended to require use of corporate bond-yields, not EROA, in determining the discount rate for purposes of determining pension funding.[163] For all of these reasons, the Company maintained that the Commission should reject the Department's proposal and instead use the FAS 87 discount rate of 4.74 percent in calculating the XES Plan expense for ratemaking purposes.

122. Finally, the Company noted that the Commission declined to follow the Department's recommendation to match the discount rate with the EROA when calculating the pension expense in the recent CenterPoint case. Instead, the Commission set the expense based on a five-year average of actual discount rates. The Company suggested that such an approach may provide a reasonable compromise in this case.[164]

123. In Surrebuttal Testimony and at the evidentiary hearing, the Department opposed the idea of using a five-year average of FAS 87 discount rates for purposes of determining the XES Plan expense. The Department maintained that the EROA is a better measure of the time value of money for purposes of calculating the pension expense.[165]

c. Analysis

124. In the last rate case, the Administrative Law Judge concluded that the Department's recommendation to set the discount rate for the XES Plan equal to the EROA rate, as is done for the NSPM Plan, was the most reasonable approach for ratemaking purposes based on the record before her. The Administrative Law Judge

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[161] Ex. 83 at 7 (Schrubbe Rebuttal); Xcel Reply Br. at 55-56.
[162] Xcel Reply Br. at 54; Department Initial Br. at 99-100 (citing "Fundamentals of Current Pension Funding and Accounting for Private Sector Pension Plans").
[163] *See* 29 U.S.C. § 1083 (h)(2)(C) (2012); Xcel Reply Br. at 54.
[164] Ex. 129 (Schrubbe Opening Statement); *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. GR-13-316 FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 11-12 (June 9, 2014) (CPE 2013 ORDER).
[165] Ex. 435 at 84-85 (Campbell Surrebuttal); Tr. Vol. 5 at 56-57 (Campbell).

noted that the Company had not adequately explained why a different discount rate should be used for the XES Plan.[166]

125. In this case, by contrast, the Company provided a much more specific explanation of the differences between the FAS 87 accounting used for the XES Plan and the ACM accounting used for the NSPM Plan. The Company also provided a detailed explanation as to why it would be problematic to use the EROA as the discount rate for the XES Plan even though the NSPM Plan takes that approach.

126. As a result, the Administrative Law Judge reaches a different conclusion in this case. The record in this case demonstrates that both FAS 87 and the ACM are designed to ensure accurate reporting of pension expense but use different methodologies. For that reason, use of the FAS 87 bond-matching discount rate will help ensure that the XES Plan, which is subject to FAS 87, is fully funded. In addition, the record demonstrates that the Company's calculation of its FAS 87 discount rate was based on objective criteria and is similar to the rates used by other utilities.[167] Finally, as the Company noted, 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 and interest cost elements of the FAS 87 calculation would have been higher.[168] For these reasons, the Administrative Law Judge concludes the use of the FAS 87 discount rate is more reasonable than use of the EROA rate as the discount rate for the XES Plan.

127. The Administrative Law Judge also concludes that use of a five-year average of FAS 87 rates is more reasonable than the Company's proposed single year FAS 87 rate. A review of FAS 87 discount rates for the last five years shows that the 4.74 percent discount rate calculated by the Company in its Rebuttal Testimony is on the lower end of rates for the last five years.[169]

128. To guard against the possibility that the current FAS 87 rate is somewhat lower than normal, the Administrative Law Judge recommends that the Commission set the discount rate for the XES Plan based on a five-year average of FAS 87 discount rates. Such an approach is consistent with the Commission's recent decisions in the CenterPoint and MERC rate cases, and addresses the Department's concern that the Company's proposed discount rate is based on a single point in time.[170] The five year average for the Company results in a discount rate of 5.05 percent for the XES Plan.[171]

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[166] 12-961 REPORT at 34, ¶164; *see also*, 12-961 ORDER at 7 (Commission concurring with the conclusions of the Administrative Law Judge).
[167] Ex. 83 at 7 (Schrubbe Rebuttal).
[168] Ex. 81 at 89 (Moeller Direct); Ex. 126 (Schrubbe Opening Statement).
[169] Ex. 83 at 44 (Schrubbe Rebuttal).
[170] *See* CPE 2013 ORDER at 11-12; *In the Matter of the Petition by Minnesota Energy Resources Corporation (MERC) for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-011/GR-13-617, Findings of Fact, Conclusions and Order at 15-16 (October 28, 2014) (MERC 2013 ORDER).
[171] *See* Ex. 83 at 44 (Schrubbe Rebuttal).

The Administrative Law Judge concludes that this rate is reasonable and strikes an appropriate balance between the Department's position and the Company's position.

iv. 2008 Market Loss[172]

129. As noted above in paragraphs 97-105, in calculating the Company's test year qualified pension expense, the Company uses the ACM method for the NSPM Plan and FAS 87 for the XES Plan. Both accounting methods take into account prior period losses and gains.[173] The Company has calculated its total qualified pension expense using this approach for several decades.[174]

130. The Company did not change its method of calculating its qualified pension expense after the 2008 Market Loss. Rather, the 2008 Market Loss is reflected in the 2014 test year qualified pension expense in the same manner as any other gain or loss.[175]

131. In this rate case, the Company has requested $20.9 million for its qualified pension expense in the 2014 test year.[176] Of that amount, approximately $12.1 million is attributable to the 2008 Market Loss ($8.6 million from the NSPM Plan and $3.5 million from the XES Plan). [177]

a. Company's Position on the 2008 Market Loss

132. The Company maintained that its treatment of the 2008 Market Loss in calculating its qualified pension expense for the 2014 test year is reasonable and should be reflected in rates. The Company made several arguments in support of its position.

133. First, the Company stated that retirement benefits are a legitimate cost of service, and the Company should be allowed to recover the reasonable costs attributable to those retirement benefits.[178]

134. Second, the Company maintained that its inclusion of prior period gains and losses, including the 2008 Market Loss, is necessary to determine an accurate level of pension expense in accordance with standard accounting practices.[179] The Company noted that the Department itself recognizes that the 2008 Market Loss

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[172] Issue 5.
[173] Ex. 81 at 18-19, 21-27 (Moeller Direct).
[174] *See* Ex. 81 at 16-40, 57-58, 62 (Moeller Direct).
[175] Ex. 126 at 1 (Schrubbe Opening Statement); Ex. 81 at 16-32 (Moeller Direct).
[176] Ex. 83 at 61 (Schrubbe Rebuttal).
[177] Ex. 81 at 53, Schedule 5 (Moeller Direct).
[178] Ex. 81 at 56 (Moeller Direct); Ex. 429 at 99 (Campbell Direct).
[179] Ex. 81 at 56 (Moeller Direct).

reduced the value of the Company's pension plan assets, and the reduced value gives rise to an increased pension expense.[180]

135. Third, the Company asserted that its symmetrical treatment of gains and losses has provided substantial benefits to ratepayers over time and argued it would be unreasonable to require the Company to absorb the losses when the customers received the benefits of the gains. The Company noted that from 2000 to 2014, the cumulative benefit to ratepayers of gains recognized has been approximately $332 million on a Minnesota jurisdictional basis.[181] In addition, from 2000 to 2011, the qualified pension expense was at or below zero because of asset gains or liability gains.[182]

136. Fourth, the Company claimed that neither shareholders nor Company employees have received any benefits from market gains in the years in which the pension trust fund's earnings exceeded expectations.[183]

137. Finally, the Company asserted that the Company's calculation of its qualified pension expense is consistent with "normal ratemaking."[184] 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.[185]

b. The Department's Position on the 2008 Market Loss

138. The Department disagreed with the Company's position that its treatment of the 2008 Market Loss is reasonable. Instead, the Department recommended that 50 percent of the $12.1 million attributable to the 2008 Market Loss be excluded from the test year expense. The Department provided a number of reasons for its proposed reduction.[186]

139. First, the Department asserted that it is unreasonable for ratepayers to bear 100 percent of the 2008 Market Loss.[187]

140. Second, the Department expressed concern that a large portion (approximately 60 percent) of the 2014 test year pension expense is attributable to the

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[180] Xcel Initial Br. at 58 (citing Ex. 429 at 128 (Campbell Direct)).
[181] Ex. 81 at 60 (Moeller Direct).
[182] *Id.* at 60.
[183] *Id.* at 56.
[184] Ex. 83 at 24 (Schrubbe Rebuttal).
[185] Ex. 81 at 63 **(**Moeller Direct).
[186] Ex. 450 at 6 (Campbell Opening Statement).
[187] *Id.* at 6; Ex. 435 at 94 (Campbell Surrebuttal).

2008 Market Loss, especially given that the financial market has returned to pre-2008 market levels.[188]

141. Third, the Department maintained that the Company has made investment choices that "seem to have caused higher-than-necessary 2008 market losses to be charged to ratepayers." Specifically, the Department claimed that the Company appeared to be "overly optimistic about its equities positions in the financial market prior to 2008 and later moved to a more conservative investment too soon, before the financial market had time to come back to current levels such that the Company did not avoid the downswing and then missed the upswing of the market."[189]

142. Fourth, the Department expressed concern about ratepayers being charged for 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…" match expense that is also included in the 2014 test year.[190]

143. Fifth, the Department disagreed with the Company's view that its treatment of gains and losses is symmetrical. The Department maintained that the Company's treatment of gains and losses is not symmetrical because in years when the gains exceeded the expenses, the Company did not give a refund to ratepayers.[191]

144. Sixth, the Department asserted that the Company is attempting "to get recovery of *all* of the 2008 market loss from ratepayers in the short term."[192]

145. Finally, the Department disputed the Company's contention that neither shareholders nor the Company benefit by market gains exceeding expectations, because if the Company's pension plan is overfunded then the Company does not have to make payments into the pension fund.[193]

c. Analysis

146. In the last rate case, the Company's qualified pension expense also reflected the phase-in and amortization of the 2008 Market Loss. In that case, as in this case, the Company calculated its pension expense using long-standing accounting practices.[194]

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[188] Ex. 450 at 6 (Campbell Opening Statement); Ex. 435 at 93 (Campbell Surrebuttal).
[189] Ex. 450 at 6 (Campbell Opening Statement); Ex. 435 at 93-94 (Campbell Surrebuttal).
[190] Ex. 450 at 6-7 (Campbell Opening Statement); Ex. 435 at 91 (Campbell Surrebuttal).
[191] Ex. 450 at 7 (Campbell Opening Statement); Ex. 435 at 91 (Campbell Surrebuttal).
[192] Ex. 450 at 7 (Campbell Opening Statement) (emphasis in the original); Ex. 435 at 91-92 (Campbell Surrebuttal).
[193] Ex. 450 at 7 (Campbell Opening Statement).
[194] 12-961 REPORT at 35-36; 12-961 ORDER at 7.

147. In the last rate case, the Administrative Law Judge concluded that it was reasonable for the Company to recover its 2008 pension fund losses through its standard accounting practices.[195]

148. The Commission agreed, but limited its decision to that rate case.[196] As part of its Order, the Commission required the Company to provide further "evidence of the Company's policy and practice pertaining to past and future pension policies, including surplus, … in the initial filing of its next rate case." The Commission also required the Company to "provide discussion and support why other stakeholders, other than ratepayers, should not bear pension costs, in general, and more specifically, not bear the pension costs related to the restoration of the fund's market losses."[197]

149. That additional information requested by the Commission and the other evidence in the record demonstrate that the Company's proposed treatment of gains and losses, including the 2008 Market Loss, in calculating its test year qualified pension expense is reasonable. The record shows the Company's treatment of the 2008 Market Loss is consistent with the Company's long standing practice of including both market gains and losses in its calculation of the pension expense. While this approach results in a significant pension expense in the 2014 test year, ratepayers have received much more substantial benefits from this approach in prior years. As the Company demonstrated, the cumulative benefit to customers of recognizing both gains and losses has been approximately $332 million on a Minnesota jurisdictional basis from 2000 to 2014.[198]

150. In addition, as a result of recognizing pension asset earnings and losses, the pension expense recovered in rates has historically been well below the Service Cost (the actual cost of providing the pension benefit to Company employees). For example, as shown in the figure below, for the NSPM Plan, the pension expense has been below the Service Cost in every year since 2000.[199]

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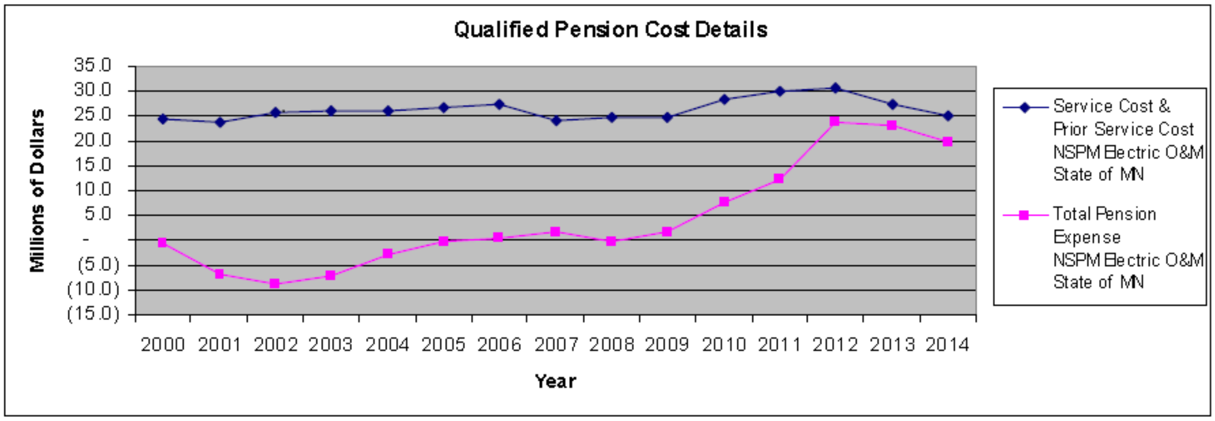
[195] 12-961 REPORT at 35-36; 12-961 ORDER at 7.
[196] 12-961 ORDER at 7, 51.
[197] *Id.* at 51-52, ¶¶ 35, 44. The Company provided this information with its initial filing in this rate case. *See* Ex. 81 at 13-14, 20-21, 46-49, 55-64, 104-121, Schedules 2, 5 (Moeller Direct); Ex. 78 at 2, 70-73 (Figoli Direct); Ex. 84 at 2, 4-33 (Wickes Direct); Ex. 126 at 1 (Schrubbe Opening Statement).
[198] Ex. 81 at 60 (Moeller Direct).
[199] *Id.* at 59-60.

Table 2



151. These facts demonstrate that the Company's approach fairly allocates both the gains and the losses to ratepayers.

152. In addition, the Administrative Law Judge concludes that none of the grounds set forth by the Department provide a reasonable basis for reducing the amount of the 2008 Market Loss reflected in the 2014 test year expense.

153. The Department's argument that the Company's approach is not symmetrical fails to recognize the benefit to ratepayers of having the gains offset pension expense both at the time of the gain and in the future by returning any excess to the pension fund. It would be inequitable to recognize the gains, but not the losses, in calculating the Company's pension expense for ratemaking purposes.

154. The Department's suggestion that the pension expense may be larger than necessary because the Company may not have reasonably managed its assets lacks proof in the record. The Department's claim is not based on any empirical evidence such as a comparison of the performance of the Company's pension assets to the performance of other pension funds of a comparable size. Nor has the Department demonstrated that a reasonable pension fund manager would have managed the assets differently. Rather, the Department has only expressed a general concern about the performance of the assets. This vague concern does not demonstrate that the Company's test year qualified pension expense is unreasonable and should be reduced as recommended by the Department.

155. Similarly, there is no evidence in the record to support the contention that the Company's pension expense should be reduced because the Company's retirement benefits are "generous" as claimed by the Department.[200] To the contrary, the record shows that the Company's benefits are comparable to those of its peers, and its

[200] *See* Ex. 450 at 6-7 (Campbell Opening Statement).

benefits for its new employees are lower than many of its peers. In addition, providing a competitive level of benefits is necessary for the Company to attract and retain the skilled employees who are needed to provide reliable service to ratepayers.[201]

156. Likewise, the Department is mistaken when it claims that the Company is seeking "to get recovery of *all* of the 2008 market loss from ratepayers in the short term."[202] As the Company explained, the Company is not seeking to recover all of the 2008 Market Loss in the short term. Rather, under FAS 87 and ACM, the loss is both phased-in and amortized resulting in recovery over the long-term.[203]

157. Finally, contrary to the Department's assertion, there is no benefit to the shareholders from this longstanding approach to calculating pension expense because the Company does not pay out the gains to shareholders. Instead, the gains help to reduce rate increases by limiting the future pension expense.[204]

158. For these reasons, the Administrative Law Judge concludes that the Company's approach of recognizing pension gains and losses is reasonable, and the Company's proposed phase-in and amortization of the 2008 Market Loss should be included in the 2014 test year expense. It would not be reasonable to exclude the effects of the 2008 Market Loss when ratepayers have benefited substantially from past market gains. The Department's recommendation to reduce the amount included in the test year expense related to the 2008 Market Loss is not supported by the record.

v. Alternative Proposals

159. 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.[205]

160. The Company proposed to continue the normalization approach adopted in the last rate case. In that case, the Commission authorized the Company 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.[206]

161. The Company offered two additional proposals to further moderate the effects of the 2008 Market Loss in this case.[207] The first proposal compares a five-year average, normalized qualified pension expense from 2014 through 2018, which is approximately $18.24 million, to the Company's actual qualified pension expense each year. Under this proposal, the difference would be deferred each year until the

[201] Ex. 81 at 56, 70-71, 80 (Moeller Direct); Ex. 78 at 4-15, 24, 67-72 (Figoli Direct).
[202] *See* Ex. 450 at 7 (Campbell Opening Statement).
[203] Ex. 81 at 18-32 (Moeller Direct).
[204] *Id.* at 62.
[205] Ex. 83 at 30 (Schrubbe Rebuttal).
[206] *Id.* at 31, 34; 12-961 ORDER at 7.
[207] Ex. 83 at 31 (Schrubbe Rebuttal).

normalized amount is revisited in 2017 or 2018. At that time, the deferred amount will be amortized over a period of time approved by the Commission.[208]

162. The second proposal would also use the five-year average from 2014 through 2018 ($18.24 million) 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 expenses for each year during this time period (i.e. 2014-2018).[209] In both alternatives, the Company would provide annual compliance filings.[210]

163. The Department objected to the Company's normalization proposals. The Department maintained that none of the proposals are reasonable. The Department also stated that if the Commission does not accept the Department's pension expense recommendations, then the "least objectionable" is an amended version of the second proposal.[211] The Department suggested four changes to the Company's second proposal.

164. First, the Department recommended that the Company not be allowed to earn a return on any deferred amounts. The Department asserted that the Company "already receives a return on the prepaid pension asset" and allowing the Company to earn a return would provide "an inappropriate incentive to make poor investment choices for pension assets."[212] The Company opposed this modification asserting that the deferred amounts should earn a return because they are being funded by shareholders during the deferral period. The Company also disagreed with the Department's assertion that the Company would have an incentive to make poor investment decisions pointing out that the Company's proposal allows recovery of the lesser of actual pension expense or currently forecasted amounts.[213]

165. Second, the Department proposed 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."[214] As noted above, the Company proposed that feature as part of its Rebuttal Testimony.[215]

[208] *Id.* at 31-34.
[209] *Id.* at 34-35.
[210] *Id.* at 32, 35.
[211] Ex. 450 at 7-8 (Campbell Opening); Ex. 435 at 99-102 (Campbell Surrebuttal); Tr. Vol. 5 at 26-27 (Campbell).
[212] Ex. 435 at 101 (Campbell Surrebuttal); Department Initial Br. at 116.
[213] Xcel Reply Br. at 50-51; Ex. 83 at 35 (Schrubbe Rebuttal).
[214] Department Initial Br. at 116.
[215] Ex. 83 at 37 (Schrubbe Rebuttal) ("[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.").

166. Third, the Department requested that the Company "be required to make a case for why the Company should be allowed to amortize any unfunded balances in the future."[216] The Department suggested that any future recovery by the Company be allowed only if the Company can show that it made reasonable investment decisions regarding pension assets.[217] The Company opposed this modification because the deferred amounts will consist of actual pension expense and the deferral is for the benefit of the customers.[218]

167. Fourth, the Department proposed that the Company be required to calculate the allowed pension expense in each year using a discount rate equal to the EROA.[219] The Company opposed this modification for the same reasons set forth above in the discount rate section.

168. Given the disagreement between the Department and the Company regarding the Company's new normalization proposals, it is not clear that adopting a new normalization mechanism for the qualified pension expense is in the public interest. Moreover, adopting either of the new proposals would have only a relatively small impact on the 2014 test year revenue requirement because the amount of the deferral would be approximately $2.7 million at the most.[220] Given the dispute regarding the new proposals and the limited benefit, the Administrative Law Judge recommends that the Commission not adopt either of the new normalization proposals set forth by the Company.

169. The Administrative Law Judge does, however, recommend that the normalization mechanism adopted in the last case be continued because both the Administrative Law Judge and the Commission determined that approach is beneficial to ratepayers.[221]

vi. Recommendations for the Next Rate Case

170. The Department recommended that the Commission require the Company to address, in its next rate case, the reasonableness of its target asset allocation for its pension fund assets, including ages of retirees and employees. The Company has agreed to do so. The Company also has agreed to provide information addressing its investment strategies and target asset allocations since 2007.[222]

171. The Administrative Law Judge concludes the Department's request will provide useful information and recommends that the Commission require the Company to provide the agreed-upon information in its initial filing in the next rate case.

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[216] Ex. 435 at 102 (Campbell Surrebuttal).
[217] *Id.*; Department Initial Br. at 116.
[218] Xcel Reply Br. at 51-52.
[219] Department Initial Br. at 116 (quoting Ex. 435 at 101 (Campbell Surrebuttal)).
[220] Ex. 83 at 36 (Schrubbe Rebuttal).
[221] *See* 12-961 REPORT at 38, ¶ 186; 12-961 ORDER at 7.
[222] Ex. 116 at 2 (Tyson Opening Statement).

C. Retiree Medical Expenses/FAS 106 (2014)[223]

172. 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 calculated under FAS 106 for certain employees who retired prior to 2000.[224] These post-retirement medical benefits are paid to retired employees for health care costs such as medical, dental, vision, and life insurance.[225]

173. The current expenses are a legacy cost of prior programs, which were eliminated for all active employees over ten years ago.[226]

174. 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 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.[227]

175. In its initial filing, the Company used four assumptions to calculate its FAS 106 test year O&M expense: (1) an EROA of 7.25 percent for the bargaining employee plan, and an EROA of 6.25 percent for the non-bargaining employee plan; (2) a measurement date of December 31, 2012; (3) inclusion of 2008 Market Loss; and (4) a discount rate of 4.08 percent.[228]

176. In Rebuttal Testimony, the Company agreed to update the measurement date to December 31, 2013.[229] The updated information increased the discount rate from 4.08 to 4.82 percent, which decreased the test year expense by $666,522.[230]

177. The Company asserted that recovery of its retiree medical expenses is reasonable because the expenses represent benefits the former employees have already earned, and the Company is required to comply with its obligations to disabled and retired employees. The Company maintained that "these expenses are akin to

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[223] Issue 6.
[224] Ex. 81 at 115, Schedule 2 (Moeller Direct); Ex. 78 at 66 (Figoli Direct); Ex. 423 at 43 (Bryne Direct).
[225] Ex. 423 at 37 (Byrne Direct).
[226] *Id.* at 37.
[227] Ex. 81 at 114 (Moeller Direct).
[228] *Id.* at 115 *Id.*; Ex. 423 at 41 (Byrne Direct).
[229] Ex. 83 at 60 (Schrubbe Rebuttal); Ex. 90 at 21-22 (Heuer Direct); *see also* Ex. 423 at 41 (Bryne Direct).
[230] Ex. 427 at 12 (Byrne Surrebuttal).

accounts payable, which are amounts the Company must pay to satisfy its legal obligations." [231]

178. The Department was the only other party to file testimony on the Company's test year expense for retiree medical benefits. The Department disputed two aspects of the Company's calculation of its 2014 retiree medical expenses, but otherwise did not oppose the Company's recovery of its test year expense.[232]

i. 2008 Market Loss

179. The Department disagreed with the Company's treatment of the 2008 Market Loss in calculating its retiree medical expenses under FAS 106, and recommended the Commission reduce the test year amount by $88,500 to reflect a disallowance of half the 2008 Market Loss amount included in the expense.[233] 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 the 2008 Market Loss for the qualified pension. The Department reasoned that the 2008 Market Loss should be treated the same because the FAS 106 retiree medical expense is calculated in the same manner as the qualified pension expense under FAS 87.[234]

180. The Company opposed the Department's proposed disallowance related to the 2008 Market Loss for FAS 106 retiree medical expenses for the same reasons it opposed the Department's disallowance for the 2008 Market Loss for the qualified pension expense.[235]

ii. Discount rate

181. The Department also disagreed with the Company's use of a discount rate based on a bond-matching study in calculating the retiree medical expenses under FAS 106. Instead, the Department recommended that the discount rate for FAS 106 be set to match the respective EROA percentages for the bargaining employees' plan and for the non-bargaining employees' plan, consistent with the Department's recommendation for the qualified pension expense.[236] The Department 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.[237] The Department made its recommendation for the same reasons it recommended

[231] Ex. 81 at 121 (Moeller Direct).
[232] Department Initial Br. at 54-60; Ex. 423 at 37-43 (Bryne Direct); Ex. 427 at 12, 22-24, 28-29 (Bryne Surrebuttal).
[233] Ex. 423 at 42-43 (Byrne Direct).
[234] *Id.* at 41-42.
[235] Ex. 83 at 29 (Schrubbe Rebuttal).
[236] Ex. 423 at 42 (Byrne Direct).
[237] *Id.*

increasing the FAS 87 discount rate for the qualified pension expense to match the EROA.[238]

182. The Company disagreed with the Department's recommendation related to the FAS 106 discount rate on the same basis as it opposed the Department's recommendation for the qualified pension discount rate.[239]

iii. Analysis

183. Because the Company's FAS 106 retiree medical expenses are calculated in the same manner as the qualified pension expense under FAS 87, the 2008 Market Loss should be treated in the same manner for both expenses. For the reasons discussed above in the Quantified Pension Expense Section, the Administrative Law Judge concludes that the Company's proposed inclusion of the 2008 Market Loss is reasonable and consistent with the Company's long-standing practice of including both market gains and losses in its calculation of this expense.

184. Similarly, for the reasons set forth in Quantified Pension Expense Section above, the Administrative Law Judge concludes that it is not appropriate to increase the FAS 106 discount rate to match the EROAs for the bargaining and non-bargaining employee plans. Instead, the updated FAS 106 discount rate of 4.82 percent should be used in calculating retiree medical expenses for the 2014 test year.[240]

D. Paid Leave/Total Labor (2014)[241]

185. In its initial filing, the Company requested recovery of approximately $49.9 million in paid leave costs.[242]

186. In Direct Testimony, the Department proposed a downward adjustment of approximately $6.5 million to the Company's 2014 paid leave costs based on the Company's history of over-forecasting paid leave costs from 2011 to 2013.[243] In Rebuttal Testimony, the Company explained that its paid leave costs are a component of its total labor cost, 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.[244]

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[238] *Id.* at 42; Tr. Vol. 5 at 13 (Byrne).
[239] Ex. 83 at 47 (Schrubbe Rebuttal).
[240] In Paragraph 127 above, the Administrative Law Judge ultimately recommended that the discount rate be set at a five-year average of the FAS 87 discount rates. For FAS 106, however, there is no evidence in the record of the discount rates from prior years. For that reason, the Administrative Law recommends using the current FAS 106 discount rate of 4.82 percent.
[241] Issue 7.
[242] Ex. 429 at 171 (Campbell Direct).
[243] *Id.* at 95-98, 171.
[244] Ex. 87 at 3-9 (Stitt Rebuttal).

187. After reviewing the Company's response, the Department agreed that paid leave costs are appropriately considered as compensation within the context of the total labor cost. As a result, the Department withdrew its proposed paid leave adjustment.[245]

188. The Department instead proposed a $5.6 million downward adjustment to the Company's total labor cost on a Minnesota jurisdictional basis.[246] The Department's proposal was based on its view that the Company's proposed $419.0 million total labor cost for the 2014 test year is not reasonable. The Department asserted that the cost should be limited to a three percent annual increase over 2012 actual total labor costs. This results in a reduction of $5.6 million to the 2014 test year expense on a Minnesota jurisdictional basis.[247]

189. The Department based its position on its review of the Company's historical costs as well as the Department's general experience with labor costs.[248] The Department noted that the Company's total labor cost increased three percent from 2011 to 2012, but from 2012 to 2013 the total labor cost increased 12.2 percent.[249] The large increase in labor costs from 2012 to 2013 was due primarily to extended outages at the Company's nuclear plants and the unusually high number of storms.[250] The Department recognized that the Company's proposed total labor cost for the 2014 test year is 3.9 percent lower than the 2013 actual cost, but asserted that the 2013 actual cost is not an appropriate starting point for determining the reasonableness of the 2014 cost because the 2013 total labor cost was abnormally high.[251] The Department maintained that the three percent increase from 2011 to 2012 is more representative of labor cost increases, which are normally in the range of two to three percent.[252]

190. The Department stated that the 2014 test year amount is an increase of 7.8 percent from 2012 actuals, which equals an annualized (year over year) increase of 3.9 percent from 2012 actuals. The Department maintained the Company did not provide sufficient detail to demonstrate the reasonableness of its proposed 3.9 percent annual increase from 2012 actuals.[253] In addition, the Department argued that the Company makes no claim that its 2014 labor costs will be abnormally high as it did in 2013.[254] For these reasons, the Department maintained that its proposed downward adjustment of $5.6 million should be adopted by the Commission.

191. The Company responded that it provided detailed testimony demonstrating the reasonableness of its 2014 total labor cost. The Company noted that

[245] Ex. 435 at 74 (Campbell Surrebuttal); Tr. Vol. 5 at 33 (Campbell).
[246] Ex. 435 at 73-74 (Campbell Surrebuttal).
[247] *Id.*
[248] *Id.* at 72; Department Initial Br. at 159.
[249] Ex. 435 at 72 (Campbell Surrebuttal).
[250] *Id.* at 72.
[251] *Id.* at 72.
[252] *Id.* at 72.
[253] Department Initial Br. at 158.
[254] *Id.* at 159.

its total labor cost is comprised of its individual business unit labor costs, and stated that no party challenged "the reasonableness, prudence or necessity of the Company incurring these costs, on an individual basis."[255]

192. The Company explained that the level of labor costs for its Nuclear Business area and the level for its Business Systems area are the reason that the Company's total labor cost exceeds the Department's proposed three percent cap.[256]

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

> These cost increases have been primarily driven by the cost increases for our internal labor for three following reasons: (1) we 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.[257]

194. In addition, Mr. O'Connor noted that the increased labor expenses in 2014 are designed to help control costs over the longer term. He also stated that the Company recognizes that such increases are not sustainable and noted that the Company's current budget for 2014 through 2018 has an average annual O&M increase of two to three percent.[258]

195. With respect to Business Systems labor costs, Company witness Mr. David C. Harkness identified the need for the increased labor spending within the Business Systems Business Area, identifying increases in headcount,[259] and an increase in contract labor for a variety of support needs.[260] Mr. Harkness also provided support and justification for these increases.[261]

196. Because these costs were not contested by any party, the Company maintained that it has demonstrated the reasonableness of its 2014 test year total labor expense.[262]

197. The Company opposed the Department's proposed downward adjustment, arguing it will deny the Company recovery of its representative labor costs. The Company stated that, consistent with the test year concept, the Company has

[255] Xcel Initial Br. at 69; Ex. 17 at Vol. 6, Schedules 3-4 (Initial Filing).
[256] Ex. 129 at 2 (Stitt Opening Statement); Tr. Vol. 2 at 38–39 (Stitt).
[257] Ex. 51 at 83 (O'Connor Direct).
[258] *Id.* at 83-90.
[259] Ex. 62 at 76 (Harkness Direct).
[260] *Id.* at 78.
[261] *Id.* at 76.
[262] Xcel Initial Br. at 70-71.

forecasted its cost of service for the 2014 test year and has proposed a total labor budget reflecting this cost of service.[263]

198. The Company also disagreed with the Department's view that the Company's costs should be based on a three percent annual increase. The Company maintained 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.[264] The Company further stated that the Department's own analysis indicates that the Company's total labor costs vary from year to year.[265] Therefore, the Company argued that the total labor cost in the 2014 test year should be determined on the merits of the forecasted cost of service during the test year, rather than the historical comparisons suggested by the Department.[266]

199. Based on a review of the record, the Administrative Law Judge concludes that the Company has demonstrated that its total labor cost for the 2014 test year is reasonable. The Company provided detailed testimony supporting its test year amount, and demonstrated that virtually all of the labor costs above the Department's proposed three percent cap come from the Company's Nuclear Business area and its Business Systems area. The Department has not provided any evidence showing that these particular labor costs (or any other particular labor costs) could be reduced or are not reasonable. The Department's suggestion that the Company should be limited to a three percent increase fails to consider the specific facts driving the 2014 test year expense. For these reasons, the Company has shown its test year expense is reasonable and no adjustment is necessary.

E. Depreciation and Plant Retirements in the 2015 Step - Passage of Time (2015 Step)[267]

200. As noted above, the Company's current rate case application includes a multiyear rate plan proposal. The Company is the first utility to file a multiyear rate proposal in Minnesota.[268]

201. In a traditional rate case, the Commission sets the base rates that a utility must charge until the next rate case. In 2011, the Legislature authorized the use of a multiyear rate plan.[269] Under a multiyear rate plan (MYRP), the Commission establishes

[263] *Id.* at 71.
[264] Ex. 87 at 6-7 (Stitt Rebuttal) (discussing the drivers of the different total labor costs for the different years presented).
[265] Ex. 435 at 72 (Campbell Surrebuttal).
[266] Xcel Initial Br. at 72 (citing *Petition of Interstate Power Co.,* 416 N.W.2d 800, 810 (Minn. 1987)).
[267] Issue 10.
[268] Ex. 99 at 9 (Clark Direct).
[269] 2011 Minn. Laws ch. 97, § 12 at 6 (codified at Minn. Stat. § 216B.16, subd. 19 (2014)).

the rates the utility can charge in each year of the plan. A MYRP plan cannot exceed a period of three years.[270]

202. Minnesota law provides that the Commission may only approve a multiyear rate plan proposed by a utility "if it finds that the plan establishes just and reasonable rates for the utility."[271] The Commission is to make its determination applying the same factors as are applied in a traditional rate case. The utility has the burden of proof to demonstrate that the MYRP is just and reasonable.[272]

203. As part of the legislation creating this new regulatory tool, the Legislature provided that the Commission "may, by order, establish terms, conditions and procedures for a multiyear rate plan necessary to implement this section …."[273]

204. On June 17, 2013, the Commission issued its ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTIYEAR RATE PROCEEDINGS (MYRP ORDER).[274] Among other issues, the Commission addressed when the use of a MYRP would be warranted. The Commission determined that it would "consider multiyear rate plans that are designed to recover the cost of specific, clearly identified capital projects, and as appropriate non-capital costs." The Commission further specified that "if a utility can identify a basis to begin recovering these costs within three years, the utility has satisfied the minimum standard for justifying consideration of a multiyear rate plan."[275] In its order, the Commission noted that, in reviewing a proposed plan, the Commission will apply traditional ratemaking factors to determine if the plan will result in just and reasonable rates.[276]

205. The Company's proposed MYRP is a two-year plan, with a 2014 test year and a 2015 Step increase.[277] The 2015 Step is designed to recover costs related to 36 capital projects and associated non-capital expenses.[278]

206. 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

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[270] Minn. Stat. § 216B.16, subd. 19 (2014).
[271] *Id.*
[272] *Id.*
[273] *Id.*
[274] *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*, MPUC Docket No. E,G-999/M-12-587, ORDER ESTABLISHING TERMS, CONDITIONS, AND PROCEDURES FOR MULTIYEAR RATE PLANS at 12 (June 17, 2013) (MYRP Order).
[275] MYRP ORDER at 5, 12.
[276] *Id.* at 4 (citing Minn. Stat. § 216B.16, subd. 19).
[277] Ex. 99 at 10 (Clark Direct).
[278] *Id.* at 10, 13-17; Ex. 95 at 9-20 (Robinson Direct); Ex. 94 at 4 (Perkett Rebuttal) (stating that the 2015 Step includes 36 projects).

balances…for the various components of rate base including plant in-service, Construction Work In Progress (CWIP), accumulated depreciation provision, and accumulated deferred taxes."[279]

i. The Department's Proposed Adjustments to the 2015 Step Revenue Requirement for the Passage of Time

207. The Department asserted that the Company's proposed 2015 Step revenue requirement will not result in just and reasonable rates because the Company has not made all the necessary adjustments to account for changes in rate base and depreciation due to the passage of time from 2014 to 2015. To address this issue, the Department recommended two downward adjustments: (1) a $535,552 reduction to reflect 2015 capital retirements of transmission and distribution facilities; and (2) a $17.53 million reduction to reflect accumulated depreciation reserve changes from 2014 to 2015 for all plant in rate base, except for projects already included in the 2015 Step.[280]

208. The Department noted that its proposed adjustments are known and measurable numbers based on plant retirements for existing plants currently in rate base, and on depreciation expense and accumulated depreciation from 2014 to 2015.[281] The Department compared its proposed treatment of costs included in the 2015 Step to the treatment of costs in a rider.[282]

209. The Department maintained that "it would be inequitable to allow the Company to add $68.865 million in plant additions for 36 capital projects and to increase related property taxes (both of which increase costs to ratepayers), 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 capturing 2015 plant retirements."[283] The Department asserted that the Company's rate base will be lower in 2015 as a result of these factors and the 2015 rates should reflect that reduction.[284]

210. The Department also asserted that its position is consistent with the Commission's MYRP ORDER because the adjustments relate to capital investments and capital related items such as depreciation and taxes.[285]

[279] Ex. 95 at 5, 7 (Robinson Direct); Xcel Initial Br. at 46.
[280] Ex. 429 at 158 (Campbell Direct); Ex. 435 at 119-120 (Campbell Surrebuttal).
[281] Ex. 429 at 158 (Campbell Direct).
[282] Department Initial Br. at 227; Tr. Vol. 5 at 62-63 (Campbell).
[283] Ex. 429 at 158 (Campbell Direct).
[284] *Id.*; Department Initial Br. at 228.
[285] Ex. 429 at 176-77 (Campbell Direct); Department Initial Br. at 228.

ii. The Company's Opposition

211. The Company opposed the Department's proposed adjustments, arguing that the adjustments are neither appropriate nor reasonable.[286]

212. The Company contended that an adjustment for the passage of time is not appropriate in this case because the Company has not requested to recover all of its forecasted capital additions for 2015.[287]

213. The Company also claimed that a passage of time adjustment would discourage utilities from proposing multiyear rate plans. The Company asserted that, if a passage of time adjustment is made in a MYRP, utilities will be incented to: (1) forgo the use of a multiyear 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 multiyear rate plan, which may be inconsistent with the Commission's objectives expressed in its MYRP ORDER.[288]

214. If the Commission determines that an adjustment for the passage of time is appropriate, the Company maintained that the Department's proposed $17.53 million downward adjustment needs to be recalculated. The Company stated that the Department's proposed $17.53 million decrease is based on an erroneous discovery response provided by the Company.[289]

215. The Company explained that, during discovery, the Department issued Information Request No. 2113, which sought to quantify the 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)."[290] The Company responded to this request by summarizing only the impact of rolling the average depreciation reserve forward one year from 2014 to 2015 (excluding projects already considered in the 2015 Step), and, as a result, arrived at a reduction of $17.53 million to the 2015 revenue requirement.[291] The Company mistakenly did not include annualization of depreciation expense for all non-Step plants placed into service in 2014; nor did it include a rate of return on the annualized rate base effect of the capital projects placed into service in 2014.[292] As a result, the Company maintained that the $17.53 million figure does not reflect the full effects of the passage of time from 2014 to 2015.[293]

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[286] Xcel Initial Br. at 45.
[287] Ex. 94 at 4 (Perkett Rebuttal); Ex. 130 at 2 (Perkett Opening Statement).
[288] Xcel Initial Br. at 45, 48-49.
[289] *Id.* at 47, 51-52.
[290] *Id.* at 47; Ex. 430, Schedule 32 (Campbell Direct).
[291] Ex. 430, Schedule 32 (Campbell Direct Attachments); Ex. 94 at 5-6 (Perkett Rebuttal).
[292] Ex. 94 at 5-6 (Perkett Rebuttal).
[293] Xcel Initial Br. at 52.

216. 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.[294] The Company noted that the Department's information request (and subsequent testimony) was clear that its proposed passage of time adjustment is intended to capture both the accumulated depreciation reserve and depreciation expense.[295] The Company stated that netting these two items together, as the Department initially maintained should be done, would result in the correct passage of time adjustment of a $949,609 increase to the 2015 revenue requirement.[296]

217. The Company asserted that the Department is aware of the error but has failed to correct its proposed adjustment to reflect the increase in depreciation expense. As a result, the Company argued that the Department's proposed $17.53 million passage of time adjustment is unbalanced and asymmetrical.[297]

218. Moreover, the Company asserted that, for the passage of time adjustment to be perfectly symmetrical, 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."[298] If this approach is taken, the Company maintained that the result is an increase of $1.9 million.[299]

219. The Company also argued that the Department's proposed adjustment for plant retirements is imbalanced because the Company did not request its entire cost of service in 2015.[300]

220. For these reasons, the Company asserted that the Department's proposed adjustments are lopsided and should be rejected by the Commission.[301]

iii. Department's Response

221. In response, the Department disputed the Company's claim that no adjustment is necessary because its depreciation expense in 2015 outpaces its additions to rate base. The Department argued that the Company's assertion is based

[294] *See* Ex. 94, Schedule 2 at p. 5 (Perkett Rebuttal) (calculating both the roll forward of depreciation reserve and expenses); Xcel Initial Br. at 52.
[295] Xcel Initial Br. at 47, 52 (quoting the information request; citing Campbell testimony).
[296] Xcel Initial Br. at 52.
[297] *Id.* at 50-51; Xcel Reply Br. at 39-40; Ex. 94 at 3-7 (Perkett Rebuttal).
[298] Ex. 94 at 5 (Perkett Rebuttal).
[299] *Id.*, Schedule 3. Based on a review of Schedule 2, it is the Administrative Law Judge's understanding that the $1.9 million increase is higher than the $949,609 increase cited above in Paragraph 216 because the $1.9 million increase also includes a rate of return on the annualized rate base effect of projects placed into service in 2014 that are not part of the 2015 Step. *See* Ex. 94, Schedule 2 at 3, 5 (Perkett Rebuttal).
[300] Xcel Initial Br. at 52.
[301] *Id.* at 53.

on additions to rate base in 2015 that have not been audited or examined in this proceeding.[302]

222. The Department also disagreed with the Company's view that allowing a passage of time adjustment in this case would discourage other utilities from proposing a MYRP. The Department noted that the Legislature required a utility to prove that its proposed MYRP will result in just and reasonable rates, and consideration of the effects of the passage of time are properly part of that determination.[303]

223. In addition, the Department disputed the Company's calculation of the passage of time adjustment to account for both depreciation expense and accumulated depreciation reserve. The Department noted that the calculation should compare the *incremental increase* in depreciation expense not already captured in the 2015 Step, if any, to the change in the depreciation reserve amount. The Department asserted that the Company has not shown that the $18.5 million increase in depreciation expense is the incremental increase. The Department claimed instead that it "appears" to be the full increase in depreciation from 2014 to 2015 including additions from the Step. Using this figure would result in double recovery of the Step depreciation expense, according to the Department.[304]

224. In its Reply Brief, the Department also restated many of the same arguments that it made in its Initial Brief and in testimony in support of its proposed adjustments.[305]

iv. Analysis

225. The question of how changes in rate base, depreciation expense, and accumulated depreciation reserve due to the passage of time should be treated in a MYRP presents an issue of first impression.

226. As noted above, Minnesota law provides that the Commission may approve a MYRP only if it finds that the plan establishes just and reasonable rates, applying traditional ratemaking factors.[306] Those factors include:

> the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, *including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property*. In determining *the rate base upon which the utility is to be allowed to earn a*

[302] Post-Hearing Reply Brief of the Department (Department Reply Br.) at 34.
[303] Department Reply Br. at 36-37.
[304] *Id.* at 44-46.
[305] *Id.* at 39-41.
[306] Minn. Stat. § 216B.16, subd. 19 (2014).

> *fair rate of return*, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, *to prudent acquisition cost to the public utility less appropriate depreciation on each*, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature.[307]

227. The language in the italicized provisions above requires the Commission to consider both depreciation expense and changes in rate base in determining whether the MYRP will result in just and reasonable rates.[308] Nothing in the plain language of the statute limits the determination in the step year(s) only to costs associated with specific capital projects.[309]

228. In addition, while the Commission's MYRP ORDER authorizes a utility to "propose" a MYRP to seek recovery of "specific, clearly identified capital projects" and "associated non-capital costs," it also requires that the utility demonstrate that the MYRP will result in just and reasonable rates, applying traditional ratemaking factors.[310]

229. Because those factors include consideration of the utility's depreciation expense and rate base, the Administrative Law Judge agrees with the Department that the Commission should consider the effects of the passage of time on depreciation and rate base in determining the 2015 Step revenue requirement.[311] Otherwise, the 2015 Step will not take into account known and measurable changes in depreciation expense, rate base, and accumulated depreciation reserve for non-Step projects placed into service in 2014, but will only reflect changes due to Step projects. Consideration of the effects due to the passage of time on rate base and depreciation is necessary to ensure just and reasonable rates.

230. A careful review of the record in this case shows that the Department's proposed passage of time adjustments to 2015 Step revenue requirements do not fully account for capital-related effects of the passage of time. The Department's $17.53 million downward adjustment only reflects the change in accumulated depreciation for non-Step projects placed into service in 2014; it does not reflect the increased expenses due to annualization of depreciation expense or the additions to rate base from these same set of projects.[312] When these additional passage of time components are considered, they more than offset the passage of time reductions recommended by the Department.[313]

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[307] Minn. Stat. § 216B.16, subd. 6 (emphasis added).
[308] Minn. Stat. § 216B.16, subds. 6, 19.
[309] *Id.*
[310] MYRP Order at 1, 4-5, 12.
[311] *See* Minn. Stat. § 216B.16, subd. 6.
[312] Ex. 94 at 5, 7 (Perkett Rebuttal)
[313] *See* Ex. 94 at 5, 7, Schedule 2 at 3 and 5 (Perkett Rebuttal); *see also* Xcel Initial Br. at 47, 52.

231. In its Reply Brief, the Department questioned whether the $18.48 million increase in depreciation expense calculated by the Company reflects the incremental increase in depreciation expense beyond that already included in the 2015 Step calculation. The Department asserted that the amount appears to be the full increase in depreciation expense from 2014 to 2015.[314] The evidence demonstrates, however, that the $18.48 million amount is the incremental increase, not the full amount.

232. In an attachment to her testimony, Company witness Ms. Lisa H. Perkett provided a calculation of the increased depreciation expense for the passage of time from 2014 to 2015 excluding 2015 Step projects.[315] This calculation was done to correct an error in the Company's response to Department Information Request No. 2113.[316] This Information Request asked specifically for a calculation of the effect of the passage of time without the 2015 Step projects.[317] As a result, Ms. Perkett's updated calculation also excludes the 2015 Step projects and represents the incremental increase, not the full increase. [318]

233. This conclusion is confirmed by the Rebuttal Testimony of Ms. Perkett. In her Rebuttal Testimony, she calculates the passage of time impact for "non-Step projects placed in service in 2014."[319] "[T]he result is not a $17.5 million reduction [as claimed by the Department], but a $1.9 million increase."[320]

234. Based on the foregoing analysis, the Administrative Law Judge concludes that no downward adjustment to the Company's 2015 Step revenue requirement for the passage of time is necessary. In addition, because the Company has not requested an adjustment for the passage of time, no increase is necessary.

F. Return on Equity and Capital Structure (2014 and 2015)[321]

235. In order for a public utility to provide adequate service, the utility must be able to compete for necessary funds in the capital markets. To attract these funds the utility must earn enough to offer competitive returns to investors.[322]

236. A fair rate of return (ROR) is one that enables the utility to attract sufficient capital, at reasonable terms. Regulators seek to set the ROR at a level that, when

[314] Department Reply Br. at 45.
[315] Ex. 94 at Schedule 2, page 5.
[316] *See id.*; Xcel Initial Br. at 52.
[317] Ex. 430, Schedule 32 (Attachments to Campbell Direct) (I.R. No. 2113 with the original answer).
[318] Ex. 94 at 5, Schedule 2 at 7 (Perkett Rebuttal).
[319] *See* Ex. 94 at 5, Schedule 2 at 3 (Perkett Rebuttal).
[320] Ex. 94 at 5 (Perkett Rebuttal).
[321] Issues 1 and 12.
[322] Ex. 400 at 2-3 (Amit Direct).

multiplied by the rate base, will give the utility a reasonable return on its total investment, but no more.[323]

237. The ROR is the overall cost of capital. The ROR is calculated as the sum of each component of the capital structure times its corresponding cost. The capital structure is made up of components which may include common equity, short-term debt and long-term debt. These amounts are represented as dollar amounts and as percentages of the total capital.[324]

238. In this case, the cost of short-term debt and the cost of long-term debt to be used in calculating the Company's ROR are not disputed.[325] Several parties disagree, however, about the cost of common equity (or return on equity) to be used in the ROR calculation. In addition, the capital structure is disputed between the Company and the ICI Group.[326] These issues are addressed in turn below.

i. Return on Equity[327]

239. Minnesota law requires the Commission to set electric rates at a level that allows the public utility to earn a fair and reasonable return on equity (ROE).[328] A fair and reasonable ROE is one that is: (1) sufficient to enable the regulated company to maintain its credit rating and financial integrity; (2) sufficient to enable the utility to attract capital; and (3) commensurate with returns being earned on other investments having equivalent risks.[329]

240. In order to attract investors, the Company must pay an equity return similar to the equity return that investors expect to earn on investments of comparable risk in the market.[330] The Commission has noted in prior cases that, in determining the ROE, "the returns being offered by other investments of comparable risk available in the market" must be analyzed.[331]

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[323] Ex. 400 (Amit Direct) at 3; Minn. Stat. § 216B.16, subd. 6; *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679, 692-93 (1923); *Federal Power Comm'n, et al. vs. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

[324] Ex. 400 at 4 (Amit Direct).

[325] The Company and the Department were the only parties that provided testimony on the issues of the cost of long-term debt, and the cost of short-term debt. *See* Ex. 400 at 46-47, 51-52 (Amit Direct); Ex. 31 at 25-28, Schedule 3 (Tyson Rebuttal); Ex. 403 at 9 (Amit Surrebuttal).

[326] *See* Initial Post-Hearing Brief of ICI Group *(*ICI Group Initial Br.) at 14-15; Xcel Initial Br. at 117-119.

[327] Issue 1.

[328] Minn. Stat. § 216B.16, subd. 6. Pursuant to the MYRP ORDER, if the Commission adopts the Company's proposed MYRP, the ROE set in this proceeding will apply to both the 2014 and 2015 Step revenue requirements. MYRP Order at 7.

[329] Ex. 400 at 3 (Amit Direct); Ex. 27 at 6-7 (Hevert Direct); *Bluefield Waterworks & Improvement Co.*, 262 U.S. at 692-93; *Federal Power Comm'n,* 320 U.S. at 603.

[330] Ex. 400 at 3 (Amit Direct); Ex. 27 at 7 (Hevert Direct).

[331] *In re Petition of Otter Tail Power Co.,* Docket No. E017/GR-07-1178, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 55 (Aug. 1, 2008).

241. Because the cost of equity is not directly observable, it must be estimated based on quantitative and qualitative information. Various models have been developed as tools to estimate the cost of equity. Because these models may be subject to limiting assumptions or other methodological constraints, multiple analytical approaches are often used.[332]

242. The Discounted Cash Flow (DCF) model is a market-oriented method, based on the theory that the current price of a stock is equal to the present value of all the expected future dividends discounted by the appropriate rate of return.[333] The DCF model is used widely in regulatory proceedings to estimate the cost of equity and is typically applied in rate cases in Minnesota.[334]

243. Under the constant growth DCF method, if annual dividends grow at a constant rate over an infinite period, the required ROE is estimated using the following formula:

expected dividend yield	+	expected growth rate in dividends	=	estimated (required) ROE.[335]

244. Another DCF approach is the Two Growth Rates DCF (Two Growth DCF). This approach is used when the short-term projected dividend growth rate for a company is unlikely to be sustained in the long run. The Two Growth DCF accommodates two different growth rates. It assumes that, for a relatively short time period, earnings and dividends may grow annually at a different rate than the long-term, sustainable growth rate and, at the end of this short period, both earnings and dividends will grow at a constant, sustainable annual rate.[336]

245. The Capital Asset Pricing Model (CAPM) can be used to check the reasonableness of DCF results. The CAPM analysis is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free rate of return, plus a risk premium to compensate investors for the non-diversifiable or “systematic” risk of that security.[337] To perform a CAPM analysis, it is necessary to determine the rate of return on a riskless asset, along with the appropriate beta and the appropriate required rate of return on the market portfolio. The beta measures the portion of the variability in a stock’s return that maintains a systematic relationship with a broad market index, and indicates the direction and degree of change in a stock’s return relative to the changes in the market as a whole.[338]

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[332] Ex. 27 at 29 (Hevert Direct).
[333] Ex. 400 at 4-5 (Amit Direct); Ex. 27 at 30 (Hevert Direct).
[334] Ex. 27 at 30 (Hevert Direct).
[335] Ex. 400 at 4-5 (Amit Direct); Ex. 27 at 30-31 (Hevert Direct).
[336] Ex. 400 at 5-6 (Amit Direct); Ex. 27 at 34 (Hevert Direct).
[337] Ex. 27 at 39-40 (Hevert Direct).
[338] Ex. 400 at 16, 37-38 (Amit Direct); Ex. 27 at 40 (Hevert Direct).

246. The Bond Yield Plus Risk Premium analysis can also be used to test the reasonableness of DCF results. This approach is based on the fundamental principle that equity investors bear the residual risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. In other words, because returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that risk. Risk premium approaches estimate the cost of equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds. Since the Equity Risk Premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate *ex-ante* or forward-looking estimates of the cost of equity, and others that consider historical, or *ex-post,* estimates. An alternative approach is to use actual authorized returns for electric utilities to estimate the Equity Risk Premium.[339]

247. As described in detail below, the parties disagree as to what constitutes a fair and reasonable ROE. The Company recommended a 10.25 percent ROE throughout this proceeding. The Company also asserted that if the Commission does not believe a ROE of 10.25 percent is reasonable, then the Commission should adopt a ROE that is no lower than 9.83 percent, the ROE set in the last rate case.[340] The Department initially proposed a ROE of 9.80 percent, but subsequently updated its DCF analysis to reflect more current data and thereafter recommended a 9.64 percent ROE.[341] The ICI Group recommended a ROE of 9.0 percent.[342] The Commercial Group supported the Department's final recommendation or an even lower ROE.[343]

a. The Company's Initial ROE Analysis

248. The Company proposed a ROE of 10.25 percent in its Direct Testimony. The Company determined that its cost of equity currently is in the range of 10.00 percent to 10.70 percent. Based on quantitative and qualitative analyses, the Company concluded that a ROE of 10.25 percent is reasonable and appropriate.[344]

249. The Company's recommendation was based primarily on the DCF model, including the use of the Two Growth DCF adjustment to address individual growth rates that were outliers, high or low, relative to the mean. The Company also considered the results of the CAPM and the Bond Yield Plus Risk Premium approach to assess the reasonableness of the results of its DCF analysis. In addition, in developing its recommended ROE, the Company took into account other factors including: the

[339] Ex. 27 at 44 (Hervert Direct).
[340] Ex. 115 (Hevert Opening Statement).
[341] Ex. 403 at 6-7 (Amit Surrebuttal).
[342] Ex. 250 at 15 (Glahn Direct).
[343] Initial Post-Hearing Brief of the Commercial Group (Commercial Group Initial Br.) at 9.
[344] Ex. 400 at 2, 6, 7 (Amit Direct). As discussed in further detail below**,** Dr. Amit later updated his DCF/Two Growth DCF analysis to reflect more current data and, based on the updated analysis, finally recommended a 9.64 percent ROE. Ex. 403 at 2 (Amit Surrebuttal).

Company's capital expenditure program; its proposed decoupling mechanism; its multiyear rate plan proposal; and recent increases in interest rates.[345]

250. The Company conducted its DCF analysis on proxies for the Company because the Company is not a publicly-traded entity. It is an operating subsidiary of Xcel Energy Inc. In addition, use of a proxy group serves to moderate the effects of anomalous, temporary events that may be associated with any one company. Mr. Hevert, the Company's expert, selected companies that are both publicly traded and comparable to the Company in certain fundamental respects to serve as its proxy in the ROE estimation process.[346]

251. The Company selected two proxy groups for its ROE analysis: an electric proxy group (which this Report will refer to as the Xcel Electric Comparison Group or (XECG)) and a combination proxy group (the Xcel Combination Comparison Group or (XCCG)).[347]

252. The XECG was composed of companies with substantial electric utility operations. The Company began with the 48 domestic United States utilities that Value Line classifies as Electric Utilities, and applied the following screening criteria:

a. Excluded companies that do not consistently pay quarterly cash dividends;

b. Excluded companies that were not covered by at least two utility industry equity analysts;

c. Excluded companies that did not have investment grade senior bond and/or corporate credit ratings from Standard & Poors (S&P);

d. Excluded companies whose regulated operating income over the three most recently reported fiscal years comprised less than 60.00 percent of the respective total operating income for that company;

e. Excluded companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 90.00 percent of total regulated operating income; and

[345] Ex. 27 at 3-4, 28-52 (Hevert Direct).
[346] *Id.* at 18-19.
[347] The Department's expert witness, Dr. Eilon Amit, referred to the "XECG" and the "XCCG" as the "HEGC" and the "HCCG." *See* Ex. 400 at 58-59 (Amit Direct).

f. Excluded companies that were known to be involved in a merger or other significant transaction.[348]

253. These screening criteria produced a proxy group of 17 companies. The Company then examined the operating profile of each of the 17 companies that were originally selected for inclusion in the XECG to be certain that none displayed characteristics that were inconsistent with its intent to produce a proxy group that was fundamentally similar to the Company. As a result of this review, the Company excluded one company, Edison International, because of significant, recent financial losses.[349] The Company then applied the Department's convention of excluding any companies with mean DCF results of less than 8.00 percent. As a result, two more companies were excluded: IDACORP Inc. and Hawaiian Electric Industries Inc.[350]

254. The final XECG included the following 14 companies: American Electric Power Co. Inc.; Cleco Corp.; Duke Energy Corp.; Empire District Electric Co.; Great Plains Energy Inc.; Northeast Utilities; Otter Tail Corp.; PNM Resources Inc.; Pinnacle West Capital Corp.; Pepco Holdings Inc.; Portland General Electric Co.; Southern Co.; UniSource Energy Corp.; and Westar Energy Inc.[351]

255. The Company next selected its XCCG. The XCCG consisted of utility companies that have combined electric and gas operations. To establish the XCCG, the Company began with the 59 domestic United States utilities that Value Line classifies as Electric Utilities and Natural Gas Utilities. The Company then applied the following screening criteria:

a. Excluded companies that do not consistently pay quarterly cash dividends;

b. Excluded companies not covered by at least two utility industry equity analysts;

c. Excluded companies that did not have investment grade senior bond and/or corporate credit ratings from S&P;

d. Excluded companies whose regulated operating income over the three most recently reported fiscal years comprised less than 60 percent of the respective total operating income for that company;

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[348] Ex. 27 at 22-23 (Hevert Direct).
[349] *Id.* at 24.
[350] *Id.*
[351] *Id.* at 25.

e. Excluded companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 10.00 percent of total regulated operating income;

f. Excluded companies whose regulated natural gas utility operating income over the three most recently reported fiscal years represented less than 10 percent of total regulated operating income; and

g. Excluded companies that were currently known to be party to a merger or other significant transaction.[352]

256. The Company did not include Xcel Energy Inc. in its analysis in order to avoid the circular logic that would otherwise occur.[353]

257. Sixteen companies met these screening criteria. The Company then applied the Department's convention of excluding any companies with mean DCF results of less than 8.00 percent. This resulted in the exclusion of two of the 16 companies: Consolidated Edison Inc. and Sempra Energy.

258. Based on these criteria, the final XCCG included the following 14 companies: Alliant Energy Corp.; Avista Corp.; Black Hills Corp.; CenterPoint Energy Inc.; CMS Energy Corp.; Dominion Resources Inc.; DTE Energy Company; Integrys Energy Group Inc.; NiSource Inc.; NorthWestern Corp.; SCANA Corp.; UIL Holdings Corp.; Vectren Corp.; and Wisconsin Energy Corp.[354]

259. The Company applied the DCF model to its two proxy groups, the XECG and the XCCG. As discussed above, the DCF analysis requires an estimate of both the expected growth rate and the expected dividend yield.[355]

260. To estimate the expected growth rate, the Company used three commonly-accepted sources of earnings growth rates: the Zacks consensus long-term earnings growth estimates; the First Call consensus long-term earnings growth estimates; and the Value Line long-term earnings growth estimates. Because Zacks and First Call growth rates represent consensus estimates, their use in the DCF approach ensures no single analyst's estimate unduly influences the model's results. As noted earlier, the Company also applied the Two Growth DCF approach to account for growth rates that were atypically high or low. [356]

261. To estimate the expected dividend yield, the Company used the average daily closing stock prices for the 30-trading days, 90-trading days, and 180-trading days

[352] *Id.* at 25-26.
[353] *Id.* at 26.
[354] *Id.*
[355] *Id.* at 30-31.
[356] *Id.* at 34, Schedule 2.

ended September 30, 2013, and the proxy companies' current annualized dividend per share as of September 30, 2013.[357] The Company used the 30-day, 90-day and 180-day trading periods to calculate the average stock price to ensure that the results were not skewed by anomalous events that may affect stock prices on a particular trading day. In the Company's view, the three periods it used take this concern into account while still being reasonably representative of expected capital market conditions over the long term. In addition, the Company believes its use of three averaging periods is further supported by the unstable capital market conditions that were present in 2013.[358]

262. Because utility companies tend to increase their quarterly dividends at different times throughout the year, the Company calculated the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. The Company made this adjustment to ensure that the expected dividend yield is, on average, representative of the coming 12-month period and does not overstate the dividends to be paid during that time.[359]

263. The Company also made an adjustment for flotation costs. Flotation costs are the costs associated with the sale of new issues of common stock and include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs of common stock. The DCF model does not compensate for such costs. The Company maintained that if a company does not have an opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, and the company's ability to attract adequate capital on reasonable terms will be diminished. The Company also asserted that it is appropriate to consider flotation costs even though the Company is a wholly-owned subsidiary of Xcel Energy Inc., because subsidiaries receive equity capital from their parent companies and provide returns on the capital that roll up to the parent.[360] The Company noted that the Commission has approved recovery of flotation costs in numerous past rate cases.[361]

264. The Company calculated its flotation costs in accordance with the methodology approved by the Commission in past cases. Based on the weighted average issuance costs, the Company concluded that a reasonable estimate of its flotation costs is approximately 0.13 percent (13 basis points).[362]

265. In developing its recommended ROE, the Company applied an 80/20 percent weighting to the results of the XECG and the XCCG, respectively. The Company acknowledged that the Commission has applied a 60 percent weighting to electric proxy groups and a 40 percent weighting to combination proxy groups in recent electric rate cases. However, the Company asserted that it placed 80 percent weight on

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[357] *Id.*
[358] Ex. 27 at 32 (Hervert Direct).
[359] *Id.* at 32-33.
[360] *Id.* at 35-37.
[361] *Id.* at 38 (citations omitted).
[362] Ex. 27 at 38-39, Schedule 3 (Hervert Direct).

the results of its electric proxy group to more closely reflect the fact that approximately 91 percent of the Company's total regulated income comes from electric utility operations and the purpose of this proceeding is to establish its electric rates. The Company maintained that the weighting of its combination proxy group, the XCCG, should not exceed 20 percent.[363]

266. The results of the Company's DCF analysis, including flotation costs, are summarized below:[364]

Table 3

	Low Growth Rate	**Mean Growth Rate**	**High Growth Rate**
Electric Proxy Group Results (XECG)			
30-Day Average	9.44%	10.18%	10.90%
90-Day Average	9.28%	10.02%	10.73%
180-Day Average	9.24%	9.97%	10.69%
Combination Proxy Group Results (XCCG)			
30-Day Average	9.08%	9.63%	10.21%
90-Day Average	9.00%	9.55%	10.12%
180-Day Average	9.04%	9.59%	10.16%
Weighted Average Results (80% Electric / 20% Combination)			
30-Day Average	9.37%	10.07%	10.76%
90-Day Average	9.22%	9.92%	10.61%
180-Day Average	9.20%	9.90%	10.58%

267. The Company used the CAPM and Bond Yield Plus Risk Premium approaches to test the reasonableness of its DCF results.

268. As noted above, the CAPM analysis 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. The Company's CAPM analysis and results are summarized in the Direct

[363] Ex. 27 at 20-21 (Hevert Direct).
[364] *Id.* at 39, Schedule 2 at 1-6 (Hervert Direct).

Testimony of its expert, Mr. Hevert.[365] The results of the CAPM analysis were variable, and the Company did not give any specific weight to those results. The Company's ROE recommendation does not substantially rely on the CAPM results. The Company merely used the CAPM results to assess the DCF results.[366]

269. The Company also performed a Bond Yield Plus Risk Premium analysis to test the reasonableness of its DCF results. As discussed above, this approach is based on the fundamental principle that equity investors bear the residual risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder.[367]

270. To perform its Bond Yield Plus Risk Premium analysis, the Company defined the Equity Risk Premium as the difference between the authorized ROE and the then-prevailing level of the long-term (30-year) Treasury yield. The Company examined data from 1,417 electric utility rate proceedings between January of 1980 and September of 2013 and the prevailing level of interest rates during the pendency of the proceedings, and calculated the Equity Risk Premium in each case. The Company concluded that, over time, there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. As the 30-year Treasury Yield has fallen, the Equity Risk Premium has increased. As a result, the Company maintained that simply applying the long-term average Equity Risk Premium of 4.44 percent to the current Treasury yield would significantly understate the cost of equity. Based on the regression coefficients, the Company determined that the implied ROE is 10.33 to 10.90 percent.[368]

271. The Company also considered additional factors in determining the Company's cost of equity and its recommended ROE. First, the Company considered the Company's capital expenditure program. The Company emphasized that it expects to undertake significant capital expenditures during the period of 2014 to 2017. As compared to companies in the XECG, the Company has the third highest ratio of projected capital expenditures to net plant.[369] The Company asserted that these capital investments will require ongoing access to both debt and equity markets, and investors will pay attention to the level of regulatory support provided by the Minnesota Commission as compared to the level of support provided by other state commissions. The Company contended that the Commission's decision in this proceeding will have a direct bearing on the Company's ability to maintain its credit profile and access the capital market at reasonable cost rates. The Company also noted that a return that is

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[365] Ex. 27 at 39-43, Schedules 5-6 (Hervert Direct).
[366] Ex. 27 at 39, 43, 54-55 (Hervert Direct).
[367] *Id.* at 44.
[368] *Id.* at 44-45, Schedule 7 (Hervert Direct).
[369] Ex. 27 at 46-47 (Hervert Direct).

adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness.[370]

272. Next, the Company considered whether the Company's proposed revenue decoupling mechanism, if approved, would affect its cost of capital. In the view of the Company's expert, Mr. Hevert, decoupling will not affect the cost of equity unless it can be demonstrated that: (1) the Company is materially less risky than its proxy groups by virtue of the decoupling program; and (2) the financial markets react to the incremental effect of the mechanism and measurably reduce their return requirement for the Company. The Company also asserted that of the 28 companies in its XECG and XCCG, 14 have some form of decoupling mechanism in place. As a result, the Company does not believe that equity investors would reduce their return requirements for the Company relative to the XECG or XCCG if decoupling is approved for the Company. In fact, it is Mr. Hevert's view that the Company may be seen as incrementally more risky if a decoupling mechanism is not approved because of the number of other companies with such mechanisms.[371]

273. Third, the Company considered the effect of a MYRP on the cost of equity. The Company maintained that it is important to consider the potential increases in the level of interest rates during the term of its proposed MYRP. Further, the Company asserted that it is reasonable to assume that long-term rates are more likely to increase than decrease during its MYRP, representing a significant element of risk for equity investors. In addition, equity valuations remain at risk to increases in broad market instability, movement of investments out of the utility sector, and other factors. As a result, the Company asserted that a MYRP would support a premium to the current cost of equity, but did not quantify the premium.[372]

274. Based on the quantitative and qualitative analyses discussed above, the Company concluded that a ROE in the range of 10.00 percent to 10.70 percent represents the range of equity investors' required rate of return for investment in integrated electric utilities similar to the Company in today's capital markets. Within that range, the Company recommended a ROE of 10.25 percent.[373]

275. While a 10.25 percent ROE is above the mean of its 30-day, 90-day and 180-day weighted DCF results for the XECG and the XCCG as shown in Table 3 above, the Company recommended a ROE at this level for three primary reasons.[374] First, the Company asserted that because this proceeding will set the rates for the Company's electric service operations, the results of the XECG are more important. Second, the Company maintained that it is critical that there be a supportive regulatory environment to allow the Company to finance its capital expenditures at a reasonable cost for the

[370] *Id.* at 16, 46-50.
[371] *Id.* at 51-52, Schedule 10.
[372] Ex. 27 at 52-53 (Hervert Direct).
[373] *Id.* at 55.
[374] *Id.*

reasons noted above. Third, the Company maintained that recent, significant increases in interest rates have placed upward pressure on the cost of equity since the last rate case. In addition, the Company asserted that uncertainty regarding the Federal Reserve's "Quantitative Easing" policy introduces an additional element of risk that also indicates upward pressure on the cost of equity.[375] In the Company's view, a 10.25 percent ROE reasonably represents the return required to invest in a company with a risk profile comparable to the Company.[376]

b. The Department's Initial ROE Analysis

276. The Department initially proposed a ROE of 9.80 percent. Like the Company, the Department used both the constant growth DCF model and the Two Growth DCF model in estimating the required ROE for the Company. The Department also used the CAPM to support its analysis.[377]

277. Like the Company, the Department used two proxy groups for its DCF analysis: one which consisted of all-electric utilities (the Final Electric Comparison Group or FECG), and one which consisted of combination gas-and-electric utilities (the Final Combination Comparison Group or FCCG).[378]

278. The initial universe for the FECG included all electric utilities that were listed in the October 31, 2013, Compustat Data Base (a service provided by S&P); had a primary SIC code of 4911 (electric utilities); had publicly-traded shares on one of the stock exchanges; and had S&P bond ratings in the range of BBB- to A+ (the Company's bond rating is A-).[379]

279. To ensure that the companies in the FECG have risks similar to those of the Company, the Department then applied the following screens to eliminate: (1) foreign companies; (2) companies whose main operations do not consist of regulated retail electric services; (3) companies that did not pay dividends or just started to pay dividends and have no reliable dividend history; (4) companies whose 2012 regulated revenues and regulated operating incomes were less than 60 percent of total revenues and total net income, respectively; (5) companies which were in the process of merging with another company or in the process of significant restructuring; and (6) companies which had both beta[380] and standard deviation of past price changes which deviated by more than one standard deviation from the group's mean. Sixteen companies remained

[375] *Id.* at 3-4, 55.
[376] *Id.* at 55-56.
[377] Ex. 400 at 2, 6, 7 (Amit Direct). As discussed in further detail below**,** Dr. Amit later updated his DCF/Two Growth DCF analysis to reflect more current data and, based on the updated analysis, finally recommended a 9.64 percent ROE. Ex. 403 at 2 (Amit Surrebuttal).
[378] Ex. 400 at 7-20 (Amit Direct); Ex. 401 at EA-12, EA-22 (Amit Direct Attachment (Att.)).
[379] Ex. 400 at 10 (Amit Direct).
[380] The "beta" represents both relative volatility (i.e. the standard deviation) of returns, and the correlation in returns between the subject company and the overall market. Ex. 27 at 40 (Hervert Direct).

after these screens were applied.[381] The Department then eliminated one company that had negative growth rates in its expected earnings per share based on its determination that such growth rates are inappropriate to use in the context of a DCF analysis, leaving 15 companies.[382]

280. The Department next excluded any company with a mean DCF result of less than 8 percent because its risk premium analysis showed that a ROE of less than 8 percent is not financially viable. The Department noted that it is important for the companies in the DCF comparison group to be financially viable because it is in the public interest to ensure that the ROE is not set too low and the utility has a reasonable opportunity to recover its costs and finance the necessary capital improvements to the system. The Department determined that five companies in the group had expected ROEs of less than 8 percent and thus did not pass the financial reasonableness test.[383]

281. After applying all of these screens, ten companies remained. The Department's FECG is composed of those ten companies: American Electric Power Co.; Cleco Corp.; Empire District Electric Co.; Great Plains Energy Inc.; NextEra Energy Inc.; Pepco Holdings Inc.; PNM Resources Inc.; Pinnacle West Capital Corp.; Portland General Electric Co.; and UIL Holdings Corp.[384]

282. The Department used a similar process to select its FCCG, the combination proxy group. The initial universe for the FCCG consisted of all of the combination companies listed in the Compustat Data Base that had a primary SIC code of 4931 (combination utilities), a S&P bond rating between BBB- to A+, and whose shares are publicly traded on one of the stock exchanges.[385]

283. To eliminate companies that do not have an investment risk comparable to the Company, the Department applied additional screens and eliminated: (1) foreign companies; (2) companies for which the main operations did not consist of regulated retail electric service; (3) companies with no dividends; (4) companies with less than 60 percent regulated revenues and regulated net income; (5) companies that were in the process of merging with another company or in the process of other significant restructuring; and (6) companies for which both beta and standard deviation of stock price changes deviated by more than one standard deviation from the group's mean. The Department also eliminated two companies for which the DCF ROE resulted in a rate of return lower than 8.00 percent.

284. The remaining 14 companies comprised the FCCG: ALLETE Inc.; Alliant Energy Corp.; Avista Corp.; CMS Energy Corp.; DTE Energy Co.; Duke Energy Corp.;

[381] Ex. 400 at 10-13 (Amit Direct); Ex. 401 at EA-2 – EA-8 (Amit Direct Att.).
[382] Ex. 400 at 13-14 (Amit Direct); Ex. 401 at EA-9 (Amit Direct Att.).
[383] Ex. 400 at 14-17 (Amit Direct); Ex. 401 at EA-12 (Amit Direct Att.).
[384] Ex. 400 at 17 (Amit Direct); Ex. 401 at EA-13 at 1 of 2 (Amit Direct Att.).
[385] Ex. 400 at 17-18 (Amit Direct); Ex. 401 at EA-14 (Amit Direct Att.).

NiSource Inc.; Northeastern Utilities; Northwestern Corp.; SCANA Corp.; TECO Energy Inc.; Westar Energy Inc.; Wisconsin Energy Corp.; and Xcel Energy Inc.[386]

285. The Department then assessed the investment risk of the FECG, the FCCG, Xcel Energy Inc., and the Company by applying direct market-oriented risk measures (beta and STDPC) and financial risk measures (common equity ratio, long-term debt ratio, and S&P bond rating). The Department concluded that the FECG and FCCG groups had fairly similar investment risks. In addition, Xcel Energy Inc. had a somewhat smaller direct market-oriented risk but somewhat greater financial risk than the two comparison groups. The only risk measures available for the Company — the equity and long-term debt ratios and the bond rating — suggested that the Company was somewhat less risky than either the FECG or the FCCG.[387]

286. Next, the Department conducted a DCF analysis for its FECG and its FCCG.

287. To calculate the expected growth rates of the Companies included in its FECG and FCCG, the Department used three commonly accepted sources of earnings growth rates: Zacks, Value Line, and the First Call.[388] The Department based its estimate of expected growth rates only on projected growth rates because historical growth rates may be poor indicators of future growth rates.[389] In addition, the Department used only the projected earnings per share (EPS) growth rates in its DCF analysis because: (1) over the long run, the growth in book value per share (BVPS) and dividends per share (DPS) are derived from the growth in EPS; (2) various financial studies and publications support the use of projected EPS growth rates as the best predictors of stock prices; and (3) an analysis performed by Company expert witness, Mr. Robert Hevert, in 2007 demonstrated that the EPS projected growth rates are the best projected growth rates to predict stock prices for electric utilities and that DPS and BVPS growth rates are not useful.[390] However, the Department also examined the reasonableness of analysts' projected earnings.[391]

288. At the time of its initial analysis, the Department's best point estimate of the expected growth rate for the FECG group was 5.76 percent and the range of the growth rates was from a low of 4.65 percent to a high of 6.82 percent.[392] Its best point

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[386] Ex. 400 at 19-20 (Amit Direct); Ex. 401 at EA-15 – EA-22 (Amit Direct Att.).
[387] Ex. 400 at 21-22 (Amit Direct).
[388] *Id.* at 24.
[389] *Id.* at 23-24.
[390] *Id.* at 27-29.
[391] *Id.* at 31-32, 36.
[392] Ex. 400 at 26, 43 (Amit Direct); Ex. 401 at EA-13 (Amit Direct Att.). The low expected growth rate for each company is the lowest growth rate among Zacks, First Call, and Value Line; the low average growth rate for the group is the average of all the companies' low expected growth rates. Similarly, the high expected growth rate for each company is the highest growth rate among Zacks, Thomson and Value Line, and the high growth rate for the group is the average of all the companies' high expected growth rates. Ex. 400 at 26 (Amit Direct).

estimate of the expected growth rate for the FCCG group was 5.25 percent, and the range of the growth rates for that group was from a low of 4.58 percent to a high of 6.06 percent.[393]

289. To calculate the expected dividend yield, the Department used the four-week period closing prices for the period of October 1, 2013 to October 31, 2013. These were the most current available prices at the time the Department submitted its Direct Testimony.[394] The Department applied a growth-rate adjustment to reflect the fact that the companies in the comparison groups may raise their dividend rates in different quarters.[395]

290. The Department determined that the average expected dividend yield for the FECG group is 4.14 percent, and the dividend yield ranges from a low of 4.12 percent to a high of 4.16 percent.[396] The average expected dividend yield for the FCCG group was 4.09 percent, and the dividend yield for FCCG group ranged from a low of 4.09 percent to a high of 4.12 percent.[397]

291. After combining the expected growth rates with the expected dividend yields, the Department determined that the required ROE for the FECG ranged from a low of 8.77 percent to a high of 10.98 percent, and found that the best point estimate for the required ROE for that group was 9.90 percent.[398] The Department further found that the required ROE for the FCCG ranged from a low of 8.67 percent to a high of 10.18 percent, with the best point estimate for the required ROE for the FCCG at 9.35 percent.[399]

292. Because the Department determined that some of the analysts' projected growth rates in the FCCG were not reasonable to be used as proxies for the DCF's long-term, sustainable growth rates, the Department performed a Two Growth DCF analysis on five companies in the FCCG. Those five companies all had mean expected growth rates that were plus or minus (+/-) one standard deviation outside the range of the FCCG's mean expected growth rate.[400] Based on a Two Growth DCF analysis, the Department calculated the ROEs for the FCCG group ranged from a low ROE of 8.97 percent to a high ROE of 9.77 percent with an average of 9.35 percent.[401]

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393 Ex. 400 at 43 (Amit Direct); Ex. 135 at EA-19 (Amit Direct Att.).
394 Ex. 400 at 24-25 (Amit Direct).
395 *Id.* at 30.
396 *Id.* at 30; Ex. 401 at EA-13 (Amit Direct Att.).
397 Ex. 400 at 35 (Amit Direct); Ex. 401 at EA-23 (Amit Direct Att.).
398 Ex. 400 at 35 (Amit Direct).
399 *Id.* at 35; Ex. 401 at EA-25 (Amit Direct Att.).
400 Ex. 400 at 36 (Amit Direct); Ex. 401 at EA-25 (Amit Direct Att.)
401 Ex. 400 at 36 (Amit Direct); Ex. 401 at EA-27 (Amit Direct Att.).

293. The Department did not perform a Two Growth DCF analysis for any of the companies in the FECG because none of the companies in the Department's FECG appeared to have a non-sustainable projected growth rate.[402]

294. Finally, the Department adjusted the DCF results of the FECG and FCCG to account for floatation costs. Based on its review of information provided by the Company, the Department calculated a flotation cost adjustment of 12 basis points.[403]

295. The following table summarizes the results of the Department's DCF analyses in its Direct Testimony, including an adjustment for flotation costs:[404]

Table 4

	Low	Average	High
FECG	8.89%	10.02%	11.10%
FCCG	9.09%	9.47%	9.89%

296. The Department conducted a CAPM analysis as a check on the reasonableness of its DCF analyses.[405] The use of the CAPM raises some complex issues, including difficulties in determining the appropriate beta, the appropriate riskless asset, and the effect of taxes.[406]

297. In performing the CAPM check, the Department used the average yield on 20-year Treasury bonds as a proxy for the risk-free asset. This yield was 3.50 percent at the time. The Department acknowledged that a 20-year Treasury bond is not, in fact, a risk-free asset and using it in a CAPM analysis may result in an upward bias of the ROE.[407] For the market return rate, the Department used the S&P 500 Index as a proxy for the market portfolio. The Department determined that the required rate of return on the S&P 500 was 11.70 percent.[408] The Department used a beta of 0.745 for the FECG group and a beta of 0.736 for the FCCG group.[409]

298. The Department's CAPM result for the FECG group, adjusted for flotation costs, was 9.73 percent. Its CAPM result for the FCCG group after adjustment for flotation costs, was 9.66 percent.[410]

[402] Ex. 400 at 31-32 (Amit Direct).
[403] *Id.* 32, 36-37; Ex. 401 at EA-34 (Amit Direct Att.); Ex. 28 at 5 (Hevert Rebuttal).
[404] Ex. 400 at 37, Table 4 (Amit Direct).
[405] Ex. 400 at 37 (Amit Direct).
[406] *Id.* at 37-38.
[407] *Id.* at 39-40.
[408] *Id.* at 41.
[409] *Id.*
[410] *Id.*

299. The Department's CAPM results were inside the range of the Department's DCF results for the FECG and FCCG, respectively. For that reason, the Department concluded that the results of the CAPM analysis confirmed the reasonableness of its DCF results.[411]

300. Based on the Department's DCF analyses for the FECG and FCCG groups, it estimated that the required ROE for the Company ranged from a low of 8.89 percent to a high of 11.10 percent.[412]

301. To develop its recommended ROE, the Department assigned a weight of 60 percent to the FECG group and 40 percent to the FCCG group. The Department maintained that the 60/40 split is appropriate. Giving 60 percent weight to the FECG recognizes that the focus of the current proceeding is to estimate the required rate of return for the electric operations of the Company. The FCCG group also provides additional important information and, therefore, the Department concluded that a 40 percent weight must be assigned to those results as well. The Department noted that the weights assigned by both the Department and the Company are subjective.[413]

302. Based on these weights, the Department concluded that the required ROE for the Company ranged from a low of 8.97 percent to a high of 10.62 percent. Applying these weights to the mean ROEs of the FECG and the FCCG, the Department determined that a reasonable ROE for the Company was 9.80 percent.[414]

c. The Department's View of the Company's Initial ROE Analysis

303. The Department also responded to the ROE analysis contained in the Company's Direct Testimony. While the Department agreed with many aspects of the Company's analysis, it was concerned with several key aspects, and as a result, did not agree with its final recommendations.[415]

304. With respect to the Company's DCF analysis, the Department raised concerns with the following aspects of the Company's analysis:

a. The Department agreed with the Company's decision to use 30-day periods to calculate the dividend yields but indicated that the Company's use of prices over 90- and 180-days to calculate dividend yields may be inappropriate. Under the basic economic principle that financial markets are efficient (i.e. that current stock prices fully reflect all publicly available information), it may be proper to avoid using long-term historical prices

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[411] *Id.* at 42.
[412] *Id.*
[413] *Id.* at 42-43.
[414] *Id.* at 43.
[415] *Id.* at 57-58.

> that may reflect irrelevant information and result in biased dividend yields. In the Department's view, the use of 90- and 180-day average dividend yields may "create a mismatch between such dividend yields and more recent projected growth rates."[416]
>
> b. The Department also disagreed with the Company's decision to assign 80 percent weight to the results for its XECG and only 20 percent weight to the results for its XCCG. As long as the investment risks for the XECG and XCCG groups are similar and as long as the companies in both groups operate under similar economic and regulatory environments, the Department indicated that there should not be a significant difference between the weights assigned to the estimated ROEs for the two groups.[417] The Department further noted that Value Line lists all of the companies included in the Company's XECG and XCCG groups as electric utilities. Moreover, the Department noted the similarity in the definitions of SIC 4911 (Electric Services) and SIC 4931 (Electric and Other Services Combined), and asserted that three of the companies in the Company's XCCG are classified as electric utilities under SIC 4911. As a result, the Department argued that investors may not view companies in the XECG and the XCCG groups as being significantly different from each other.[418]

305. The Department adjusted the Company's DCF analysis for its XECG and XCCG by using only the Company's 30-day average dividend yield. This resulted in ROE ranges (including flotation costs) of 9.44 percent to 10.90 percent, with an average of 10.18 percent, for the XECG. For the XCCG, it resulted in ROE ranges of 9.06 percent to 10.21 percent, with an average of 9.63 percent.[419] Using the Department's weighted average of 60/40 for the XECG and XCCG groups, respectively, the required rate of return would be 9.96 percent. This result is only 16 basis points higher than the Department's initial recommended ROE of 9.80 percent.[420]

306. In addition to having concerns with the Company's DCF analysis, the Department raised concerns about the Company's CAPM analysis included in its Direct Testimony.[421]

307. Finally, the Department disagreed with the Company's Bond Yield Plus Risk Premium analysis[422]

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[416] *Id.*
[417] *Id.* at 59.
[418] *Id.* at 61.
[419] *Id.* at 59.
[420] *Id.*
[421] *Id.* at 62-66.
[422] *Id.* at 67-68 (Amit Direct).

d. The Company's Updated ROE Analysis

308. In Rebuttal Testimony, the Company updated all of the ROE analyses presented in its Direct Testimony with data as of May 30, 2014, and found that the updated results were quite consistent with the earlier results. Based on these results and other factors discussed below, the Company continued to recommend a 10.25 percent ROE, and ROE range of 10.00 percent to 10.70 percent.[423]

309. In conducting its updated DCF analysis, the Company again relied on the constant growth DCF model with the Two Growth DCF approach to moderate the effects of substantially high or low growth rate estimates. The Company revised its XECG and its XCCG based on updated data using the same screening criteria as it used in its initial DCF analysis. Due to pending transactions, the Company excluded Pepco Holdings Inc. and UniSource Energy Corp. from its revised XECG, and it excluded CenterPoint Energy Inc., Dominion Resources Inc., and UIL Holdings Corp. from its revised XCCG. In addition, the Company added Hawaiian Electric Industries Inc. to its revised XECG and added Sempra Energy to its updated XCCG because their mean expected rates of return now exceeded 8.00 percent. The Company also excluded Empire District Electric Co. from its revised XECG because its mean expected rate of return was less than 8.00 percent.[424]

310. The results of the Company's DCF analysis for its updated XECG, including an adjustment for flotation costs, are summarized below:[425]

Table 5

	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%
Revised Combined Proxy Group Results			
30-Day Average	8.93%	9.70%	10.45%
90-Day	9.05%	9.82%	10.57%

[423] Ex. 28 at 2, 54-57 (Hevert Rebuttal).
[424] *Id.* at 54-55 (Hevert Rebuttal).
[425] *Id.* at 56, Table 1, Schedule 1.

	Low Growth Rate	Mean Growth Rate	High Growth Rate
Average			
180-Day Average	9.20%	9.97%	10.72%
Weighted Average Results (80% Revised Electric / 20% Revised Combination)			
30-Day Average	9.02%	9.92%	11.03%
90-Day Average	9.09%	9.98%	11.10%
180-Day Average	9.12%[426]	10.01%	11.13%

311. The Company also updated its CAPM analysis. In doing so, the Company used the same inputs described in its Direct Testimony, updated through May 30, 2014. Based on updated market information, its CAPM analyses produced a range of ROE estimates from 10.65 percent to 13.13 percent. The Company did not place any specific reliance on its CAPM results but used it to corroborate the results of its DCF analysis.[427]

312. The Company's updated Bond Yield Plus Risk Premium analysis included authorized ROEs as reported by Regulatory Research Associates through May 30, 2014. To calculate the expected risk premium and ROE, it used the current and projected 30-year Treasury yield. Its updated result was 10.16 percent to 10.77 percent. As with the CAPM analysis, it used the Bond Yield Plus Risk Premium analysis to corroborate the results of its DCF analysis.[428]

313. After considering its updated results, the Company continued to recommend a 10.25 ROE. The Company maintained that the 80/20 weighting of the XECG and XCCG is still warranted because over 90 percent of the Company's operations relate to electric service and the XECG companies have a similar proportion of electric service.[429] In addition, the Company continued to emphasize the need to take into consideration the Company's substantial capital investment plans and the implications for investors. Based on these factors and the consistency of the original and updated results, the Company recommended that the Commission adopt a ROE of 10.25 percent.[430]

[426] Mr. Hevert's Schedule 1 shows the 180-day low growth rate weighted average to be 9.12 percent even though both the FECG and FCCG proxy group results for the low-growth rate were 9.20 percent. *See* Ex. 28, Schedule 1 (Hervert Rebuttal).
[427] Ex. 28 at 56, Schedule 4 (Hervert Rebuttal).
[428] Ex. 28 at 56, Schedule 5 (Hervert Rebuttal).
[429] Ex. 28 at 4, 18-23, 57 (Hervert Rebuttal).
[430] *Id.* at 57.

e. The Company's Response to the Department's Initial ROE Analysis

314. In Rebuttal Testimony, the Company also compared its ROE analysis with the Department's ROE analysis.[431]

315. The Company noted that its updated DCF results were similar to the results presented in the Department's Direct Testimony. The Company asserted that the areas of disagreement are narrow in scope, and that the differences in their ROE recommendations related to a difference in judgment rather than a material difference in their data or analyses.[432]

316. According to the Company, the main areas of disagreement with the Department regarding the ROE analyses involve: (1) the appropriate weight to be given to the results of the electric and combination proxy groups; (2) the screening criteria and proxy group selection; (3) certain elements of the CAPM analyses; and (4) the application of the Bond Yield Plus Risk Premium analysis.[433]

317. The Company noted that the most significant area of disagreement is the appropriate weight to be given to results of the proxy groups.[434] The Company used an 80/20 weighting of its electric and combination proxy group DCF results and the Department used a 60/40 weighting.[435] The Company maintained that its weighting is more reasonable because 91.67 percent of the Company's net income comes from electric service. The Company noted that the average net income from electric service of companies in the Department's FECG is 90.00 percent, whereas the average net electric service income of companies in the Department's FCCG is 78.39 percent. For that reason, the Company asserted that no less than 80 percent weight should be applied to the electric proxy group.[436]

318. With regard to screening criteria and proxy group selection, the Company noted some differences in approach, such as the Department's use of certain SIC codes. On the other hand, there were also a number of similarities in the criteria used by the two parties. As a result, the Company concluded that the approaches used by the Department and the Company were sufficiently comparable and the differences did not materially affect the results of their analyses.[437]

319. The next area where the Company and the Department were not in complete agreement was the CAPM analysis. The Company noted two main

[431] The Company's responses to the testimony of the ICI Group, the Commercial Group and the AARP on ROE are discussed in separate sections below.
[432] Ex. 28 at 1-2 (Hevert Rebuttal).
[433] *Id.* at 18.
[434] *Id.* at 4.
[435] *Id.* at 18.
[436] *Id.* at 18-21.
[437] *Id.* at 23-26.

differences in their respective CAPM analyses: (1) the term of the Treasury security used as the risk-free rate component of the model; and (2) the calculation of the Market Risk Premium. The Company maintained that the different approach used by the Department in these two areas has the effect of understating its CAPM results.[438]

320. The Company also disagreed with the Department's criticism of its Bond Yield Plus Risk Premium analysis, and asserted that it provides a meaningful quantification of the relationship between Treasury yields and the cost of equity.[439]

321. Finally, the Company also disputed the Department's claim that the Company is somewhat less risky for investors than the Department's proxy groups, and concluded that no adjustment to the ROE should be made on this basis.[440]

f. The Department's Updated ROE Analysis

322. In Surrebuttal Testimony, the Department updated its initial ROE analysis using more current closing prices and more recent projected growth rates based on its view that "it is important to use the most recently available dividend yields when relying on a DCF analysis."[441] The Department used the same methodology and sources of information in calculating the updated ROE as it had used in calculating the initial recommended ROE.[442]

323. In its updated analysis, the Department included Hawaiian Electric Industries Inc. in its revised FECG because the company's mean expected rate of return, based on updated information, exceeded 8.00 percent.[443] The Department also excluded Empire District Electric Co. (stock symbol EDE) from the FECG because its mean expected rate of return was less than 8.00 percent. In addition, the Department excluded Pepco Holdings Inc. because it was in the process of being acquired by Excelon Corp., and UIL Holdings Corp. because it was in the process of being purchased by Philadelphia Gas Work. The Department's revised FECG consisted of the remaining eight companies.[444]

324. In its revised FCCG, the Department included one additional company, Amern Corp. because its mean rate of return exceeded 8.00 percent. As a result, the Department's revised FCCG consisted of 15 companies.[445]

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[438] *Id.* at 27-29.
[439] *Id.* at 29-32, Chart 5.
[440] Ex. 28 at 12-17 (Hevert Rebuttal).
[441] *See* Ex. 403 at 1 (Amit Surrebuttal)
[442] *Id.* at 2-7 (Amit Surrebuttal).
[443] *Id.* at 2.
[444] *Id.*
[445] *Id.*

325. Based on the Department's updated analysis, the Department recommended a ROE of 9.64 percent for the Company.[446] This recommendation is 16 basis points lower than its initial recommendation of 9.80 percent.[447]

326. The Department calculated updated dividend yields using the closing prices from the most recently available 31 calendar days (June 7, 2014 to July 7, 2014). The updated average dividend yields for the revised FECG and revised FCCG were 3.60 percent and 3.84 percent, respectively. As in the initial analysis, these dividend yields include an increase by one half of the expected growth rates to account for the fact that companies in these groups may raise their dividend rates in different quarters.[448]

327. For consistency, the Department also updated the expected growth rates used in its DCF analysis for the FECG and FCCG groups based upon the average of the most recently-available Zacks, First Call, and Value-Line projected EPS growth rates, following the same methodology described in Dr. Amit's prefiled Direct Testimony.[449] The updated expected growth rates are summarized below:[450]

Table 6

Updated Expected Growth Rates

Group	Low Expected Growth Rates	Mean Expected Growth Rates	High Expected Growth Rates
FECG	5.25%	6.19%	7.33%
FCCG	4.98%	5.73%	6.43%

328. As in its initial analysis, the Department substituted the Two Growth DCF analysis for the constant growth DCF analysis for companies whose mean expected growth rates deviated from the group's mean expected growth rates by more than one standard deviation. Due to the change in the expected growth rates, the Two Growth DCF method was applied to two companies in its updated analysis: PNM Resources Inc. and Pinnacle West Capital Corp.[451]

329. The results of the Department's updated analysis, as adjusted for flotation costs, are summarized below:[452]

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[446] *Id.*
[447] *Id.*
[448] *Id.* at 3, EA-SR-1, EA-SR-5 (Amit Surrebuttal).
[449] Ex. 403 at 3-4, EA-SR-4, EA-SR-5 (Amit Surrebuttal).
[450] Ex. 403 at 4, Table 1, EA-SR-1, EA-SR-5 (Amit Surrebuttal).
[451] Ex. 403 at 6, Table 3, and EA-SR-5 (Amit Surrebuttal).
[452] Ex. 403 at 6 (Amit Surrebuttal).

Table 7

Updated DCF/TGDCF Results

Group	Low	Mean	High
FECG	8.90%	9.72%	10.59%
FCCG	8.90%	9.52%	10.09%

330. The Department again assigned a weight of 60 percent to the FECG results and 40 percent to the FCCG results. Based on this weighting of its updated results, the Department concluded that a reasonable ROE for the Company ranges from a low of 8.90 percent (0.6 x 8.90% + 0.4 x 8.90%) to a high of 10.39 percent (0.6 x 10.59% + 0.4 x 10.09%), with a midpoint of 9.64 percent (0.6 x 9.72% + 0.4 x 9.52%). The Department recommended the midpoint, 9.64 percent, as the ROE for the Company.[453]

331. The Department also updated its CAPM estimates by using the most recently-available betas from the Value Line Investment Survey (May, June 2014) and the June 2014 daily average of the yield on 20-year Treasury bonds. It also used a 9.77 percent projected growth rate for the S&P 500 Index and a 1.89 percent dividend yield based on information as of July 15, 2014. It determined that the required market rate of return on the S&P 500 is 11.75 percent. Its updated CAPM estimates, including flotation costs, were 10.05 percent for the FECG and 9.55 percent for the FCCG.[454]

332. The Department calculated the average weighted CAPM to be 9.85 percent, using a 60/40 weighting of its FECG and FCCG results. The Department concluded that, when using expected risk premiums, the CAPM was useful in confirming the reasonableness of its DCF estimates for the required ROE for the Company.[455]

333. In its Surrebuttal Testimony, the Department addressed the updated DCF analysis contained in the Company's Rebuttal Testimony. The Department noted the same areas of disagreement with the Company's analysis as it discussed in Direct Testimony.[456] With regard to the weighting of the proxy groups, the principal area of disagreement, the Department reiterated that the companies in its FCCG have similar investment risk to companies in its FECG. The Department asserted that it is overall investment risk, not the percentage of income received from electric operations, that should be used to determine the appropriate ROE for the Company. For these reasons,

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[453] *Id.* at 6-7.
[454] *Id.* at 7-8.
[455] *Id.* at 8.
[456] *Id.* at 19.

the Department asserted that its proposed 60/40 weighting of the FECG and FCCG continues to be appropriate.[457]

334. The Department modified the Company's updated DCF analyses by: using only the 30-day period; using more recent prices and growth rates; and updating its Two Growth DCF analysis where appropriate. The Department's update of the Company's DCF resulted in a mean ROE of 9.63 percent for the XECG and 9.43 percent for the XCCG, including a 12 point flotation cost adjustment. If the Company's proposed weights of 80/20 percent are used, the resulting ROE is 9.59 percent, including flotation costs. If the Department's 60/40 weighting is used, the resulting ROE is 9.55 percent, including flotation costs. These results are close to the Department's recommended ROE of 9.64 percent.[458]

335. The results of the Department's updated DCF analyses for its comparison groups and the Company's comparison groups are summarized below:

Table 8 - ROE

Group	Low	Mean	High
Electric			
Department (FCCG)	8.90%	9.72%	10.59%
Company (XCCG)	8.79%	9.63%	10.67%
Combination			
Department (FCCG)	8.90%	9.52%	10.09%
Company (XCCG)	8.82%	9.43%	10.00%
Weighted (60/40)			
Department (FCCG)	8.90%	9.64%	10.39%
Company (XCCG)	8.80%	9.55%	10.40%

The Department concluded that the above updated DCF results confirmed the reasonableness of its recommended 9.64 percent ROE for the Company.[459]

[457] *Id.* at 16-17.
[458] *Id.* at 19-20, 22.
[459] *Id.* at 22.

g. The ICI Group's ROE Analysis

336. The ICI Group proposed a ROE of 9.0 percent. The ICI Group recommended a 9.0 percent ROE based on its DCF results and a review of ROE decisions in other jurisdictions.[460]

337. The ICI Group took a different approach to the DCF analysis than the Department and the Company. The ICI Group conducted four different DCF analyses: a Dividend Growth DCF analysis; an Earnings Growth DCF analysis; a Sustainable Growth (2014) DCF analysis; and a Sustainable Growth (Future) DCF analysis.[461]

338. The ICI Group used one proxy group instead of two proxy groups in conducting its analysis.[462]

339. The ICI Group selected a proxy group of companies starting with the companies that Value Line classifies as electric utilities. The ICI Group did not include Xcel Energy Inc. in its group of comparable utilities because it concluded that including Xcel would introduce an element of circularity into its calculations. The ICI Group then applied the following screening criteria:

a. Excluded companies that were not expected by Value Line to enjoy earnings and/or dividend growth during the period studied;

b. Excluded companies that had not paid dividends consistently for the past three calendar years;

c. Excluded companies that were currently known to be involved in a merger; and

d. Excluded companies whose principal business was the transmission of electric power rather than the sale of electricity at retail.[463]

340. After applying these screens, 27 companies remained. These 27 companies constitute the proxy group used by the ICI Group to conduct its four DCF analyses.[464]

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[460] Ex. 250 at 15 (Glahn Direct).
[461] *Id.* at 21-23. The "Sustainable Growth" method is based on the theory that a firm's growth is a function of its expected earnings and the extent to which those earnings are retained and reinvested in the enterprise. To conduct this analysis, the ICI Group's multiplied each company's earnings retention percentage by its return on book equity. Ex. 28 at 37 (Hevert Direct); Ex. 250 at 22 (Glahn Direct).
[462] Ex. 250 at 19-23 (Glahn Direct); Ex. 402 at 6 (Amit Rebuttal).
[463] Ex. 250 at 17-18 (Glahn Direct).
[464] *See id.* at 23.

341. To estimate the current stock price of each company in its proxy group, the ICI Group used a three-month average of the month-end stock prices covering the period of March 2014 to May 2014.[465]

342. To estimate the expected dividend yield, the ICI Group multiplied the most recent declared dividend by four and then adjusted the resulting annual dividend by one-half of the sustainable dividend growth rate.[466]

343. To estimate the expected growth rate, the ICI Group used four different approaches, which resulted in the four different DCF analyses. These included:

a. Using Value Line's forecasted dividends to estimate dividend growth;

b. Using Value Line's forecasted earnings to estimate earnings growth;

c. Performing an analysis of sustainable dividend growth using estimated 2014 returns and retention ratios from Value Line; and

d. Performing an analysis of sustainable dividend growth using Value Line projections of future returns and retention ratios.

As indicated above, the ICI Group only used information from Value Line in conducting its analyses. It did not use information from Zacks or First Call.[467]

344. These four DCF analyses produced the following results:[468]

Table 9

Projection Method	Dividend Yield	Plus	Projected Growth	Equals	Return On Equity
Dividend Growth	3.6%		5.4%		9.0%
Earnings Growth	3.6%		4.8%		8.4%
Sustainable Growth (2014)	3.6%		4.1%		7.7%
Sustainable Growth (Future)	3.6%		4.3%		7.9%

345. The ICI Group did not add flotation costs to its results.[469]

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[465] *Id.* at 20, Schedule 2 (Glahn Direct).
[466] Ex. 250 at 19 (Glahn Direct).
[467] *Id.* at 20-22.
[468] *Id.* at 23.

346. Based on the results of these four DCF analyses for its proxy group, the ICI Group estimated that the Company's cost of equity ranges from 7.7 percent to 9.0 percent.[470] The ICI Group determined that a 9.0 percent ROE would be an appropriate level of return for the Company. The ICI Group noted that a 9.0 percent ROE is at the high end of the range produced by its estimates.[471]

347. In support of its position, the ICI Group pointed to ROE decisions in Maryland, Arkansas, and New York that occurred after the Company's November 2013 filing of the current rate case. Those decisions authorized ROEs ranging from 9.2 percent to 9.75 percent.[472]

348. The ICI Group did not perform a CAPM or Bond Yield Plus Risk Premium analysis to confirm the results of its DCF analysis. The ICI Group maintained that such analyses should not be used in this rate case because the extraordinary intervention in the debt markets by the Federal Reserve calls into question whether current interest rates can be relied upon as reflective of true market conditions.[473]

349. The ICI Group also expressed concerns about the DCF analyses performed by the Company and the Department. First, the ICI Group maintained that it is not appropriate to include an adjustment for flotation costs in the DCF analysis because Xcel Energy Inc. will not be selling common shares to finance electric utility operations or investments during the period in which rates are expected to be in effect.[474] Second, the ICI Group questioned the Department's and Company's elimination of companies with DCF results that fall below an 8.0 percent threshold. The ICI Group disagreed with the Department's assertion that these companies are not financially viable, noting that these companies continue to have shareholders and continue to pay dividends.[475]

h. Responses to the ICI Group's ROE Analysis

350. The Company and the Department both disagreed with the ICI Group's recommended ROE and the ICI Group's approach to calculating its recommended ROE.

351. The Company identified several problems in the ICI Group's ROE analysis. First, the Company disagreed with the ICI Group's screening criteria and the method by which it applied its screens. The Company maintained that the weaknesses in the ICI Group's method resulted in a proxy group that is not sufficiently comparable to

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[469] *See id.* at 22, 25.
[470] *Id.* at 23.
[471] *Id.*
[472] Ex. 250 at 23-24 (Glahn Direct).
[473] *Id.* at 25.
[474] *Id.*
[475] Ex. 251 at 5 (Glahn Surrebuttal).

the Company to provide reliable results.[476] The Company asserted that the ICI Group's failure to select a comparable proxy group alone is sufficient reason to give no weight to the ICI Group's analysis.[477]

352. Second, the Company asserted that the ICI Group's ROE analysis is not reliable because the ICI Group relied on a single approach (the constant growth DCF model) and used a single source of data (Value Line). The Company maintained that relying on a single approach and using only Value Line data can lead to flawed or misleading results.[478] The Company noted that both the Company and Department used the Two Growth DCF model along with the constant growth DCF model, and also used data from multiple sources (First Call, Zacks, and Value Line). In addition, both performed a CAPM analysis to confirm the results of their DCF/Two Growth DCF analyses. The Company also performed a Bond Yield Plus Risk Premium Analysis.[479]

353. Third, the Company stated that the sustainable dividend growth approach used by the ICI Group to determine the expected growth rate in two of its four DCF analyses is not analytically sound.[480] For example, the model used by the ICI Group does not provide for growth funded from external equity. As a result, the ICI Group's approach biases the expected growth rate (and therefore the DCF estimate) downward. In addition, according to the Company, historical market data and independent research do not support the principal assumption of the model used by the ICI Group, namely that increased earnings retention ratios are directly and positively related to futures earnings growth. The Company also noted that the sustainable dividend growth approach has not been accepted by the Commission in any prior rate case.[481]

354. Finally, the Company asserted that the ICI Group's recommended ROE of 9.00 percent cannot be "reasonably corroborated by, or reconciled with observable and relevant data." The Company maintained that the ICI Group's discussion of recent ROE decisions in other jurisdictions is biased because it fails to mention nine (9) other recent ROE decisions in other jurisdictions, where a ROE of 10.00 percent or higher was authorized.[482]

355. The Department also raised a number of concerns with the ICI Group's ROE analysis. Like the Company, the Department asserted that the ICI Group's selection of companies for its comparison group was not reasonable. The Department noted that the ICI Group failed to follow its own screening criteria when it eliminated

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[476] Ex. 28 at 34-35 (Hevert Rebuttal); Ex. 250, Schedule 3 (Glahn Direct).
[477] Xcel Initial Br. at 28-29.
[478] Ex. 28 at 33-36 (Hevert Rebuttal).
[479] *Id.*
[480] *Id.* at 37 (citation omitted).
[481] Xcel Initial Br. at 29.
[482] Ex. 28 at 32 (Hevert Rebuttal).

companies with positive projected earnings and/or dividend growth.[483] In addition, the ICI Group included four companies that are involved in significant restructuring.[484]

356. The Department also maintained that the ICI Group's DCF analyses were not reliable because, among other reasons: 1) there is a mismatch between the expected growth rate applied to the dividend yield and the expected growth rate used for the expected growth rate component of the DCF, with one exception; 2) all of the DCF analyses include several companies with unreasonably low ROEs, significantly lower than eight percent; 3) short-term rather than long-term expected growth rates were used; 4) the ICI Group substituted its own calculation of the projected dividend per share growth rates for Value Line's projected five-year dividend per share and earnings per share growth rates; and 5) the ICI Group failed to include flotation costs.[485] For these reasons, the Department concluded that the ICI Group's DCF results are without merit.

i. Position of the Commercial Group and Responses

357. The Commercial Group argued that the record demonstrates that the 10.25 percent ROE recommended by the Company is "unreasonably high."[486] The Commercial Group also claimed that the 9.64 percent ROE recommended by the Department is "generally consistent with investor expectations, and may in fact be overly generous toward NSP."[487]

358. The Commercial Group urged the Commission to consider the ROEs authorized in other jurisdictions from 2012 through May 2014 in evaluating the appropriate ROE for the Company. It emphasized that, according to SNL Financial, a financial news and reporting company, the average ROE awarded for vertically integrated utilities from 2012 through May 2014 has declined from 10.1 percent in 2012 to 9.84 percent in 2014.[488] The Commercial Group also noted that interest rates have fallen in the one-year period since the Company first performed its ROE analysis for this case, and, as the Company has acknowledged, changes in the cost of equity are directionally related to the changes in the level of interest rates.[489] On that basis, the Commercial Group asserted that the 9.84 percent figure for 2014 ROEs is a "significant yardstick data point and given the steady drop in interest rates this past year, [] the figure may need to be adjusted downward."[490]

359. The Commercial Group also argued that the Company's recommended ROE of 10.25 percent should be adjusted downward based on its analysis of how other

483 Ex. 402 at 2-6 (Amit Rebuttal); Tr. Vol. 3 at 117-134 (Glahn).
484 Ex. 402 at 2-6 (Amit Rebuttal).
485 *Id.* at 6-13.
486 Commercial Group Initial Br. 8.
487 *Id.* 9.
488 Ex. 225 at 8-9 (Chriss Direct).
489 *See* Ex. 226 at 1-2; Ex. 27 at 13 (Hevert Direct); Ex. 115 (Hevert Summary).
490 Commercial Group Initial Br. at 4-5.

state commissions have evaluated the recommendations of Mr. Hevert, the Company's REO expert, in similar proceedings.[491] The Commercial Group provided a table setting forth the results of 34 proceedings in which Mr. Hevert provided ROE testimony on behalf of a utility. The table shows that in each instance the authorized ROE was lower than the ROE recommended by Mr. Hevert. The table also shows that the authorized ROEs were, on average, 104 basis points lower than Mr. Hevert's recommended ROE.[492]

360. The Commercial Group maintained that several other factors also support a ROE at the low end of any reasonable range. Those factors relate to the Company's ratemaking structure, and include:

a. the use of a future test year;

b. the ability of the Company to implement an interim rate increase prior to the full examination of the rate filing;

c. the inclusion of Construction Work in Progress (CWIP) in rate base;

d. the multi year nature of this rate case, which would allow the Company to increase rates for costs it incurs beyond the 2014 test year; and

e. the proposed revenue decoupling mechanism.[493]

361. The Company responded that the Commercial Group expert, Steve W. Chriss, did not perform any independent, market-based analyses of the Company's cost of equity or perform a comparison of the Company's rate structures to those of other utilities.[494]

362. The Company noted that, based on the Commercial Group's approach, the average authorized ROE for vertically integrated utilities has been approximately 10.0 percent since 2012, which falls within the Company's recommended range. The Company emphasized that its currently authorized ROE falls in the bottom one-third of authorized ROEs for vertically integrated utilities since 2012 and moving downward to the Department's recommended 9.64 percent would put the Company in the bottom 20 percent of returns authorized since August 2013. The Company maintained this fact is important to consider in determining the Company's ROE in this case because the authorized ROE is "a very visible measure of the regulatory environment in which utilities operate. The regulatory environment, in turn, is important to utility analysts and investors."[495]

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[491] *Id.* at 5-6, Table 1.
[492] *Id.*
[493] *Id.* at 8-9; Ex. 225 at 6-7, 10-11 (Chriss Direct).
[494] Ex. 28 at 45 (Hevert Rebuttal).
[495] *Id.* at 45, 47; Xcel Reply Br. at 22.

363. The Company also disagreed with the Commercial Group's suggestion that the Company's ratemaking structures warrant a reduction in ROE. The Company asserted that it is important to review the use of ratemaking structures by other utilities to determine whether these structures are risk mitigating relative to the proxy companies, and indicated that the Commercial Group had not done so. The Company determined that seven of the 12 companies in its revised XECG were permitted to use forecasted test-years or partially forecasted test years in at least one regulatory jurisdiction. It also found that eight of the 12 companies in the group operate in one or more regulatory jurisdictions that allow CWIP to be included in the rate base or allow a cash return on CWIP for specified projects.[496]

364. The Department also disagreed with the Commercial Group's reliance on ROEs authorized in other jurisdictions. The Department asserted that reliance on such results is not analytically sound because the ROEs used by the Commercial Group in its analysis are based on outdated data.[497]

365. With regard to CWIP, the Department noted that the manner in which the Company is treating CWIP in this rate case is consistent with its treatment in past rate cases. The Department asserted that, to the extent that CWIP affects the required ROE, any such impact is already accounted for by investors in their ROE expectations. Therefore, in the Department's view, no additional adjustment in ROE is necessary.[498]

j. The Relationship between Decoupling and ROE

366. AARP asserted that decoupling shifts sales risk onto consumers and stabilizes a company's revenues. AARP maintained that the ROE should be adjusted downward to reflect this change in risk profile if decoupling is approved.[499] Specifically, AARP recommended that the ROE should be reduced by 10 basis points or set at the low end of the range of ROEs found to be reasonable if decoupling is approved.[500]

367. Similarly, as noted above, the Commercial Group asserted that approval of decoupling would justify a ROE at the lower end of the reasonable range.[501]

368. The Company, the Department, and the Clean Energy Intervenors disagreed. They all concluded that it is not reasonable to adjust the Company's ROE downward to recognize the impact of decoupling if approved.[502]

369. The Company asserted that a downward adjustment to ROE is not necessary to account for decoupling because the approval of a decoupling mechanism

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[496] Ex. 28 at 48-49 (Hevert Rebuttal).
[497] Ex. 402 at 15 (Amit Rebuttal).
[498] *Id.* at 16 (Amit Rebuttal).
[499] *Id.* at 21-22.
[500] Ex. 310 at 18, 21 (Brockway Direct); Ex. 311 at 2 (Brockway Rebuttal).
[501] Ex. 28 at 45 (Hevert Rebuttal).
[502] Ex. 403 at 26-28 (Amit Surrebuttal).

would not fundamentally alter the Company's risk profile relative to its peers. The Company emphasized that the relevant analytical issue is not the impact of decoupling on the Company's overall risk profile, but rather whether the Company would be materially less risky than its peers by virtue of the structure. The Company claimed that many of the companies in its comparison groups have partial or complete decoupling provisions combined with other revenue stabilization policies.[503] In addition, the Company estimated the beta of Pepco Holdings Inc., which has over 65 percent of its revenue subject to decoupling mechanisms, versus the companies in its two comparison groups and found the beta to be one. According to the Company, this indicates that Pepco's investment risk is similar to the investment risk of other electric utilities, notwithstanding its decoupling mechanisms.[504] The Company also pointed to a March 2014 Brattle Group study, which indicated that there is "no statistically significant evidence of a decrease in the cost of capital following adoption of decoupling."[505] A review of rate proceedings in which decoupling was authorized also showed that in the vast majority of cases, utility commissions have not made explicit adjustments to ROE in response to implementation of a decoupling mechanism. For these reasons, the Company concluded that no downward adjustment to ROE should be made if decoupling is approved.[506]

370. Likewise, the Department recommended no additional adjustment to ROE if decoupling is authorized. The Department asserted that the main issue is the Company's investment risk relative to the investment risk of companies in the comparison groups. The Department agreed that the Company has demonstrated that many of the utilities in its comparison groups have partial or full decoupling provisions combined with other various revenue stabilization policies. In addition, the Department pointed to the Brattle Group study, which it found to be sound, and Mr. Hevert's estimated beta for Pepco Holdings Inc. as further support for its position that no adjustment to the ROE is necessary if the Commission approves a decoupling mechanism for the Company. [507]

371. CEI also relied on the Brattle Group study to show that a downward adjustment to ROE is not warranted if the Commission approves decoupling. In addition, CEI pointed to an analysis done by the Washington Utilities and Transportation Commission on the issue in 2013, which concluded that there is no empirical evidence to show that decoupling reduces a utility's cost of equity.[508]

372. In response, AARP argued that the Brattle Group study is not reliable because the study did not distinguish between different types of decoupling and did not control for the possibility that other factors could affect the ROEs of the utilities covered

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[503] Ex. 27 at 51 (Hevert Direct).
[504] Ex. 28 at 40-51 (Hevert Rebuttal).
[505] *Id.* at 52.
[506] *Id.* at 53-54.
[507] *Id.* at 27-28.
[508] Ex. 290 at 5-6 (Cavanaugh Direct).

by the study.[509] In addition, AARP maintained that reliance on the estimated beta for Pepco Holdings Inc. is misplaced because there is no evidence that Pepco Holdings Inc. is a comparable proxy for the Company.[510] AARP also disputed the Company's claim that a number of companies in its comparison group have similar forms of decoupling. AARP asserted that the Company failed to demonstrate that the decoupling mechanisms of the proxy companies were comparable enough that equity investors would not take into account the presence of decoupling for the Company if approved.[511] Finally, AARP noted that a number of public utility commissions have ordered that the authorized ROE be reduced upon the implementation of a decoupling mechanism, or they have approved settlements in which such a reduction was made.[512]

k. ROE Conclusions and Recommendation

373. After carefully considering the evidence in the record and the arguments of the parties, the Administrative Law Judge recommends that the Commission approve a Return on Equity of 9.77 percent. The reasons for this recommendation are set forth below.

1. Analysis of Parties' DCF Results

374. Three parties to this case presented DCF analyses: the Company, the Department, and the ICI Group.

375. Both the Company and the Department followed generally accepted practices in developing their proxy groups and conducting their DCF analyses, including using a combination of the constant growth DCF model and the Two Growth DCF model.[513] In addition, each conducted a CAPM analysis as a check on their DCF analysis. The Company also conducted a Bond Yield Plus Risk Premium analysis.[514]

376. The ICI Group's DCF approach, on the other hand, suffers from a number of serious defects. First, the proxy group used by the ICI Group is not sufficiently comparable to the Company to be reliable.[515] For example, the ICI Group's proxy group includes companies involved in mergers or other significant transactions, and includes companies with substantial unregulated operations.[516] Second, even if the proxy group were sufficiently comparable, the ICI Group's DCF analyses are not analytically sound because the ICI Group relied on a single source of data, Value Line, for its growth

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[509] Initial Post-Hearing Brief of AARP (AARP Initial Br.) at 15-16; Ex. 311 at 16 (Brockway Rebuttal); Ex. 312 at 8 (Brockway Surrebuttal).
[510] Ex. 312 at 7 (Brockway Surrebuttal).
[511] AARP Initial Br. at 14; Ex. 310 at 21-22 (Brockway Direct); Ex. 27 at 51 (Hevert Direct).
[512] AARP Initial Br. at 16; Ex. 311 at 18 (Brockway Rebuttal).
[513] Ex. 27 at 18-39 (Hevert Direct); Ex. 28 at 2 (Hevert Rebuttal); Ex. 400 at 7-37 (Amit Direct); Ex. 403 at 1-8 (Amit Surrebuttal).
[514] Ex. 27 at 39-45 (Hevert Direct); Ex. 400 at 37-42 (Amit Direct). *See also* Tr. Vol. 3 at 117-134 (Glahn).
[515] Ex. 28 at 34-35 (Hevert Direct); Ex. 402 at 2-6 (Amit Rebuttal).
[516] Ex. 28 at 34-35 (Hevert Rebuttal); Ex. 402 at 4 (Amit Rebuttal); Ex. 250, Schedule 3 (Glahn Direct).

rates.[517] The ICI Group's reliance on Value Line alone is problematic because it "exposes the analysis to a degree of estimation error that can easily be mitigated by including other sources (such as Zacks and First Call)."[518] It is for that reason that both the Department and the Company relied on three sources: Value Line, Zacks, and First Call. Moreover, the ICI Group used a sustainable growth analysis to estimate the growth rate in two of its four DCF analyses. This approach has not been accepted by the Commission, is biased downward, and is based on questionable assumptions.[519] For these reasons, the Administrative Law Judge concludes that the ICI Group's DCF results are not reliable and should be given no weight in the determination of a reasonable ROE.

377. The DCF analyses of the Company and the Department, on the other hand, are generally analytically sound and their results warrant serious consideration in the determination of a reasonable ROE. As in the last rate case, there are two main differences in approach between the Company and the Department that affect the resulting recommended ROEs: (1) the weighting of the proxy group results; and (2) the time periods to be used for average stock prices.[520]

378. With regard to the weighting of the proxy group results, the Administrative Law Judge concludes that the Department's proposal to assign 60 percent weight to the electric comparison group results and 40 percent weight to the combination comparison group results is more reasonable than the 80/20 weighting proposed by the Company. First, both the electric and combination proxy groups were developed based on screening criteria that ensure the groups have similar investment risks to that of the Company.[521] Second, an analysis of the Department's two proxy groups, based on direct market-oriented risk measures, confirms that the proxy groups have similar investment risks to the Company. Therefore, it is appropriate to assign a 60/40 weighting.[522] Third, while the purpose of this proceeding is to set the Company's electric rates, it is important to recognize that the Company is a subsidiary of Xcel Energy Inc., which includes combined electric and gas operations. The 60/40 weighting is a more appropriate reflection of these facts. Finally, the 60/40 weighting is consistent with the Commission's decision in the last rate case, wherein both the Administrative Law Judge and Commission concluded that a 60/40 weighting was more reasonable than an 80/20 weighting.[523]

379. With regard to the time periods, the Company based its analysis on average prices over 30-, 90-, and 180-day periods. In contrast, the Department based

[517] Ex. 28 at 35 (Hevert Rebuttal).
[518] *Id*.
[519] *Id.* at 37; Ex. 402 at 10-111 (Amit Rebuttal).
[520] Ex. 400 at 57-61 (Amit Direct); Ex. 403 at 16-17 (Amit Surrebuttal); Xcel Reply Br. at 15; Department Initial Br. at 25-28.
[521] Ex. 27 at 19 (Hevert Direct); Ex. 400 at 8-10 (Amit Direct).
[522] Ex. 400 at 21-22, 42 (Amit Direct).
[523] 12-961 ORDER at 11-12; 12-961 REPORT at 82-83.

its analysis on a 30-day period only.[524] In addition, the Company calculated the dividend yields for its updated 30-day period analysis using the average prices over the period of May 1, 2014 to May 30, 2014, while the Department's updated dividend yields are based on the average prices over the more recent period of June 7, 2014 to July 7, 2014.[525]

380. Normally, more recent information will better reflect current market expectations regarding the expected ROE for the Company.[526] Use of a single, shorter time period for averaging, however, can lead to anomalous results.[527] The averaging period should be reasonably representative of expected capital market conditions over the long term.[528]

381. In the last case, the Administrative Law Judge recommended using the Department's Surrebuttal 30-day period for determining the ROE because that time period was sufficiently long and the Department's more recent data was a better reflection of current market expectations than the Company's older data.[529]

382. In this case, however, the Administrative Law Judge concludes that the record shows that the 30-day period used in the Department's Surrebuttal testimony may not be representative of the time period in which the ROE will remain in effect. More specifically, the record shows that the dividend yields used in the Department's Surrebuttal Testimony were significantly lower than the dividend yields used in its Direct Testimony, falling by 54 and 26 basis points, respectively, from the Department's initial analysis.[530] These decreased dividend yields were the result of unusually high stock prices during the June-July 2014 time period used in the Department's Surrebuttal Testimony. Since that time, utility stock prices have declined relative to the overall stock market and moved more in line with historic expectations.[531] As a result, the Department's updated 30-day dividend yields included in its Surrebuttal Testimony may reflect a short-term anomaly.[532]

383. Because the Company has proposed a MYRP and to minimize the potential effect of any market idiosyncrasies that may have contributed to the variability in the dividend yields, the Administrative Law Judge concludes that the authorized ROE should be based on data from more than just the one 30-day period used in the Department's Surrebuttal Testimony. Similar to the approach taken by the Commission

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[524] Ex. 443 at 2 (Amit Summary Statement).
[525] *Id.* at 1.
[526] *Id.* at 2-3; Ex. 400 at 57-58 (Amit Direct).
[527] *See* Ex. 27 at 32 (Hevert Direct).
[528] *Id.*
[529] 12-961 ORDER at 82.
[530] Ex. 115 at 2 (Hevert Opening Statement); *Compare* Exs. 402 at EA-13, EA-23 (Amit Direct Attachments) *with* 403 at EA-SR-1, EA-SR-5 (Amit Surrebuttal Attachments).
[531] Ex. 115 at 2 (Hevert Opening Statement). Dividend yields go down as stock prices go up under the DCF formula. *Id.*; Ex. 27 at 30-31 (Hevert Direct).
[532] Ex. 115 at 2 (Hevert Opening Statement).

in the recent MERC rate case, the Administrative Law Judge recommends that the Commission consider the DCF results from the three most recent 30-day time periods.[533] More specifically, the Administrative Law Judge recommends that the Commission consider the DCF results from: the 30-day period included in the Department's Direct Testimony (covering October 1-31, 2013); the 30-day period included in the Company's Rebuttal Testimony (covering May 1-30, 2014); and the 30-day period included in the Department's Surrebuttal Testimony (covering June 7-July 7, 2014).

384. Using the 30-day DCF results from the three analyses (Department Direct, Company Rebuttal, and Department Surrebuttal) and applying a weighting of 60/40 provides an estimated ROE of 9.77 percent. The calculation is set forth below:

Department Direct[534]	9.80%
Company Rebuttal [535]	9.86%
Department Surrebuttal[536]	9.64%
Total	29.30%
Divided by 3	
Average	9.77%

385. The reasonableness of a 9.77 percent ROE for the Company is confirmed by other evidence in the record. First, a 9.77 percent ROE is similar to the 9.85 ROE calculated by the weighted CAPM results provided in the Department's Surrebuttal Testimony.[537] In addition, the Company's need to access capital for its substantial capital investment plans strongly suggest that a 9.77 percent ROE is more reasonable than the 9.64 ROE recommended by the Department in Surrebuttal Testimony.[538] A 9.64 percent ROE could send a negative signal to potential investors because it is at the low end of ROEs approved since the beginning of 2014, whereas 9.77 percent reflects the average.[539] For these reasons, the Administrative Law Judge recommends that the Commission adopted a ROE of 9.77 percent, including flotation costs.[540]

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[533] *See* MERC ORDER at 41 (averaging of the Department's initial and updated DCF results).
[534] Ex. 400 at 2, 43 (Amit Direct).
[535] *See* Ex. 28, Schedule 1, pages 1 and 4 (showing the 30-day DCF results of 9.97 percent for the XECG and 9.70 percent for the XCCG; applying a 60/40 weighting produces a result of 9.86 percent).
[536] Ex. 403 at 4-7 (Amit Surrebuttal).
[537] *Id.* at 8.
[538] Ex. 115 at 3-4 (Hevert Opening Statement); Ex. 28 at 45-47 (Hevert Rebuttal).
[539] *See* Ex. 115 at 1, 4 (Hevert Opening Statement); Xcel Reply Br. at 21 (list which includes four ROE decisions since January 2014; 9.77 is the average of those four decisions); Ex. 28, Schedule 3 (Hevert Rebuttal).
[540] *See In the Matter of the Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 30-31 (June 9, 2014) ("2014 CPE Order") (noting

2. Proposed Adjustments to the ROE

386. Several parties suggested downward adjustments to the recommended ROE for various reasons. The Administrative Law Judge concludes that no downward adjustment to the recommended 9.77 percent ROE is necessary.

387. First, the ICI Group argued that flotation costs should be excluded from the ROE calculation. The Administrative Law Judge concludes that flotation costs are properly included even if no new issuances of securities are planned because flotation cost adjustments are made not only to reflect current or future financing costs, but also to compensate investors for costs incurred for past issuances. Failure to allow such an adjustment may deny the Company the opportunity to earn its return.[541]

388. Second, the Commercial Group asserted that there should be a downward adjustment if CWIP is included in rate base because CWIP shifts the risk from the Company to the ratepayers. The Commercial Group also maintained that the use of a future test year and the recovery of interim rates favor a lower ROE. The Administrative Law Judge concludes that no adjustment is necessary based on the inclusion of CWIP, the use of a future test year, or the recovery of interim rates because these are common practices in Minnesota rate proceedings. As such, investors would have already taken these practices into account.[542] In addition, a significant number of companies in the proxy groups use forecasted test years and include CWIP in rate base.[543]

389. Finally, AARP suggested that the recommended ROE be reduced by ten basis points if the Commission authorizes a revenue decoupling mechanism because decoupling stabilizes a company's revenues and shifts the sales risk onto consumers. As the Department and the Company correctly noted, however, the issue for establishing ROE is not whether decoupling reduces the Company's sales risk but rather how the Company's investment risk compares to that of other comparable companies with and without decoupling. The Company demonstrated that many of the companies in its proxy groups have some type of decoupling in place. Thus, its comparison groups already factor in decoupling. In addition, a Brattle Group study found that there is "no statistically significant evidence of a decrease in the cost of capital following adoption of decoupling."[544] Finally, the Company showed that Pepco Holdings Inc., which has decoupling in place for over 65 percent of its revenue, has a similar risk profile to other electric utilities. This analysis of Pepco Holdings Inc.'s risk profile indicates that decoupling does not measurability affect a utility's risk profile.[545]

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the Commission has historically relied heavily, but not exclusively, on the DCF results in determining the authorized ROE).

[541] Ex. 400 at 32 (Amit Direct); Ex. 402 at 11-12 (Amit Rebuttal).

[542] *See* Ex. 28 at 47-48 (Hevert Rebuttal); Ex. 402 at 16 (Amit Rebuttal).

[543] Ex. 28 at 48-49 (Hevert Rebuttal).

[544] *Id.* at 52.

[545] *Id.* at 40-51.

For these reasons, the Administrative Law Judge concludes that no downward adjustment is necessary if the Commission adopts a decoupling mechanism in this case.

390. In summary, for the reasons stated above, the Administrative Law Judge recommends that the Commission adopt a ROE of 9.77 percent.

ii. Capital Structure and Overall Cost of Capital (2014 and 2015 Step)[546]

391. Once the ROE and cost of debt are determined, the overall cost of capital or rate of return (ROR) is calculated.[547]

392. In order to calculate the ROR for the Company, it is necessary to determine the amount of long-term debt, short-term debt, and common equity held by the Company. These amounts, which are represented as dollar amounts and as percentages of the total capital, are referred to as the capital structure.[548]

393. A utility's capital structure provides the long-term structural foundation for the financing necessary to support its operations and capital investments.[549]

394. The Commission generally uses a reasonableness standard to evaluate a utility's capital structure.[550] In assessing whether a utility's actual capital structure is reasonable, the Commission considers: how the utility's debt and equity ratios compare to those of similarly-situated utilities; whether the utility's capital structure is an actual capital structure based on market forces or an internal accounting structure; whether the utility's capital structure supports long-term credit quality given the utility's capital investment forecast, future financing requirements, and the need to access public capital markets; and whether the utility's capital structure provides long-term cost benefits to customers.[551]

a. The Company's Proposed Capital Structure for 2014 Test Year

395. 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-

[546] Issue 12.
[547] As noted above, the Company and Department have reached agreement on the cost of long-term and short-term debt. For the 2014 test year, the parties have agreed that the short-term rate should be 0.62 percent and the long-term rate should be 4.90 percent. For the 2015 Step, the parties have agreed that the short-term rate should be 1.12 percent and the long-term rate should be 4.94 percent. Ex. 31 at 27-28, 29 (Tyson Rebuttal); Ex. 403 at 10 (Amit Surrebuttal). No other party provided testimony on the issue.
[548] Ex. 400 at 44 (Amit Direct).
[549] Ex. 30 at 7 (Tyson Direct),
[550] *Id.* at 7-8.
[551] *Id.* at 8.

term debt.[552] For the 2015 Step, the Company initially proposed a capital structure of 52.50 percent common equity, 45.63 percent long-term debt, and 1.87 percent short-term debt.[553] The Company provided testimony and schedules supporting its calculation for each component of the capital structure.[554]

396. The long-term debt component for the 2014 test year was calculated based on the average forecasted month-end balances for the 12-month period from January 2014 through December 2014, including scheduled retirements and forecasted long-term debt issuances during that period.[555] The short-term debt component was calculated based on the forecasted 12-month average of the month-end commercial paper balances over the same period (January through December 2014).[556] The common equity component was calculated based on the average of 13 month-end equity balances from December 2013 through December 2014.[557]

397. The methods used by the Company to calculate long-term debt, short-term debt, and common equity for the 2014 test year are consistent with the methods that were used in the Company's last rate case.[558]

398. The Company found that the proposed capital structure is comparable to that of other utilities. The Company's expert, Robert Hevert, calculated that the mean equity ratio of the operating utility subsidiaries of the XECG proxy group is 50.49 percent, with a range of 45.05 percent to 58.80 percent, and the mean equity ratio of the operating utility subsidiaries of the XCCG group is 52.33 percent, with a range of 45.84 percent to 60.41 percent.[559]

399. The Department's expert, Eilon Amit, compared the Company's proposed capital structure to his FECG's capital structure and S&P's credit criteria and concluded that the Company's proposed capital structure is reasonable.[560] Although the Company's proposed equity ratio is somewhat higher than the average equity ratio for the Department's FECG, the Department determined that it is still a reasonable equity ratio.[561]

400. The Department agreed that the Company's proposed calculations of the long-term debt, short-term debt, and common equity components for the 2014 test year

[552] *Id.* at 4.
[553] *Id.* at 4.
[554] *Id.* at 27-38 and GET-1, Schedules 6- 7, 10, and 12-14 (Tyson Direct).
[555] Ex. 30 at 27 and GET-1, Schedule 6 (Tyson Direct); Ex. 400 at 46 (Amit Direct).
[556] Ex. 30 at 30 and Schedule 7 (Tyson Direct); Ex. 400 at 46 (Amit Direct).
[557] Ex. 30 at 34 and Schedule 10 (Tyson Direct); Ex. 400 at 47 (Amit Direct).
[558] Ex. 30 at 28, 34 (Tyson Direct); Ex. 400 at 46, 47 (Amit Direct).
[559] Ex. 27 at 53 (Hevert Direct).
[560] Ex. 400 at 48 (Amit Direct).
[561] *Id.* at 50.

were appropriate and that the Company's proposed capital structure was reasonable, subject to updated calculations in the Company's Rebuttal Testimony.[562]

401. In its Rebuttal Testimony, the Company provided updated information relating to the long-term debt, short-term debt, and common equity components of its proposed 2014 capital structure.[563] The updated information included, among other things:

- The actual cost of short-term debt and the actual short-term debt daily balances for January through April 2014;
- Revised projected short-term debt interest rates for May through December 2014;
- The actual 4.125 percent interest rate on the $300 million, 30-year first mortgage bonds that were issued on May 13, 2014;
- A combined debt ratio of 47.50 percent including a minimal decrease to the 2014 long-term debt balance and a corresponding increase to the updated 2014 short-term debt balance and ratio; and
- The Company's common equity ratio of 52.50 percent.[564]

402. Based on the updated information, the revised calculation of the capital structure for the 2014 test year is:

- 52.50 percent common equity;
- 45.60 percent long-term debt; and
- 1.90 percent short-term debt.[565]

403. In its Surrebuttal Testimony, the Department agreed with the updated capital structure and the updated costs of short- and long-term debt.[566]

404. At the time the Company filed its Rebuttal Testimony, it continued to propose the use of the same capital structure set forth in its Direct Testimony.[567] During the hearing, however, the Company agreed to incorporate the updated cost of debt in its

[562] *Id.* at 46-51.
[563] Ex. 31 at 25-28 and GET-2, Schedules 3 and 5 (Tyson Rebuttal).
[564] Ex. 31 at 25-26 (Tyson Direct).
[565] Ex. 31, GET-2, Schedule 3 (Tyson Rebuttal); Ex. 403 at 9 (Amit Surrebuttal).
[566] Ex. 403 at 9-10 (Amit Surrebuttal).
[567] Ex. 31 at 25, 28 (Tyson Rebuttal).

final revenue requirement.[568] As a result, the Company and the Department are in agreement that the Company's capital structure, as updated in the Company's Rebuttal Testimony, is reasonable and appropriate for test year 2014.

b. The Company's Proposed Capital Structure for the 2015 Step

405. As noted above, the Company initially proposed a capital structure for the 2015 Step of 52.50 percent common equity, 45.63 percent long-term debt, and 1.87 percent short-term debt.[569]

406. The Company's proposed 2015 Step capital structure is generally comparable to the proposed 2014 capital structure.[570] The proposed 52.50 percent equity ratio is the same.[571] The 45.63 percent long-term debt ratio is slightly higher than the 45.61 percent ratio for the 2014 test year and takes into account a projected $500 million long-term debt issuance by the Company in August 2015 that is expected to be outstanding for five months during 2015.[572] The proposed 2015 Step short-term debt ratio of 1.87 percent is slightly lower than the 1.89 percent ratio for the 2014 test year and takes into account the Company's anticipated issuance of commercial paper to meet its working capital requirements and higher projected short-term interest rates during 2015.[573]

407. The Company used the same methodology to calculate its proposed 2015 short-term debt, long-term debt, and common equity components as it did for 2014, and the proposed 2015 debt and equity ratios were essentially the same as those proposed for 2014.[574]

408. The Company's proposal to base its 2015 Step rate increase request on a different capital structure, using different costs of short- and long-term debt than it used for its 2014 rate increase request, is consistent with the Commission's MYRP ORDER.[575]

409. The Department agreed that the Company's proposed 2015 Step capital structure was reasonable, subject to review of updated information provided by the Company in Rebuttal Testimony.[576]

410. In its Rebuttal Testimony, the Company provided updated information relating to the long-term debt, short-term debt, and common equity components of its

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[568] Tr. Vol. I at 104-106; Ex. 116 at 1-2 (Tyson Opening Statement).
[569] Ex. 30 at 4 (Tyson Direct).
[570] *Id.* at 35.
[571] *Id.*
[572] *Id.* at 36.
[573] *Id.* at 36-37.
[574] Ex. 400 at 55-56 (Amit Direct).
[575] *Id.* at 53-54; *see* MYRP Order at 12.
[576] Ex. 400 at 55-56 (Amit Direct).

proposed 2015 Step capital structure.[577] The updated information included, among other things:

- Revised projected short-term debt interest rates for 2015;
- The 2015 cost of long-term debt resulting from the actual lower cost for the May 2014 issuance, along with an updated forecast of the cost of the $500 million long-term debt issuance projected for August 2015; and
- The Company's average common equity ratio of 52.50 percent.[578]

411. Based on the updated information, the revised calculation of the capital structure for the 2015 Step is:

- 52.50 percent common equity;
- 45.61 percent long-term debt; and
- 1.89 percent short-term debt.[579]

412. In its Surrebuttal Testimony, the Department agreed that the updated 2015 capital structure and the updated costs of short- and long-term debt are reasonable.[580]

413. As noted above, the Company agreed during the hearing to incorporate the updated cost of debt in its final revenue requirement.[581] As a result, the Company and the Department are in agreement that the Company's capital structure, as updated in the Company's Rebuttal Testimony, is reasonable and appropriate for the 2015 Step as well as for test year 2014.

c. Objections of the ICI Group

414. The ICI Group is the only party that has objected to the Company's proposed capital structure. The ICI Group asserted that the Company is an "accounting fiction, an entry on the books" of its parent company, Xcel Energy Inc. (XEI).[582] It recommended that the Commission limit the amount of common equity that the Company may include in its capital structure to the actual amounts employed by its

[577] Ex. 31 at 28-30 and GET-2, Schedules 7-9 (Tyson Rebuttal).
[578] Ex. 31 at 28 and Schedule 7 (Tyson Rebuttal); Ex. 403 at 29 (Amit Surrebuttal).
[579] Ex. 31, GET-2, Schedule 7 (Tyson Rebuttal); Ex. 403 at 29 (Amit Surrebuttal).
[580] Ex. 403 at 9-10 (Amit Surrebuttal).
[581] Tr. Vol. I at 104-106; Ex. 116 at 1-2 (Tyson Opening Statement).
[582] Ex. 251 at 6 (Glahn Surrebuttal).

parent company, Xcel Energy Inc., as projected by Value Line: 47.5 percent in 2014 and 49.0 percent in 2015.[583]

415. Both the Company and the Department expressed strong disagreement with the ICI Group's recommendation.

416. The Company emphasized that it is a Minnesota corporation, which is a separate legal entity from its parent, Xcel Energy Inc.,[584] and has its own separate capital structure apart from Xcel Energy Inc.[585] The Company issues its own long-term debt and its common equity represents its accumulated retained earnings plus any net infusion of common equity capital from Xcel Energy Inc. to the Company.[586] The Company reports its capital structure in its own separate SEC filings.[587] Various credit ratings agencies, such as S&P's, Moody's Investor Services, and Fitch Ratings, assign credit ratings to the Company as a corporate entity and to each of its individual bonds as they are issued.[588]

417. The Company asserted that the Company's capital structure is "an actual, market-based capital structure."[589] When planning and managing the capital structure for the Company, the Company considers a number of factors including: credit rating evaluations that reflect rating agency assessments of the Company's business and financial risk; the Company's position in relation to its long-term construction cycle and the scale of its capital investments relative to earnings; the capital structures of other utilities; the long-term stability of the capital structure in relation to the long life of the Company's asset investments; the current macroeconomic outlook and associated risk factors; and the need to manage the maturities of long-term debt to avoid excessive refinancing risk exposure.[590]

418. The Company argued that it finances its operations based on a target equity range of 52.00 percent to 53.00 percent, and does not finance its capital investments according to Value Line's projections of common equity and long-term debt at the parent company level.[591] Moreover, the Company pointed out that Value Line does not include short-term debt in its projections but the Company's proposed capital structure does.[592]

419. The Department asserted that the ICI Group's proposal to use XEI's capital structure as projected by Value Line fails to recognize that the Company has its

[583] Ex. 250 at 26 (Glahn Direct); Ex. 251 at 4-6 (Glahn Surrebuttal).
[584] Ex. 400 at 45 (Amit Direct).
[585] Ex. 30 at 9 (Tyson Direct); Ex. 400 at 45 (Amit Direct).
[586] Ex. 402 at 14 (Amit Rebuttal).
[587] Ex. 30 at 9 (Tyson Direct); Ex. 31 at 5 (Tyson Rebuttal); Ex. 400 at 45 (Amit Direct).
[588] Ex. 30 at 9 (Tyson Direct); Ex. 31 at 5 (Tyson Rebuttal); Ex. 400 at 45 (Amit Direct).
[589] Ex. 30 at 8-9 (Tyson Direct); Ex. 31 at 5 (Tyson Rebuttal).
[590] Ex. 30 at 9-12 (Tyson Direct); Ex. 31 at 6-8 (Tyson Rebuttal).
[591] Ex. 28 at 42 (Hevert Rebuttal).
[592] *Id.*

own capital structure and "violates basic financial and economic principles."[593] The Department pointed out that XEI has its own independent capital structure, which reflects XEI's investment risk, and noted that XEI's investment risk may be somewhat different than the Company's investment risk.[594] During the hearing, the Department maintained that the ICI Group's proposed capital structure for the Company "is inconsistent with the basic regulatory principle that [the Company] is allowed to recover all its prudent costs of providing service."[595]

d. Capital Structure Conclusions and Recommendation

420. After careful consideration of the evidence in the record and the arguments of the parties, the Administrative Law Judge recommends that the Commission approve the Company's proposed capital structure, as updated in Rebuttal Testimony, for the 2014 test year and the 2015 Step.

421. The Company's proposed capital structure, as updated, has been shown to be reasonable and appropriate for the reasons set forth below.

422. First, the Company's capital structure is generally consistent with the capital structures of other utilities, both at the operating subsidiary level as analyzed by the Company,[596] and at the parent company level as analyzed by the Department.[597] To the extent that the Company's equity ratio is slightly higher than the averages of the groups analyzed, that is justified by the Company's significant capital expenditures of approximately $7.6 billion in its combined gas and electric utility business from 2005 to 2012.[598]

423. Second, the methodology the Company used to calculate the components of the proposed capital structure (long-term debt, short-term debt, and common equity capital) is consistent with that used in the Company's previous rate case,[599] and the actual capital structure the Company proposed for 2014 is generally comparable to the capital structure approved by the Commission in the Company's last rate case.[600] In addition, the proposed 2015 capital structure is generally comparable to the proposed 2014 capital structure.[601]

424. Finally, the ICI Group's assertion that the Company is merely "an accounting fiction" has no factual support in the record. To the contrary, the record demonstrates that the Company has an actual and market-based capital structure that

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[593] Ex. 402 at 14 (Amit Rebuttal).
[594] *Id.* at 14 (Amit Rebuttal).
[595] Tr. Vol. 4 at 35-36 (Testimony of Amit); Ex. 443 at 4 (Amit Opening Statement).
[596] Ex. 27 at 53-54 and Schedule 11 (Hevert Direct); Ex. 28 at Schedule 6 (Hevert Rebuttal).
[597] Ex. 400 at 48 (Amit Direct); Ex. 28 at 9-17 (Hevert Rebuttal).
[598] Ex. 31 at 9 (Tyson Rebuttal).
[599] Ex. 400 at 46-47 (Amit Direct); Ex. 30 at 27-30, 34-38 (Tyson Direct).
[600] Ex. 30 at 27 (Tyson Direct).
[601] *Id.* at 35 (Tyson Direct); Ex. 400 at 55 (Amit Direct).

is separate from that of XEI. The Company's separate capital structure is reflected in financial reporting and in its communications with financial markets.[602] Adoption of the approach recommended by the ICI Group would be contrary to the well-established regulatory principle that the Company should be allowed to recover all of its prudent costs.

425. Accordingly, the Administrative Law Judge recommends that the Commission approve the following capital structures:

2014 test year:

- 52.50 percent common equity;
- 45.60 percent long-term debt; and
- 1.90 percent short-term debt.

2015 Step:

- 52.50 percent common equity;
- 45.61 percent long-term debt; and
- 1.89 percent short-term debt.

e. Overall Cost of Capital Recommendation

426. If the Commission adopts the 9.77 percent ROE as recommended by the Administrative Law Judge and the Commission also adopts the Company's updated capital structure and agreed upon cost of debt, the result is an overall cost of capital of 7.375 percent for the 2014 test year and 7.403 percent for the 2015 Step year. The table below summarizes the calculations.

Table 10

2014 Test Year Overall Cost of Capital

Component	Capitalization Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	45.60	4.90	2.234
Short-Term Debt	1.90	0.62	0.012
Common Equity	52.50	9.77	5.129
Total	100.00%		7.375%

Table 11

2015 Step Year Overall Cost of Capital

Component	Capitalization Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	45.61	4.94	2.253
Short-Term Debt	1.89	1.12	0.021
Common Equity	52.50	9.77	5.129
Total	100.00%		7.403%

[602] Ex. 31 at 5 (Tyson Rebuttal); Ex. 402 at 14-15 (Amit Rebuttal).

G. Prairie Island EPU (2014)[603]

427. The Company has requested that it be allowed to recover the costs for its abandoned EPU project (EPU Project) at the Prairie Island nuclear power plant. In its Direct Testimony, the Company sought recovery of $78.9 million, consisting of $66.1 million of total expenditures on the Project, plus accrued Allowance for Funds Used During Construction (AFUDC) of $12.8 million. The Company proposed that this amount would be amortized over 12 years while earning a full rate of return, or over six years with no return.[604]

428. The OAG and the ICI Group opposed the Company's recovery of the cancelled EPU Project's costs.[605] The Department and MCC agreed that the Company should be allowed to recover its Project costs, but recommended that the costs be recovered over a longer period, approximately 20 years, and without a return.[606]

429. At the hearing, the Company stated that it would accept cost recovery over 20.3 years, the remaining life of the facility, with a 2.24 percent debt-only return.[607]

i. Background

430. The Prairie Island nuclear power plant consists of two pressurized water reactors that together produce a nominal value of 1100 MW of electrical power.[608] The two reactors received 40 year operating licenses: Unit I in 1973, and Unit 2 in 1974.[609]

431. During 2003 and 2004, the Company began considering whether to increase the power output of the plant as well as whether to undertake actions to extend the useful life of the plant.[610]

432. The EPU Project was proposed by the Company to meet growing energy needs forecasted over the course of several resource plans.[611] The EPU Project sought to increase the capacity of Prairie Island's two nuclear units by 164 MW to meet this growing demand. This 164 MW increase included an 18 MW increase from a proposed Measurement Uncertainty Recapture (MUR) uprate.[612] A MUR allows for somewhat greater recovery of electricity (up to 2 percent) from an existing nuclear facility through installation of upgraded feed water flow measurement equipment.[613]

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[603] Issue 3.
[604] Ex. 99 at 31 (Clark Direct); Ex. 100 at 48 (Clark Rebuttal).
[605] Ex. 370 at 44 (Lindell Direct); Ex. 250 at 12 (Glahn Direct).
[606] Ex. 437 at 17-18 (Lusti Direct); Ex. 340 at 11 (Schedin Direct).
[607] Ex. 442 at 6-7 (Lusti Surrebuttal); Ex. 134 at 1 (Clark Opening Statement).
[608] Ex. 49 at 5 (McCall Direct).
[609] *Id.* at 6 (McCall Direct).
[610] *Id.* at 7-8 (McCall Direct).
[611] Ex. 48 at 6-9 (Alders Direct).
[612] Ex. 49 at 10 (McCall Direct); Ex. 48 at 10-11 (Alders Direct).
[613] Ex. 48 at 11 (Alders Direct).

433. The Company proposed the EPU Project at Prairie Island at the same time as it planned certain Life Cycle Management (LCM) activities. The LCM activities were designed to update the plant's facilities and systems to support continued operation of the plant under a proposed 20-year license extension.[614]

434. In 2008, the Company applied to the Commission for a Certificate of Need (CON) for the EPU Project.[615] The Company estimated the costs of the EPU Project at approximately $322 million.[616] The Commission approved the CON in December 2009.[617]

435. In addition to Commission approval for the EPU, the Company needed approval from the NRC of its proposed license extension and of its EPU/MUR work.[618] The Company submitted an application to the NRC in April 2008 for a 20-year extension of the NRC licenses for both units.[619] In addition to the NRC license extension, the Company also was required to file and obtain NRC approval of License Amendment Requests (LAR) for the MUR and the EPU.[620]

436. To obtain the complex engineering analyses necessary for NRC "acceptance" (determination of completion) and ultimate NRC approval of the LAR for the EPU, the Company contracted with Westinghouse, the original equipment manufacturer for the reactors. The contract provided that Westinghouse would develop the required design analyses, engineering reports, and calculations needed to submit a LAR package for the EPU.[621] The contract contained provisions for early termination charges should the contract be terminated through no fault of Westinghouse.[622] The Westinghouse contract accounts for approximately two-thirds of the EPU Project costs.[623]

437. The NRC granted the Company a license for the MUR project in August of 2010 and the work was completed in October 2010, resulting in an additional 18 MW of

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[614] The PI nuclear reactor licenses were set to expire in 2013 and 2014. *See* Ex. 48 at 10 (Alders Direct); Ex. 49 at 7-8 (McCall Direct).

[615] *In the Matter of the Application to the Minnesota Public Utilities Commission for Certificates of Need for the Prairie Island Nuclear Generating Plant for Additional Dry Cask Storage and Extended Power Uprate*, Docket No. E002/CN-08-510 and E002/CN-08-509, INITIAL FILING, (May 16, 2008).

[616] Ex. 49 at 14 (McCall Direct).

[617] *In the Matter of the Application to the Minnesota Public Utilities Commission for Certificates of Need for the Prairie Island Nuclear Generating Plant for Additional Dry Cask Storage and Extended Power Uprate*, Docket No. E002/CN-08-510 and E002/CN-08-509, ORDER ACCEPTING ENVIRONMENTAL IMPACT STATEMENT, AND GRANTING CERTIFICATE OF NEED AND SITE PERMIT WITH CONDITIONS, Docket No. E002/CN-08-510 and E002/CN-08-509 (Dec. 18, 2009).

[618] Ex. 49 at 12 (McCall Direct).

[619] Ex. 48 at 10 (Alders Direct).

[620] *Id.* at 11 (Alders Direct).

[621] Ex. 49 at 15-17 (McCall Direct).

[622] *Id.* at 18-19 (McCall Direct).

[623] *Id.* at 16 (McCall Direct).

power generation capacity for a cost of $13.4 million, excluding AFUDC.[624] The Company anticipated obtaining NRC approval for the license extensions in 2010 or 2011, and planned to file its LAR for the EPU in mid-2011.[625]

438. Following approval of its CON, the Company began to encounter circumstances it had not anticipated. In January 2011, the Company determined that the originally estimated uprate of 164 MW could not be achieved cost-effectively and lowered the estimated uprate capacity to 132 MW.[626] In addition, the Company began to have concerns about delays. The Fukushima Daiichi nuclear accident in March 2011 caused the NRC to tighten its LAR approval requirements. After a meeting with the NRC in August 2011, the Company determined that obtaining NRC approval for the Prairie Island EPU would be more expensive and take longer than it had anticipated.[627] Moreover, the price of natural gas, an alternative fuel for power generation, fell during this period. At the same time, the Company also was experiencing a softening of demand for electricity.[628]

439. While the Company still viewed the Prairie Island EPU Project as economically viable, the Company began decreasing the amount of resources dedicated to the EPU Project in the third quarter of 2011 to allow time for the Company's regulatory group to evaluate additional information and update the Commission. By the end of 2011, the Company suspended all work on the EPU Project with the exception of certain deliverables from Westinghouse.[629] The Company permitted Westinghouse to continue to work to avoid paying early termination penalties and because it determined that the EPU Project was still economically viable.[630]

440. In October 2011, the Company informed the Commission that it would be updating its 2010 Resource Plan, indicating that it was encountering obstacles impeding its timely implementation of the EPU.[631] Two months later, the Company filed its Resource Plan update and stated that it would be submitting a Notice of Changed Circumstances filing with respect to the EPU Project, which it did in March 2012.[632]

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[624] *Id.* The costs for the MUR were recovered when the MUR was implemented, and are not part of the EPU costs for which recovery is sought in this case. *See* Ex. 48 at 11 (Alders Direct).
[625] Ex. 48 at 11 (Alders Direct).
[626] Ex. 49 at 23-31 (McCall Direct).
[627] *Id.* at 26-30 (McCall Direct); Ex. 48 at 14-15 (Alders Direct).
[628] Ex. 49 at 31 (McCall Direct); Ex. 48 at 15 (Alders Direct).
[629] Ex. 49 at 32-34 (McCall Direct); Ex. 48 at 14-15 (Alders Direct).
[630] Ex 49 at 19, 35 (McCall Direct).
[631] *In the Matter of the Petition of Northern States Power Co., a Minnesota corporation, for Approval of the 2011-2025 Resource Plan*, Docket No. E002/RP-10-825, LETTER FROM JAMES ALDERS TO DR. BURL HAAR (Oct. 7, 2011).
[632] *In the Matter of the Application of Northern States Power Co. for a Certificate of Need for the Prairie Island Nuclear Generating Plant for an Extended Power Uprate,* Docket No. E002/CN-08-509, NOTICE OF CHANGED CIRCUMSTANCES AND PETITION (Mar. 30, 2012).

441. The March 2012 Notice of Changed Circumstances filing informed the Commission that the expected implementation dates for the EPU would be delayed by two years, from 2014-2015 to 2016-2017, due to delays in the NRC approval process. In addition, the filing indicated that the EPU was expected to produce less power than estimated earlier and that costs for similar projects were turning out to be greater than anticipated. Based on an analysis of these factors, the Company concluded that the EPU Project still had a positive, but relatively small, net benefit for ratepayers at that time.[633]

442. In response to the Notice of Changed Circumstances filing, the Department filed comments in June 2012 supporting the continuation of the EPU Project. The Department's recommendation was based on its determination that the EPU Project was still likely to be cost-effective despite delays in timing and updated assumptions.[634]

443. Unfavorable conditions for the EPU Project persisted and in October 2012, the Company notified the Commission that it no longer supported continuing with the EPU Project.[635] Based on an updated analysis, the Company concluded that the outstanding risks of delay and increased costs outweighed the small remaining benefit, rendering further investment in the Prairie Island EPU Project unreasonable.[636] The Commission orally approved cancellation in December 2012 at an agenda meeting, issuing its written Order in February 2013.[637] The February 2013 Order approved the termination of the EPU Project but did not resolve the issue of whether cost recovery would be allowed. Instead, the February 2013 Order provided that the issue of cost recovery would be addressed "in the context of Xcel's rate case."[638]

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[633] Ex. 51 at 129 (O'Conner Direct); Ex 48 at 15-16 (Alders Direct).

[634] *In the Matter of Northern States Power Company's Notice of Changed Circumstances and Petition regarding its Application for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, Docket No. E002/CN-08-509, COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES at 7 (June 12, 2012). The OAG criticized the Department for basing its support for continuation on an analysis using cost estimates from the original application in 2008, even though by 2012, the Project's estimated costs had dropped by $28 million to $294 million from $322 million. *See* Ex. 370 at 37-38 (Lindell Direct). Lower costs alone would increase the Project's estimated net benefits and support the Department's recommendation to continue the Project.

[635] *In the Matter of Northern States Power Company's Notice of Changed Circumstances and Petition regarding its Application for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant,* Docket No. E002/CN-08-509, SUPPLEMENTAL FILING TO NOTICE OF CHANGED CIRCUMSTANCES AND PETITION (Oct. 22, 2012).

[636] *Id.* at 8; Ex. 48 at 20-21 (Alders Direct).

[637] 12-961 REPORT at 87.

[638] *In the Matter of Northern States Power Company's Notice of Changed Circumstances and Petition regarding its Application for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, Docket No. E002/CN-08-509, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY (Feb. 27, 2013).

ii. The Commission's Decision regarding Prairie Island EPU Costs in the Last Rate Case

444. After the Commission approved cancellation of the EPU Project in February 2013 in the Prairie Island docket, certain parties to the on-going rate case raised the issue of cost recovery. Those parties argued that the Company should be barred from recovering the costs of the cancelled EPU Project because the Company failed to specifically request deferred accounting treatment of the cancelled Prairie Island EPU costs in the rate case. The Company disagreed.[639]

445. The Commission concluded that the record in the last rate case was not sufficient to reach a decision regarding whether cost recovery should be allowed. In addition, the Commission specifically provided: "The Company will be required to fully justify its request for rate reimbursement of project costs in its next rate case."[640]

iii. The Company's Current Request

446. The Company's initial filings in this proceeding sought recovery of $66.1 million in Prairie Island EPU Project costs, which is the total amount of the expenditures to carry out the EPU Project, plus accrued AFUDC of $12.8 million.[641] The Company proposed to amortize the cost recovery over 12 years while earning a return on the asset or over six years if no return is permitted.[642] Recovery of these costs over 12 years with a return would increase the Company's revenue requirement by $8.48 million.[643]

447. In Rebuttal Testimony, the Company stated it would accept recovery over 12 years with no return. At the hearing, the Company also indicated that recovery of all costs over 20.3 years, the remaining life of the Prairie Island plant, with a 2.24 percent return on debt only would be acceptable.[644] If the Commission accepts this proposal, the Company's 2014 Test Year revenue requirement would drop by $4.87 million compared to the revenue requirement in its Direct Testimony and there would be an additional $1.31 million reduction in its Rebuttal revenue requirement.[645]

iv. The Positions of the ICI Group and the OAG

448. The ICI Group contended that the Company should not be allowed recovery any of the EPU Project costs because the EPU Project was never "used and

[639] 12-961 ORDER at 7; 12-961 REPORT at 87-89.
[640] 12-961 ORDER at 7.
[641] Ex. 49 at 16 (McCall Direct). As noted above, the costs for the MUR were recovered when the MUR was implemented, and are not part of the EPU costs for which recovery is sought in this case. *See* Ex. 48 at 11 (Alders Direct).
[642] Ex. 99 at 31 (Clark Direct).
[643] Ex. 88 at 91 (Heuer Direct).
[644] Tr. Vol. 2 at 112 (Clark); Tr. Vol. 5 at 83-84 (Lusti).
[645] Ex. 146 at 1 (Heuer Opening Statement).

useful." The ICI Group maintained that allowing recovery would "encourage utilities to pursue imprudent or marginal projects." [646] However, in the event that the Commission allows recovery of the EPU Project costs, the ICI Group supported a 20-year recovery period. In addition, if the Commission allows a return on costs, the ICI Group recommended that the return be very low, reflecting "the nearly risk-free aspect" of the EPU Project.[647]

449. The OAG argued the Commission should deny all EPU Project costs because the Company has not requested deferred accounting for the cancelled EPU Project costs.[648] The OAG maintained that deferred accounting is a prerequisite to recovery of the costs.[649]

450. In the alternative, the OAG argued that if some recovery is permitted: (1) the Company should not recover any AFUDC or costs incurred after August 2011 when the Company should have known the EPU Project was no longer viable; (2) the Company should not recover $10.1 million in EPU Project costs that were written off in 2012 and are not within the 2014 test year; and (3) the Company should not earn a return on the cancelled EPU Project costs.[650]

451. In support of its position regarding denial of $9.2 million in AFUDC costs, the OAG noted that Federal Energy Regulatory Commission (FERC) rules bar recovery of AFUDC accrual once a project is no longer viable and ongoing.[651] The OAG asserted that after the Company's August 2011 meeting with NRC staff, it should have been clear to the Company that the EPU Project was no longer viable given the cost increases, the delays in the EPU Project, reduced power output from the EPU Project and reduced customer demand forecasts.[652] The OAG also maintained that its position that the EPU Project was no longer viable at that point is consistent with a decision by the Massachusetts Department of Public Utilities (MDPU) in which the MDPU denied Boston Edison recovery of AFUDC costs that accrued after the company should have cancelled a project.[653]

452. In addition to disallowing AFUDC after August 2011, the OAG argued that the Commission should deny recovery of EPU Project costs that were incurred after that point. The OAG's main concern is that the Company continued to make payments to Westinghouse, its contractor, after it decided to suspend the EPU Project.[654] The OAG does not dispute the fact that the termination clauses contained in the Westinghouse contract meant that there was little to be gained by cancelling the contract after August

[646] Ex. 250 at 11-12 (Glahn Direct).
[647] *Id.* at 12 (Glahn Direct).
[648] Ex. 370 at 40-41 (Lindell Direct).
[649] *Id.* at 41 (Lindell Direct).
[650] Initial Post-Hearing Brief of OAG (OAG Initial Br.) at 1, 7-21.
[651] Ex. 370 at 43-44 (Lindell Direct); Ex. 373 at 22 (Lindell Surrebuttal); OAG Initial Br. at 13-14.
[652] OAG Initial Br. at 8-13.
[653] *Id.* at 14-15.
[654] Ex. 100 at 57 (Clark Rebuttal).

2011.[655] The OAG asserted, however, that it was imprudent for the Company to enter into a contract structured in such a way that ratepayers would continue to pay the contractor in the event the project became imprudent.[656]

453. In addition, the OAG opposed recovery of a $10.1 million pre-tax charge that the Company had taken in 2012 in recognition of the uncertainty around whether the Commission would allow recovery of EPU Project costs. The OAG argued that it is not proper to allow recovery of a write-off in rates because it is not a test year expense.[657]

454. Finally, to the extent the Commission allows recovery of any EPU Project costs, the OAG urged a 20.3-year recovery period with no return.[658] The OAG argued that no return should be allowed because the Project is not used and useful. The OAG also noted that in past cases where the Commission has allowed recovery of costs for cancelled projects, it has done so with no return.[659]

v. The Positions of the Department and MCC

455. Initially, the Department recommended that the Company be allowed to recover full EPU Project costs and AFUDC over 20.3 years, the remaining life of the facility, without earning a return on the asset. In support of its position, the Department stated that the amount the Company sought to recover was "far less than the amount the Company originally proposed for the project" in the CON proceeding and that the Company filed a Notice of Changed Circumstances in a timely fashion as required by Minn. R. 7849.0400, subp. 2(H) (2013).[660]

456. During the course of the hearing, the Department took the position that it would also be acceptable to permit recovery of EPU Project costs over the 20.3 year

[655] *Id.*
[656] OAG Initial Br. at 17-18.
[657] Ex. 370 at 42-44 (Lindell Direct); Ex. 373 at 18-19 (Lindell Surrebuttal); OAG Initial Br. at 18-19.
[658] Ex. 370 at 44 (Lindell Direct).
[659] OAG Initial Br. at 20-21.
[660] Ex. 437 at 16-17 (Lusti Direct). Minn. R. 7849.0400, subp. 2(H) reads:

> If an applicant determines that a change in size, type, timing, or ownership other than specified in this subpart is necessary for a large generation or transmission facility previously certified by the commission, the applicant must inform the commission of the desired change and detail the reasons for the change. A copy of the applicant's submission to the commission must be sent to each intervenor in the certificate of need hearing proceeding on the facility. Intervenors may comment on the proposed change within 15 days of being notified of the change. The commission shall evaluate the reasons for and against the proposed change and, within 45 days of receipt of the request, notify the applicant whether the change is acceptable without recertification. The commission shall order further hearings if and only if it determines that the change, if known at the time of the need decision on the facility, could reasonably have resulted in a different decision under the criteria specified in part 7849.0120.

period but with a 2.24 percent return on debt.[661] The Department did not strongly endorse this approach, but rather provided the debt-only alternative for the Commission's consideration.[662]

457. MCC initially advocated for a 20-year recovery period with no return on equity.[663] In Surrebuttal Testimony, MCC stated that it did not oppose the Department's recommendation to permit recovery over 20.3 years with no return on equity and a 2.24 percent return on debt.[664]

vi. The Standard for Allowing Recovery for Cancelled Projects

458. According to the ICI Group, the "used and useful" standard should apply to the determination of whether the Company should be allowed recovery of its canceled Prairie Island EPU Project costs.[665]

459. In past cases, the Commission has applied the "prudently incurred in good-faith" standard, not the "used and useful" standard, to determine whether the costs of cancelled projects should be recovered from ratepayers.[666] In applying the standard, the Commission has examined the unique facts in each case.[667]

460. For example, in 2011, the Commission allowed Interstate Power & Light Co. (IPL) to recover its costs from its cancelled Sutherland Generation Station Unit 4 project (SGS Unit 4).[668] In that matter, the Iowa Utilities Board had approved construction of a coal-fired electric unit in 2008. In March 2009, IPL decided not to proceed with construction, citing "escalating costs, unstable economic conditions and financial markets; unclear environmental regulation regarding future greenhouse gas emissions" and actions by the Iowa Utilities Board purportedly delaying construction.[669] Although the Administrative Law Judge recommended denying recovery because the

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[661] Department Reply Br. at 38; Ex. 134 at 1 (Clark Opening Statement).
[662] Department Reply Br. at 38 ("if the Commission believes it is reasonable to allow Xcel to earn only the debt component of its cost of capital on the $78.9 million over the remaining life of the plant" then the appropriate calculation would yield a 2.24 percent return on debt). *See also* Ex. 442 at 6 (Lusti Surrebuttal).
[663] Ex. 340 at 11 (Schedin Direct).
[664] Ex. 342 at 7 (Schedin Surrebuttal); MCC Initial Br. at 3.
[665] Ex. 250 at 11 (Glahn Direct).
[666] *In the Matter of the Application of Interstate Power and Light Co. for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276 FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 33 (Aug. 12, 2011); *In the Matter of the Application of Otter Tail Power Co. for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. GR-10-239, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 12 (Apr. 25, 2011); Department Reply Br. at 35-36.
[667] *In the Matter of the Application of Interstate Power and Light Co. for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 33 (Aug. 12, 2011).
[668] *Id.*
[669] *Id.* at 31.

Commission had previously rejected the Company's request for deferred accounting for the project costs, the Commission nonetheless allowed recovery, stating:

> the Commission does not view the question of cost recovery for the Sutherland plant as controlled by an accounting issue. The Commission has consistently treated the issue of abandoned plant costs as turning on the unique facts and circumstances surrounding each rate case and each plant.
>
> . . .
>
> [t]here 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.[670]

461. Based on this precedent, the Administrative Law Judge concludes the proper standard of review for the canceled EPU Project costs is whether the costs were prudently incurred in good-faith to meet a future need.

vii. Analysis

462. Before analyzing whether the EPU Project costs were prudently incurred, it is necessary to first address the threshold issue posed by the OAG: namely, whether the Company should be permitted to seek recovery of its EPU Project costs in this case at all given that the Company has not requested deferred accounting of its EPU Project costs. In its 12-961 ORDER, the Commission expressly authorized the Company to seek recovery of these costs in this rate case when it stated: "The Company will be required to fully justify its request for rate reimbursement of project costs in its next rate case."[671] The Commission did not require the Company to request deferred accounting first.[672] Based on the clear language in the 12-961 ORDER, the Administrative Law Judge concludes that the Commission intended to allow the Company to seek recovery of these costs in this rate case. This conclusion is consistent with the Commission's decision in the IPL case, discussed above, wherein the Commission stated that it "does not view the question of cost recovery … as controlled by an accounting issue."[673]

463. The next issue to be addressed is whether the Company has demonstrated that its EPU Project costs were prudently incurred in good faith. Based

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[670] *Id.* at 33.
[671] 12-961 ORDER at 7.
[672] *Id.*
[673] *In the Matter of the Application of Interstate Power and Light Co. for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 31 (Aug. 12, 2011).

on a careful review of the record, the Administrative Law Judge concludes the Company has met its burden. The record shows that at the time the CON was issued and the Company first undertook the EPU Project, the EPU Project was determined to be a cost-effective means of addressing a projected increase in demand.[674] While circumstances changed after the Commission issued the CON for the EPU Project, the Company's cost/benefit analysis continued to show a positive value for the Project in March 2012 when the Company filed its Notice of Changed Circumstances.[675] In comments filed in June 2012, the Department agreed that the EPU Project remained cost-effective and recommended that the Commission allow the EPU Project to continue.[676] The Department's position was based on its own independent analysis.[677] In October 2012, based on new information and further analysis, the Company notified the Commission that it had concluded that the EPU Project should be suspended because, in the view of the Company, the outstanding risks of delay and increased cost outweighed the small benefit of proceeding with the EPU Project.[678]

464. During the course of the Company's continuing review of the costs and benefits of the EPU Project, the Company took steps to minimize costs.[679] The Company prudently suspended all work on the EPU Project, with the exception of the Westinghouse work, when it appeared the EPU Project would have only a marginal net benefit.[680] The Company explained that its contract with Westinghouse would have required payment regardless of whether Westinghouse was permitted to continue work because of the early termination clauses.[681] While the OAG challenges the prudence of the termination liability clauses in the Westinghouse contract, its criticism rests entirely on hindsight and is speculative.[682] The requirement for recovery is that the utility's actions must be reasonable and undertaken in good faith. The Company has met this standard.

465. Similarly, there is no basis for excluding AFUDC prior to the Commission's oral cancelation of the Project in December 2012. The OAG's argument rests on its suggestion that the Company should have known that the EPU Project was not viable as early as August 2011 when the Company met with NRC staff and learned that the

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[674] *In the Matter of the Application to the Minnesota Public Utilities Commission for Certificates of Need for the Prairie Island Nuclear Generating Plant for Additional Dry Cask Storage and Extended Power Uprate*, Docket No. E002/CN-08-510 and E002/CN-08-509 ORDER ACCEPTING ENVIRONMENTAL IMPACT STATEMENT, AND GRANTING CERTIFICATE OF NEED AND SITE PERMIT WITH CONDITIONS (Dec. 18, 2009).
[675] Ex. 48 at 15-16, 18 (Alders Direct).
[676] *In the Matter of Northern States Power Co.'s Notice of Changed Circumstances and Petition regarding its Application for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, Docket No. E002/CN-08-509, COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES at 6-7 (June 12, 2012).
[677] *Id.* at 2-6.
[678] Ex. 48 at 20 (Alders Direct).
[679] Ex. 49 at 34-35 (McCall Direct).
[680] *Id.* at 33-34.
[681] *Id.* at 34-35.
[682] Ex. 373 at 20-21 (Lindell Surrebuttal); *see also* eDockets No. 20123-73154-01 (attached service list for the Notice of Changed Circumstances filing by the Company showing the OAG was served).

Project licensing would likely take longer and be more costly than expected.[683] The OAG's argument, however, ignores the fact that both the Company and the Department conducted a detailed cost/benefit analysis in 2012 and determined that the Project was still viable.[684] For these reasons, the Administrative Law Judge concludes that the Company should be allowed to recover its Prairie Island EPU Project costs, including accrued AFUDC. The OAG's arguments to the contrary are without merit.

466. Nor does the Administrative Law Judge agree with the OAG's suggestion that the Company be barred from recovering the 2012 pre-tax charge of $10.1 million related to EPU Project costs.[685] The $10.1 million pre-tax charge does not represent a "write-off" as the OAG asserted but rather reflects the Company's judgment that recovery of a return on the EPU Project costs is not certain given past Commission decisions.[686] The Commission's decision in this case will remove that uncertainty and the Company's accountants will make any necessary adjustments to reconcile the Company's estimate with the Commission's ultimate disposition.[687]

467. Having determined that the Company should be allowed to recover its Prairie Island EPU Project costs, including AFUDC, the remaining issues for determination are: (1) the time period for cost recovery; and (2) whether the Company should be allowed a return on those costs. The Administrative Law Judge concludes that recovery over 20.3 years with a debt only return of 2.24 percent reflects a reasonable outcome for both ratepayers and shareholders. If completed, the Prairie Island EPU Project would have served ratepayers throughout the remaining life of the facility, which is currently 20.3 years.[688] Thus, a 20.3 year recovery period for the investment is reasonable. Given that the recovery period is approximately 20 years, the Administrative Law Judge concludes that it is reasonable to allow a debt-only return of 2.24 percent, as agreed to by the Department and Company. A debt-only return properly recognizes the time value of money.

H. Rate Case and Monticello Prudency Review Expense Amortization (2014)[689]

468. The Company's test year includes expenses totaling approximately $950,000 to account for the cost of conducting the prudence investigation in Docket No.

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[683] OAG Initial Br. at 13.
[684] Ex. 48 at 15-16, 18 (Alders Direct); *In the Matter of Northern States Power Company's Notice of Changed Circumstances and Petition regarding its Application for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, Docket No. E002/CN-08-509, COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES at 6-7 (June 12, 2012).
[685] Ex. 370 at 43 (Lindell Direct); Ex. 373 at 17 (Lindell Surrebuttal).
[686] Ex. 47 at 6 (Weatherby Rebuttal); Tr. Vol. 1 at 182 (Weatherby).
[687] Ex. 47 at 7-8 (Weatherby Rebuttal) (analysis of the OAG's proposed accounting treatment for the $10.1 million pre-tax charge and hypothetical reconciliation to the Commission's ultimate Order determining recovery).
[688] Ex. 438 at 18 (Lusti Direct) (providing the remaining life of the facility).
[689] Issue 8.

E002/CI-13-754 (the Monticello CI Docket) as well as approximately $2.7 million in rate case expenses for the present case.[690]

469. The Company proposed to amortize the Monticello CI Docket costs and rate case costs over two years. The Company requested a two-year amortization period based on the Company's expectation that it will file its next rate case in late 2015, using a 2016 test year.[691]

608. The Department agreed with the amount of the rate case expenses and Monticello CI Docket expenses included in the 2014 test year.[692]

471. The Department also agreed with the two-year amortization of rate case expenses.[693]

472. The Department, however, disagreed with the two-year recovery period for the Monticello CI Docket costs. Instead, the Department proposed that the costs be amortized over the remaining life of the Monticello facility (16.8 years) without a return. The Department recommended the longer amortization period because the prudence investigation in that docket pertains to the overall facility and will have ramifications over the life of the facility.[694]

473. The Department's recommendation decreases the test year rate case amortization expense by $418,452.[695]

474. The Company opposed the Department's recommendation to amortize the costs for the Monticello CI Docket over the remaining life of the facility. The Company asserted that the 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.[696]

475. The Company claimed that its proposed two-year amortization period for the costs of the Monticello CI Docket is more appropriate because the costs pertain to a one-time investigation and are relatively small. The Company asserted that these costs are similar to rate case costs and should be treated in a similar manner.[697] The Company noted that a rate case, like the Monticello CI Docket, may have long-term

[690] Ex. 88 at 142 (Heuer Direct); Ex. 437 at 28 (Lusti Direct).
[691] Ex. 88 at 142 (Heuer Direct).
[692] Ex. 437 at 28-29 (Lusti Direct).
[693] *Id.*
[694] *Id.*; Ex. 442 at 17-18 (Lusti Surrebuttal).
[695] Ex. 437 at 29 (Lusti Direct).
[696] Ex. 90 at 24 (Heuer Rebuttal).
[697] *Id.* at 24-25.

financial effects on a utility, but amortization of rate case costs is typically limited to shorter periods to reflect the primary period affected by the proceeding.[698]

476. Finally, the Company claimed it would be inappropriate to require the Company to bear the Monticello CI Docket 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.[699]

477. The Department disagreed with the Company's view that the Monticello CI Docket costs are similar to rate case costs. The Department noted that in a rate case, the Commission sets rates for a specific point in time, and the costs of the rate case are recovered over the time span when the new rates are to be in effect. In the Monticello CI Docket, the Commission is reviewing the reasonableness and prudence of the Monticello LCM/EPU costs. The Department stated that the Commission's decision will continue for the life of the facility, not only until the next rate case is filed, as with rate case expenses.[700]

478. The Department also disagreed with the Company's suggestion that it should be allowed to earn a return on the costs if the amortization period is set at 16.8 years, the remaining life of the facility. The Department asserted that by not allowing a return, there would be a sharing of these costs between ratepayers and shareholders; ratepayers would pay the Company back for the prudency review costs over the life of the facility, and the shareholders would recover the costs of the review but not earn a return on it.[701]

479. The Administrative Law Judge concludes that it is reasonable to amortize the Monticello CI Docket costs over a period of two years. Like costs in a rate case, the Monticello CI Docket costs are being incurred to determine which expenses should be included in rates. Moreover, in this rate case, the Commission is deciding a similar prudency issue for the Prairie Island EPU as discussed above. Yet, the Department has not suggested that the portion of the rate case expenses attributable to that review be amortized over the remaining life of the Prairie Island plant.[702] Instead, it has recommended that the Company be allowed to recover all of its proposed rate case expenses over a two-year period.[703] The Administrative Law Judge finds no reason to treat the Monticello CI Docket costs any differently.

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698 Xcel Initial Br. at 111.
699 Ex. 90 at 24 (Heuer Rebuttal); Xcel Reply Br. at 96.
700 Ex. 442 at 17 (Lusti Surrebuttal).
701 *Id.* at 18.
702 *See* Ex. 437 at 29 (Lusti Direct).
703 *Id.*

I. Changes to In-Service Dates for Capital Projects (2014 and 2015 Step)[704]

480. The Company has included costs associated with 733 capital projects in the revenue requirement for the 2014 test year and costs associated with 116 projects in the 2015 Step revenue requirement.[705]

481. In response to a discovery request, the Company acknowledged that 49 of the 733 projects included in the 2014 test year would not be in-service until 2015, and two of the 116 projects in the 2015 Step would not be in-service until after 2015.[706] The Department recommended removing the costs associated with the projects that had a delay to the in-service date because those projects will not be used and useful during the relevant time frame.[707]

482. The delayed projects include $67.3 million in capital additions that moved outside the 2014 test year. Disallowance of those projects would result in a $2.18 million reduction to the 2014 revenue requirement. 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. 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.[708]

i. The Company's Position

483. The Company opposed the Department's proposed downward adjustments, asserting that its 2014 test year and 2015 Step revenue requirements are representative of its actual costs.[709]

484. The Company argued that the Department's position is inconsistent with the concept of a representative test year, in which planned projects are identified at a particular point in time and represent the reasonable costs of providing electric service.[710]

485. The Company cited the Commission's decision in *In the Matter of the Complaint by Myer Shark et al Regarding Xcel Energy's Income Taxes,* Docket No. E,G002/C-03-1871 (Oct. 1, 2004) (*Myer Shark* case) in support of its position.[711] In the *Myer Shark* case, the Commission stated that the "test year method by which rates are

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704 Issue 11.
705 *See* Ex. 429 at 152 (Campbell Direct) (referencing the Company's response to Department I.R. No. 123).
706 Ex. 450 at 8 (Campbell Opening Statement); Ex. 429 at 152 (Campbell Direct).
707 Ex. 429 at 153 (Campbell Direct); Department Initial Br. at 118-19.
708 Ex. 429 at 152-53 (Campbell Direct); Ex. 430 at NAC-28, 3 (Campbell Direct Attachments).
709 Ex. 100 at 15-18 (Clark Rebuttal).
710 *Id.* at 15.
711 Xcel Initial Br. at 104-05.

set rests on the assumption that changes in the Company's financial status will be roughly symmetrical – some favoring the Company and others not." [712]

486. 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 the 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 impact the timing of capital project completion (either through delay or acceleration).[713]

487. The Company maintained that when project in-service dates change, the Company allocates the capital budget to fund: (1) like-kind replacements, which include work similar in scope, timing, and cost to the original project; (2) emergent work, which includes work that was not originally planned but becomes necessary to complete; and (3) normal business changes that involve reallocations based on normal changes in project priorities due to changing circumstances.[714]

488. The Company asserted that if the Commission determines an update of in-service dates is appropriate, it should be allowed to substitute other capital projects for those that have been delayed in 2014. With regard to capital projects in the 2015 Step, the Company stated that no adjustment is needed because a refund mechanism applies in the event a Step project is delayed or cancelled.[715]

ii. The Department's Response

489. The Department disagreed with the Company's position. The Department maintained that the most current information for in-service dates should be used to determine the 2014 test year and 2015 Step revenue requirements.[716]

490. The Department argued that its proposed adjustments are consistent with the concept of a test year and stem from its attempts to verify in-service dates to ensure that ratepayers do not pay for projects that are not used and useful during a test year.[717]

491. The Department also opposed the Company's suggestion that it be allowed to substitute new projects that were not included in the Company's initial filing for projects for which in-service dates have changed because there has not been a sufficient opportunity to review the new projects. As a result, the Department

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[712] *In the Matter of the Complaint by Myer Shark et al Regarding Xcel Energy's Income Taxes,* Docket No. E,G002/C-03-1871, ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 4 (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,* Docket No. E-015/GR-87-223, ORDER AFTER RECONSIDERATION AND REHEARING (May 16, 1988)).
[713] Ex. 100 at 14 (Clark Rebuttal); Ex. 94 at 38-39 (Perkett Rebuttal).
[714] Ex. 94 at 39-42 (Perkett Rebuttal).
[715] Ex. 100 at 18-19 (Clark Rebuttal).
[716] Ex. 450 at 8 (Campbell Opening Statement); Ex. 429 at 153 (Campbell Direct).
[717] Department Initial Br. at 118, 120; *see* Ex. 435 at 105 (Campbell Surrebuttal).

maintained that allowing substitutions would unfairly burden the parties and the public interest by narrowing the time available for review of the substituted projects.[718]

492. Even if the substitutions are allowed, the Department claimed that the substitutions proposed by the Company would still result in a downward adjustment based on the information provided by the Company.[719]

493. For these reasons, the Department continued to recommend the downward adjustments that it proposed in Direct Testimony.[720]

iii. Analysis

494. As discussed above, the Commission is required to set rates that allow the utility an opportunity to recover its costs of providing service, including depreciation of and a return on capital investments that are "used and useful" in providing service to ratepayers.[721]

495. The Minnesota Supreme Court has held that utility property is "used and useful" when it: (1) is "in service"; and (2) is "reasonably necessary to the efficient and reliable provision of utility service."[722]

496. Based this standard, the Administrative Law Judge concludes that the 2014 test year and 2015 Step should be based on the most current in-service dates for capital projects because otherwise the rates will include recovery of costs for projects that are not yet "used and useful."

497. Contrary to the Company's suggestion, the Commission's decision in the *Myer Shark* case does not command a different result. In that case, the Commission examined whether a refund should be issued to ratepayers for tax expenses that were included in the test year but ultimately were not incurred by the Company, and determined that no refund was necessary. The Commission reasoned that actual costs may differ from the test year, but the changes will be roughly symmetrical. The issue in that case was raised after the rates were established, not during a rate case when the features of the test year are being determined.[723] Thus, the *Myer Shark* decision does not address the issue of what costs should be included in the test year, the matter that is disputed here.

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[718] Ex. 435 at 104-05 (Campbell Surrebuttal); Department Initial Br. at 122.
[719] Ex. 435 at 108 (Campbell Surrebuttal); Ex. 429 at 151 (Campbell Direct).
[720] Ex. 450 at 9019 (Campbell Opening Statement).
[721] Minn. Stat. § 216B.16, subd. 6.
[722] *Senior Citizens Coalition of Northern Minnesota v. Minnesota Pub. Utilities Comm'n*, 355 N.W.2d 295, 300 (Minn. 1984).
[723] *In the Matter of the Complaint by Myer Shark et al Regarding Xcel Energy's Income Taxes,* Docket No. E,G002/C-03-1871, ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 2-5 (Oct. 1, 2004).

498. In addition, while the Administrative Law Judge recognizes that the utility industry is a dynamic business and priorities change, the utility still has a legal obligation to demonstrate that its test year rate base and depreciation expense include projects that are used and useful.[724] Projects that have been delayed do not meet this standard.[725]

499. With regard to the Company's proposal that it be allowed to substitute replacement projects for capital projects that have been delayed, the Administrative Law Judge concludes that the Company should only be allowed to substitute replacement projects when: (1) the Company has shown that the replacement projects are necessary, the costs are prudent, and the projects will be in-service during the test year; and (2) the other parties have had sufficient time to review the proposed replacement projects.[726] The Administrative Law Judge concludes that such an approach is a reasonable compromise between the Company's position and the Department's position because it recognizes that a utility's capital plans are bound to change somewhat during the course of a long MYRP proceeding but also holds the Company to its burden of proof.

500. In Rebuttal Testimony, Company witness Lisa H. Perkett identified certain substitute projects for the 2014 test year. Inclusion of these projects would appear to decrease the Department's proposed revenue reduction from $2.18 million to $1.8 million for changes to in-service dates in 2014.[727] No party disputed the need for these specific substitute projects or the costs. The Department, however, disputed the propriety of including substitute projects generally on the grounds that such projects would not be subject to adequate review by the parties. While ensuring the parties have adequate time to review the proposed new projects is important, in this case, the Department was provided the list of substitute projects on March 21, 2014 in response to an Information Request and these same projects are included in Ms. Perkett's Rebuttal Testimony filed in June 2014.[728]

501. Based on the evidence in the record and for the reasons discussed above, the Administrative Law Judge recommends that the Commission reduce the Company's proposed 2014 test year revenue requirement and 2015 Step test year revenue requirement to reflect the updated in-service dates for projects included in the Company's initial filing, but also allow the substitution of the projects specified by Company witness Ms. Perkett in her Rebuttal Testimony.[729]

[724] Minn. Stat. § 216B.16, subd. 6.
[725] *See id.*
[726] *Id.*
[727] Ex. 94 at 39-42, Schedule 11 (Perkett Rebuttal); Ex. 430 at NAC-28 at 3, Attachment E (Campbell Direct); Ex. 94 at Scheduled 11 (Perkett Rebuttal).
[728] *See* Ex. 430 at NAC-28 at 3, Attachment E (Campbell Direct).
[729] *See* Ex. 94 at Schedule 11 (Perkett Rebuttal).

J. Return on Nuclear Refueling Outage Costs (2014)[730]

502. Nuclear refueling outage costs include maintenance expenses that are incurred at a plant during a nuclear refueling outage.[731] Nuclear refueling outage expenses can be significant. In addition, these expenses can vary significantly from year to year depending on the number of outages per year.[732]

503. The Company uses the deferral and amortization method of accounting for these expenses as a means to promote stability, predictability, and fairness to its customers.[733] Under the deferral and amortization method, the outage expenses are deferred in the month in which they occur and are amortized over the period of time between the expenditure and the next outage for that unit. Nuclear refueling outages typically occur every 18 to 24 months.[734]

504. In its calculation of this expense under the deferral and amortization method, the Company includes a carry charge equal to its rate of return while the costs are deferred.[735] The Company includes the carrying charge to reflect the cost of financing the expense.[736] The carrying charge included in the 2014 test year is approximately $4.6 million.[737]

505. The Company has been using the deferral and amortization method of accounting for its nuclear refueling outage expenses since the conclusion of its 2008 rate case. The Commission approved this cost treatment "to ensure greater accuracy in cost recovery, to match more closely the time these costs are incurred with the time they are recovered, and to avoid substantial fluctuations in these costs between rate cases."[738]

i. The OAG's Position

506. In the past three rate cases, the OAG opposed the Company's use of the deferral and amortization method.[739] The OAG also opposed the recovery of a carrying charge in past cases. In this case, the OAG does not oppose the Company's use of the deferral and amortization method, but does recommend that no carrying charge be allowed on nuclear refueling outage expenses.[740]

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[730] Issue 64.
[731] Ex. 97 at 21 (Robinson Rebuttal)
[732] *Id.* at 22.
[733] *Id.*
[734] *Id.*; Ex. 370 at 45 (Lindell Direct).
[735] Ex. 370 at 45 (Lindell Direct).
[736] Ex. 97 at 23 (Robinson Rebuttal).
[737] Ex. 370 at 45 (Lindell Direct).
[738] 12-961 ORDER at 40.
[739] Ex. 373 at 24 (Lindell Surrebuttal).
[740] Ex. 370 at 47 (Lindell Direct); Ex. 373 at 26 (Lindell Rebuttal); OAG Initial Br. at 28-29.

507. The OAG noted that from 2008 to 2013, customers have paid $16.7 million in carrying charges as a result of the Company using the deferral and amortization method. The OAG further stated that the Company is proposing to include an additional $4.6 million as a carrying charge on nuclear refueling outage expenses for its 2014 test year.[741] The OAG asserted that the deferral and amortization method does not require that a carrying charge be included in the amount recovered.[742]

508. The OAG also maintained that the inclusion of a carrying charge, set at the rate-of-return, creates an incentive for the Company to expand the scope of its nuclear refueling outage work because doing so provides a profit that benefits its shareholders.[743] In support of its position, the OAG highlighted that the Company's standard O&M expenses increased by only 1.8 percent from 2011 to 2014, while the Company's nuclear refueling outage expenses increased by 37 percent during that same time period.[744]

ii. The Company's Response

509. The Company opposed the OAG's recommendation that the Commission exclude a carrying charge on its nuclear refueling outage expenses.[745] The Company asserted that the Commission should continue to allow the Company to earn a carrying charge set at its rate of return on the unamortized amount to reflect the time value of money until the expense is recovered. The Company maintained that fundamental ratemaking principles contemplate that the Company be allowed to earn a return on the unamortized balance (net of accumulated deferred taxes) when, as here, the Company uses operating funds to cover nuclear refueling outage costs prior to receiving funds from customers.[746]

510. In addition, the Company disputed the OAG's view that allowing a carrying charge creates an incentive for the Company to inflate its nuclear refueling outage costs. The Company stated that it uses its best efforts to implement sound accounting and budgeting principles to estimate its costs as accurately as possible. The Company maintained that the Company has an ongoing obligation to demonstrate that its nuclear refueling outage costs are reasonable and accurate.[747]

iii. Analysis

511. The Commission addressed this same issue in the Company's 2012 rate case. In that case, the OAG also opposed the inclusion of a carrying charge under the deferral and amortization method. The Commission disagreed with the OAG and

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741 Ex. 370 at 45-46 (Lindell Direct).
742 *Id.* at 45.
743 *Id.* at 46; *see also* Ex. 373 at 26 (Lindell Surrebuttal).
744 Ex. 370 at 46 (Lindell Direct)
745 Ex. 97 at 23-24 (Robinson Rebuttal); Xcel Initial Br. at 113-114.
746 Ex. 97 at 23-24 (Robinson Rebuttal); Xcel Initial Br. at 114.
747 *Id.* at 24.

concluded that "the rate of return is the appropriate time-cost of money in this situation."[748]

512. The issue was also addressed in the 2010 rate case. In that rate case, the Administrative Law Judge concluded that:

> The deferral and amortization method incorporates a carrying charge to reflect the time value of money until the costs are recovered. So long as the practice of including a carrying charge is balanced with payments to ratepayers when costs are deferred, the practice is reasonable.[749]

In its order in the 2010 rate case, the Commission did not address the issue in detail but did adopt the Findings, Conclusions, and Recommendation of the ALJ on the issue.[750]

513. For these same reasons, it continues to be reasonable for the Company to include a carrying charge under the deferral and amortization method of accounting for nuclear refueling outage expenses. Consistent with the Commission's decision in the last rate case, the Administrative Law Judge concludes that the Company should be allowed to include a carrying charge equal to its rate of return.

K. Nuclear Refueling Outage Costs - 2015 Step Treatment[751]

514. As noted above, nuclear refueling outage costs include maintenance expenses that are incurred at a plant during a nuclear refueling outage. Because these costs can be significant and variable, the Company uses the deferral and amortization method of accounting for its nuclear refueling outage expenses.[752]

515. The Company included $89.3 million in test year amortization expenses for nuclear refueling outages.[753] During discovery, the Company provided additional information related to the 2015 Step year nuclear outage amortization expenses.[754] 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.[755]

516. The Company disagreed with the Department's proposal for several reasons. First, the Company maintained that the 2015 Step should only reflect changes directly related to new capital projects included in the 2015 Step.[756] Second, the

[748] 12-961 ORDER at 40.
[749] 10-971 REPORT at ¶ 286.
[750] *See* 10-971 ORDER at 33, ¶ 2.
[751] Issue 27.
[752] Ex. 97 at 21-22 (Robinson Rebuttal)
[753] Ex. 51 at 119, Schedule 16 (O'Connor Direct).
[754] Ex. 431 at 63, Schedule 12 (Campbell Direct).
[755] Ex. 429 at 67, 169-70 (Campbell Direct).
[756] Ex. 100 at 35 (Clark Direct).

Company stated that these nuclear refueling outage expenses are not capital-related costs. To the extent the Company has any outage costs that are capital-related, those costs are captured under the individual projects and subject to their own accounting rules and recovery treatments.[757] Third, the Company noted that nuclear refueling outage expenses are amortized to normalize the impact of these expenses, not because they are capital expenses.[758] Finally, the Company claimed that it has other expenses, such as nuclear fees and active health care costs, that have increased but it has not requested recovery of those increased costs in the 2015 Step.[759]

517. In response, the Department agreed with the Company that the nuclear outage costs are separate O&M expenses and are not capital-related costs. As a result, the Department withdrew its recommended $5.5 million adjustment.[760]

518. The OAG, however, disagreed with the Company's characterization of its nuclear refueling outage expenses as O&M expenses and continued to support the Department's proposed $5.5 million adjustment even after the Department withdrew its recommendation.[761]

519. The OAG provided several arguments in support of its position. First, the OAG maintained that these expenses are related to capital investments because they are a necessary part of operating nuclear power plants. Second, the OAG argued that nuclear refueling outage expenses should be treated as a capital cost because the Company earns a return on these expenses. Third, the OAG noted that the Company has included depreciation expense for its 2015 Step projects in its 2015 revenue requirement. The OAG asserted that nuclear refueling outage expenses should be treated in a similar manner to depreciation expenses because both expenses are amortized.[762] Finally, the OAG argued that it is unreasonable to include the 2014 amount for nuclear outage expenses in the 2015 Step revenue requirement because the Company will not incur the higher 2014 expense in 2015.[763]

520. In the MYRP ORDER, the Commission determined that requiring an examination of all expenses in each step year would defeat the goal of promotingadministrative efficiency through a MYRP. For that reason, the Commission limited the adjustments in the test year revenue requirement to capital-related expenses.[764]

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[757] *Id.*
[758] *Id.*
[759] *See* Ex. 101 at 4-5 (Clark Surrebuttal).
[760] Ex. 435 at 14-16 (Campbell Surrebuttal); Ex. 442 at 43 (Lusti Surrebuttal); Ex. 450 at 1 (Campbell Opening Statement).
[761] Ex. 372 at 6 (Lindell Rebuttal); OAG Initial Br. at 29-31.
[762] *Id.*
[763] OAG Initial Br. at 31.
[764] MYRP ORDER at 5, 10, 12. As discussed above in Section E, consideration of the effects of the passage of time on depreciation expense and rate base, which are capital-related items, is consistent

521. The record in this case demonstrates that the nuclear amortization expenses at issue are not capital-related expenses, but are refueling O&M expenses.[765] Pursuant to the MYRP ORDER, these expenses are not subject to adjustment in the 2015 Step revenue requirement.

522. In addition, even if an adjustment were made to reflect the decrease in this O&M expense as the OAG recommends, then similar adjustments would also need to be made to all other non-capital related O&M expenses; some of which likely will go up in 2015. Such symmetry is necessary to ensure a fair and reasonable representation of the Company's O&M costs. Adjusting only this one item in isolation will not result in just and reasonable rates.

523. For these reasons, the OAG's recommendation to adjust the 2015 Step revenue requirement to reflect the change in the nuclear refueling outage expenses in 2015 is not warranted.

L. CWIP/AFUDC[766]

i. Background

524. Construction Work in Progress (CWIP) and the Allowance for Funds Used During Construction (AFUDC) are used to account for and recover the cost of capital during construction. CWIP represents the accumulation of construction costs that directly relate to putting a fixed asset into use. AFUDC is used to account for the cost of financing during construction.[767]

525. The Commission is authorized to consider CWIP and AFUDC in rate setting for public utilities. Minn. Stat. § 216B.16, subd. 6 (emphasis added), states in pertinent part:

> In *determining the rate base* upon which the utility is to be allowed to earn a fair rate of return, the commission *shall give due consideration* to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, *to construction work in progress*, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a

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with the Commission's MYRP ORDER. In addition, Minn. Stat. § 216B.16, subd. 6, specifically requires consideration of these items in setting rates. While Minn. Stat. § 216B.16, subd. 6, also requires consideration of the utility's O&M costs in setting rates, consideration of one O&M cost in isolation will not result in just and reasonable rates. In limiting step year adjustments to capital-related items, the Commission has in effect determined that the other costs (including nuclear refueling O&M costs) included in the test year are reasonable for use in setting rates in the step years.

[765] Ex. 100 at 35 (Clark Direct).

[766] Issue 63.

[767] Ex. 92 at 52 (Perkett Direct); *see also* 12-961 ORDER at 9.

capital nature.

Also, Minn. Stat. § 216B.16, subd. 6a (2014) (emphasis added), provides:

> *To the extent that construction work in progress is included in the rate base*, the *commission shall determine in its discretion whether and to what* extent the income used in determining the actual return on the public utility property shall *include an allowance for funds used during construction*, considering the following factors:
>
> (1) the magnitude of the construction work in progress as a percentage of the net investment rate base;
>
> (2) the impact on cash flow and the utility's capital costs;
>
> (3) the effect on consumer rates;
>
> (4) whether it confers a present benefit upon an identifiable class or classes of customers; and
>
> (5) whether it is of a short-term nature or will be imminently useful in the provision of utility service.

526. In past rate cases, the Commission generally has authorized electric utilities in Minnesota to treat CWIP and AFUDC as follows:

- CWIP is placed into rate base;
- There is an offset to the income statement for AFUDC incurred in the year;
- The combination of CWIP in rate base and the inclusion of AFUDC in net operating income effectively eliminates the cost of financing construction from the revenue requirement during the during the construction period.
- Once the asset goes into service, CWIP and AFUDC are recovered over the life of the asset through the recording of book depreciation expense.
- There are a few exceptions to the Commission's general practice of allowing CWIP into rate base with an AFUDC offset. There is no AFUDC offset: (1) where the Commission authorizes a current return for the project (e.g. transmission and renewable energy projects); and (2) for projects that are less than $25,000 or less than 30 days in construction.[768]

[768] Ex. 92 at 52-54 (Perkett Direct); Ex. 94 at 16-17 (Perkett Rebuttal).

527. In the Company's last rate case, the Commission approved the standard treatment of CWIP and AFUDC but required the Company to provide additional information on its CWIP and AFUDC practices in this case. Specifically, the Commission provided:

> In the initial filing in its next rate case, Xcel shall provide evidence of [the Federal Regulatory Energy Commission'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 placed in CWIP.[769]

528. In this rate case, the Company has proposed to set its rates using the same treatment of CWIP and AFUDC as approved in its last rate case. This treatment of CWIP and AFUDC has been in effect since 1977.[770]

529. In addition, to comply with Order Point 52 from the 12-961 ORDER, the Company provided testimony on FERC's accounting requirements for AFUDC and CWIP.[771] The Company explained that its AFUDC rate is based on a formula prescribed by FERC in the Uniform System of Accounts, and demonstrated that its AFUDC and CWIP accounting is consistent with FERC requirements.[772]

530. While no party disputes that the Company has complied with FERC accounting requirements,[773] the OAG and the Commercial Group have objected to the Company's proposed ratemaking treatment of CWIP and AFUDC.[774] The OAG noted that accounting and ratemaking are two separate issues. The OAG further explained that Commission rules require that public utilities in Minnesota follow FERC accounting requirements, but there is no similar requirement in Minnesota with regard to FERC ratemaking requirements.[775]

ii. The Objections of the OAG and the Commercial Group

531. The OAG and the Commercial Group both raised concerns about the inclusion of CWIP in rate base. The OAG maintained that the Company's inclusion of CWIP in rate base while accruing AFUDC is inconsistent with FERC's ratemaking treatment of CWIP and AFUDC.[776] The OAG explained that in setting wholesale rates, FERC requires that the utility either: (1) include CWIP in rate base and stop accruing

[769] 12-961 ORDER at 54.
[770] Ex. 94 at 25 (Perkett Rebuttal); Xcel Reply Br. at 73.
[771] Ex. 91 at 1-10 (Guest Direct); Ex. 92 at 53, 55-57 (Perkett Direct).
[772] Ex. 91 at 6-10 (Guest Direct); Ex. 92 at 53, 55-57 (Perkett Direct); Xcel Initial Br. at 85-86.
[773] *See* Ex. 370 at 21 (Lindell Direct); Tr. Vol. 3 at 207-208 (Lindell)
[774] Ex. 370 at 16-30 (Lindell Direct); Ex. 225 at 3-4 (Chriss Direct); OAG Initial Br. at 6-21; Commercial Group Initial Br. at 12.
[775] Ex. 373 at 3 (Lindell Rebuttal).
[776] Ex. 370 at 24 (Lindell Direct).

AFUDC; or (2) exclude CWIP from rate base and continue to accrue AFUDC.[777] As noted above, however, the OAG acknowledged that FERC's wholesale ratemaking requirements, including those applicable to CWIP and AFUDC, are not required to be used in setting retail rates in Minnesota.[778] The OAG also asserted that including CWIP in the rate base is contrary to the cost recovery "requirement that capital investments be 'used and useful' in the provision of utility service" because many of the CWIP projects will not be in service during the test year.[779]

532. The Commercial Group agreed with the OAG that "inclusion of CWIP in rate base charges ratepayers for assets that are not yet used and useful in the provision of utility service."[780] The Commercial Group asserted that the Company's proposal requires ratepayers to pay for assets during a period when they are not yet receiving benefits from those assets, which violates the "matching principle."[781] The matching principle provides that customers should only bear costs when they receive a benefit.[782] The Commercial Group also maintained that inclusion of CWIP in rate base shifts risks, which are normally borne by shareholders, to ratepayers. The Commercial Group recommended that if the Commission does include CWIP in rate base, then the Company's return on equity should be reduced.[783]

533. The OAG recommended that CWIP be excluded from rate base and the AFUDC offset be removed from the income statement.[784] According to the OAG, excluding CWIP from the 2014 rate base and excluding the associated AFUDC offset from the income statement will reduce the 2014 test year revenue requirement by approximately $3.8 million and increase the 2015 Step revenue requirement by approximately $0.9 million.[785] The OAG recommended that if CWIP is excluded from rate base, then the Company be allowed to accrue AFUDC on "those projects that require external financing and are not funded by cash operations." [786] The OAG maintained that this proposed approach is consistent with FERC ratemaking principles.[787]

534. The OAG also recommended that accrual of AFUDC be limited only to projects costing more than $25 million. The OAG asserted that the Company is able to finance small and medium projects with internal funds recovered through rates, making

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[777] *Id.* at 20. The OAG also noted that when CWIP is included in rate base, FERC only allows 50% of CWIP to be included. *Id.* at 19.
[778] Ex. 373 at 3 (Lindell Rebuttal).
[779] Ex. 370 at 27 (Lindell Direct).
[780] Ex. 225 at 10 (Chriss Direct).
[781] *Id.*
[782] *Id.* at 3, 10.
[783] *Id.*
[784] Ex. 370 at 24, 29 (Lindell Direct).
[785] *Id.* at 24.
[786] *Id.* at 28.
[787] *Id.* at 24.

AFUDC unnecessary for projects under $25 million.[788] In support of its recommendation, the OAG claimed that the state of Florida has rules that limit accrual of AFUDC to projects that exceed one half of one percent of total plant in service. Applying a similar one-half of one percent to the total plant in service for NSP would be equal to approximately $38 million based on NSP's plant in service of $7.5 billion.[789] The OAG also noted that neither MERC nor CenterPoint, two gas utilities operating in Minnesota, have included CWIP or AFUDC in setting their rates. The OAG maintained that these utilities finance their construction projects with internally generated funds.[790]

535. The OAG also suggested that the AFUDC rate for eligible projects be set at 2.62 percent rather than the 6.79 percent used by the Company. The OAG stated that the Company has included the maximum AFUDC rate allowed under FERC accounting rules.[791] As noted above, the Company calculated the 6.79 percent rate using FERC's formula. This formula assumes that a utility's short-term debt is the first source of funds used for financing construction. The remainder of construction is assumed to be financed out of long-term debt, preferred stock, and common equity on the basis of these funds as they existed at the end of the prior year.[792] The OAG noted that the Commission is not required to use "FERC's formulaic AFUDC calculation" in setting the AFUDC rate in Minnesota.[793] According to the OAG, an AFUDC rate that is less than the maximum rate (6.79 percent here) would be compliant with FERC accounting rules.[794] The OAG suggested that the Company's AFUDC be calculated using the average of the Company's short-term debt rate and long-term debt rate because, in the OAG's view, the Company has not demonstrated that it requires the use of equity to fund projects in the test year. This results in a rate of 2.62 percent.[795]

536. In sum, the OAG argued that the Company has not demonstrated that its proposed treatment of CWIP and AFUDC are necessary for the utility to recover its financing costs and attract investors.[796]

iii. The Company's Response

537. The Company responded that its approach of including CWIP with an AFUDC offset, (subject to limited exceptions), is reasonable and consistent with Commission precedent and FERC accounting standards. The Company also maintained that its approach reflects the requirements of Minn. Stat. § 216B.16 (2014), which requires the Commission to give "due consideration to … construction work in

[788] *Id.* at 23; Ex. 373 at 13-14 (Lindell Rebuttal).
[789] *Id.* at 28; Ex. 373 at 15 (Lindell Rebuttal) (Mr. Lindell did not provide the cite to the rule in his testimony); OAG Initial Br. at 39.
[790] Ex. 370 at 23 (Lindell Direct).
[791] *Id.* at 28.
[792] Ex. 91 at 4-6 (Guest Direct); Ex. 92 at 55-56 (Perkett Direct).
[793] Ex. 370 at 21, 28 (Lindell Direct).
[794] Ex. 373 at 3 (Lindell Surrebuttal).
[795] Ex. 370 at 28 (Lindell Direct); Tr. Vol. 3 at 210; OAG Reply Br. at 7-8.
[796] OAG Reply Br. at 7-8.

progress" in establishing rate base.[797] The Company also asserted that the main difference between the Minnesota approach and the FERC approach to the treatment of CWIP and AFUDC for ratemaking purposes is one of timing of cost recovery.[798]

538. The Company noted the Commission has recognized that its approach to CWIP and AFUDC benefits ratepayers.[799] The Company maintained that the OAG's proposed ratemaking treatment of CWIP and AFUDC would not be beneficial to ratepayers. The Company pointed out that the OAG's proposal to exclude CWIP from rate base is based on FERC ratemaking principles. According to the Company, to be fully consistent with FERC ratemaking principles, short-term debt would also need to be excluded from the Company's capital structure.[800] The Company noted that the OAG failed to account for this change to the cost of capital in its testimony.[801] The Company calculated that removing CWIP, the AFUDC offset, and the cost of short-term debt from the capital structure would increase the revenue requirement in 2014 by $8.5 million and would increase the revenue requirement in the 2015 Step by $12.4 million.[802]

539. The Company asserted that the CenterPoint and MERC determinations regarding CWIP were driven by unique facts and should not be viewed as changing longstanding treatment of CWIP and AFUDC for the Company.[803]

540. The Company also opposed the OAG's recommendation that AFUDC accrual be limited to projects exceeding $25 million. Instead, the Company recommended that the Commission retain its current policy of excluding AFUDC for only "short-term" projects (i.e. those that will be completed in less than 30 days) and projects that will cost $25,000 or less. The Company asserted that if the OAG's $25 million threshold for AFUDC is adopted, the Company would suffer a "permanent disallowance" of AFUDC for approximately 62 percent of its projects in the 2014 test year. The Company maintained that such a change would deny the Company a reasonable opportunity to earn its return.[804] The Company also disagreed with the OAG's assertion that the Company could finance projects costing less than $25 million with its operating revenues. The Company noted that the Commission sets its rates so that its revenues equal costs, including depreciation and a return on equity. Because revenues equal expenses, the Company asserted that it does not have excess internal funds to finance the construction of capital projects.[805] The Company also disputed the OAG's characterization of the Florida rules governing CWIP and AFUDC, stating that the

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[797] Ex. 94 at 17-20 (Perkett Rebuttal); Xcel Initial Br. at 85-89; Xcel Reply Br. at 73.
[798] Ex. 94 at 25 (Perkett Rebuttal); Xcel Initial Br. at 85-87.
[799] Ex. 92 at 59 (citing Order from the Company's 1985 rate case, Docket No. E002/GR-85-558).
[800] Ex. 94 at 19, 23 (Perkett Rebuttal); Xcel Reply Br. at 75.
[801] Xcel Reply Br. at 76.
[802] Ex. 94 at 25 (Perkett Rebuttal).
[803] *Id.* at 25-27.
[804] *Id.* at 29.
[805] *Id.* at 31.

Florida rules typically include CWIP in rate base for projects up to a certain size and implementation period, after which AFUDC accrual may apply.[806]

541. Finally, the Company disagreed with the OAG's proposal that the AFUDC rate be set by averaging the cost of short-term and long-term debt rather than using the FERC formula. The Company maintained that the OAG's proposal fails to recognize that the Company uses equity in addition to short-term debt and long-term debt to finance capital projects. The Company also disagreed with the OAG's view that the Company should be required to trace equity issuances to specific projects in order for equity to be included in the AFUDC rate because, as the OAG's witness John Lindell acknowledged, it is not possible to trace the specific funds used to finance a construction project.[807]

iv. Analysis

542. The Company has shown that its proposed inclusion of CWIP and AFUDC is consistent with FERC accounting requirements, Minn. Stat. § 216B.16, and long-standing Commission precedent. As explained in more detail below, the OAG has failed to show that any change to the Company's longstanding accounting for CWIP and AFUDC is necessary or reasonable.

543. First, the OAG has not demonstrated that its proposal to exclude CWIP and the AFUDC offset, and instead allow AFUDC to accrue until the plant is placed in service, would result in more reasonable rates. If the OAG's approach were adopted, to be consistent with FERC ratemaking principles, the Commission would also need to exclude short-term debt from the Company's capital structure. The record in this case shows that this approach would increase the 2014 test year revenue requirement by $8.5 million and increase the 2015 Step revenue requirement by $12.4 million.[808]

544. The OAG argued that the Commission does not need to exclude short-term debt from the cost of capital even if it excludes CWIP from rate base because FERC's ratemaking principles are not binding on the Commission. This argument, however, fails to recognize that short-term debt generally does not support rate base but rather it is commonly used for temporary financing of construction projects.[809] Because short-term debt is used to fund CWIP, it would not be reasonable to exclude CWIP from rate base but still include short-term financing in the capital structure. Significantly, the OAG has not identified any state jurisdiction that has taken the OAG's proposed approach to CWIP and cost of capital. Moreover, the OAG's proposal to exclude CWIP from rate base fails to give "due consideration to … construction work in progress" as required by Minn. Stat. § 216B.16, subd. 6. For these reasons, the

[806] Xcel Initial Br. at 92-93 (citing Florida Rule 25-6.0141 Allowance For Funds Used During Construction).
[807] Xcel Reply Br. at 76; Tr. Vol. 3 at 212 (Lindell).
[808] Ex. 94 at 25 (Perkett Rebuttal).
[809] *Id.* at 23-24.

Administrative Law Judge concludes that the Company's proposed inclusion of CWIP with an AFUDC offset, except in limited circumstances, is more reasonable and balanced than the OAG's alternative approach.

545. Second, the OAG has not demonstrated a reasonable basis for limiting accrual of AFUDC to projects that exceed $25 million. The OAG's proposal would deny the Company an opportunity to recover its financing costs for approximately 62 percent of its capital projects included in the 2014 test year.[810] The cost of financing these projects is a real cost that the Company incurs.[811] Contrary to the assertion of the OAG, there is no evidence that the Company has sufficient excess revenue to be able to fund 62 percent of its capital projects without external financing. The OAG failed to consider that retail revenues are set at a level to cover the Company's costs of providing service and not set at a level that allows revenue to be used as a replacement for capital.[812] Thus, limiting accrual of AFUDC to projects that exceed $25 million would deny the Company a fair opportunity to recover its financing costs for projects under that amount.

546. Third, the OAG has not demonstrated that it is reasonable to set the AFUDC rate at 2.62 percent, rather than 6.79 percent as proposed by the Company. The Company's proposed rate is calculated in accordance with the FERC formula.[813] The OAG's proposed rate, on the other hand, is the average of the Company's short-term and long-term debt rates. The OAG maintained that non-debt sources of financing should only be included in the AFUDC rate if the Company can demonstrate that it actually has used equity to fund particular construction projects.[814] The OAG asserted that the Company has funds available from the rates it collects, including excess interim rates, and does not need equity to fund its capital projects.[815] Here again, the OAG failed to consider that the Company's rates are set to cover its costs. In addition, the OAG also ignores that excess interim rates are refunded with interest.[816] As a result, the Company utilizes equity in addition to debt to finance its capital projects.[817] Finally, it would not be reasonable to adopt the OAG's suggestion that equity should only be included in the AFUDC rate if the Company can clearly trace a particular equity

[810] *Id.* at 29.
[811] Ex. 92 at 30 (Perkett Direct); *see also In re Northern States Power Co.*, 46 P.U.R. 4th 17 FERC ¶ 61,196 at 61,382-82 (1981) (Opinion No. 134) (finding 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.")
[812] Ex. 94 at 31 (Perkett Rebuttal).
[813] Xcel Initial Br. at 89-90.
[814] OAG Initial Br. at 36.
[815] OAG Initial Br. at 37; Ex. 370 at 28 (Lindell Direct); Tr. Vol. 3 at 220-221 (Lindell).
[816] Ex. 92 at 31 (Perkett Direct); Minn. R. 7825.3300 (2013). In this case, the OAG has argued that the Commission should refund excess interim rates, if any, with interest equal to the Company's rate of return, not the average prime rate, as provided in Minn. R. 7825.3300. OAG Initial Br. at 40-41.
[817] Ex. 94 at 30 (Perkett Rebuttal).

issuance to a specific project because, as the OAG has acknowledged, it is not possible to trace specific funds to a particular construction project.[818]

547. For these reasons, the Administrative Law Judge recommends no change to the Company's treatment of AFUDC and CWIP, which is based on long-standing Commission precedent.

M. Corporate Aviation[819]

548. The Company has included approximately $954,000 for corporate aviation costs in its 2014 test year cost-of-service. This amount represents half of the approximately $1.9 million of corporate aviation costs that the Company has budgeted for 2014 on a Minnesota jurisdictional basis.[820] The Company maintained that its request to include 50 percent of the corporate aviation costs is reasonable and consistent with Commission precedent.[821]

549. The Company asserted that it obtains the following benefits from the use of corporate aviation services: travel expense savings; employee time savings; increased in-flight productivity; scheduling convenience; reduced stress and post-trip fatigue; and personal security. The Company believes that these benefits result in more efficient and cost-effective provision of utility service.[822]

550. To support its claim of prudency, the Company commissioned a cost-benefit analysis of corporate aircraft use from January 2012 to June 2013. More than 70 percent of the flights were between St. Paul and Denver.[823] The study showed that the use of corporate aviation allowed the Company's employees to reach their destinations faster and that the employees are getting more work done in transit. The study concluded that, on average, 68 percent of the Company's corporate aviation costs provide a benefit when compared to the costs of commercial air travel.[824]

551. In addition, as part of its initial filing the Company provided certain flight report data from its corporate jet trip logs for the period from September 1, 2012 to August 31, 2013 in a Microsoft Excel spreadsheet. The spreadsheet includes the following data for each passenger trip: the date of the flight; the aircraft flown; the origin of the trip; the destination; the passenger's name; the passenger's job title; the company that the passenger works for; and the passenger's "Business Purpose." The Company

[818] OAG Initial Br. at 26; Tr. Vol. 3 at 212 (Lindell).
[819] Issue 65.
[820] Ex. 75 at 28 (O'Hara Direct).
[821] Ex. 77 at 12 (O'Hara Rebuttal); Xcel Initial Br. at 108-109.
[822] Ex. 75 at 29 (O'Hara Direct).
[823] *Id.*, GJO-1, Schedule 10 (O'Hara Direct).
[824] Ex. 75 at 30-31, GJO-1, Schedule 10 (O'Hara Direct).

included this data with its initial filing in response to Order Point 48 of the Commission's Order in the last rate case.[825]

552. The OAG opposed the Company request to include $954,000 in corporate aviation costs in the test year, arguing that the Company has not demonstrated that its costs are reasonable.[826] The OAG identified three areas of concern: (1) the cost per flight included by the Company; (2) inclusion of costs for flights that the OAG maintains do not have ratepayer benefit; and (3) insufficient detail in the flight logs to determine if the flights are necessary and prudent to utility service.[827] To address these concerns, the OAG recommended that the Company's proposed test year expense be reduced by 96 percent to $34,143.[828] Each of these concerns and the proposed adjustments are discussed in detail below.

553. First, the OAG maintained that the Company's overall cost of corporate aviation on a per-flight basis is too expensive. The OAG estimated the Company's cost per one-way flight to be approximately $1,589. The OAG calculated this amount by dividing the total costs budgeted for corporate aviation to Xcel Energy Inc. ($5,861,000)[829] by the total number of one-way trips (3,688) reported by Xcel Energy Inc. between September 2012 and August 2013.[830] The OAG asserted that even 50 percent of the $1589 per flight cost is unreasonable, and $300 per flight should be used instead to calculate the corporate aviation expense for the 2014 test year. The OAG asserted that $300 per one-way flight (or $600 for a round trip flight) is "essentially double what the OAG found several years ago as a reasonable cost of a round-trip ticket" from Denver to St. Paul.[831] The OAG calculated that using $300 per flight would result in a Minnesota jurisdictional corporate aviation expense of $360,300, not $954,000.[832] This is the first downward adjustment recommended by the OAG to the corporate aviation expense.

554. Second, the OAG recommended that the $360,300 amount be reduced by $16,514 to address its concern that Xcel's flight logs show that 169 of the 3688 flights logged between September 2012 and August 2013 were for personal use, investor benefit, and aviation use. The OAG maintained that these uses do not benefit ratepayers. More specifically, the OAG recommended a reduction of $3,518 to address the 33 entries that listed a "Business Purpose" entry of "Personal Travel" and to address three additional instances where the person traveling was the spouse of an Xcel

[825] Ex. 75 at 31, GJO-1, Schedule 12 (O'Hara Direct).
[826] OAG Initial Br. at 22-28.
[827] Ex. 370 at 50-58 (Lindell Direct).
[828] *Id.*; Ex. 77 at 5 (O'Hara Rebuttal) (calculating the amount of the proposed reduction).
[829] This is an Xcel Energy Inc. total corporation number, not a NSP Minnesota electric jurisdictional number. *See* Ex. 75 at GJO-1, Schedule 13 (O'Hara Direct).
[830] Ex. 370 at 50 (Lindell Direct); Ex. 76 at GJO-1, Schedule 12 (O'Hara Direct).
[831] Ex. 370 at 51 (Lindell Direct).
[832] Ex. 370 at 52 (Lindell Direct) ($360,300 was calculated by multiplying the number of one-way trips (3,688) by the 2014 jurisdictional allocator of the $300 cost per flight); Ex. 77 at 6 (O'Hara Rebuttal).

employee.[833] In addition, the OAG recommended a reduction of $8,892 to address the 91 entries in which the Business Purpose was either "Investor Relations" or "Shareholder Meeting." The OAG also recommended a reduction of $4,104 to address 42 entries for "Aviation Use."[834]

555. Third, the OAG maintained that many of the "Business Purpose" descriptions in the Company's flight logs are not specific enough to justify cost recovery, and recommended further reductions to address this concern. Specifically, the OAG recommended the following reductions: $162,980 for 1668 entries listed as "Business Area Travel"; $65,466 for 670 entries listed as "Director Travel" or "Manager Travel;" and $81,197 for 831 entries listed as "Xcel Executive Business Travel." These suggested reductions total $309,634.[835] In addition, the OAG argued that the Company should not be allowed recovery for travel coded in these categories because these "Business Purpose" descriptions are vague, and the Company has no system to review whether the employees selecting these codes have a valid business purpose for the flight.[836]

556. The Company responded that it did not agree with the OAG's proposed adjustments to its test year corporate aviation expense. The Company stated that it followed past Commission practice and requested 50 percent of its Minnesota electric jurisdiction aviation costs in the test year. The Company asserted that limiting its test year expense in this manner serves to address many of the concerns raised by the OAG such as the limited amount of personal travel and travel related to investor relations. With regard to the specificity of its flight logs, the Company asserted that Minn. Stat. § 216B.17, subd. 17 (2014) provides that a utility can use existing company reports such as flight logs to provide information regarding aviation expenses.[837] In addition, the Company asserted that corporate flights were taken for valid business purposes. The Company indicated that a valid business purpose is a requirement for scheduling Company aircraft. In addition, the Company noted that the flight logs from September 2012 to August 2013 show that the appropriate passengers were on board (mostly Service Company employees) and show that the passengers traveled mostly between Company locations.[838]

557. The Company also noted that the OAG's calculation of the price per ticket of $300 does not account for employee time savings or increased productivity.[839] The Company's aviation services study did factor in benefits associated with employee time

[833] Ex. 370 at 53 (Lindell Direct). This amount was "jurisdictionalized" by Mr. Lindell to remove only the costs attributable to NSP's Minnesota electric operations. *Id.*, n. 57 (Lindell Direct). The same is true of the other similar reductions that he suggested.
[834] Ex. 370 at 53-54 (Lindell Direct).
[835] *Id.* at 55-56.
[836] OAG Initial Br. at 27; OAG Reply Br. at 2-3.
[837] Xcel Reply Br. at 92.
[838] Ex. 77 at 5-7, 9-10 (O'Hara Rebuttal); Xcel Initial Br. at 108-110; Xcel Reply Br. at 95.
[839] Ex. 77 at 7 (O'Hara Rebuttal).

savings and increased productivity.[840] According to the Company, increased productivity is the most important benefit of using corporate aviation.[841] The Company noted that the Minnesota Department of Transportation, which provides aviation services for state personnel, has also recognized that the use of aviation services has many advantages, including productivity.[842]

558. Based on the record in this case, the Administrative Law Judge concludes that the Company has demonstrated that it is reasonable to include $954,425, or 50 percent of the approximately $1.9 million that the Company has budgeted in 2014 for corporate aviation costs on a Minnesota electric jurisdictional basis. The Company's request is based on a detailed analysis of its costs, and properly considers increased productivity and employee time savings.[843] The Company's request is also consistent with Commission precedent.[844]

559. Further, the OAG's proposed adjustments to the Company's test year expense are not supported by the record (e.g. cost per flight) or are already covered by the 50 percent reduction in Minnesota jurisdictional aviation expenses (e.g. personal travel).

560. First, the record shows that the OAG's suggestion that the test year expense be calculated using a cost of $300 per trip is not reasonable. The $300 cost is not based on current price data and fails to account for a number of factors that can affect the prices that the Company would have to pay for commercial air travel such as flights to different locations, the time period between reservation and travel, and fees related to ticket changes or cancellations. Most importantly, the $300 price for a commercial one-way ticket does not take into account the employee time savings and increased productivity that result from the use of corporate aviation. For these reasons, it is not reasonable to use $300 per flight to establish the Company's corporate aviation expense.

561. Second, with regard to the OAG's suggestion that the Company's test year corporate aviation expense be reduced to account for costs that do not benefit ratepayers, the Administrative Law Judge concludes the Company's proposal to include only 50 percent of its total Minnesota jurisdictional aviation expense in the test year in effect excludes such costs. More specifically, flights for personal travel, shareholder meetings, investor relations, and aviation uses—the categories that the OAG asserted

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[840] Ex. 75 at 30.
[841] *Id.* at 29.
[842] Ex. 77 at 4 (O'Hara Rebuttal); Ex. 75, GJO-1, Schedule 10 at 6 (O'Hara Direct).
[843] Ex. 32 at 28-30, GJO-1, Schedule 9 (O'Hara Direct); Ex. 34 at 2-6 (O'Hara Rebuttal).
[844] *See* Docket E002-GR/10-961 (Northern States Power Company); Docket E002-GR/12-961 (Northern States Power Company); Docket No. E015/GR-08-415 (Minnesota Power); Docket No. E015/GR-09-1151 (Minnesota Power); Docket No. E017/GR-10-239 (OtterTail Power Company).

do not benefit ratepayers—together account for only 4.6 percent of all annual flights.[845] Even if one accepts the OAG's view that none of these uses benefit ratepayers,[846] the record does not support making an adjustment to exclude these uses as recommended by the OAG because the Company's test year expense already excludes 50 percent of the corporate aviation costs allocated to the Minnesota electric jurisdiction.[847] In addition, about 10 percent of corporate aviation costs are allocated to Xcel Energy Inc., the holding company.[848] Therefore, it is reasonable to conclude that the costs for the flights that the OAG alleges do not benefit ratepayers are already excluded either through the 50 percent reduction in 2014 Minnesota jurisdictional expense or through allocation to Xcel Energy Inc. Thus, no further adjustment is needed to account for purposes that do not benefit ratepayers.

562. Third, the record supports recovery for travel coded as: Executive Business Travel; Director Travel; Manager Travel; or Business Area Travel. The OAG argued that these Business Purpose descriptions, which account for about 86 percent of all passenger trips from September 2012 to August 2013, are insufficient to demonstrate that this travel is needed to provide utility service. The OAG maintains the descriptions are vague and not subject to internal review.[849] The record, however, shows that flights on Company aircraft can only be scheduled for valid business reasons.[850] In addition, approximately 97 percent of all corporate aircraft flights from September 2012 to August 2013 were between Company locations.[851] These facts confirm that the flights coded as Executive Business Travel, Director Travel, Manager Travel and Business Area Travel were taken for valid business purposes.

563. Furthermore, the Commission has previously approved corporate aviation expenses for NSP and other utilities without requiring the level of detail sought by the OAG.[852] While the Commission did require the Company to provide certain flight log

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[845] The number of flights for personal use (33), spousal travel (3), investor relations and shareholder meetings (91), and aviation use (42), add up to 169 flights. *See* Ex. 370 53-54 (Lindell Direct). This number, 169, divided by the total flights, 3688, equals 4.6 percent.

[846] The Administrative Law Judge agrees with the OAG that personal travel by employees and travel by spouses do not benefit ratepayers, but finds it is a closer question as to whether travel for shareholder meetings, investor relations and aviation uses benefit ratepayers. For purposes of this analysis, the Administrative Law Judge assumes none of these categories benefit ratepayers.

[847] The Administrative Law Judge recognizes that the Company's aviation study concluded that 68 percent of the Company's corporate aviation costs provide a benefit when compared to the costs of commercial air travel. Ex. 75 at 30 (O'Hara Direct). Given that the Company is proposing to recover 50 percent of its costs, this leaves a margin of 18 percent which is unrecovered. This margin more than covers the 4.6 percent of costs attributable to trips for personal travel, shareholder meetings, investor relations, and aviation uses.

[848] Ex. 77 at 8 (O'Hara Rebuttal).

[849] OAG Initial Br. at 26-28**;** Ex. 77 at 9 (O'Hara Rebuttal).

[850] Ex. 77 at 9-10 (O'Hara Rebuttal).

[851] *Id.*

[852] *See* 12-961 ORDER at 11; 10-971 ORDER at 36; *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Serv. Rates in Minnesota*, Docket No. E015/GR-08-415, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 47 (May 4, 2009); *In the Matter of the Application of Minnesota*

information with its initial filing in this rate case, the Commission's Order did not require the level of detail regarding the passenger's Business Purpose that the OAG argues should be required.[853] Moreover, because the Commission's Order was issued in September 2013 and the Company made its filing initial filing in this rate case in November 2013, the Company did not have time to change its software to include the level of detail sought by the OAG for the applicable time period – flight logs from September 2012 to August 2013. Thus, while the Company could improve the level of detail in its Business Purpose descriptions, the Administrative Law Judge concludes that the Company has provided sufficient evidence in this case to demonstrate that flights for Executive Business Travel, Director Travel, Manager Travel and Business Area Travel are reasonable and necessary for the provision of utility service.

564. The Commission may want to consider whether more specific Business Purpose codes should be implemented by the Company for use in future rate cases. To the extent the Commission believes additional detail regarding the Business Purpose for each passenger trip should be provided in future rate case filings, the Administrative Law Judge respectfully recommends that the Commission specify the level of detail that must be provided and ensure that the Company has sufficient time to change its data systems to comply in a timely manner.

565. Finally, the Administrative Law Judge concludes that the Company has substantially complied with Order Point 48 in the 2013 Rate Case Order. In that Order, the Commission provided in relevant part:

> In the initial filing of its next rate case, the Company shall include more detailed flight data reports (preferably in live Microsoft Excel electronic format) of its corporate jet trip logs for its most recent 12-month operational period. The report, by flight, must identify the charged employee, each employee passenger and his/her assigned operating company, the other passengers on flight and reason for use, and primary purpose for scheduling the flight. The Company shall include information for the calculation of the requested recovery amount of corporate aviation.

566. As discussed above, the Company provided flight reports in live Microsoft Excel electronic format with its November 2013 initial filing in this rate case. The reports cover the 12-month period from September 1, 2012 to August 31, 2013. The reports include all of the information required by Order Point 48 except the data on the individual employee to whom the flight is "charged" and "the primary purpose for

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Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E015/GR 09-1151, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 34 (Nov. 2, 2010); *In the Matter of the Application of Otter Tail Power Co. for Authority to Increase Rates for Electric Utility Serv. In Minnesota*, Docket No. E017/GR 10-239, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 38 (Apr. 25, 2011).

[853] 12-961 ORDER at 53, ¶ 48.

scheduling the flight."[854] The Company explained that it did not include this data because the Company's software does not track these two categories of data.[855] The Company also stated that flights are not charged to individual employees, but rather total corporate aviation costs are allocated to NSP and all other affiliates using a three-digit work order number. In addition, with regard to the primary purpose of the flight, the flight logs do include a "Business Purpose" for each passenger as discussed above.[856] In sum, the Company complied with Order Point 48 to the best of its ability given the timing of the initial filing in this rate case.

N. Sherco Unit 3 Outage—Replacement Fuel Costs[857]

567. In November 2011, the Sherburne County Generating Station (Sherco) coal-fired power plant experienced a catastrophic failure of Unit 3, resulting in a reduction of the plant's power generating capacity.[858] As a result, the Company was required to purchase replacement power to cover the deficit created by the outage in Unit 3.[859] According to the Department, from November 2011 to October 2012, $22.7 million in additional power costs were incurred as a result of the extended outage of Unit 3.[860] The Company has sought recovery of the replacement power costs through the Fuel Clause Adjustment mechanism rather than through base rates.[861]

568. The issue of recovery for Sherco Unit 3 replacement power costs has been discussed in the AAA proceedings before the Commission, in Docket No. E999/AA-12-757 and Docket No. E999/AA-13-599.[862] The Company filed an extensive report in Docket No. E999/AA-13-599 discussing the cause of the Sherco Unit 3 failure.[863]

569. MCC has also raised the issue in this case. Specifically, MCC recommended that the replacement power costs from the Sherco Unit 3 outage be capitalized and recovered over the life of the power plant.[864] According to MCC, the replacement power costs from the Sherco Unit 3 outage should be recovered from future ratepayers who will benefit from the reconstruction and increased capacity of Sherco Unit 3 as a result of the failure in 2011, not current ratepayers.[865]

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[854] Ex. 75, GJO-01, Schedule 12 (O'Hara Direct).
[855] Ex. 75 at 31 (O'Hara Direct).
[856] *Id.*
[857] Issue 68.
[858] 12-961 REPORT at 18.
[859] *Id.* at 20.
[860] *Id.*
[861] Ex. 100 at 44 (Clark Rebuttal).
[862] Ex. 437 at 67-68 (Lusti Direct).
[863] Ex. 340 at 14 (Schedin Direct).
[864] *Id.* at 13-14 (Schedin Direct); MCC Initial Br. at 5-6.
[865] Ex. 340 at 14 (Schedin Direct).

570. The Department disagreed with MCC and recommended that the issue of replacement power costs from the Sherco Unit 3 outage be addressed as part of the AAA docket.[866]

571. The Company also believes the issue of replacement power cost recovery should be addressed as part of the AAA docket.[867] The Company asserted that replacement power costs should not be capitalized because the cost of power should be borne by the customers who used the power during the Sherco Unit 3 outage.[868]

572. Because replacement power costs are for power that was used during the outage of Sherco Unit 3, the Administrative Law Judge concludes that the issue of cost recovery is properly addressed as part of the AAA docket.

O. Black Dog—Unit 2 and 5 Outage Costs (2014)[869]

573. Units 2 and 5 of the Black Dog Generating Plant experienced a three-month outage from December 2012 to March 2013. The outage occurred due to a bowed rotor. The rotor bowed when it was removed from its turning gear while hot due to human error.[870]

574. Because the outage was the result of human error, XLI proposed disallowing investment of $24,104 and operating costs of $1.84 million. XLI also proposed that any replacement fuel costs should be disallowed in the AAA proceeding.[871]

575. The Company pointed out that the $1.84 million of additional operating costs were incurred in 2013 and that these costs were not included in the 2014 test year.[872] The Company also noted that the $24,104 of capital addition is embedded within the rate base for the 2014 test year because that capital addition was incurred during the 2012-2013 outage.[873] As a result, the Company argued XLI's proposed adjustments would result in retroactive ratemaking.[874]

576. The Company also argued that XLI is improperly seeking to impose a standard of perfection, not prudence, on the determination of whether a utility should be allowed recovery of costs it has incurred.[875]

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[866] Ex. 437 at 68 (Lusti Direct).
[867] Ex. 100 at 44 (Clark Rebuttal); Ex. 37 at 4 (Anderson Rebuttal).
[868] *Id.*
[869] Issue 76.
[870] Ex. 58 at 54 (Mills Direct).
[871] Ex. 260 at 23-24 (Pollock Direct).
[872] Ex. 90 at 35 (Heuer Rebuttal).
[873] Ex. 60 at 17 (Mills Rebuttal).
[874] Xcel Initial Br. at 115-116.
[875] *Id.* at 115; Ex. 60 at 18 (Mills Rebuttal).

577. XLI disagreed and maintained that the Company has not demonstrated that its action were prudent both before and after the outage. XLI noted that the Company has provided information about how it responded to the error that caused the Black Dog outage, but the Company has not provided a justification for the error itself or information about what steps the Company was taking to prevent such errors before they occurred.[876]

578. The Administrative Law Judge concludes that XLI's proposed disallowances in the 2014 test year for the Black Dog outage constitute retroactive ratemaking because the disallowances relate to costs incurred prior to the 2014 test year.[877] XLI had an opportunity to address issues relating to the Black Dog outage in the last rate case. Because the Administrative Law Judge has determined that XLI's proposal would result in retroactive ratemaking, it is not necessary to address the standard of care for incurring those costs.

579. Based on the above determinations, the Administrative Law Judge recommends that the Commission not adopt XLI's proposed disallowances in the 2014 test year for the 2012-2013 outage at Black Dog. With regard to whether any replacement fuel costs should be disallowed, that issue is properly addressed in the AAA proceeding.

P. Pleasant Valley Wind and Borders Wind (2015 Step)[878]

580. The Company proposed to include the capital costs for two Company-owned wind projects, Pleasant Valley Wind and Borders Wind, in the 2015 Step.[879] The Company expects both of these projects to be in-service by the end of 2015.[880]

581. The Company receives production tax credits (PTCs) for its Company-owned wind facilities based on the production of the facilities.[881] In past rate cases, the Company has included the estimate of PTCs it expects to receive, and then used the Renewable Energy Standard (RES) rider to true-up actual PTC levels.[882] In its initial filing, however, the Company did not incorporate PTCs for the Pleasant Valley and Borders Winds projects that are expected to begin operating in 2015.[883] The Department and the OAG recommended an increase in revenues of $11.093 million in the 2015 Step year to represent the PTCs that the Company will receive for the two new wind farms, subject to a true-up in the RES rider.[884]

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[876] XLI Reply Br. at 9.
[877] *See* Minn. Stat. § 216B.16, subd. 5 (2014).
[878] Issue 30
[879] Ex. 51 at 69-70 (O'Connor Direct).
[880] Ex. 58 at 63-66 (Mills Direct).
[881] Ex. 372 at 4 (Lindell Rebuttal).
[882] Ex. 429 at 40 (Campbell Direct).
[883] *Id.*
[884] Ex. 372 at 5 (Lindell Rebuttal); Ex. 429 at 41 (Campbell Direct).

582. MCC, on the other hand recommended that the Company recover its costs for the Pleasant Valley and Borders Wind projects (less PTCs) through the RES rider rather than in the 2015 Step.[885] MCC maintained that recovery through the RES rider is preferable because if there are delays, then the costs will not be recovered until the facilities are placed into service. MCC also noted that the use of the RES rider would be required even if the costs are included in the 2015 Step because of the true-up for PTCs proposed by the Department and the OAG.[886] Finally, MCC calculated that ratepayers would pay approximately $5.34 million more in 2015 if recovery is through rate base rather than the RES rider.[887]

583. In Rebuttal Testimony, the Company accepted the proposal of the Department and the OAG regarding treatment of PTCs for these projects in the 2015 Step, but also stated that it is not opposed to MCC's recommendation to include both the capital costs and associated PTCs for the Pleasant Valley and Borders Wind projects in the RES Rider.[888]

584. Based on the Company's agreement on the PTC issue, the Department and the OAG consider the PTC issue resolved.[889]

585. With regard to MCC's proposal to recover the costs of the Pleasant Valley and Borders Wind projects in the RES rider, the Department stated that it prefers recovery in rate base because the record shows that it is very unlikely that these facilities will not be in-service in 2015 and because of the Commission's desire to reduce the use of riders to recover costs. The Department noted, however, that it is not opposed to recovery through the RES rider.[890]

586. The determination of whether to include the Pleasant Valley and Borders Wind project costs in the 2015 Step or RES rider depends upon whether the Commission seeks to limit the amount of funds recovered through riders or whether the Commission seeks to moderate the effects of the 2015 Step by including these costs in the RES rider. Either approach would result in reasonable treatment of these costs.

Q. Nuclear Theoretical Depreciation Reserve (2014)[891]

i. Background

587. "Depreciation" is defined in Commission 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

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885 Ex. 345 at 3-4 (Maini Surrebuttal).
886 *Id.*
887 *Id.* at 3.
888 Ex. 100 at 27-28 (Clark Rebuttal); Ex. 97 at 7 (Robinson Rebuttal).
889 Ex. 435 at 4-5 (Campbell Surrebuttal); OAG Initial Br. at 40.
890 Ex. 435 at 7-11 (Campbell Surrebuttal); Department Initial Br. at 225-26.
891 Issue 75.

known to be in current operation and against which the utility is not protected by insurance."[892] Assets may depreciate due to wear and tear, decay, inadequacy, obsolescence, and a variety of other causes.[893]

588. "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 of valuation."[894]

589. According to the National Association of Regulatory Utility Commissioners (NARUC):

> [T]he purpose of depreciation is not to build a reserve for the future…the sole purpose of depreciation accounting is to ratably allocate the capital costs of the property over its average service life through current charges to utility expenses.[895]

590. Under Minn. R. 7825.0800 (2013), a utility must use the straight-line method for calculating depreciation unless the Commission authorizes an exception. The Commission can deviate from straight-line depreciation and authorize amortization of surplus depreciation over a defined period of time (e.g. five year period) if it finds there is a specific justification for doing so.[896]

591. A depreciation surplus occurs when the book (or accumulated depreciation) reserve exceeds the theoretical reserve. The theoretical reserve is the reserve that would exist if all the facts that go into the depreciation calculation that are currently known were known at the time the asset was placed in service.[897]

ii. The Commission's Decision Regarding Nuclear Production Plant Depreciation in the 12-961 Rate Case

592. In the last rate case, XLI asserted that the Company had a $219 million depreciation reserve surplus for its nuclear production plant and proposed that the Company amortize these funds over a five-year period.[898] The Company and Department opposed XLI's proposal.[899]

593. The Commission declined to adopt XLI's proposal. The Commission found that "the preponderance of the evidence indicates that these reserves

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[892] Minn. R. 7825.0500, subp. 6 (2013).
[893] *Id.*
[894] *Id.* (citing NARUC*, Public Utility Depreciation Practicus,* August 1996 at 1, 187).
[895] Ex. 263 at 13 (Pollock Surrebuttal).
[896] Minn. R. 7825.0800 (2013).
[897] Ex. 260 at 12 (Pollock Direct); Ex. 92 at 44 (Perkett Direct).
[898] 12-961 ORDER at 26.
[899] *Id.* at 27.

appropriately reflect the cost of production plant retirements, including interim retirements, as explained by Xcel and the Department."[900]

594. The Commission, however, stated that its decision was not intended to preclude "continued monitoring and analysis," and directed "the parties to explore the matter more fully" in this case.[901] In addition, the Commission specifically ordered the Company to address in this rate case "whether there should be any adjustments to depreciation reserves for Xcel's nuclear production assets."[902]

iii. Current Nuclear Production Plant Depreciation Reserve Surplus

595. Consistent with the Commission's directive in the last rate case, the Company provided testimony in this rate case regarding its book and theoretical nuclear depreciation reserves. The Company noted that the question of whether there is a nuclear theoretical reserve surplus stems from the fact that each of its nuclear units has received a license extension. A depreciation surplus could result due to the fact that depreciation rates were previously set to recover costs over the initial license periods and now the remaining lives have been extended.[903]

596. The Company's analysis indicates that as of December 12, 2012, the Company had a theoretical nuclear plant reserve balance of $1,260,417,415 and a total actual nuclear plant reserve balance of $1,357,887,703. This results in a reserve surplus of approximately $97,740,288 on a total Company basis, or approximately $72.5 million on a Minnesota jurisdictional basis. The Company noted that the existence and amount of the reserve surplus depends on several current assumptions including remaining life, interim retirements and removal, and net salvage.[904]

a. XLI's Position and Amortization Proposal

597. XLI disagreed with the Company's calculation and asserted that the Company substantially underestimated the magnitude of the surplus. XLI claimed that the Company's calculation is flawed because it includes future interim capital additions[905] and does not use vintage accounting.[906] When the theoretical reserve is calculated using the vintage accounting and excluding interim capital additions, the

[900] *Id.* at 29.
[901] *Id.*
[902] *Id.* at 47, ¶12.
[903] Ex. 92 at 44 (Perkett Direct).
[904] *Id.* at 46; Ex. 260 at 10 (Pollock Direct); Tr. Vol. 2 at 66-68 (Perkett).
[905] Future interim plant additions are additions that will occur in the future but before the plant license expires. Ex. 260 at 13-14 (Pollock Direct).
[906] As discussed in more detail in Paragraph 600 vintage accounting looks at the life of the asset on a stand-alone basis, even where that asset's life is longer than the remaining operating period of the nuclear plant where the asset is being installed. *See* Ex. 94 at 9 (Perkett Rebuttal).

Company's nuclear depreciation surplus is $208 million on a Minnesota jurisdictional basis according to XLI.[907]

598. XLI asserted that a large surplus indicates that the current generation of customers is subsidizing future customers, which results in generational inequity.[908]

599. To ensure that both present and future customers are treated equitably and to help mitigate rate increases in this case, XLI recommended that the $208 million surplus be amortized over five years.[909] XLI asserted that its recommendation is consistent with the Commission's decision in the last rate case where it required amortization of the depreciation surplus for transmission, distribution, and generation (TDG) plant accounts over eight years.[910]

b. The Company's Position

600. The Company disagreed with XLI's calculation of the nuclear depreciation surplus and XLI's amortization proposal. The Company contended that XLI's use of vintages to determine depreciation expense for nuclear facilities is inappropriate because 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 stand-alone life of the asset.[911] Company witness Lisa H. Perkett gave the following example: "[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.…[T]he pump would have a 15-year life expectation."[912] The Company asserted that its use of remaining lives is a superior method.[913] With regard to the other disputed assumption, interim capital additions, the Company maintained that it is proper to consider these additions when calculating the reserve surplus to understand the impacts to current and future ratepayers.[914]

601. The Company also asserted 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.[915]

602. Moreover, the Company maintained that, as to generational inequity, future ratepayers are put at risk by XLI's proposal. The Company stated that any

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[907] Ex. 260 at 13-16 (Pollock Direct); Ex. 264 at 1 (Pollock Opening Statement).
[908] Ex. 260 at 11 (Pollock Direct).
[909] *Id.* at 11, 18.
[910] Ex. 263 at 8-9 (Pollock Surrebuttal); XLI Initial Br. at 7.
[911] Ex. 94 at 9 (Perkett Rebuttal); *see also* Ex. 260 at 15-16 (Pollock Direct) (explaining calculation of the theoretical reserve by vintage).
[912] Ex. 94 at 9 (Perkett Rebuttal).
[913] *Id.*
[914] *Id.* at 10.
[915] Xcel Initial Br. at 103 (citing 12-961 ORDER at 27, 29).

reduction in the current reserve due to use of the theoretical reserve surplus would cause an increase in the depreciation to be paid by customers in the future. This would occur because the amounts in the current reserve are needed to retire the Company's nuclear plants and any amount used now will have to be recovered in the future over the remaining life of the plant. "In addition, every dollar currently residing in accumulated depreciation also reduces rate base by a dollar, lowering [the Company's] revenue requirement." Those increases would be on top of the increases in future depreciation expense.[916]

603. The Company suggested that there is another way to reduce the current amount of depreciation.[917] The Company explained that the method, which would require approval to deviate from the Generally Accepted Accounting Principles (GAAP), would employ regulatory accounting to depreciate nuclear units over a remaining life longer than the license life.[918] No other party expressed interest in this proposal.

c. The Department's Position

604. The Department disagreed with XLI's characterization of the nuclear depreciation reserve as having a surplus and opposed XLI's amortization proposal.

605. The Department asserted that the "'surplus' is only an estimate, not a guaranteed surplus."[919] Even assuming XLI's estimate is accurate, the Department opposed XLI's amortization plan because ratepayers would be required "not only to repay this depreciation expense but also to pay a return on higher rate base as well." As a result, the short-term reduction provided by the amortization would result in higher rates over the long-term for ratepayers.[920]

606. The Department also claimed that XLI's proposal is not consistent with past Commission's decisions on the Company's annual and five-year depreciation studies, nor is it consistent with past Integrated Resource Plan decisions.[921]

607. Finally, the Department contended that XLI's claim of overpayment is incomplete and incorrect because XLI's method of estimating the surplus does not consider what is occurring during the current rate case in the 2014 test year and the 2015 Step year or 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

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[916] Ex. 94 at 11 (Perkett Rebuttal).
[917] *Id.* at 13-14.
[918] *Id.*
[919] Ex. 434 at 2 (Campbell Rebuttal).
[920] *Id.*
[921] *Id.*

related to the Monticello LCM/EPU Project and the cancelled Prairie Island EPU Project.[922]

[922] *Id.* at 3.

d. The OAG's Position

608. The OAG also opposed XLI's proposed amortization plan. The OAG asserted that the plan would harm ratepayers because they would be "paying for depreciation twice and also [would] pay a return on the higher rate base that results from amortization of the depreciation reserve." The OAG noted that the proposal would not achieve any real rate reduction for ratepayers, only a short-term benefit.[923]

e. XLI's Response

609. XLI disagreed with the Department's suggestion that the surplus does not exist. XLI noted that a significant nuclear depreciation reserve surplus has been indicated in several past depreciation studies.[924]

610. In addition, XLI continued to support its method of calculating the nuclear depreciation reserve surplus. XLI asserted that use of the vintage method is appropriate because the licenses for the Company's nuclear facilities could be extended again.[925] XLI also claimed that considering future interim plant additions is contrary to the definition of depreciation, which relates to recovery of invested capital.[926]

611. XLI also opposed the other parties' view that the surplus should be used to dampen depreciation increases in the future. According to XLI's witness, Mr. Pollock, the depreciation surplus is not a "slush fund" to absorb future capital additions, and failing to amortize the surplus would result in current rates exceeding cost.[927]

612. In addition, XLI asserted that the future payback requirement that would result from the amortization of the surplus is not a legitimate reason to reject XLI's proposal. It maintains that the net present value paid with the amortization proposal is the same as the sums that would be paid if the proposal is not adopted. However, by employing accelerated depreciation, intergenerational equity would be restored.[928]

613. XLI also reiterated that its proposal is consistent with the Commission's decision concerning the amortization of the TDG deprecation surplus in the Company's last rate case.[929] In that case, the Commission noted that several policy considerations influenced the Commission's decision regarding whether to require amortization of a depreciation surplus, including: rate shock mitigation; rate stability; and intergenerational equity.[930]

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[923] Ex. 141 at 1 (Lindell Opening).
[924] Ex. 263 at 11 (Pollock Surrebuttal).
[925] *Id.* at 18.
[926] *Id.* at 12.
[927] *Id.* at 5, 9-10, 15; XLI Initial Br. at 7.
[928] Ex. 263 at 13-14 (Pollock Surrebuttal).
[929] *Id.* at 14.
[930] 12-961 ORDER at 28-29.

iv. Analysis

614. In this case, both the Company and XLI have demonstrated, based on financial analysis, that a nuclear depreciation reserve surplus exists. They disagree, however, as to the amount of the reserve.[931]

615. With regard to the calculation of the amount of the surplus, the Administrative Law Judge agrees with the Company that the vintage accounting method is not appropriate for determining the nuclear plant depreciation expense because the useful life of a nuclear power plant is determined by its license. Contrary to XLI's assertion, it is not reasonable to assume that the licenses for the Prairie Island and Monticello plants will be extended beyond their existing terms. There are no pending extension requests for either Prairie Island or Monticello and, even if there were, NRC approval is not guaranteed.

616. The Administrative Law Judge, however, questions the Company's inclusion of future plant additions in its calculation of the nuclear depreciation reserve surplus. As noted by XLI, depreciation is intended to recover the costs of capital that is already invested, not future investments. Nonetheless, inclusion of the future interim additions is helpful for understanding the likely impacts on ratepayers.

617. Based on this analysis, the Administrative Law Judge concludes that XLI's calculation of the nuclear depreciation surplus likely overestimates the surplus because it is based on vintage accounting. Conversely, the Company has likely underestimated the surplus by including interim plant additions.

618. Because XLI has likely overestimated the nuclear reserve surplus, the Administrative Law Judge recommends the Commission reject XLI's proposal to amortize $208 million in nuclear production depreciation reserve over five years.

619. Whether the Commission should order amortization of a smaller amount (such as the $72.5 million surplus calculated by the Company) or take no action will depend on the determination of the size of the revenue deficiencies in 2014 and the 2015 Step and will require consideration of a variety of factors such as rate shock mitigation, rate stability, intergenerational equity, and the need to ensure adequate funding for plant retirements.[932] The Commission may also want to consider the potential rate impacts of adopting one or both of the Company's proposed rate moderation proposals, which are discussed below, in making its determination regarding treatment of the nuclear plant depreciation reserve surplus.

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[931] Ex. 92 at 46 (Perkett Direct); Ex. 264 at 1 (Pollock Opening Statement).
[932] *See* 12-961 ORDER at 28; Ex. 94 at 11 (Perkett Rebuttal).

R. Company Rate Moderation Proposals (2014 and 2015 Step)[933]

620. As discussed above in paragraph 599, the Commission ordered the Company in the last rate case to amortize the difference between its actual and theoretical depreciation reserves for TDG assets over a period of eight years.[934] As a result, the Company began amortizing the TDG reserve surplus of approximately $261 million over eight years beginning in 2013. As of the beginning of 2014, there was $228.5 million remaining to be amortized over the next seven years.[935]

621. To moderate the impact of rate increases on customers from the Company's current rate case, the Company proposed to accelerate return of the TDG depreciation surplus over the next three years by amortizing 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016. These amounts would be used to reduce the revenue deficiency that the Company would otherwise recover through rates.[936] This proposal would have the effect of moderating the degree of rate increases over these years as compared to straight-line, eight-year amortization of the TDG theoretical reserve authorized in the last rate case.[937]

622. The Company also presented a second rate moderation proposal. The Company suggested that a portion of funds received from the settlement of litigation with the Department of Energy (DOE) regarding spent nuclear fuel be used to reduce its revenue deficiency for 2015.[938] More specifically, the Company proposed to use the settlement funds received in 2013 and 2014 (in excess of amounts needed for annual nuclear decommissioning accrual) to reduce the 2015 revenue requirement.[939] The Company initially estimated this amount to be approximately $35.8 million, but subsequently revised its estimate downward to approximately $25.7 million. The Company agreed that this amount would be trued-up to actual DOE funds received in 2013 and 2014.[940]

623. The Department is supportive of the Company's two rate moderation proposals. The Department stated that, as a general principle, it does not usually favor an accelerated return of a depreciation reserve surplus for the same reasons as those discussed in the previous section. The Department, however, found the Company's suggested 50/30/20 proposal for the TDG surplus to be reasonable. The Department pointed out that in the last rate case the Commission authorized amortization of the TDG depreciation reserve surplus over eight years.[941] In addition, in this case the

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[933] Issues 9 and 34.
[934] 12-961 ORDER at 47, ¶11.
[935] Ex. 99 at 27 (Clark Direct).
[936] *Id.*
[937] Ex. 100 at 36 (Clark Rebuttal).
[938] Ex. 95 at 33 (Robinson Direct); Ex. 99 at 28 (Clark Direct).
[939] Ex. 99 at 28 (Clark Direct).
[940] Ex. 97 at 13-14 (Robinson Rebuttal); Ex. 130 at 1 (Perkett Opening Statement); Ex. 450 at 3-4 (Campbell Opening Statement).
[941] Department Initial Br. at 245; 12-961 ORDER at 28-29.

Commission's Order setting interim rates allowed the implementation of the Company's 50/30/20 approach for interim rates. As a result, the Department determined that the final rate decision should reflect a similar approach to amortization of the TDG surplus. The Department also agreed with the proposed use of the excess DOE settlement funds to reduce the revenue deficiency in 2015.[942]

624. While supportive of the 50/30/20 proposal coupled with use of excess DOE funds, the Department suggested that a 50/40/10 approach, along with use of DOE funds, would be preferable. The Department based its recommendation on its financial analysis of several alternative scenarios.[943]

625. Like the Department, XLI supported the Company's proposal to amortize the depreciation reserve surplus for TDG assets over three years.[944]

626. The Commercial Group did not address the amortization proposal but did address the Company's proposed use of DOE settlement funds. The Commercial Group agreed with the use of the funds as a moderation mechanism but proposed that the funds be used to moderate rate increases in both 2014 and 2015, not just in 2015. The Commercial Group recommended that the funds received in 2013 be used to reduce the revenue deficiency for the 2014 test year, and funds received in 2014 be used to reduce any 2015 Step increase. The Commercial Group also suggested that if the Commission does not approve the use of a Step increase, then the entire amount of excess DOE funds should be used to offset any approved rate change for the 2014 test year.[945] The Commercial Group maintained that such an approach would balance any need for rate moderation with the need of ratepayers to receive their funds on a timely basis.[946]

627. The OAG disagreed with both of the Company's rate moderation proposals. The OAG asserted that the Company's proposals are simply an attempt to make its rate increases look more reasonable and do not offer any real savings to customers.[947] The OAG stated that the Company's accelerated depreciation proposal shifts cost recovery to future periods and allows the Company to earn a return on the amortized amounts. The OAG also maintained that use of the DOE funds to reduce rates does not provide any real benefit because the proposal uses money that otherwise would be refunded to customers.[948]

628. The Company disagreed with the OAG's view that customers would not benefit from its rate moderation proposals. The Company maintained that customers

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[942] Ex. 429 at 88-94 (Campbell Direct); Ex. 435 at 65-69 (Campbell Public Surrebuttal); Ex. 250 at 3-4 (Campbell Opening Statement).
[943] Ex. 429 at 94 (Campbell Direct); Ex. 250 at 3-4 (Campbell Opening Statement).
[944] XLI Initial Br. at 6.
[945] Ex. 225 at 12 (Chriss Direct); Commercial Group Initial Br. at 10.
[946] Commercial Group Initial Br. at 10.
[947] Ex. 370 at 12 (Lindell Direct).
[948] *Id.* at 12-13, 16 (Lindell Direct).

would benefit from its two rate moderation proposals because the moderation would: (1) result in more stable and predictable rate increases between 2014 and 2016; (2) enhance regulatory efficiency; and (3) reduce the impacts of the Company's current investment cycle on its customers.[949]

629. In response to the Department, the Company stated that it does not support the Department's proposed 50/40/10 amortization approach because "the long-term benefits of returning the theoretical reserve to ratepayers more quickly may be outweighed by a greater bounce back effect in 2016."[950] The Company also provided a 50/0/50 percent schedule as an illustrative example for the Commission's consideration.[951]

630. The determination of whether one or more rate moderation mechanisms should be adopted in this case will depend on the size of the revenue deficiencies for 2014 and the 2015 Step that result from the revenue requirement decisions made by the Commission in this proceeding.

631. If the Commission decides some rate moderation is necessary, the Administrative Law Judge recommends that the Commission use the excess DOE settlement funds from 2013 and 2014 to reduce the level of rate increases. The Administrative Law Judge makes no recommendation, however, regarding whether the funds should be used as an offset only in 2015 as suggested by the Company, or spread between 2014 and 2015 as suggested by the Commercial Group. That determination will depend upon the final revenue deficiencies for those two years.

632. With regard to the Company's proposal to accelerate return of the TDG reserve surplus, the Administrative Law Judge agrees with both the OAG and the Department that accelerating the return will reduce rates in the short-term but result in higher rates in later years. Notwithstanding this fact, there may be circumstances where such an approach would be warranted to avoid rate shock in the short-term and/or to address intergenerational equity.[952] Moreover, in this case, the Commission authorized the use of a 50/30/20 percent approach in setting the interim rates.[953] As a result, it may be reasonable to continue some form of accelerated return of the TDG depreciation reserve surplus in final rates.

S. Rate Shock[954]

633. The ICI Group has asked the Commission to deny the Company's proposed 10.4 percent rate increase over two years, as set forth in its initial filing, on the

[949] Ex. 100 at 39 (Clark Rebuttal).
[950] Xcel Reply Br. at 80.
[951] Ex. 100 at 42 (Clark Rebuttal); Xcel Reply Br. at 80.
[952] *See* 12-961 ORDER at 28 (listing the factors the Commission considers in determining such issues).
[953] ORDER SETTTING INTERIM RATES at 2-3 (January 2, 2014).
[954] Issue 79.

grounds that the Company's filing constitutes "rate shock."[955] Technically, rate shock applies when a rate increase is so large that it results in a significant drop in usage, reflecting the unwillingness or inability of customers to pay for those services.[956]

634. The ICI Group pointed out that this case is the fifth rate case filed by the Company in the past decade, and asserted that the cumulative effect of these rate cases, with the current request, represents a 48 percent increase in the cost of service over the pre-2005 annual revenue base.[957] The ICI Group claims the current proposed rate increases drastically impact its group members because they must pay the increased cost of electric services for facilities operating around the clock with few opportunities to reduce costs.[958]

635. The Administrative Law Judge concludes that the ICI Group's rate shock argument lacks merit. Under Minnesota law, a utility is entitled to recover reasonable, on-going costs associated with providing utility service.[959] The determination regarding any request for a rate increase is based on the factors set forth in Minn. Stat. § 216B.16, subd. 6, including "the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service."[960] These factors do not include rate shock.[961] Thus, contrary to the ICI Group's assertion, rate shock alone is not a basis for denying the Company's proposed rate increases.

T. Multiyear Rate Plan (MYRP)[962]

636. As noted above, the Company has proposed a multiyear rate plan.[963] This is the first rate case in Minnesota where a MYRP has been proposed.[964]

637. Pursuant to Minn. Stat. § 216B.16, subd. 9, the utility proposing the MYRP has the burden of proving the proposed plan will result in just and reasonable rates for its customers.[965]

638. In this case, the Company's proposed MYRP is a two-year structure consisting of a 2014 test year rate increase and a 2015 Step rate increase. According to the Company, the proposed MYRP includes recovery of a full year of costs for the

[955] ICI Group Initial Br. at 2-3.
[956] *Lloyd v. Pennsylvania Public Utility Comm'n*, 904 A.2d 1010, 1018 n.14 (Pa. Commw. Ct. 2006).
[957] Ex. 250 at 3-4 (Glahn Direct).
[958] *Id.* at 5.
[959] Minn. Stat. § 216B.16, subd. 6; *In re Request of Interstate Power Co. for Authority to Change Its Rates for Gas Serv. in Minnesota,* 559 N.W.2d 130, 134 (Minn. Ct. App. 1997).
[960] Minn. Stat. § 216B.16, subd. 6.
[961] *Id.*
[962] Issue 79A.
[963] Ex. 99 at 4 (Clark Direct); Minn. Stat. § 216B.16, subd. 19.
[964] Ex. 99 at 9 (Clark Direct).
[965] Minn. Stat. § 216B.16, subd. 19.

2014 test year as well as recovery of certain 2015 capital additions and related expenses that are too large to forgo initial recovery until 2016.[966]

639. The Company believes its proposed MYRP is the best response to the significant investments it is undertaking to supply reliable and safe electric service to customers.[967] According to the Company, the proposed MYRP offers several benefits to stakeholders, including: greater rate predictability for customers; opportunities for rate moderation; regulatory efficiency; a long-term view of the Company financials; support for state energy policies; and a reduction in regulatory lag.[968] The Company points to several other states, including California and Colorado, where MYRPs are successfully utilized.[969] Because its proposal is the first MYRP proposal in Minnesota, the Company took a conservative approach by only including one step increase in 2015 rather than two step increases in 2015 and 2016.[970] Notably, the Company plans to file another rate case in November 2015, using a 2016 test year.[971]

640. The ICI Group raised several concerns with the Company's MYRP proposal. First, the ICI Group opposes changing the current "regulatory lag" ratemaking framework to a form of "regulatory lead" where rate increases are determined based on forecasts of future investments instead of actual results.[972] If the economy improves, the ICI Group claims the Company will be in a position to over-earn or gain a financial windfall based on rates set too high.[973] Second, the ICI Group believes the MYRP does not simplify the ratemaking process but instead complicates the ratemaking process.[974] The ICI Group recommended that the Company's proposed MYRP be denied and the Commission limit the rate increase to a one-time change based on the 2014 test year costs and assets.[975]

641. The ICI Group is the only party to argue the Company's rate increases should be limited to the 2014 test year. Other parties to this proceeding recommended changes to the 2014 test year and 2015 Step revenue requirements, but have not recommended denial of the MYRP.

642. The concerns of the ICI Group regarding the Company's proposed MYRP go to the underlying policy question of whether a MYRP is a sound regulatory tool. In 2011, the Minnesota Legislature determined that MYRPs can be beneficial when it enacted the law allowing utilities to propose MYRPs to the Commission.[976] Pursuant to

[966] Ex. 25 at 16-17 (Sparby Direct).
[967] Ex. 100 at 4 (Clark Rebuttal).
[968] Ex. 99 at 6-7 (Clark Direct).
[969] Ex. 26 at 10-11 (Sparby Rebuttal).
[970] *Id.* at 11 (Sparby Rebuttal).
[971] Ex. 99 at 12 (Clark Direct).
[972] Ex. 250 at 7 (Glahn Direct).
[973] *Id.*
[974] Ex. 251 at 2 (Glahn Surrebuttal).
[975] Ex. 250 at 9 (Glahn Direct).
[976] Minn. Stat. § 216B.16, subd. 19.

Minn. Stat. § 216B.16, subd. 19, the utility has the burden of proving the proposed MYRP will result in just and reasonable rates for its customers.[977] As discussed in the other sections of this Report, the record in this case shows the Company's proposed MYRP, as modified in this Report, will result in just and reasonable rates. Therefore, the Administrative Law Judge recommends that the Commission deny the ICI Group's request to limit any rate increase to the 2014 test year.

VII. Key Resolved Revenue Requirement Issues

643. Attachment A to this Report lists the revenue requirement issues and other issues that were resolved during the course of this proceeding.

644. Two of the key resolved issues, Sales and Property Tax, are discussed below because of their significance to the overall revenue requirements for the 2014 test year and the 2015 Step.

A. Sales[978]

645. Accurately forecasting sales is important to ensure that the Company recovers its costs, no more and no less.[979] 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.[980] Conversely if the forecast underestimates sales, rates will be set too high resulting in customers paying more than what is necessary for the Company to recover its costs.[981]

646. The Company's sales forecast was a contested issue in the last 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 DSM.[982] In the last rate case, the Administrative Law Judge recommended that the Commission adopt the Department's proposals and the Department's alternative of using a four-year average to calculate embedded DSM.[983] The Commission adopted the Department's proposals but did not adopt the four-year average approach to DSM.[984]

647. In its Direct Testimony in this case, the Company endeavored to address the concerns raised in the prior rate case,[985] in part by utilizing a different methodology to account for future DSM.[986] The Department disagreed with several aspects of the

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977 *Id*.
978 Issue 13.
979 Ex. 38 at 4 (Marks Direct); Ex. 404 at 1 (Shah Direct).
980 Ex. 43 at 2 (Hyde Direct).
981 *Id.*
982 Ex. 43 at 4 (Hyde Direct).
983 *Id.*
984 Ex. 43 at 4 (Hyde Direct); Ex. 404 at 18 (Shah Direct).
985 Ex. 43 at 4 (Hyde Direct).
986 Ex. 38 at 31 (Marks Direct).

Company's sales forecast, particularly the Company's use of DSM and its customer counts.[987]

648. 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 Conservation Improvement Program (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.[988]

649. In Rebuttal Testimony, the Company proposed that the sales forecast be based on weather-normalized actual data for the test year.[989] This alternative methodology rendered unnecessary a decision on the DSM adjustment issue and the customer count issues.[990] 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.[991] The actual sales data must be weather-normalized to be representative of sales in future years.[992]

650. The Company committed to include weather-normalized actual sales data for the remainder of 2014 in a compliance filing.[993] The Company agreed to use the Department's coefficients for the calculation of the weather-normalization.[994] 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.[995] The Company committed to work with the Department to ensure that the calculations are correct,[996] and also 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.[997]

651. The Department agreed with the Company's proposal to use weather-normalized actual data for the 2014 test year.[998]

652. MCC accepted the proposal by the Company and the Department to use the weather-normalized 2014 actual sales.[999] No other party commented on the sales forecast issue.

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[987] Ex. 404 at 8 (Shah Direct).
[988] Ex. 343 at 14 (Maini Direct).
[989] Ex. 44 at 1 (Hyde Rebuttal).
[990] *Id.*; Ex. 406 at 9, 11 (Shah Surrebuttal).
[991] Ex. 44 at 5 (Hyde Rebuttal).
[992] *Id.*
[993] Ex. 44 at 6 (Hyde Rebuttal).
[994] Ex. 119 at 1 (Hyde Opening Statement).
[995] Ex. 140 at 5-6 (Heuer Opening Statement).
[996] *Id.* at 5.
[997] Ex. 40 at 17 (Marks Rebuttal).
[998] Ex. 444 at 1 (Shah Opening Statement); Tr. Vol. 4 at 54 (Shah).

653. As explained by Company witness Jannell Marks, weather-normalized actual 2013 sales were significantly lower than the forecast approved by the Commission in the last case.[1000] Weather-normalized actual 2013 sales were 0.3 percent higher than the Company's forecast.[1001] In this case, to avoid the significant under-recovery of a forecast set too high, or an over-recovery 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.

B. Property Tax Amount (2014)[1002]

654. Minnesota property taxes represent a significant expense for the Company. In Direct Testimony, the Company provided a detailed explanation of the methodology by which the Company forecasts its 2014 property taxes.[1003] The Company noted that its Minnesota property taxes, which represent almost 97 percent of its total property tax expense,[1004] have increased rapidly over the last ten years.[1005] The Company forecasted its 2014 electric and natural gas property taxes (including Minnesota, North Dakota, and South Dakota) to be $206 million on an NSP total Company basis,[1006] resulting in property taxes attributable to Minnesota electric operations for purposes of ratemaking to be $149.2 million.[1007]

655. The Department noted that the Company had over-recovered its allowed and/or forecasted property taxes in past years by an average of 9 percent. On that basis, the Department recommended that the 2014 property tax expense be reduced by 9 percent, or $13.5 million, to $135.7 million.[1008]

656. In Rebuttal Testimony, the Company used additional information it had received from the Minnesota Department of Revenue (DOR) to validate its original forecast.[1009] Using the additional information, the Company maintained that its total 2014 electric and natural gas property taxes would be $200.1 million.[1010] This resulted in property tax expenses attributable to Minnesota electric operations, for purposes of ratemaking, of $145 million.[1011]

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[999] Ex. 145 (Maini Opening Statement); Tr. Vol. 4 at 13 (Maini).
[1000] Ex. 38 at 18 (Marks Direct).
[1001] Ex. 40 at 8 (Marks Rebuttal).
[1002] Issue 14.
[1003] Ex. 32 at 1-18 (Duevel Direct).
[1004] *Id.* at 2.
[1005] *Id.* at 19.
[1006] *Id.* at 1-2.
[1007] *Id.* at 1-2, Schedule 10; *see also* Ex. 14 at Tab A-58 (Application Vol. 4A).
[1008] Ex. 437 at 36 (Lusti Direct).
[1009] Ex. 34 at 3 (Duevel Rebuttal).
[1010] *Id*.
[1011] Tr. Vol. 4 at 138 (Duevel).

657. In Surrebuttal Testimony, the Department acknowledged that its prior analysis had been incorrect.[1012] 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 percent increase over the actual 2013 figure.[1013]

658. 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.[1014] The result of the Department's alternative proposal was a property tax expense for ratemaking purposes of $141 million, an $8.2 million reduction from the Company's initial proposal.[1015]

659. MCC did not object to the validated figures presented in the Company's Rebuttal Testimony, and also stated that the Department's alternative proposal of $141 million would be appropriate.[1016]

660. 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.[1017] 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.[1018] The Department and MCC agreed to the Company's true-up proposal.[1019] No other party commented on 2014 property taxes.

661. 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.[1020] 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

[1012] Ex. 442 at 25-26 (Lusti Surrebuttal).
[1013] *Id.* at 29 (Lusti Surrebuttal).
[1014] *Id.* at 30.
[1015] *Id*.
[1016] Ex. 342 at 12 (Schedin Surrebuttal).
[1017] Ex. 117 at 1 (Duevel Opening Statement); Ex. 140 at 2 (Heuer Opening Statement).
[1018] Ex. 117 at 1 (Duevel Opening Statement); Tr. Vol. 1 at 137-39 (Duevel); Ex. 451 at 2 (Lusti Opening Statement).
[1019] Ex. 451 at 2 (Lusti Opening Statement); Tr. Vol. 1 at 137 (Duevel).
[1020] Ex. 451 at 2 (Lusti Opening Statement).

property tax expense would be reflected in final rates in this case, up to a cap of $145.0 million (Minnesota electric jurisdiction).[1021]

662. 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.[1022] 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 property tax expense), the Company agreed to make ongoing annual refunds of the difference until the Company files the next rate case.[1023]

663. The resolution reached by the Company and the Department is reasonable and should be adopted.

VIII. Rate Design Issues

A. Rate Design Principles

664. Once the Commission has determined the revenue requirements for a utility, it must then decide how to structure rates to recover the utility's revenue deficiency from various customer classes. This process is known as rate design.

665. Rate design, in contrast to the determination of the revenue requirement, is a quasi-legislative function. This step of the ratemaking process largely involves policy decisions to be made by the Commission.[1024] The Commission must balance competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.[1025]

666. The Commission has historically considered a variety of cost and non-cost factors when designing rates, including: cost of service; economic efficiency; ability to pay; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; and ability to bear, deflect, or otherwise compensate for additional costs.[1026]

667. The Commission has relied on the following four principles in establishing reasonable rate design:

i. Rates should be designed to allow the utility a reasonable opportunity to recover its revenue requirements, including the cost of capital;

[1021] *Id.*; Tr. Vol. 3 at 161-164, 168-69 (Heuer).
[1022] Ex. 451 at 2 (Lusti Opening Statement).
[1023] *Id.*
[1024] *St. Paul Area Chamber of Commerce v. Minnesota Pub. Serv. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977).
[1025] 12-961 ORDER at 5.
[1026] *St. Paul Area Chamber of* Commerce, 251 N.W.2d at 357.

ii. Rates should promote the efficient use of resources by sending appropriate price signals to customers, reflecting the cost of serving those customers. An appropriate price signal encourages conservation by customers;

iii. Rate changes should be gradual in order to limit rate shock to consumers. Rate stability and continuity are important to both the utility and the consumer. Consumers benefit from protection against rate shock associated with dramatic increases in rates, and utilities are afforded the opportunity to recover a steady revenue requirement; and

iv. Rates should be understandable and easy to administer. Maintaining ease in administration and understanding helps ensure that customers have a better understanding of their utility bills.[1027]

668. These principles are based on the provisions of Minnesota statutes which require that rates must be reasonable and not unreasonably preferential or prejudicial either by class or by person. Rate design should favor energy conservation and the use of renewable energy to the maximum extent reasonable.[1028] Doubts about the reasonableness of the rates should be resolved in favor of the consumer.[1029]

669. While the Company has the burden of proving that its proposed MYRP will result in just and reasonable rates, the party seeking a change in current rate design has the burden to show that its proposed rate design change is just and reasonable.[1030]

B. Class Cost of Service Study[1031]

670. Typically, the first step in determining the appropriate rate design is to conduct a Class Cost of Service Study (CCOSS). The purpose of a CCOSS is to identify, as accurately as possible, the responsibility of each customer class for each cost incurred by the utility in providing service.[1032] The CCOSS is one important factor in determining how to design rates for customer classes.[1033]

671. The development of a CCOSS typically includes three main processes:

[1027] Ex. 420 at 2-3 (Peirce Direct).
[1028] Minn. Stat. §§ 216B.03, 216C.05 (2014).
[1029] Minn. Stat. § 216B.03.
[1030] *See* Minn. Stat. § 216B.16, subds. 4, 19; *Northwestern Bell Telephone Party v. State*, 299 Minn. 1, 216 N.W.2d 841 (1974) (noting that rates fixed by the Commission are presumed to be just and reasonable); Minn. R. 1400.7300, subd. 5 (2013) (providing that the party proposing that certain action be taken has the burden of proof unless the substantive law provides a different burden or standard).
[1031] Issue 51.
[1032] Ex. 408 at 18 (Ouanes Direct).
[1033] *Id.*

- First, utility costs are functionalized, or grouped, according to their purposes – normally production, transmission, or distribution.

- Second, the functionalized costs are classified according to how they are incurred: (1) customer costs, such as metering and billing, which vary according to the number of customers served, not their energy use; (2) demand costs, such as the distribution system, which are sustained in order to serve the peak demand on the system, regardless of the number of customers; and (3) energy costs, such as fuel, which correspond to the quantity of energy produced.

- Third, the costs are allocated among the various customer classes according to each class's imposition of costs on the system.[1034]

672. In this case the Company filed two separate CCOSSs. The Company filed the 2014 CCOSS to reflect a 2014 test year.[1035] The Company also filed a 2015 CCOSS, reflecting an additional $98.4 million of revenue requirements in a 2015 Step increase.[1036]

673. The Company allocated costs among four customer classes: Residential, Commercial and Industrial (C&I) Non-demand, C&I Demand, and Street Lighting (Lighting).

674. Four parties raised objections or concerns regarding some aspect of the Company's CCOSS: the Department, the OAG, XLI, and MCC. In addition, AARP filed a brief supporting the OAG's recommendations regarding the CCOSS.[1037]

675. The objections and concerns of the parties that were not resolved during the course of the proceeding relate to the following issues:

- The Classification of Fixed Production Plant;

- The Classification of the Costs of Company Owned-Wind Facilities;

- Updating of Fixed Production Plant Cost Data;

- Use of the D10S Capacity Allocator;

- Allocation of Other Production Operation and Maintenance (O&M) Costs;

[1034] *Id.* at 19-20.
[1035] Ex. 102 at 5 (Peppin Direct).
[1036] *Id*. at 9.
[1037] AARP Initial Br. at 18-19.

- The Use of the Minimum Distribution System;
- Allocation of Economic Development Discounts; and
- Allocation of Interruptible Rate Discounts.

These disputed issues are addressed in turn below.[1038]

i. The Classification of Fixed Production Plant

a. Plant Stratification Method versus Straight Fixed Variable Method

676. In conducting its CCOSS analysis, the Company classified fixed production plant costs into capacity-related versus energy-related sub-functions using a process called "Plant Stratification" (also known as the Equivalent Peaker method). The Company has used this same classification method since the 1970s.[1039]

677. Under this method, capacity-related costs are based on the cost of a comparable combustion turbine (CT) peaking plant, which is built at the lowest capital cost and highest operating cost, to serve customer demand when there are no lower cost resources available (i.e. during times of peak demand). These costs are allocated based on customer demand at peak times. The energy-related portion of fixed generation costs reflects costs in excess of the capacity-related portion that is based on the comparable peaking plant. The energy-related costs are those of intermediate and baseload generation facilities. These facilities are built to provide low-cost energy, not capacity.[1040]

678. As in prior rate cases, MCC recommended that the Company adopt the Straight Fixed Variable method instead of Plant Stratification to classify fixed production plant. The Straight Fixed Variable method classifies all fixed production plant costs as demand-related because plant capacity is required to meet peak demand and reserve margin requirements. Variable costs such as fuel align with energy consumption and are therefore classified as energy-related.[1041] MCC argued that the Straight Fixed Variable method should be used based on its view that high energy users, such as large customers, are allocated more than their share of costs under the Plant Stratification method.[1042] MCC made this same argument in the last rate case.[1043]

1038 A description of the uncontested and/or resolved CCOSS issues can be found in Appendix A, the Final Issue List, and in the proposed findings of fact submitted by the parties.
1039 Ex. 102 at 12 (Peppin Direct).
1040 *Id.* at 12-14.
1041 Ex. 343 at 19-20 (Maini Direct).
1042 *Id.* at 16-17.
1043 *See* 12-961 REPORT at 138 ¶ 662.

679. The Department disagreed with MCC's recommendation and supported the Company's methodology. The Department noted that the Commission chose not to approve this same proposal by MCC in the Company's last rate case. The Department asserted that MCC's approach "'fails to recognize the dual nature of baseload plants in meeting both the peak demands and the annual energy requirements of customers'" that the Commission has found to be important in past rate cases.[1044]

680. The Department asserted that the Plant Stratification method properly shows the dual value of baseload plants and is consistent with the goals of least cost planning and cost savings. If the Company acquired production plants only to meet peak capacity needs at the lowest cost, the Company would be building only peaking generators, at the lowest cost per unit of capacity. Instead, the Company chooses a mix of generation facilities of varying capital costs to attain the dual goals of sufficient capacity and viable energy costs.[1045]

681. In several past rate cases, the Commission has compared Plant Stratification to the Straight Fixed Variable method, and determined that Plant Stratification is the more reasonable method to classify fixed production plant costs.[1046] MCC has put forward no new convincing argument to show that the Straight Fixed Variable method should be substituted. Nor has MCC responded to the Commission's emphasis on the need to recognize the dual nature of base load plants. For these reasons, the Administrative Law Judge concludes that the Company's continued use of the Plant Stratification method is reasonable.

b. Proposed Modifications to the Plant Stratification Method

682. While XLI did not dispute the use of the Plant Stratification method, XLI recommended that the Company modify its analysis in two ways: (1) use the estimated cost of a *new* peaker developed in the Windsource docket in place of the current-dollar *replacement* value of a peaker used by the Company; and (2) replace current-dollar replacement costs for other types of plants (nuclear, fossil, combined cycle, and hydro) with depreciated replacement values for these plants.[1047]

683. With these changes, the stratification allocation for each plant type would be calculated by comparing the cost of a new, *undepreciated* peaking plant (using the price from the Windsource docket) to the *depreciated* replacement value of the other plant type (nuclear, fossil, combined cycle, etc.).[1048]

[1044] Ex. 412 at 4-5 (Ouanes Rebuttal) (citing *In the Matter of the Application of Interstate Power and Light Co. for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-001/GR-10-276, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 50-51 (August 12, 2011)).
[1045] Ex. 412 at 2-6 (Ouanes Rebuttal).
[1046] *See* 12-961 ORDER at 15; 12-961 REPORT at 137-39.
[1047] Ex. 260 at 34-35 (Pollock Direct).
[1048] *Id.* at 35.

684. XLI based its recommendation on the fact that rates are set using net depreciated investment and its premise that depreciated replacement value would send stronger price signals because customers would recognize the actual effect of capacity additions on rates.[1049]

685. Under the existing Plant Stratification method, the Company compares the current-dollar replacement value of a peaker with the current-dollar replacement cost of the other types of plants to arrive at the capacity-related and energy-related stratification allocation for each plant type.[1050]

686. A comparison of the results under the two approaches is set forth below:[1051]

Table 12

	Company		**XLI**	
Plant Type	**Capacity Percentage**	**Energy Percentage**	**Capacity Percentage**	**Energy Percentage**
Peaking (CT)	100.0%	0.0%	100.0%	0.0%
Nuclear	20.9%	79.1%	47.8%	52.2%
Fossil	39.0%	61.0%	91.8%	8.2%
Combined Cycle	75.4%	24.6%	86.2%	13.8%
Hydro	17.0%	83.0%	19.0%	81.0%

687. The Company countered that XLI's recommended method would result in an apples to oranges comparison by mixing the *undepreciated* costs of a new peaking plant with the *depreciated* replacement values for nuclear, fossil, and other plant types. According to the Company, comparing apples to apples—that is, new, undepreciated peaking costs to the much higher cost of new, undepreciated nuclear, fossil, and other plant types would result in less, rather than more, plant costs classified as capacity than with the Company's current replacement costs used in the Plant Stratification method.[1052]

688. The Company also maintained it is not appropriate to use the cost of a new peaking plant developed in the Windsource docket, as XLI suggested, because the Windsource docket developed the cost of a *new* peaking plant, but the *replacement* cost of a peaking plant is the relevant plant cost for CCOSS purposes.[1053]

[1049] *Id.* at 34-36.
[1050] Ex. 102 at 12-13 (Peppin Direct).
[1051] Ex. 103 at 13, Table 7 (Peppin Rebuttal).
[1052] Ex. 103 at 11-12 (Peppin Rebuttal).
[1053] *Id.* at 12.

689. The Department agreed with the Company that XLI's method would inaccurately compare the cost of installing a new peaking unit with all other plants' depreciated replacement value, overstating the relative investment cost of peaking capacity.[1054] The OAG also opposed XLI's proposed changes to the Plant Stratification methodology for similar reasons.[1055]

690. The Administrative Law Judge concludes that XLI's proposed changes to the Plant Stratification methodology are not reasonable. As explained by the other parties, comparing the cost of a new peaking plant to the depreciated value of other types of generating plants, as XLI has recommended, is not analytically sound.

ii. The Classification of the Costs of Company-Owned Wind Facilities

691. There are four Company-owned wind generation projects included in the Company's CCOSSs: (1) Grand Meadow; (2) Nobles; (3) Pleasant Valley; and (4) Border Winds.[1056] Grand Meadow and Nobles are included in the 2014 CCOSS and in the 2015 Step CCOSS. Pleasant Valley and Border Winds are only included in the 2015 Step CCOSS.[1057]

692. The Grand Meadow and Nobles projects are older projects that were included in the Company's last rate case.[1058] Pleasant Valley and Border Winds are new projects that are expected to be on-line by the end of 2015.[1059]

693. In the last rate case, the Company classified the Grand Meadow and Nobles wind generation plants on the same basis as other fixed production plant costs, through the use of the Plant Stratification method. As a result, these wind plants were classified as about 4 to 5 percent capacity-related and 95 to 96 percent energy-related.[1060] In the current case, the Company changed its analysis for Grand Meadow and Nobles and has classified these two wind facilities as 100 percent capacity.[1061]

694. The Company, however, has applied the traditional Plant Stratification method to the Pleasant Valley and Border Winds facilities.[1062]

[1054] Ex. 412 at 10-11 (Ouanes Rebuttal).
[1055] Ex. 377 at 9-10 (Nelson Rebuttal).
[1056] Ex. 103 at 16 (Peppin Rebuttal).
[1057] *Id.*
[1058] *See* Ex. 377 at 12 (Nelson Rebuttal) (quoting *In the Matter of the Application of Northern States Power Co., a Minnesota Corporation for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-002/GR-08-1065, Rebuttal Testimony of Phillip J. Zins at 25-26 (May 5, 2009) and REN-22 (showing Grand Meadow and Nobles projects); 12-961 ORDER at 25 (authorizing recovery of Nobles costs).
[1059] Ex. 58 at 61-66 (Mills Direct).
[1060] Ex. 102 at 27 (Peppin Direct); Ex. 408 at 22 (Ouanes Direct).
[1061] Ex. 102 at 27 (Peppin Direct).
[1062] Ex. 103 at 16 (Peppin Rebuttal).

695. The Company asserted that its change for Nobles and Grand Meadow is appropriate because the Plant Stratification method is designed to recognize the fact that peaking plants are built to serve customer demand when there are no lower cost resources available and intermediate and baseload generation resources are added to provide low-cost energy. By selecting the optimal mix of these resources, the Company is able to minimize system costs over time.[1063] The Company maintained that Grand Meadow and Nobles do not fit this model of resource selection because they were added to comply with the Company's 2007 Renewable Energy Plan, not to meet demand or capacity needs. The Company stated, however, that Grand Meadow and Nobles were "economical when acquired."[1064]

696. The Company distinguished its treatment of the Grand Meadow and Nobles plants in this rate case from that of Pleasant Valley and Border Winds because the new wind farms, Pleasant Valley and Border Winds, were acquired to minimize system costs.[1065]

697. The Company also maintained that classifying the Grand Meadow and Nobles facilities as 100 percent capacity-related would serve as a partial offset to the approximately 600 MW of wind energy that are provided by Purchased Power Agreements (PPAs) and recovered through the Company's fuel cost charge. [1066]

698. The Company did not make either of these arguments in its last rate case even though costs for both Grand Meadow and Nobles were included in the Company's last rate case filed in November 2012.[1067]

699. XLI supported the Company's new approach to classification of Grand Meadow and Nobles.[1068] Likewise, MCC advocated that the Nobles and Grand Meadow costs be classified as 100 percent capacity-related or alternatively, by use of the "Percent of Base Revenue" method.[1069]

700. The Department opposed the Company's change in treatment of Nobles and Grand Meadow and recommended that the Company continue to classify and allocate all of its Company-owned wind generation, including Nobles and Grand Meadow, using the Plant Stratification method. The Department noted that in comparison to peaking facilities, which are brought on-line to fulfill capacity needs and are thus classified as demand-related, wind facilities can only generate electricity when the wind permits. The Department concluded that energy utilities would not acquire wind generation as a means to ensure sufficient capacity, as they would a peaking

[1063] Ex. 102 at 27 (Peppin Direct).
[1064] *Id.*
[1065] Ex. 103 at 17 (Peppin Rebuttal).
[1066] Ex. 102 at 27 (Peppin Direct).
[1067] *See generally* 12-961 REPORT.
[1068] Ex. 262 at 7-16 (Pollock Rebuttal).
[1069] Ex. 343 at 22-23 (Maini Direct).

plant; costs of wind generation therefore should not be classified as 100 percent capacity-related.[1070]

701. The Department also noted that the Commission has already rejected the Company's suggestion that the Plant Stratification method is not appropriate for Company-owned wind facilities acquired to satisfy a statutory provision. The Department pointed to the Commission's approval in the 2010 rate case of the Company's classification and allocation of wind costs according to the Plant Stratification method:

> The Commission is satisfied with Xcel's treatment of company-owned wind facilities. State legislative policy undoubtedly encourages the development of renewable generation as part of electric utilities' generation portfolios. However, it does not follow that those resources are necessarily not least-cost. Xcel's attribution of wind-facility costs primarily to energy needs closely matches the characteristics of wind facilities. Wind resources by and large replace other energy resources, and contribute very little to capacity.[1071]

702. The Department also disagreed with the Company's argument that classification of wind costs as 100 percent capacity-related would properly serve as an offset to the Company's recovery of the costs of wind obtained in PPAs through its fuel charge. The Department argued the Company should pursue a change to policy governing recovery of PPA costs in another forum.[1072]

703. The Department noted that application of the Plant Stratification method to Nobles and Grand Meadow would result in a calculation of approximately 4 to 5 percent capacity-related and 95 to 96 percent energy-related, as opposed to the 100 percent capacity-related allocation proposed by the Company.[1073]

704. The OAG also disagreed with the Company's proposed classification of Grand Meadow and Nobles as 100 percent capacity-related and recommended instead that the Company allocate the costs associated with Grand Meadow and Nobles as 100 percent energy-related.[1074] In support of its position, the OAG noted that Minn. Stat. § 216B.1691 (2014), which mandates electric utilities' use of renewable energy, sets the standard on the basis of a required percentage of the utility's total retail electric sales (total energy generated), not on the basis of the maximum demand served.[1075] The OAG quoted the Company's witness in the 2008 rate case stating why the Company's

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[1070] Ex. 408 at 22 (Ouanes Direct).

[1071] *Id.* at 26 (quoting *In the Matter of the Application of Northern States Power Co. for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 21 (May 14, 2012)(10-971 ORDER)).

[1072] *Id.* at 24.

[1073] *Id.* at 22.

[1074] Ex. 375 at 10 (Nelson Direct).

[1075] *Id.* at 8.

Plant Stratification methodology for Company-owned wind generation costs results primarily in energy-related classification:

> The purpose for accelerated development of wind energy is to obtain the environmental benefits of this particular source of energy (not capacity) as compare [sic] to other energy (not capacity) sources. It is also well known that wind energy is intermittent and available only when the wind blows, which is further evidence that it is a source of intermittent energy, which may provide only a small capacity value. This is all reflected in the small 4.7% capacity value resulting for the Grand Meadow resource in the Company's stratification analysis.[1076]

705. If the Commission does not require the classification of the Nobles and Grand Meadow plant costs as 100 percent energy-related, the OAG would also support the continued use of the Plant Stratification method. [1077]

706. The Administrative Law Judge concludes that the Company has not demonstrated that it is reasonable to classify the Grand Meadow and Nobles generation facilities as 100 percent capacity-related. As the Commission noted in its 10-971 ORDER, wind facilities generally replace other energy resources, and "contribute very little to capacity" because they are only available when the wind blows.[1078] The Company has failed to provide any evidence that Nobles and Grand Meadow have any different operational characteristics than other wind facilities that would justify classifying them as 100 percent capacity-related. The fact that these facilities were built to satisfy a legislative renewable energy policy does not change their operational characteristics, and therefore does not provide a rational basis for classifying these facilities as 100 percent capacity-related.[1079]

707. Nor is the classification of the Nobles and Grand Meadow costs as 100 percent capacity-related justified by the Company's recovery of the costs of wind energy PPAs through its fuel charge. The CCOSS is not the proper forum for mitigating the effects of the fuel clause as a cost recovery mechanism for purchased power.

708. Just as classifying wind generation as 100 percent capacity-related is not reasonable, neither is the alternative of classifying wind generation as 100 percent energy-related as suggested by the OAG. Such a classification is inconsistent with the

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[1076] Ex. 377 at 12 (Nelson Rebuttal), quoting *In the Matter of the Application of Northern States Power Co., a Minnesota Corp. for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-002/GR-08-1065, Rebuttal Testimony of Phillip J. Zins at 25-26 (May 5, 2009). (emphasis in original).
[1077] Ex. 375 at 10 (Nelson Direct).
[1078] 10-971 ORDER at 20-21.
[1079] In addition, while not selected through resource planning, the Company maintains these facilities were "economical" when built. Ex. 102 at 27 (Peppin Direct).

Commission's determination in the 10-971 rate case that wind generation provides some limited capacity value.[1080]

709. The Commission has repeatedly confirmed the Company's use of the Plant Stratification method for the proper classification and allocation of the Company's production plant, including costs of Company-owned wind generation. The application of the Plant Stratification method to wind generation continues to be the most reasonable alternative shown in the record. Accordingly, the Administrative Law Judge recommends that the Commission require the Company to modify its 2014 and 2015 Step CCOSSs to classify the costs of the Grand Meadow and Nobles wind farms on the same basis as its other fixed production plant costs using the Plant Stratification method.

iii. Updating of Fixed Production Plant Cost Data.

710. At the time the Company filed its Direct Testimony, replacement cost and summer capacity rating data were not available for its Pleasant Valley and Border Winds facilities. The Company therefore used the costs for the Nobles and Grand Meadow wind facilities as a proxy for Pleasant Valley and Border Winds facilities in the classification of Fixed Production Plant in its 2015 CCOSS. At the time the Company filed its Rebuttal Testimony, however, plant-specific replacement cost information was available for Pleasant Valley and Border Winds. The Company therefore incorporated this information into its 2015 Step CCOSS as part of its Plant Stratification analysis.[1081]

711. The Department questioned the propriety of presenting updated data in Rebuttal Testimony. The Department further noted that the Company limited its update of its initially filed 2012 cost data in the 2015 Step CCOSS to the Pleasant Valley and Border Winds projects, even though 2013 cost data were available for all production plant costs. If the Commission finds the updated cost data acceptable, the Department stated, the Company should be required to use 2013 data for all fixed production plant costs as well as plant-specific data for Pleasant Valley and Border Winds in the application of its Plant Stratification methodology.[1082]

712. Newly received cost information, if presented in a timely and consistent fashion, can help provide the most accurate cost causation information for participants and decision-makers. In this case, the Department has not indicated that the information was filed too late for it and other parties to analyze in the rate case. Therefore, the Administrative Law Judge concludes it is reasonable to require the Company to update its CCOSS results using 2013 cost data for Pleasant Valley and Border Winds as well as for all other production plant costs in its Plant Stratification analysis.

[1080] 10-971 ORDER at 21.
[1081] Ex. 103 at 3 (Peppin Rebuttal).
[1082] Ex. 414 at 12-13 (Ouanes Surrebuttal).

iv. Use of the D10S Capacity Allocator

713. Once fixed production costs have been split into capacity and energy sub-functions, the costs must then be allocated to the different customer classes.[1083] In the Company's CCOSSs, the capacity-related portion is allocated to the various classes by determining each class's load that is coincident with the NSP system peak, as measured by the test year class hourly load shapes.[1084] The Company's summer peak-based allocator is called the D10S Capacity Allocator.[1085]

714. In order to ensure adequate reliability for its customers in the case of equipment failure, a utility must maintain planning reserves above the level needed to meet peak demand. On June 1, 2013, the Midcontinent Independent System Operator Inc. (MISO) set rules requiring that the planning reserve margin be based on a utility's peak that is coincident with MISO's peak, which is in the summer. The Company stated that its summer-based allocation method is consistent with system adequacy rules.[1086]

715. The OAG disagreed. Using the Company's data, the OAG showed that the Company's peak differs from MISO's by approximately 8 percent. The peak time of day also differed.[1087] Because MISO's peak is earlier in the day than the Company's, the OAG claimed MISO's peak is likely to fall less heavily on residential customers, who often return from work in the summer and turn on their air conditioners.[1088] The OAG concluded that the Company's method did not align with cost causation, and recommended that the Company be required to calculate its D10S Capacity Allocator using each class's demand that is coincident with MISO's peak, not the Company's peak. [1089]

716. While agreeing that alignment with MISO's peak would reflect cost causation in the CCOSS, the Company stated that it cannot calculate its capacity allocator using MISO's peak because MISO does not produce a forecast of its hourly loads for a test year.[1090]

717. The OAG recommended that the Commission require the Company to collect the data necessary to perform the calculation. The OAG's witness Ron Nelson acknowledged, however, that he is "unaware of the data that is currently available or could be acquired in the future" to support the calculation.[1091] Therefore, while the OAG has raised a noteworthy issue, the Administrative Law Judge concludes that the OAG

[1083] Ex. 102 at 14 (Peppin Direct).
[1084] Ex. 103 at 37 (Peppin Rebuttal).
[1085] Ex. 102 at 14 (Peppin Direct).
[1086] *Id.* at 15.
[1087] Ex. 375 at 11-12 (Nelson Direct).
[1088] Ex. 378 at 12 (Nelson Surrebuttal).
[1089] Ex. 375 at 13 (Nelson Direct).
[1090] Ex. 103 at 37-38 (Peppin Rebuttal).
[1091] Ex. 378 at 13 (Nelson Surrebuttal).

has not developed a sufficient record in this proceeding to support the viability of its recommendation.

v. Allocation of Other Production O&M Costs

718. Electric utilities have certain O&M costs, other than fuel and purchased power expenses, related to production plants. These costs include labor, materials, supplies and the supervision and engineering expenses associated with operating and maintaining the utility's power plant.[1092] These costs are termed Other Production O&M Costs.

719. In its last rate case, the Company continued its practice of classifying Other Production O&M Costs into either capacity-related or energy-related according to the corresponding percentage of the original underlying power plant investment. The result was an allocation of 25 percent of Other Production O&M Costs as capacity-related and 75 percent as energy-related.[1093]

720. In that rate case, the Department did not oppose the Company's method of classification of Other Production O&M Costs, but recommended that the Company refine its method further in its next rate case filing:

> Xcel should identify 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. [1094]

721. The Commission adopted the Department's recommendation.[1095]

722. The Company called the allocation methodology it had used for Other Production O&M Costs through the last rate case the Overall Investment method. It termed the allocation method ordered by the Commission for use in this rate case the "location" method. Citing the NARUC manual, the Company noted that another allocation methodology could also be used: the Predominant Nature method. The Company stated that the Predominant Nature method is similar to the first step of the Location method (identifying any and all Other Production O&M Costs that vary directly with the amount of energy produced) but goes beyond it to identify all Other Production O&M Costs according to their "predominant," that is, their capacity-related or energy-related nature.[1096]

[1092] 10-971 ORDER at 87.
[1093] Ex. 102 at 21 (Peppin Direct); 12-961 REPORT at 135-36.
[1094] 12-961 REPORT at 136.
[1095] 12-961 ORDER at 53.
[1096] Ex. 102 at 22 (Peppin Direct).

723. The Company did not use the Location method ordered by the Commission in its proposed CCOSS, but rather used the Predominant Nature method. The Company reached this decision after analyzing the results of both methods.[1097]

724. In conducting its analysis, the Company first examined its Other Production O&M Costs and found two costs that vary directly based on energy output: chemicals and water use. These items together total $13.0 million in the 2014 test year, or 2.6 percent of total Other Production O&M Costs. In the CCOSS, the Company classified these costs as energy-related and allocated them using its energy allocator. The Company then classified and allocated the remaining $493.1 million Other Production O&M Costs.[1098]

725. The Company determined that application of the Location method to these costs results in 65 percent of Other Production O&M Costs being classified as capacity-related and 35 percent as energy-related.[1099] Application of the Predominant Nature method, on the other hand, resulted in 78.4 percent of these costs being classified as capacity-related and 21.6 percent as energy-related.[1100]

726. A comparison of the results of the Location method, the Predominant Nature method, and the Overall Investment method (used in the last rate case) is set forth in the table below:[1101]

Table 13

Classification Methodology	**Capacity-Related**	**Energy-Related**
Location method	35.0%	65.0%
Predominant Nature Method	78.4%	21.6%
Overall Investment Method	25.0%	75.0%

727. The Company decided to use the Predominant Nature method in its present CCOSSs based on its view that the Predominant Nature method is "more consistent with the desire expressed during the 2013 rate case that the Company take a more expansive view of energy-related Other Production O&M Costs."[1102]

728. The Department disagreed with the Company and instead recommended that the Company be required to use the Location method to allocate Other Production O&M Costs in its 2014 and 2015 CCOSSs.[1103]

[1097] *Id.* at 19-24.
[1098] *Id.* at 19-20.
[1099] *Id.* at 20-21, 24.
[1100] *Id.* at 22-24.
[1101] *Id.* at 21, 24.
[1102] *Id.* at 25.
[1103] Ex. 408 at 28-35 (Ouanes Direct).

729. The Department asserted that the Company's use of the Predominant Nature method is inconsistent with the Commission's Order in the last rate case, wherein it required the Company to use the Location method.[1104]

730. The Department also cited the Commission's and the Company's past preference for the Overall Investment method over a strict fixed/variable distinction attributing costs according to demand/energy. The Department quoted the 10-961 ORDER, which states in relevant part:

> Xcel defends its decision to classify these "other" costs as demand- and energy-related in the same proportions as the plant where they were incurred. And Xcel disputes XLI's assertion that it is reasonable to assign plant labor costs entirely to demand and to assign materials and maintenance entirely to energy. Xcel argues that XLI's approach is not appropriate because fixed and variable costs do not directly correlate to demand and energy as XLI suggests.
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> *******
>
> The Commission concludes that Xcel reasonably allocated its plants' "other" operation and management expenses as 15% demand-related and 85% energy-related. Xcel's allocation of "other" costs in the same proportion as their corresponding generation plant best corresponds to the causes of those costs.
>
> The fixed/variable distinction does not correspond to whether those expenses are attributable to energy or demand; a number of fixed expenses at a nuclear plant, for example, arise in connection with fuel consumption and handling, and so do not fit neatly in this binary distinction. Xcel's method is preferable, because it does not misallocate the costs on the basis of their fixed or variable nature.[1105]

731. Because this analysis supports use of the Location method over the Predominant Nature method, the Department argued that the Commission should require the Company to use the Location method in this case. The Department noted that if the Location method is used rather than the Predominant Nature method, the result would be a decrease of approximately $12.5 million in the contribution of the Residential class to the Company's 2014 revenue requirement with a corresponding increase of about $12.4 million in the C&I Demand class contribution to the Company's 2014 revenue requirement. There would be a similar result in 2015 as well.[1106]

[1104] Ex. 408 at 33-34 (Ouanes Direct); 12-961 ORDER at 53, ¶ 49.
[1105] *Id.* at 29-31 (quoting 10-971 ORDER at 17-18).
[1106] Ex. 408 at 35-36 (Ouanes Direct).

732. Like the Department, the OAG recommended that the Company use the Location method instead of the Predominant Nature method in the CCOSS.[1107]

733. MCC and XLI supported the Company's use of the Predominant Nature method.[1108]

734. The propriety of the Overall Investment method for classifying Other Production O&M Costs has been confirmed in past Company testimony and in past Commission orders. In the last rate case, the Commission required a further refinement of the method through the application of the energy allocator to costs that vary directly with the amount of energy produced and allocation of the remainder of costs on the basis of Plant Production. As noted above, this approach is known as the Location method. In contrast, the Company's application of the Predominant Nature method goes beyond the refinement ordered by the Commission in the last rate case by assigning all remaining costs based on their "predominant nature."

735. The Company has not shown that its grouping and analysis of these Other Production O&M Costs based on their predominant nature moves the marker closer to cost causation. The Predominant Nature method displays the same oversimplified fixed/variable analysis that the Commission has previously found lacking. The Location method, required by the Commission in the 12-961 ORDER, is the most reasonable method of classifying Other Production O&M Costs in the record.

736. For these reasons, the Administrative Law Judge recommends that the Commission require the Company to modify its 2014 and 2015 CCOSSs to use the Location method rather than the Predominant Nature method.

vi. The Use of the Minimum Distribution System

737. In the Company's analysis of distribution costs, it used the Minimum Distribution System (MDS) method, a type of minimum system study, to separate the costs of its primary lines, secondary lines, secondary transformers and service drops into customer-related and capacity-related components. Under this CCOSS analysis, a utility compares the cost of the minimum size of each type of distribution facility used to the actual cost of the facilities installed. The cost of the minimum size facilities is the customer-related component of total costs and the capacity-related component is the difference between the total installed cost and the minimum sized cost.[1109] The theory of such a minimum system study is that any distribution equipment larger than the minimum required to allow a customer to receive service (the customer cost) has been installed in order to allow the utility to meet demand.[1110]

[1107] Ex. 377 at 14-18 (Nelson Rebuttal).
[1108] Ex. 343 at 25 (Maini Direct); Ex. 345 at 17 (Maini Surrebuttal); XLI Initial Br. at 12.
[1109] Ex. 103 at 28-29 (Peppin Rebuttal).
[1110] Ex. 375 at 15 (Nelson Direct).

738. The OAG pointed out that the NARUC Manual allows a minimum system study to be conducted under the Zero-Intercept method as well as the Minimum Size method. Under the Zero-Intercept method, a regression analysis is used to create a unit cost for a distribution unit that is no-load (i.e. zero capacity). As with the Minimum Size method, the costs of the minimum system are classified as customer costs and the remainder of the distribution costs as capacity costs.[1111]

739. The NARUC Manual states that the Minimum Size method of assigning distribution costs tends to produce a larger customer component than the Zero-Intercept method. The OAG asserted that the Zero-Intercept method is also more accurate because it constructs a minimum system devoid of material costs, with zero demand.[1112] In addition, the OAG stated that the Company's data accompanying its minimum size analysis are too inexact to allow the OAG to cross-check the results, and that the Company's criteria for choosing the distribution equipment in its study are vague.[1113] The OAG also noted that most of the distribution cost data were last calculated in 1991 and that the Company used the Handy Whitman Index to extrapolate to present costs for the various distribution elements, rather than analyzing actual costs.[1114]

740. The OAG recommended that the Company be required to conduct a zero-intercept analysis in its next rate case, and provide sufficient data to conduct a minimum size analysis as well. Also, based on its view that the Company has overstated certain distribution equipment costs in its minimum system study, the OAG recommended that the Company should be required to allocate 10 percent more distribution costs as capacity costs and 10 percent less as customer costs in this case. The OAG noted that it did not have the data necessary to conduct a complete analysis of the Company's actual minimum system costs.[1115]

741. The Company defended the accuracy of its minimum system study. The Company maintained that the OAG's proposed 10 percent adjustment is based on the cost of one item, but ignores the cost of other items that are understated. As a result, the Company asserted that the OAG's proposed adjustment is arbitrary and should be rejected.[1116]

742. Nonetheless, the Company stated it is willing to reexamine the assumptions supporting its minimum system study and the installed distribution costs in its next rate case.[1117] The Company stated that it does not currently possess the

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[1111] *Id.* at 15-17.
[1112] *Id.* at 16.
[1113] *Id.* at 21-22.
[1114] Ex. 377 at 2 (Nelson Rebuttal).
[1115] Ex. 375 at 26 (Nelson Direct); OAG Initial Br. at 51-54.
[1116] Xcel Initial Br. at 131 (citing information in the demonstrating certain costs in its minimum system study are understated).
[1117] Ex. 104 at 6 (Peppin Surrebuttal).

property and financial records necessary for the more stringent zero-intercept analysis. The gathering of such data would take several months of analysis.[1118] While the NARUC Manual found the Zero Intercept method more accurate than the Minimum Size method in most instances, the Company noted that the Manual also found the differences between the two methods relatively small. If it were able to compile the necessary data, the Company did not object to following the OAG's recommendation to file a zero-intercept analysis in its next rate case.[1119]

743. No other party filed testimony on this issue.

744. The Administrative Law Judge concludes that the OAG has raised valid concerns regarding the value of the data the Company has used to support its minimum system study. The data presented were last gathered nearly a quarter of a century ago, with no attempt to provide fact-specific updates. Although the analysis under the Zero-Intercept method may be more rigorous than under the Minimum Size method, the NARUC Manual has found that it is more accurate. For these reasons, the Company should be required to file a zero-intercept analysis of distribution costs in its next rate case. In addition, because the Minimum Size method is a useful cross check of the Zero-Intercept method, the Company should also file an updated Minimum Distribution System study as a comparative analysis.

745. The gathering of more sophisticated and updated distribution cost information in the next rate case will be an ongoing improvement to the CCOSS. Requiring the updating of data and the filing of a zero-intercept analysis in the next rate case is a more reasonable approach to addressing the issues raised by the OAG than adjusting the Company's distribution costs by 10 percent in this case.

vii. Allocation of Economic Development Discounts

746. In its last rate case, the Company proposed two economic development tariffed services to attempt to retain and expand the operations of large customers. The Company proposed to allocate the economic development discount costs as 61 percent capacity-related and 39 percent energy-related. XLI argued that the costs should be allocated relative to base rate, excluding base fuel costs. The Company countered that its proposed allocation was proper because the discounts will allow the Company to spread overhead costs more broadly, thus benefiting all customers. While finding the Company's cost allocation acceptable, the Administrative Law Judge recommended that the Company incorporate further study of the proper cost allocation of economic development discounts in its next rate case.[1120] The Commission agreed with the Administrative Law Judge's recommendation.[1121]

[1118] Ex. 103 at 34 (Peppin Rebuttal).
[1119] *Id.* at 31.
[1120] 12-961 REPORT at 137; EX. 102 at 18 (Peppin Direct).
[1121] 12-961 ORDER at 55, ¶ 57.

747. In response, the Company evaluated three alternative economic development discount allocations in this rate case: (1) weighting the capacity and energy allocators as in the last rate case; (2) using test year 2014 present revenues; and (3) using test year 2014 base revenues.[1122]

748. The Company determined that it would use the test year 2014 present revenues allocator because the programs are designed to attract new and retain existing large customers.[1123] The Company asserted this approach reasonably balances the interests of all classes in a manner that is consistent with the goal of helping to support economic development in its CCOSS analysis.[1124]

749. The Department disagreed with the Company's approach. The Department argued that the discounts are provided on an energy basis and therefore the cost of the "lost revenues" should be recovered on the basis of a straight kWh energy allocator.[1125] The OAG agreed, reasoning that the discounts are a policy decision to attract and retain large customers, who consume significant energy. Because the energy consumption by these customers is a cost causer, allocation of costs on an energy basis is consistent with cost causation principles.[1126]

750. XLI, on the other hand, agreed with the Company's allocation of economic development costs and opposed allocation through a straight KWh energy allocator. XLI stated that the discounts are designed to retain revenues from large customers that NSP would otherwise lose. Without the large customers' contribution to the Company's fixed and variable costs, NSP would experience a revenue shortfall. The retention of that revenue benefits all customers, but not on a straight alignment with energy usage as in an energy allocator.[1127]

751. MCC advocated for a third approach: allocating the development costs according to test year 2014 base revenues. In support of its position, MCC argued that the discount is based on the customer's contribution toward fixed costs (i.e. base revenues) prior to the discount.[1128]

752. The parties' different proposals are set forth in the table below:

[1122] Ex. 102 at 18 (Peppin Direct).
[1123] *Id.* at 18-19.
[1124] *Id.* at 19.
[1125] Ex. 408 at 39 (Ouanes Direct).
[1126] Ex. 375 at 31 (Nelson Direct).
[1127] Ex. 262 at 22-23 (Pollock Rebuttal).
[1128] Ex. 343 at 29-30 (Maini Direct).

Table 14

Comparison of Economic Development Discount Allocation methods[1129]

Allocation method	Residential	C&I Non-Demand	C&I Demand	Lighting
60% Capacity / 39% Energy	32.3%	3.5%	64.0%	0.2%
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%

753. The Administrative Law Judge concludes that the Company's use of the present revenue allocator in its CCOSS is the most reasonable of the three proposals for allocating the cost of economic discounts because the discounts benefit all customers. Recovering the costs based on present revenues recognizes that keeping these large customers on the system provides an overall benefit to all customers. In the view of the Administrative Law Judge, neither the straight energy method nor the present base revenue method better reflect the benefit of the retention of large customers.

viii. Allocation of Interruptible Rate Discounts

754. Under an interruptible rate arrangement, a utility has the option to buy back all or part of a participating customer's firm service when doing so is a cost-effective way for the utility to achieve peak capacity. In turn, the utility provides credits to the customers who choose to participate in the program. The Company treats interruptible credits in its CCOSS as a power supply cost of peaking capacity, analogous to the costs of a PPA or its own generation. It allocates the cost of service (including the costs of buying peaking capacity from interruptible customers) to the customer classes to determine rates for firm service. The Company then provides the credits from the firm service rate to the interruptible customers.[1130]

755. As it has in prior rate cases, XLI argued that the Company's allocation of interruptible rate credits violates CCOSS revenue-to-cost matching principles. Interruptible rate participants pay a lower rate for a level of service that is subject to curtailment and are shown as contributing less to revenue, while the costs are allocated among all classes as if they received firm service. [1131]

[1129] Ex. 103 at 41 (Peppin Rebuttal).
[1130] *Id.* at 13-14.
[1131] Ex. 260 at 46 (Pollock Direct).

756. XLI's argument has been addressed and answered in prior rate cases. In the 10-971 ORDER, the Commission found as follows:

> In this case, Xcel treats the cost of a demand-side resource, Interruptible service credits, just as it treats the costs of a supply-side resource, such as additional generation or purchased power. That is, it includes the cost of the resource in the cost of firm service, which it may then – in an unrelated transaction – discount for customers willing to endure interruption. The two actions are discrete and both are appropriate by their own terms.[1132]

757. XLI has brought forward no new evidence or argument to support a finding that the Company's treatment of interruptible service credits is unreasonable. Therefore, the Administrative Law Judge recommends that the Commission reject XLI's proposed change to the allocation of interruptible rate discounts.

C. Revenue Apportionment[1133]

758. Once the CCOSS analysis is complete, the Commission evaluates how to apportion the approved revenue requirement among the various customer classes. There is no requirement that the rates for all classes be equal, but any rate difference must be reasonable and supported by one or more of the rate design principles discussed above.[1134]

759. Revenue apportionment is important because it ultimately determines the price customers are charged for their electrical service.

760. Ideally, revenue apportionment for the customer classes would match the cost allocations by class identified in the CCOSS.[1135] Moving classes closer to cost is consistent with the rate design principle that rates should promote the efficient use of resources and minimize subsidies among classes. Deviation from CCOSS-based apportionment for non-cost factors results in some customer classes subsidizing others. An inter-class subsidy occurs when the revenue responsibility apportioned to a class of customers fails to recover the cost of serving those customers, and the difference is made up by over-recovering costs from other customer classes. Minimizing inter-class subsidies is perceived to be "fair" to all ratepayers, and it gives customers accurate information (or "price signals") about the cost of electricity. If customers believe that electricity is less expensive than its actual cost, they may not have the appropriate incentive to reduce their energy use.[1136]

[1132] 10-971 ORDER AT 25.
[1133] Issue 52.
[1134] *See* Minn. Stat. § 216.03 and ¶ 667 *supra*.
[1135] Ex. 420 at 11 (Peirce Direct).
[1136] *Id*. at 10.

761. However, cost allocations are not absolutely precise because there is often more than one method that may be employed to allocate costs to customer classes. Moreover, rates may need to be modified to comply with the rate design principle that rate changes should be gradual to avoid rate shock.[1137]

762. The Company, Department, MCC, XLI, Commercial Group, OAG, and AARP each provided recommendations regarding the allocation of the revenue requirement among customer classes.

763. The Company, Department, MCC, XLI, and the Commercial Group all agreed that rates should be moved closer to cost of service.[1138] They differ, however, as to the degree of the movement to cost.

764. The Company and Department recommended moderated movement to cost, as measured by their respective CCOSSs.[1139] The Company asserted that moderated, rather than full, movement to cost is reasonable given the recent rate increase in 2013 and the Company's proposed changes to its CCOSS methodology.[1140] The Department maintained that movement towards cost needs to be balanced with the goal of avoiding rate shock.[1141]

765. MCC and XLI advocated for full movement to cost as measured by their own CCOSSs. MCC and XLI asserted that cost-based rates would help to address the increasing uncompetitiveness of the Company's business rates as well as the adverse economic effects that result from uncompetitive business rates.[1142]

766. The Commercial Group also recommended full movement to cost, but stated that it is not opposed to the Company's proposed revenue apportionment.[1143]

767. The SRA supported the Company's revenue apportionment, which proposes no increase for the Lighting Class in 2014 and virtually no increase for the Lighting Class in 2015. The Company limited increases for the Lighting Class because

[1137] *Id*. at 11.
[1138] Ex. 105 at 9 (Huso Direct); Ex. 420 at 9 (Peirce Direct); Ex. 343 at 30-34 (Maini Direct); Ex. 260 at 37-40, 47 (Pollock Direct); XLI Initial Br. at 4-5, 16.
[1139] Ex. 105 at 8-9 (Huso Direct); Ex. 106 at 4-5 (Huso Rebuttal); Ex. 420 at 9 (Peirce Direct); Ex. 422 at 3 (Peirce Surrebuttal).
[1140] Ex. 105 at 9-10 (Huso Direct).
[1141] Ex. 420 at 11 (Peirce Direct).
[1142] Ex. 343 at 30-34 (Maini Direct); Ex. 345 at 20-21 (Maini Surrebuttal); Ex. 260 at 37-40, 47 (Pollock Direct).
[1143] Commercial Group Initial Br. at 11; Ex. 225 at 14 (Chriss Direct).

the Company's CCOSS results show that the Lighting Class is already paying rates above cost.[1144]

768. The OAG did not agree that the CCOSS results in this case should be the basis for revenue apportionment. Instead, the OAG recommended that the Commission essentially maintain the existing revenue apportionment.[1145] The OAG based its recommendation on its view that the CCOSS is an imprecise tool and on the importance of non-cost factors such as customers' ability to pay.[1146] In support of its position, the OAG asserted that the Company's retail rates already rank among the highest in the Midwest among investor-owned utilities and many residential customers have no ability to pay increased costs.[1147] AARP supported the OAG's position.[1148]

769. The Company provided the following table setting forth the parties' positions:

Table 15

Comparison of Recommended Allocations of Proposed Revenue Increase[1149]

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%	*	*

1144 SRA Initial Br. at 1, 3-4, 12.
1145 Ex. 375 at 38-39 (Nelson Direct).
1146 Ex. 374 at 38-42 (Nelson Direct); OAG Initial Br. at 65-66.
1147 Ex. 370 at 9-10 (Lindell Direct); OAG Initial Br. at 66.
1148 AARP Initial Br. at 18-19; AARP Reply Br. at 8-9.
1149 Xcel Initial Br. at 139, Table 4 (citing Ex. 107, at 5, Tables 3 and 4 (Huso Rebuttal); Ex. 422, at 3-4, Tables 3 and 4 (Peirce Surrebuttal); Ex. 375, at 39, Tables 9 and 10 (Nelson Direct); Ex. 378, at 18 (Nelson Surrebuttal); Ex. 343, at 20, Table 5 (Maini Direct); Ex. 345, at 20-21 (Maini Surrebuttal); Ex. 260, at 46-47 (Pollock Direct) (indicating XLI's proposed recommendation would move all classes to cost); Ex. 263, at 31, Schedule 22 (Pollock Surrebuttal); and noting values for the OAG, MCC and XLI in the above tables 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, and that MCC and XLI did not provide specific allocations for 2015).

770. The parties' positions reflect their underlying view of the proper CCOSS methodology.[1150]

771. The Department provided the following chart showing how the differences between the Company's and the Department's CCOSS methodologies affect whether a class is paying its cost of service under the Company's proposed revenue apportionment.

Table 16

Comparison of CCOSS Outcomes[1151]

Customer Class	**Current Revenue ($1,000s)**	**Adj. 2014 Cost ($1,000s)**	**DOC[1152] Prop. CCOSS ($1,000s) DOC IR 715-Revised**	**Current Rev/ DOC CCOSS**	**Xcel Proposed 2014 Revenue**	**Xcel Proposed as % of Proposed CCOSS**	**Proposed as % of DOC IR-715 Cost**
Residential	$1,001,398	$1,093,707	$1,074,955	93.2%	$1,087,898	99.5%	101.2%
C&I Non-Demand	$105,523	$113,274	$110,189	95.8%	$112,274	100.0%	102.8%
C&I Demand	$1,655,346	$1,749,971	$1,770,394	93.5%	$1,753,458	100.2%	99.0%
Lighting	<u>$26,477</u>	<u>$24,154</u>	<u>$25,568</u>	<u>103.6%</u>	<u>$26,477</u>	<u>109.6%</u>	<u>103.6%</u>
Total	$2,788,744	$2,981,106	$2,981,106	93.5%	$2,981,107	100.0%	100.0%

772. The Department noted that the Company's proposed revenue apportionment would move the Residential Class above cost, as measured by the Department's 2014 CCOSS. Similarly, the Company's proposed revenue apportionment would move the C&I Non-Demand Class above cost, as measured by the Department's CCOSS.[1153]

773. The Department stated that its proposed revenue apportionment based on its CCOSS results would move all classes closer to cost while moderating overall rate increases to all classes.[1154] The Department's initial proposed revenue apportionments for 2014 and 2015 are set forth below:

[1150] Xcel Initial Br. at 139.
[1151] Ex. 420 at 8, Table 3 (Peirce Direct).
[1152] DOC is short for the Department of Commerce.
[1153] Ex. 420 at 7-9 (Peirce Direct).
[1154] *Id.* at 7-10.

Table 17

Summary of the Department's Proposed 2014 Apportionment of Revenue Responsibility[1155]

Customer Class	Current Revenue	Xcel Proposed 2014 Revenue	DOC Prop. CCOSS ($1,000s)	DOC Proposed Revenue	Percent of Total Revenue	Percent Increase	DOC Proposed as % of DOC
Residential	$1,001,398	$1,087,898	$1,074,955	$1,072,268	36.0%	7.1%	99.8%
C&I Non-Demand	$105,523	$112,274	$110,189	$111,107	3.7%	5.3%	100.8%
C&I Demand	$1,655,346	$1,753,458	$1,770,394	$1,771,220	59.4%	7.0%	100.0%
Lighting	$26,477	$26,477	$25,568	$26,477	0.9%	0.0%	103.6%
Total	$2,788,744	$2,981,107	$2,981,106	$2,981,072	100.0%	6.9%	100.0%

Table 18

Summary of the Department's Proposed 2015 Apportionment of Revenue Responsibility[1156]

Customer Class	Current Revenue ($1,000's)	Xcel Proposed 2015 Revenue	DOC Prop. CCOSS DOC IR. 716	DOC Proposed Revenue	Percent of Total Revenue	DOC Prop. as a % of Cost	Percent Increase Current
Residential	$1,001,398	$1,127,053	$1,115,182	$1,107,658	36.0%	99.3%	10.6%
C&I Non-Demand	$105,523	$117,082	$113.982	$114,774	3.7%	100.7%	8.8%
C&I Demand	$1,655,346	$1,808,851	$1,823,647	$1,829,680	59.4%	100.3%	10.5%
Lighting	$26,477	$26,477	$26,651	$27,351	0.9%	102.6%	3.3%
Total	$2,788,744	$3,079,463	$3,079,462	$3,079,463	100.0%	100.0%	10.4%

774. In Surrebuttal Testimony, the Department updated its proposed 2014 and 2015 revenue apportionments to reflect the Company's revised revenue requirements. The Department did so by proportionally adjusting the updated revenues to reflect its initial proposed revenue responsibility apportionment.[1157]

775. Because the Administrative Law Judge has recommended that the Commission adopt what is largely the Department's proposed CCOSS methodology,

[1155] *Id.* at 8.
[1156] *Id.* at 9.
[1157] Ex. 422 at 3-4 (Peirce Surrebuttal).

the Administrative Law Judge concludes that the Department's proposed revenue apportionments for 2014 and 2015 should be adopted but modified for the Lighting Class in 2015. The Department's proposed revenue apportionments are reasonable because they are closely aligned with the costs determined by the Department's CCOSS and also avoid rate shock.[1158] As such, they properly balance the rate design principles of promoting efficient use of resources and ensuring that rate changes are gradual.

776. The Department's proposed 2015 revenue apportionment should be modified, however, to exclude any increase for the Lighting Class in 2015. As shown above in Table 17, the Department has proposed no increase for the Lighting Class in 2014; the same should be done in 2015. Otherwise, the Lighting Class will be paying a fair amount above its cost in 2015.[1159] To avoid this result, the Administrative Law Judge recommends that the increase in revenue that would have been attributable to the Lighting Class in 2015 be spread equally among the other classes.

777. Finally, to apply the Administrative Law Judge's recommended 2014 and 2015 revenue apportionments to the final revenue requirements determined by the Commission for those years, the Administrative Law Judge recommends that the final revenue allocation be adjusted using the proportional adjustment methodology supported by the Company and the Department.[1160]

D. Residential and Small General Service Customer Charges[1161]

778. The Company's Residential and Small General Service customers currently pay both a fixed customer charge and a volumetric energy charge, which is based on usage.

779. The customer charge is a monthly charge related to the fixed costs of making electric service available to customers. The fixed costs include service costs and facility costs. The service costs generally include the fixed costs of billing, meter reading, customer service and accounting. The facility costs include the costs of the individual customer meter and service wire connection, and the minimum level of distribution facilities that are required to provide service.[1162]

780. The Company's proposed 2014 CCOSS estimates the average fixed monthly cost of serving a residential customer is $15.86 and the average fixed monthly cost of serving a Small General Service customer is $16.84.[1163]

[1158] *See* Ex. 420 at 8-11 (Peirce Direct); Ex. 345 at 19 (Maini Surrebuttal).
[1159] *See* Ex. 420 at 9-10 (Peirce Direct).
[1160] Ex. 105 at 12-13 (Huso Direct); Ex. 420 at 11 (Peirce Direct).
[1161] Issue 54.
[1162] Ex. 105 at 14 (Huso Direct).
[1163] *Id.* at 15.

781. The Company's current Residential and Small General Service customer charges are less than the Company's CCOSS results. The Company has proposed to increase the customer charges for these classes in order to move those charges closer to cost as estimated by the Company's CCOSS results.[1164] The Company suggested increasing current residential rates by $1.25 per month and current Small General Service rates by $1.50 per month.

782. The Department concurred with increasing the customer charges for these classes of customers, but recommended smaller increases than the Company.[1165] The Department recommended increasing current monthly residential rates by $0.50 per month, and similarly recommended increasing current Small General Service rates by $0.50 per month.[1166] The remainders of the revenue requirements allocated to these classes would be collected through the volumetric charge paid by these classes.

783. The OAG, CEI, ECC, AARP, and SRA all opposed any increase in customer charges and instead suggested that any increase in Residential and Small General Service rates be to the volumetric charge.[1167]

784. The table below summarizes the parties' positions on customer charges.

Table 19

Summary of Proposed Customer Charges[1168]

Service	**Current**	**Xcel Proposed**	**CCOSS Cost**	**DOC Proposed**	**OAG, ECC, AARP, SRA, and CEI**
Residential Overhead	$8.00	$9.25	$15.86 average	$8.50	No change
Residential Underground	$10.00	$11.25	$15.86 average	$10.50	No change
Residential Electric Heat Overhead	$10.00	$11.25	$15.86 average	$10.50	No change
Residential Electric Heat Underground	$12.00	$13.25	$15.86 average	$12.50	No change
Small General Service	$10.00	$11.50	$16.84	$10.50	No change

[1164] *Id.*
[1165] Ex. 420 at 12 (Peirce Direct).
[1166] *Id.* at 12-13.
[1167] Ex. 375 at 40-52 (Nelson Direct); Ex. 280 at 26-29 (Chernick Direct); Ex. 290 at 8-9 (Cavanagh Direct); Ex. 234 at 35-41 (Colton Direct); Ex. 310 at 33 (Brockway Direct); SRA Initial Br. at 10-11 (recommending that if the Commission approves partial or full revenue decoupling, it should maintain the current customer charge); Summary of Public Comments at 2-5.
[1168] Ex. 420 at 12 (Peirce Direct)

i. The Reasons Provided by the Company and Department for an Increase.

785. The Company and the Department asserted that moving the customer charges for the Residential and Small General Service classes closer to the Company's average fixed cost of providing service as measured by the Company's CCOSS, is generally good policy because it sends appropriate price signals and will help reduce intra-class subsidies. According to the Company and the Department, the existing customer charges create intra-class subsidies.[1169]

786. The Company and the Department asserted intra-class subsidies exist because the existing customer charges are substantially less than the fixed costs for the Residential and Small General Service customer classes, as measured by the Company's CCOSS. The Company and Department maintain that customers who use little energy do not pay for the full cost of their electric service while high-usage customers pay more than the full cost of their electric service. This occurs because customers pay both a flat customer charge and a volumetric charge, which is based on usage. The charges are set so that the combined revenues from the customer charge and volumetric charge for a particular customer class equal the revenue requirement for that class. Consequently the lower the customer charge, the higher the volumetric charge must be, and vice versa. As a result, when the customer charge is set below cost, low-use customers pay less than their cost of service and high-use customers pay more. The Company's and the Department's proposals are intended to reduce the subsidization of low-use customers by high-use customers, with the Company proposing a larger reduction in the subsidy than the Department.[1170]

787. In support of its position, the Company pointed to the Commission's recent Order authorizing CenterPoint Energy to increase its customer charge by $1.50, in part to reduce intra-class subsidies.[1171]

788. In addition, the Company maintained that even if the Commission approves the Company's proposal, these customers will still have an incentive to conserve electricity because the customer charges will still be significantly below the fixed cost of service as estimated by the Company's CCOSS.[1172]

789. The Company also asserted that retaining the current below-cost customer charges is not an effective means of addressing affordability. According to the Company, affordability of electric service is better addressed by the existing Low-

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[1169] Ex. 105 at 16-17 (Huso Direct); Ex. 107 at 25 (Huso Rebuttal); Ex. 420 at 12-21 (Peirce Direct).
[1170] Ex. 105 at 16-17 (Huso Direct); Ex. 420 at 12-21 (Peirce Direct).
[1171] Ex. 107 at 27 (Huso Rebuttal) (citing *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rate in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT CONCLUSIONS, AND ORDER at 51-52 (June 9, 2014)).
[1172] Ex. 107 at 29 (Huso Rebuttal).

Income Home Energy Assistance Program (LIHEAP) and the PowerON program.[1173] These programs are more efficient and effective means of assisting low-income customers than keeping the residential customer charges at their current levels. The Company stated that for every LIHEAP customer with below-average usage who would benefit from retaining the present customer charge, there are "over 12 other [non-LIHEAP] customers with the same usage characteristics" who would also benefit.[1174]

790. The Department agreed with the Company that the Residential and Small General customer charges should be increased to "reflect the fixed costs of meters, billing and other related costs of delivering electricity to customers" and to reduce intra-class subsidies.[1175] The Department found that under the Company's current charges, customers using less than about 600 kWh per month were subsidized by customers with higher usage because of the below-cost fixed charges.[1176] Based on its analysis of LIHEAP data, the Department concluded that some of those higher-usage customers are low-income customers. The Department asserted that it is unfair for low-income, higher-use customers to subsidize low-use customers.[1177]

791. The Department suggested, however, that other concerns argue for limiting any increase in the customer charges. In that regard, the Department noted that any increase in customer charges would follow closely upon the previous increase from the last rate case which was implemented in December 2013. In addition, the Department also pointed out that if the Residential-Overhead Service customer charge proposed by the Company were implemented, the Company's Residential–Overhead Service customer charge would be higher than those approved for Minnesota's other electric utilities.[1178] The Department also noted that its proposed $8.50 monthly charge for Residential-Overhead Service, however, is consistent with the current customer charges for Minnesota Power, Otter Tail Power, and IPL as set forth in the table below.

[1173] Ex. 108 at 7 (Huso Surrebuttal).
[1174] *Id.*
[1175] Ex. 420 at 12, 14-16 (Peirce Direct).
[1176] *Id.* at 18-19.
[1177] *Id.* at 20; Ex. 422 at 9-10 (Peirce Surrebuttal).
[1178] Ex. 420 at 12-13 (Peirce Direct).

Table 20

Residential Customer Charges for Minnesota Electric Utilities[1179]

Company/Docket No.	Company Proposed Customer Charge	PUC Approved/DOC Proposed
Minnesota Power E015/GR-09-1151	$9.75	$8.00
Otter Tail Power E017/GR-10-239	$9.00	$8.50
IPL E001/GR-10-276	$10.00	$8.50

792. The Department concluded that an increase of $.50 per month appropriately balances the goals of moving rates towards cost and reducing intra-class subsidies with the concerns of affordability and avoiding rate shock.[1180]

ii. The Reasons Provided by the CEI, ECC, OAG, AARP, and SRA for No Increase.

793. The CEI, ECC, OAG, AARP, and SRA are all opposed to any increase in the customer charges for the Residential and Small General Service classes. As discussed in more detail below, several parties maintained that increasing customer charges would discourage conservation. In addition, parties raised concerns about the impacts to low-income customers from increasing residential customer charges. The CEI and OAG also claimed that the Company's CCOSS results are not suitable for making customer charge decisions. The CEI and ECC also disputed the position of the Company and the Department regarding intra-class subsidies. Finally, the OAG questioned whether the customer charges should be increased given the number of rate increases in the past several years. The parties' positions are addressed in more detail below.

a. Positions of the CEI and ECC

794. According to the CEI and ECC, increasing customer charges is inconsistent with the requirement in Minn. Stat. § 216B.03 that rates are to be set to encourage conservation to the maximum reasonable extent.[1181] CEI witness Paul Chernick explained that increasing the residential customer charge would result in a

[1179] *Id.* at 13.
[1180] Ex. 420 at 12-13, 21 (Peirce Direct); Ex. 422 at 10-12 (Peirce Surrebuttal); Department Initial Br. at 289-294.
[1181] CEI Initial Br. at 1-3, 7-8; ECC Initial Br. at 19-20.

lower volumetric rate.[1182] A lower volumetric rate will provide a reduced incentive to conserve because customers cannot save as much by reducing their energy usage.[1183]

795. CEI also claimed that the Company's CCOSS results, which are relied upon by both the Company and Department to support a higher customer charge, are useful for apportioning revenue among classes of customers but not for determining the fixed cost of serving a customer. CEI provided two reasons for its position: (1) because the CCOSS measures embedded costs rather than marginal costs; and (2) because the CCOSS includes electrical distribution costs that are not driven by the number of customers served by those facilities.[1184] As a result, in the view of the CEI, the Company's CCOSS greatly overstates the appropriate measure of the true fixed cost of serving a customer.

796. CEI contended that once the inappropriate costs are removed from the Company's CCOSS, the fixed cost to the system of adding a residential customer is $6.51 per month.[1185] Because this amount is less than the Company's current Residential customer charges, CEI asserted that low-usage residential customers are currently paying more than their fixed cost of service while high-usage customers are paying less than the costs they impose on the system.

797. Similarly, according to CEI, the fixed monthly cost of serving a Small General Service customer is $8.61 per month, which is less than the current $10.00 per month customer charge for that class.[1186] As a result, CEI maintained that customer charges should not be increased.

798. CEI also asserted that the Department's approach to determining a reasonable customer charge places too much emphasis on cost allocation and one type of intra-class subsidy, and not enough emphasis on the goals of affordability and conservation.[1187] CEI asserted that there are many subsidies incident to rate design. CEI maintained that subsidies are inevitable when customers impose different costs on the system but pay identical rates. Rather than focusing on one type of subsidy as the Department did, the CEI asserted the Commission should be more concerned with setting rates to send strong price signals that influence energy conservation.[1188]

799. ECC's opposition to increasing the customer charge arose from its concern for energy affordability for low-income households and low-income renters in particular.[1189] ECC stated that 25 percent of the Company's residential customers are

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[1182] Ex. 280 at 27.
[1183] Ex. 290 at 8 (Cavanagh Direct); Ex. 293 at 16 (Chernick Rebuttal); Ex. 234 at 36 (Colton Direct).
[1184] Ex. 280 at 27-28 (Chernick Direct).
[1185] *Id.* at 28-29 (Chernick Direct); Ex. 293 at 4-8, 14-16 (Chernick Rebuttal); Ex. 299 (Chernick Opening Statement); Ex. 234 at 40 (Colton Direct).
[1186] Ex. 293 at 7-8 (Chernick Rebuttal); Ex. 107 at 25 (Huso Direct) (listing current customer charges).
[1187] Ex. 293 at 8-14 (Chernick Rebuttal).
[1188] *Id.* at 15-16.
[1189] Ex. 235 at 1, 4 (Marshall Direct); Ex. 234 at 35, 40 (Colton Direct); ECC Initial Br. at 21-23.

income-eligible for LIHEAP assistance, but only six percent receive it.[1190] Increasing the customer charge will reduce conservation incentives for low-income customers and make it even less likely that low-income customers will be able to afford to implement conservation measures.[1191] ECC asserted that such a result is contrary to the statutory directives of encouraging conservation and promoting affordability.[1192]

800. ECC also criticized the Department's analysis of intra-class subsidies because the Department used "de-averaged" revenue but average costs.[1193] In other words, in comparing what consumers pay for energy the Department considered the average cost of serving each member of the class compared to what each customer pays the Company. ECC asserted that if costs were de-averaged too, the analysis would reveal that low-income, low-usage customers cost the least to serve because they tend to live in older buildings served by depreciated electric service facilities and they disproportionately live in multi-unit housing which is less expensive to serve on a per household basis than single-family homes.[1194] Consequently, according to ECC, increasing the residential customer charge would result in low-income, low-use customers subsidizing high-use customers who are predominately of higher income.[1195] ECC argued that such a result would be unfair and, as a result, recommended that any proposed increase in the existing residential customer charges be denied.[1196]

b. Positions of the OAG and AARP

801. The OAG is concerned about the impact on Residential and Small Business Customers from another increase to the customer charge.[1197] In its critique of the Company's proposal, the OAG observed that the Residential-Overhead Service customer charge increased from $4.59 to $8.00 between 2004 and 2014, and was subject to four increases in the last five years. Similarly, the Small General Service customer charge increased from $6.88 to $10.00 during that same time period.[1198]

802. The OAG also pointed out that the Commission has previously determined that it is more important to protect ratepayers from a large increase in the fixed customer charge after a recent increase than it is to move the customer charge closer to cost.[1199] The OAG asserted that the Commission should reach the same conclusion in

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[1190] Ex. 235 at 13 (Marshall Direct).
[1191] Ex. 239 at 35-36 (Colton Direct).
[1192] Ex. 234 at 36 (Colton Direct) (citing Minn. Stat. §§ 216B.03, 216B.16, subd. 15 (2014)); ECC Initial Br. at 19-20.
[1193] Ex. 237 at 3-4 (Colton Rebuttal).
[1194] *Id.* at 4-7.
[1195] *Id.* at 4-7.
[1196] Ex. 242 at 2 (Colton Opening Statement).
[1197] OAG Initial Br. at 75-78.
[1198] Ex. 375 at 40-41 (Nelson Direct).
[1199] *Id.* at 42.

this case and reject the proposed increases to the Residential and Small General Service class customer charges.[1200]

803. In addition, the OAG agreed with CEI that the Company's CCOSS results should not be used to set the customer charges.[1201] The OAG maintained that the Company's CCOSS methodology dramatically overestimates the customer-related costs of the distribution system and, as a result, the Company's CCOSS is not a reliable measure of fixed customer costs.[1202] The OAG also agreed with CEI's assertion that significant portions of costs classified as customer costs in the CCOSS should not be considered in determining the amount of the customer charge because those costs do not vary based on the number of customers.[1203] As a result, the OAG recommended that the Commission reject the arguments of the Company and the Department that increases in the customer charges of the Residential and Small General Service classes are necessary to move these charges closer to cost.[1204]

804. The OAG also noted that keeping the customer charges at their current levels will avoid rate shock for low-usage customers and provide a greater incentive for conservation.[1205] In addition, the OAG argued that no increase is necessary because the Company's current residential customer charges are consistent with the customer charges of the other three investor-owned electric utilities operating in the state.[1206]

805. AARP also opposed any increase to the Residential customer charges in order to avoid placing an undue burden on low-use, residential customers.[1207] AARP asserted that raising the customer charge translates into a higher percentage increase for low-use customers than it does for high-use customers based on the total bill, and that the Company's proposed $1.25 per month increase is significant for low-income households.[1208] AARP also argued that maintaining the current Residential customer charges will benefit greater numbers of households than increasing the customer charges because there are many more customers with below-average usage than there are customers with above-average usage.[1209] Finally, AARP agreed with other parties that maintaining the customer charges at their current levels will help send appropriate conservation price signals.[1210]

[1200] *Id.* at 52; OAG Initial Br. at 78.
[1201] OAG Initial Br. at 76-77.
[1202] Ex. 375 at 43-44 (Nelson Direct).
[1203] OAG Initial Br. at 77.
[1204] OAG Initial Br. at 76-77.
[1205] Ex. 375 at 52. (Nelson Direct).
[1206] OAG Initial Br. at 78.
[1207] AARP Initial Br. at 20.
[1208] Ex. 310 at 32-33 (Brockway Direct).
[1209] *Id.* at 28; Ex. 312 at 10 (Brockway Rebuttal).
[1210] AARP Initial Br. at 22-23.

c. Decoupling as an Independent Basis for Denying Any Increase in the Customer Charges

806. In addition to the reasons set forth above, decoupling was raised as a separate basis for denial of the proposed increases to the customer charges. The SRA, OAG, ECC, and CEI all recommended that if the Commission approves a decoupling mechanism for the Company, then the Commission should deny any increase to the customer charges.[1211]

807. As discussed *infra* in Section IX, the Company has been experiencing a reduction in residential and small commercial electric usage on a per customer basis in recent years. The Company expects that trend to continue.[1212] Decoupling is a mechanism that is intended to decouple sales from revenue in an effort to eliminate any disincentive the utility has to achieving customer conservation.[1213]

808. According to these parties, if decoupling is approved, there is no need to increase the customer charges to address declining sales because decoupling would provide the same cost recovery as increasing fixed charges, but without the reduction in conservation incentives.[1214]

iii. Public Comments

809. The vast majority of the public comments expressed serious concern about the size of the proposed rate increases. A number of customers also opposed any increase in the customer charge.[1215]

iv. Analysis

810. Because the Department and the Company both have recommended increasing customer charges but by different amounts, the Administrative Law Judge will first consider whether to recommend any increase and then address the size of any increase, if necessary.

811. As discussed above, the statutory goals to be considered in rate design are that rates be reasonable and not unreasonably discriminatory; that they favor energy conservation and the use of renewable energy to the maximum extent reasonable; and that "[a]ny doubt as to reasonableness should be resolved in favor of

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[1211] SRA Initial Br. at 1, 10-11; Ex. 375 at 59 (Nelson Direct); Ex. 234 at 10 (Marshall Direct); Ex. 234 at 29 (Colton Direct); Ex. 290 at 8-9 (Cavanagh Direct).
[1212] Ex. 109 at 7-8 (Hansen Direct).
[1213] Ex. 109 at 2-3 (Hansen Direct).
[1214] SRA Br. at 10-11; Ex. 375 at 59 (Nelson Direct); Ex. 234 at 29 (Colton Direct); CEI Initial Br. at 8.
[1215] *See* Attachment B.

the consumer."[1216] In addition, affordability is an important element in assessing the reasonableness of rates.[1217]

812. The Company and the Department have both recommended increases to the Residential and Small General Service customer charges based on the Company's CCOSS results and previous Commission decisions that have endorsed moving the customer charge toward cost. In this case however, CEI and the OAG both have questioned the reasonableness of relying on the Company's CCOSS results as a proxy for fixed customer costs in determining the amount of the Residential and Small General Service customer charges. While reference to the CCOSS analysis is appropriate for revenue apportionment purposes, CEI and the OAG have raised valid questions about whether the average customer costs calculated by the Company's CCOSS should be used in determining the fixed monthly customer charge. Consequently, the Administrative Law Judge finds it is appropriate to give less weight in this proceeding to the goal of moving the customer charges closer to cost as measured by the CCOSS results than in prior proceedings.

813. The record in this case also demonstrates that maintaining the Residential and Small General Service customer charges at their existing levels will help to encourage conservation consistent with Minn. Stat. § 216B.03. In addition, retaining the existing customer charges will promote affordability for low-use customers.

814. In the view of the Administrative Law Judge, the need to promote conservation and affordability outweigh the concerns of moving closer to the cost as measured by the Company's CCOSS results. This conclusion is buttressed by the fact that there have been a number of increases to the Company's customer charges in recent years.

815. Finally, because the Administrative Law Judge is recommending that the Commission adopt a decoupling mechanism for the Company, as discussed below in Section IX, it is not necessary to increase customer charges for revenue stability purposes.

816. For these reasons, the Administrative Law Judge concludes that retaining the current Residential and Small General Service customer charges is reasonable in this case, and recommends that the Commission reject the proposed increases of the Company and the Department.

E. Amount of Interruptible Service Discounts and Demand Charges[1218]

817. Customers with "interruptible service" are given a discount for agreeing to have their electricity service interrupted as needed by the Company. Maintaining a

[1216] Minn. Stat. §§ 216B.03, .07, 216C.05 (2014).
[1217] Minn. Stat. § 216B.16, subd. 15.
[1218] Issue 52.

slate of interruptible service customers provides a number of the benefits to the Company, including flexible load management.[1219] The existence of interruptible loads also reduces the planning reserve margin required by MISO rules and gives the utility more control over capacity costs.[1220]

818. The Company uses a market-based approach to set interruptible service rate discounts, seeking to establish interruptible rates at levels needed to attract an optimal supply of interruptible load for the short-term and to maintain that load for longer-term capacity planning purposes.[1221]

819. The Company has two tiers of interruptible service. The first tier involves a ten-year contract and a maximum of 150 hours of interruption, and the second tier involves a five-year contract and a maximum of 80 hours of interruption.[1222] Within each tier, performance factors A, B, and C represent percentages of maximum controllable demand occurring on average in July and August during the peak period.[1223] The interruptible service discount increases as the performance factor percentage increases.[1224]

820. The Company also has a short notice option for interruptible service. Short notice customers must have a minimum controllable demand of 3 MW and be willing to have their service interrupted within 10 minutes of being given notice.[1225] Short notice customers receive the highest discount available to interruptible service customers.[1226]

821. In 2012 and 2013, the Company utilized interruptible service twice each year.[1227] Each interruption involved only customers in the first tier.[1228]

822. The Company has proposed to increase the Level C Performance Factor interruptible service discounts by approximately six percent, and has proposed to institute corresponding increases for the other performance factors to maintain the current relationship between tiers.[1229] The following table shows the Company's current interruptible discounts and the new proposed discounts:

[1219] Ex. 343 at 35 (Maini Direct); Ex. 260 at 51 (Pollock Direct).
[1220] *Id.*
[1221] Ex. 105 at 27 (Huso Direct).
[1222] Ex. 343 at 36 (Maini Direct).
[1223] *Id.*
[1224] Ex. 105 at 27 (Huso Direct).
[1225] Ex. 260 at 48 (Pollock Direct).
[1226] Ex. 343 at 37 (Maini Direct).
[1227] Ex. 420 at 25 (Peirce Direct).
[1228] *Id.*
[1229] Ex. 105 at 26-28 (Huso Direct).

Table 21

Company's Present and Proposed Interruptible Service Discounts (Average Monthly Discount per kW)[1230]

Performance Factor Tier	2-C	2-B	2-A	1-C	1-B	1-Short Notice
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%*

823. According to the Company, the new proposed interruptible service discounts will improve the Company's ability to maintain an optimal supply of interruptible load and will help moderate the increase in demand charges.[1231]

824. The Department agreed that interruptible service discounts should be increased because interruptible service customers have seen rates increase during the past few years without a corresponding increase in the interruptible service discount.[1232] However, the Department recommended a more moderate increase of 3 percent.[1233] The Department believes a smaller increase is appropriate given the limited number of service interruptions over the last several years as well as the Company's claim that it currently has sufficient levels of interruptible load.[1234]

825. MCC agreed that interruptible service discounts should be increased. MCC pointed to the positive impact interruptible service has on the system.[1235] MCC noted that the Company's proposed increases would translate to an annual credit ranging from $37.80/KW-year to $70.20/KW-year.[1236] MCC recommended, however, that the interruptible service discount for Tier 1-C be increased from $60.60/KW-year to $77.24/KW-year with the other performance factors and tiers adjusted accordingly to

[1230] *Id.* at 27.
[1231] *Id.*
[1232] Ex. 420 at 26 (Peirce Direct).
[1233] *Id.*
[1234] *Id.*
[1235] MCC Initial Br. at 24.
[1236] Ex 343 at 38 (Maini Direct).

maintain the current relationships between them.[1237] MCC based its proposed discount calculation on its calculation of the avoided capacity cost.[1238]

826. XLI also agreed that interruptible service discounts should be increased, but believes Short Notice interruptible service customers should be given the greatest increase because they provide the most substantial benefit to the Company.[1239] XLI asserted that the Company's proposed increase for Short Notice customers is less than half the charge the Company would incur to provide comparable Short Notice generation capacity.[1240] XLI recommended a Short Notice demand discount proportionately increased in relation to the Company's proposed base revenue increase. Like MCC, XLI based its proposed discount on its calculation of the avoided capacity cost.[1241] Specifically, XLI's proposal would apply as follows:[1242]

Table 22

XLI's Recommended Short Notice Interruptible Service Discounts ($/kW-month)

Time period	Present	Proposed
Summer	$8.14	$9.56
Non-summer	$4.26	$5.36
Annual average	$5.55	$6.76

827. Although the Company has utilized interruptible service on only a few occasions during the past two years, it argued that having the option to interrupt as conditions warrant provides significant value, especially when supply and demand factors are quickly altered.[1243] The Company does not expect its proposal to materially increase the amount of interruptible load, but instead expects its proposal to help maintain an optimal supply of interruptible load.[1244] The Company believes the Department's recommended increase is too small while MCC and XLI's proposals go too far.[1245]

828. All parties agree that some increase in interruptible service discounts is necessary. Based on the evidence in the record, the Administrative Law Judge concludes that the Department's proposal to increase the Level C Performance Factor interruptible service discounts by three percent, and institute corresponding increases for the other performance factors to maintain the current relationship between tiers is

[1237] *Id.* at 40-41; Ex. 345 at 19 (Maini Surrebuttal); MCC Initial Br. at 27.
[1238] Ex. 343 at 40-41 (Maini Direct).
[1239] Ex. 260 at 49 (Pollock Direct); XLI Initial Br. at 18.
[1240] Ex. 260 at 53 (Pollock Direct).
[1241] *Id.*
[1242] Ex. 260 at 55 (Pollock Direct).
[1243] Ex. 107 at 35-36 (Huso Rebuttal).
[1244] Ex. 105 at 27 (Huso Direct).
[1245] Xcel Initial Br. at 144-45.

the most reasonable. The other parties have failed to demonstrate that a larger increase is necessary to maintain an optimal supply of interruptible load.

F. Inclining Block Rates[1246]

829. CEI has proposed an inclining block rate (IBR) pricing structure that would apply to the volumetric portion of a residential customer's bill. An IBR for electricity is a blocked or tiered pricing structure consisting of two or more volumetric prices, where a lower price is charged for the first kWh block in each month, and a higher price is charged in each subsequent kWh block.[1247] The basic motivation behind an IBR pricing structure is to encourage and reward conservation by offering lower prices to low-use customers and higher prices for high-use customers, who generally have more opportunities for conservation and energy efficiency.[1248] An IBR structure allows for higher conservation incentives without increasing revenue and, at the same time, can lower rates for a majority of customers.[1249]

830. The IBR proposed by CEI is premised on several guidelines: (1) include only residential customers; (2) retain the existing revenue level by season; (3) exclude heating customers during the winter months; (4) maintain the existing customer charge; (5) use no more than four pricing blocks; (6) increase the bills for very high-use customers by 20 percent; (7) slightly reduce the bills for average use customers; and (8) limit the bill reduction for customers with low use to a maximum decrease of 15 percent.[1250] Based on these criteria, CEI proposed a four-block IBR pricing structure that would apply solely to non-heating Residential sales. The proposed IBR structure maintains the existing differentiation in the Company's current tariff between the summer and winter seasons.[1251] CEI's proposed IBR structure is set forth below.

Table 23

Design of Summer IBR, all Residential Sales[1252]

Block	Price Change	Block Price	Block kWh's	Bills ending in Block (1,000s)	MWh billed	MWh influenced
1	-30%	6.070¢	0–350	1,015	1,364,819	213,547
2	10%	9.538¢	351–700	1,346	909,211	700,448
3	20%	10.405¢	700–1,200	1,217	627,968	1,117,010
4	46%	12.684¢	>1,200	660	416,921	1,287,915

[1246] Issue 80.
[1247] Ex. 280 at 3 (Chernick Direct).
[1248] *Id.* at 3-4.
[1249] *Id.* at 5.
[1250] *Id.* at 17-18.
[1251] *Id.* at 18-19.
[1252] *Id.* at 18.

Table 24

Design of Winter IBR, Non-Heating Residential Sales[1253]

Block	Price Change	Block Price	Block kWh's	Bills ending in Block (1,000s)	MWh billed	MWh influenced
1	-25%	5.545¢	0–300	2,051	2,158,681	374,927
2	10%	8.132¢	301–600	2,624	1,374,880	1,165,701
3	20%	8.872¢	602–1,000	1,965	877,799	1,514,549
4	28%	9.434¢	>1,000	1,245	820,847	2,177,030

831. If the proposed IBR structure is implemented, CEI maintains that the median customer would see a bill decrease of 8 percent, and a load reduction of 2 to 6 percent would occur over the first few years.[1254]

832. CEI asserted its proposed IBR structure is supported by the evidentiary record, including a detailed proposal and evidence establishing conservation benefits. CEI also stated that adoption of its IBR is consistent with the conservation policy objectives adopted by the Minnesota Legislature, and is in the public interest.[1255]

833. CEI did not propose a customer education and communication plan to use if its IBR is implemented. Instead, CEI maintained that education of customers should be done by the Company.[1256]

834. ECC endorsed the IBR proposed by CEI, claiming it serves two important functions: energy conservation and affordability.[1257] ECC believes the proposed IBR structure in this case is akin to the IBR structure adopted by the Commission for Minnesota Power in 2011.[1258] According to ECC, the two potential negative aspects of an IBR structure – impact on high-use, low-income customers and administrative issues, including customer confusion – can be easily resolved.[1259]

835. The Company initially opposed CEI's proposed IBR structure, arguing it has three over-arching problems: (1) it is ineffective as a conservation policy; (2) it will create substantial negative customer impacts; and (3) it will result in administrative burdens.[1260] According to the Company, its present rate design sends a stronger

[1253] *Id.* at 19.
[1254] *Id.* at 20-21.
[1255] CEI Initial Br. at 3.
[1256] Ex. 280 at 26 (Chernick Direct).
[1257] ECC Initial Br. at 2.
[1258] *Id.* at 3-4.
[1259] *Id.* at 9-17.
[1260] Ex. 107 at 11-12 (Huso Rebuttal).

conservation signal to customers than the IBR structure proposed by CEI.[1261] Moreover, the Company asserted the proposed IBR structure will increase the bills for a large number of customers, including disadvantaged groups like low-income, high-use customers, as well as customers in multi-unit buildings served via a single meter.[1262] The Company claimed conservation and affordability are both more effectively served with more direct and targeted approaches.[1263] The Company later entered into a stipulation regarding the IBR proposal, described below in paragraph 838.[1264]

836. The Department initially recommended further study of the proposed IBR through implementation of a parallel billing program for one year and development of a customer education program.[1265] At the evidentiary hearing, the Department withdrew its request for parallel billing.[1266]

837. The OAG opposed the IBR proposal by CEI, arguing it will have severe negative consequences for certain ratepayers, particularly those customers with limited ability to alter their energy consumption.[1267] The OAG asserted CEI's proposed IBR structure in this case is akin to CenterPoint's IBR structure that was terminated by the Commission due to detrimental unintended consequences.[1268]

838. During the evidentiary hearing, a stipulation regarding IBR was entered into by the Company, CEI, ECC, and SRA.[1269] The stipulation asks the Commission to open a separate docket to allow for further development of CEI's proposed IBR structure and to provide the parties additional time to discuss issues related to IBR.[1270] The stipulation provides that all of the evidence and argument regarding IBR from this docket would be incorporated into the new docket.[1271] The stipulation specifically allows the Company to submit one alternative proposal to CEI's proposed IBR structure, but does not expressly permit any other party to submit their own alternative IBR proposal.

839. Although the Department did not sign the stipulation, it agreed that the issue of IBR would be better resolved outside this general rate case and committed to holding stakeholder meetings to review IBR proposals as part of a separate process.[1272] The stipulation provides that the stakeholder meetings would address a number of issues, including, without limitation: identification of any additional customer groups to be excluded from a proposed IBR structure; considerations for customer education and

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[1261] *Id.* at 12-14.
[1262] *Id.* at 14-21.
[1263] *Id.* at 24.
[1264] Ex. 135 (Stipulation).
[1265] Ex. 416 at 3-6 (Grant Rebuttal).
[1266] Ex. 446 at 2 (Grant Opening Statement).
[1267] OAG Initial Br. at 77.
[1268] *Id.* at 73-74.
[1269] Ex. 135 (Stipulation).
[1270] *Id.*
[1271] *Id.*
[1272] Ex. 446 at 1-2 (Grant Opening Statement).

communication; a methodology for mitigating extended billing periods; an explanation of billing system changes necessary to implement an IBR structure; cost of any new billing system; and the impact an IBR structure would have on the Company's other tariffs, including the Residential Savers Switch, Community Solar Gardens, and net metering.[1273]

840. The OAG is opposed to the stipulation on grounds that it unreasonably restricts evaluation of possible IBR structures to only CEI's proposal and a Company proposal.[1274] AARP did not take a position on the stipulation.[1275]

841. The Administrative Law Judge concludes that the record demonstrates IBR is an effective tool for promoting conservation, and agrees with the parties to the stipulation that the proposed IBR warrants further review.[1276] The stipulation appears to set forth an appropriate process for review and resolution of the IBR issue, with two suggested modifications. First, to address the OAG's concern, the Administrative Law Judge suggests that the Commission allow all parties the opportunity to submit alternative proposed IBR pricing structures for consideration in the new docket. It would be unfair to the other parties to limit consideration only to the CEI proposal and a Company proposal. Such a limitation could result in exclusion of a more reasonable IBR rate structure. Second, the Commission should require the parties to the IBR stakeholder meetings to specifically address the issue of potential impacts on high-use, low-income customers, and require the parties to identify possible means of addressing the impacts. In the current docket, the Department, the OAG, and the Company all raised concerns about the potential impact of an IBR pricing structure on high-use, low-income customers. The Administrative Law Judge agrees that these concerns should be addressed in more depth if the Commission opens a new docket to address IBR.

IX. Decoupling[1277]

842. "[D]ecoupling" is a "regulatory tool designed to separate a utility's revenue from changes in energy sales."[1278] When properly implemented, decoupling allows the utility to receive the per-customer revenue requirement the Commission has reviewed and approved, and no more and no less.[1279]

[1273] Ex. 135 (Stipulation).
[1274] OAG Initial Br. at 75.
[1275] The other parties to this case (XLI, MCC, the Commercial Group, and ICI) do not represent residential electricity customers and therefore are not involved in this issue.
[1276] In the last rate case, an IBR proposal was submitted by ECC. The Administrative Law Judge concluded that the ECC proposal was not reasonable and therefore recommended that it not be implemented. *See* 12-961 REPORT at 157-165. The IBR structure proposed by CEI in this case is different and more developed than the ECC proposal in the last case.
[1277] Issue 39.
[1278] Minn. Stat. § 216B.2412, subd.1 (2014).
[1279] Ex. 290 at 10 (Cavanagh Direct).

843. The legislature authorized the use of decoupling specifically "to reduce a utility's disincentive to promote energy efficiency."[1280] Without decoupling, the utility has a disincentive to encourage conservation because conservation results in lower energy sales. Lower energy sales translate into lower revenue for the utility.[1281]

844. Decoupling addresses the disincentive by adjusting ratepayers bills via a revenue true-up to recover differences between the actual revenue and the level of revenue approved for the utility in its most recent rate case.[1282] Because the utility is "made whole" for the decreased revenues, it is not penalized by customer conservation.[1283]

845. The Company has requested that the Commission authorize a decoupling mechanism for the Company that would apply to revenue from residential customers and a subset of its small C&I customers.[1284] The Company has proposed the revenue decoupling mechanism because it has been experiencing declining residential and small C&I sales in recent years, and the declines are expected to continue. In addition, it has become increasingly challenging for the Company to meet its conservation goals.[1285] The Company expects that its decoupling proposal will allow it to maintain an aggressive energy efficiency portfolio.[1286]

846. The Company's decoupling proposal in this docket is the first electric utility decoupling proposal in Minnesota.[1287] The Commission has approved three different decoupling mechanisms for natural gas utilities, each on a pilot basis.[1288]

[1280] *Id.*
[1281] *See* Ex. 109 at 3 (Hansen Direct).
[1282] Ex. 290 at 3 (Cavanagh Direct). The parties generally refer to the true-up that occurs under decoupling as a "surcharge." However, the Administrative Law Judge finds the phrases " Revenue Decoupling Mechanism (RDM) billing adjustment" or "RDM billing increase" more accurately reflect the adjustments ratepayers experience with a decoupling mechanism. "Surcharge" implies that customers can be charged amounts in excess of the rates approved by the Commission in a given rate case, which is not correct. Therefore, this report will refer to the "RDM adjustment" or "RDM billing increase" that occurs with a decoupling mechanism where the parties have often used the term "surcharge."
[1283] Ex. 109 at 4 (Hansen Direct).
[1284] *Id.* at 2.
[1285] *Id.* at 7-8.
[1286] *Id.* at 8.
[1287] Ex. 110 at 13 (Hansen Rebuttal).
[1288] *See In the Matter of the Application of CenterPoint Energy, a Division of CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G008/GR-13-316; *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; *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-08-1075.

847. Half of the states in the United States have adopted decoupling mechanisms for at least one electric or gas utility, or both. A total of 52 electric utilities and 28 natural gas utilities have decoupling mechanisms in place.[1289]

A. Full Versus Partial Decoupling

848. There are two basic types of revenue decoupling: full decoupling and partial decoupling. Each type of decoupling mechanism has elements that can vary. Some of these include caps on billing adjustments, the method and frequency of calculating adjustments, and how billing adjustments are applied.[1290]

849. A full decoupling mechanism is one where the true-up amount is based on differences between forecasted revenue and actual sales that occur, regardless of the reason, including weather that deviates from forecasted ("normal") weather. Partial decoupling excludes specific deviations from the forecasted revenue, such as increased or decreased sales due to weather.[1291]

850. For example, under full decoupling, if residential customers used 5 percent less electricity than the approved base amount, and half of the decrease was due to a cooler-than-normal summer, then the true-up would include the entire 5 percent difference between the approved base amount and the actual sales. Customers would pay for the 5 percent shortfall to insure the utility reached its approved base amount.[1292]

851. Under partial decoupling that excludes weather effects, decreased electricity sales due to the cooler-than-normal summer would be removed from the calculation of the true-up. So, if residential customers used 5 percent less electricity than the approved base amount and half of the decrease was due to the cooler weather, the true-up would include only 2.5 percent of the difference. The difference due to weather would be excluded from the calculation. Under partial decoupling, in a cooler-than-normal summer the customers would pay half of the utility's shortfall.[1293]

852. If residential customers used 5 percent more electricity than the approved base amount, with half of the overage attributed to warmer-than-usual weather, full decoupling would take the total residential sales paid to the utility into account when calculating a refund to the residential sales customers. Under the same circumstances using partial decoupling, the refund to the customers would only take into account the 2.5 percent overage paid that was not attributable to warmer weather.[1294]

[1289] Ex. 290 at 4 (Cavanagh Direct); Ex. 109 at 5-6, Schedule 2 (Hansen Direct).
[1290] Ex. 417 at 9 (Davis Direct).
[1291] *Id.*
[1292] *Id.* These examples illustrating full and partial decoupling assume no cap is built into the decoupling mechanism.
[1293] *Id.* at 9-10.
[1294] Ex. 417 at 10 (Davis Direct).

853. The Commission has approved both full and partial decoupling mechanisms for gas utilities.[1295]

854. In reviewing decoupling proposals, the Commission considers whether the decoupling mechanism will reduce the utility's disincentive to promote energy efficiency, whether the decoupling proposal is consistent with the energy savings goals under Minn. Stat. § 216B.241 (2014), and whether the proposal will adversely affect utility ratepayers.[1296]

B. Company's Proposed Decoupling Mechanism

855. In this matter, the Company has proposed to implement a partial revenue decoupling mechanism (RDM) for its Residential and C&I Non-Demand customers. The proposed partial RDM would exclude weather effects.[1297]

856. The Company designed its RDM as a "per-customer" model. This means that the per-customer-revenue requirement recovered through the volumetric non-fuel, energy charge would be used as the baseline for the purpose of performing the decoupling calculations.[1298] The "RDM deferral" would be the difference, calculated monthly, between the baseline revenues and the actual, weather-normalized (eliminating the effects of abnormal weather) sales collected from customers.[1299]

857. The Company would calculate monthly deferrals as follows:

$$\mathbf{Deferral_{c,t} = (FRC_c \times C_{c,t)\,-} (FEC_c \times kWh_{c.t}^{Billed,WN})}$$

where

$\mathbf{FRC_c}$ is the fixed revenue per customer for customer group c,

$\mathbf{C_{c,t}}$ is the number of customers in customer group c during month t,

$\mathbf{FEC_c}$ is the non-fuel energy rate for customer group c, expressed in \$/kWh; and

$\mathbf{kWh_{c,t}^{Billed,WN}}$ is the weather-normalized billed sales to customer c in month t.[1300]

[1295] *Id.* at 10-11 (describing decoupling programs the Commission has approved for natural gas utilities in Minnesota).
[1296] Minn. Stat. § 216B.2412, subd. 2 (2014).
[1297] Ex. 109 at 2 (Hansen Direct).
[1298] *Id.* at 9-10.
[1299] *Id.*
[1300] *Id.* at 10.

858. The Company proposed to calculate the weather-normalized billed sales to group c in month t ($kWh_{c,t}^{Billed,WN}$) as billed sales to customer group c in month t, adjusted to account for deviations from normal weather conditions. Normal weather conditions would be determined using the same methods used to develop test year sales.[1301]

859. The Company also proposed to calculate both 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$) for each month of the test year, using test year revenues, numbers of customers and sales.[1302]

860. Other elements of the Company's proposed RDM included:

i. A total fixed revenue calculation using test year energy charges, less the CIP component, multiplied by test year sales for the corresponding customers. This calculation would be performed for each month of the test year. In addition, the calculation would be conducted at the rate code level, with revenues aggregated up to the customer group level. Customer charge revenue would be excluded from RDM because it is already decoupled from customer sales.[1303]

ii. Fixed revenue per customer for customer group c would be calculated as the fixed-cost revenue requirement described above, divided by the number of customers forecast for each month in the 2015 test year.[1304]

iii. The non-fuel energy rate for customer group c would be calculated as the fixed-cost revenue requirement divided by the sales forecast for each month of the 2015 test year.[1305]

861. By using month-specific values for these parameters rather than a single value as a constant across months, the Company intended to minimize month-to-month adjustments.[1306]

862. The Company proposed to calculate the RDM billing adjustments for Residential Non-Space Heating, Residential Space Heating, and Small C&I Non-Demand customer groups separately. No carrying charge would be applied to adjustments. The total RDM billing adjustment for each customer group would be divided by the sales forecast for that group for the coming year at the end of a 12-month

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[1301] *Id.* at 11.
[1302] *Id.*
[1303] *Id.* at 12.
[1304] *Id.* at 11.
[1305] *Id.*
[1306] *Id.* at 11-12.

period. The sales forecast would be developed using the Company's usual forecasting methods. The resulting amount would be added to or subtracted from the customer group's volumetric rate for the following 12 months.[1307] This RDM billing adjustment would be performed annually, beginning with the month after the Commission's final Order in this proceeding.[1308]

863. The Company proposed to list the RDM billing adjustment as a separate line item on customers' bills.[1309]

864. The Company proposed to implement its RDM with a soft cap. A soft cap allows the Company to defer RDM billing adjustments that exceed a predetermined amount to a deferral account for recovery in subsequent years. A hard cap, in contrast, establishes a maximum amount for the RDM billing adjustment but does not permit deferral for recovery in later years.[1310]

865. The Company's initial proposed soft cap would have applied to an RDM billing adjustment that produced an increase exceeding 5 percent of total customer group revenue, including fuel and all applicable riders.[1311] The Company later adjusted its proposal to apply to an RDM billing adjustment that produced an increase exceeding 5 percent of base revenue, excluding fuel and all applicable riders.[1312]

866. The Company conditioned its 5 percent proposed soft cap on the Commission's approval of the Company's partial RDM. If the Commission orders full decoupling, the Company proposed a 10 percent soft cap measured against base revenue, excluding fuel and all applicable riders.[1313]

867. The Company's proposed RDM has no downward limit on RDM billing adjustments.[1314]

868. The Company stated that soft caps are used in the majority of jurisdictions where decoupling has been adopted.[1315]

869. The Company agreed to submit an annual evaluation report with the following elements:

i. Total over-or under-collection of allowed revenues by class;

[1307] *Id.* at 14.
[1308] *Id.* at 15.
[1309] *Id.* at 16.
[1310] Ex. 110 at 10 (Hansen Rebuttal).
[1311] Ex. 109 at 15 (Hansen Direct).
[1312] Ex. 110 at 9 (Hansen Rebuttal).
[1313] *Id.*
[1314] Ex. 109 at 15 (Hansen Direct).
[1315] *Id.* at 5-6, S-2.

ii. Total collection of prior deferred revenue;

iii. Calculations of the RDM deferral amounts;

iv. Number of customer complaints;

v. Amount of revenues stabilized and how the stabilization impacted the Company's overall risk profile; and

vi. Comparison of how revenues under traditional regulations would have differed from those collected under partial and full decoupling.[1316]

870. While it initially believed that its RDM was ineligible for pilot status because the RDM proposal was not filed by December 30, 2011, the Company later agreed that the RDM could be appropriately implemented as a three-year pilot program.[1317]

871. The Company also agreed that no upward RDM billing adjustments should be permitted in the year following a year in which the Company fails to achieve energy savings equal to 1.2 percent of its retail sales.[1318]

C. The Positions of the Parties on the Company's RDM Proposal

872. Several parties addressed the issue of decoupling and the specifics of the Company's RDM proposal. The OAG, AARP, and ICI Group oppose implementation of decoupling for the Company. The Department and ECC support adoption of a decoupling mechanism but proposed changes in the design of the Company's proposal. The OAG and AARP also proposed design changes if decoupling is adopted. CEI, on the other hand, is supportive of the Company's proposal. The specific issues raised by the parties are addressed in more detail below.[1319]

[1316] Ex. 109 at 18-19 (Hansen Direct); Ex.110 at 4 (Hansen Rebuttal).
[1317] Ex. 109 at 16 (Hansen Direct), Ex. 110 at 2 (Hansen Rebuttal), Ex. 417 at 37-38 (Davis Direct).
[1318] Ex. 110 at 2-3 (Hansen Rebuttal); Ex. 417 at 12-14 (Davis Direct).
[1319] The other parties either did not address the issue or did not object to the Company's proposal. The MCC and XLI did not take a position on the issue. The Commercial Group did not take a position on whether decoupling should be authorized for the Company, but agreed with the Company that C&I Demand customers should be excluded if decoupling is approved. Ex. 225 at 14-15 (Chriss Direct). The SRA stated that it does not oppose decoupling if the Company's disincentive to promote conservation is eliminated by decoupling. SRA Initial Br. at 10-11.

D. Whether Decoupling Should Be Implemented

i. Positions of the OAG, AARP, and ICI Group

873. The OAG is opposed to implementation of decoupling in this case.[1320] The OAG contended that decoupling is not needed because the Company already has significant conservation incentives.[1321] The OAG argued that the Company's plan to include only Residential and C&I Non-Demand classes in the RDM belies the urgency of the Company's need for decoupling.[1322]

874. In addition, the OAG expressed concerns about adverse consequences for ratepayers if the decoupling is implemented, including confusion regarding electric bills. The OAG was not satisfied that the Company had a plan to address and remediate customer confusion following a change.[1323]

875. The OAG recommended that, if the Commission approves the RDM, it be implemented as a pilot program and that no increase in the customer charge be allowed in conjunction with approval of the proposed RDM.[1324]

876. AARP also opposed implementation of decoupling in this case. AARP agreed with the OAG that decoupling is not necessary because the Company has adequate conservation incentives already in place.[1325]

877. AARP also asserted that the RDM unfairly shifts risks to customers, prompts cross-subsidization between classes of ratepayers, and reduces the economic benefits ratepayers should earn as a result of their conservation efforts.[1326]

878. The ICI Group also opposed the implementation of decoupling. The ICI Group is concerned that the Company's proposal could be extended to larger, demand-metered customers. The ICI Group also noted that the Company already has existing incentives in place for conservation.[1327]

ii. Response of the Company and CEI

879. The Company disagreed with the premise that decoupling and conservation programs should be treated as alternative courses of action. The Company pointed out that the purpose of decoupling is to remove a utility's financial disincentive to promote conservation. The Company stated that the legislature has

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[1320] Ex. 375 at 53-54 (Nelson Direct).
[1321] *Id.*
[1322] *Id.*
[1323] *Id.* at 53.
[1324] *Id.* at 61.
[1325] Ex. 310 at 9-12 (Brockway Direct).
[1326] *Id.* at 18, 22; Ex. 311 at 6 (Brockway Rebuttal).
[1327] Ex. 250 at 13-14 (Glahn).

expressly authorized separate incentive mechanisms "to encourage the vigorous and effective implementation of utility conservation programs."[1328] The Company argued that these statutory provisions are intended as complements, not substitutes.[1329]

880. The Company noted that the Commission appears to have treated conservation incentives and decoupling as complementary in the natural gas cases where it has approved decoupling.[1330]

881. Because the Company will ultimately only collect the revenue per customer authorized in this case, the Company contended that the OAG and AARP were incorrect in their assertions that the RDM will adversely impact customers.[1331]

882. The Company addressed the OAG and AARP's additional concerns about adverse consequences to customers, asserting the level of RDM billing adjustments will be slight and that ratepayers will be able to offset such adjustments by achieving less-than-average conservation. At lower usage levels, replacing a single light bulb can offset the level of expected RDM billing adjustments. In addition, the Company contended that bill increases, on a percentage basis, will be smaller for low-use customers.[1332]

883. The Company maintained that ratepayers will be further protected by the Company's agreement that the RDM should be implemented as a pilot program, by the inclusion of a cap as a means of limiting volatility associated with a RDM, and the Company's commitment to provide annual RDM reports.[1333]

884. CEI supported the Company's decoupling proposal. CEI concurred with the Company that decoupling would reduce the Company's disincentive to promote energy efficiency.[1334] Regarding the relationship between decoupling and conservation, the CEI identified examples from Minnesota, and nationally, that CEI claimed establish a link between decoupling and energy efficiency.[1335]

885. CEI provided a survey demonstrating that RDM billing adjustments do not materially affect rewards to consumers for reducing their use of electricity.[1336]

886. CEI disagreed with the OAG and AARP that decoupling will adversely affect ratepayers. CEI noted that decoupling would not affect the underlying,

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[1328] Xcel Initial Br. at 147.
[1329] *Id.* (citing Minn. Stat. §§ 216B.2412, subd. 1; .16, subd. 6c).
[1330] *Id*.
[1331] Ex. 109 at 9-11 (Hansen Direct).
[1332] Exs. 109 Schedule 6 (Hansen Direct); Ex. 110 at 6-100 (Hansen Rebuttal).
[1333] Exs. 109 at 15 (Hansen Direct); Ex. 110 at 2-4, 9 (Hansen Rebuttal).
[1334] Ex. 109 at 2-9 (Hansen Direct); Ex. 42 at 3-5 (Sundin Rebuttal); Ex. 290 at 7-8 (Cavanagh Direct); Ex. 294 at 3-4 (Cavanagh Rebuttal).
[1335] Ex. 290 at 11 (Cavanagh Direct); CEI Initial Br. at 22-24.
[1336] Ex. 290 at 9 (Cavanagh Direct); Ex. 291 (Morgan Survey).

Commission-approved revenue requirement, and cited a national study for the proposition that decoupling adjustments are generally very modest.[1337]

iii. Analysis

887. The Administrative Law Judge finds that both the legislature and the Commission have shown a strong interest in continuing to learn how decoupling can be utilized to minimize a utility company's disincentive to actively pursue energy efficiency.[1338]

888. Because the Company's proposal is the first electric utility decoupling proposal in Minnesota, the RDM proposal provides the Commission with a unique opportunity to understand how decoupling will function in the electric utility context.

889. Revenue decoupling is a tool that is widely-used in a number of states to help separate energy utility companies' revenues from changes in energy sales. The Company demonstrated that, while it has been meeting its energy efficiency goals, compliance will be more difficult in coming years.[1339]

890. With regard to concern about customer confusion following decoupling, the OAG acknowledged that there is no evidence in the record that decoupling causes customer confusion concerning electric bills.[1340]

891. Properly implemented, revenue decoupling can balance the Company's obligation to promote energy efficiency and conservation without adversely affecting ratepayers.

892. For these reasons, the Administrative Law Judge concludes that it is reasonable to implement decoupling for the Company.

E. Decoupling Design Specifics

893. Having determined that implementation of decoupling is reasonable, the Administrative Law Judge will next address issues relating to the design of the specific decoupling program.

894. While supporting decoupling as a concept, the Department disagreed with certain design elements of the Company's proposed RDM.[1341] The Department contended that three features of the RDM must be changed in order to satisfy the

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[1337] Tr. Vol. 3 at 83-84 (Cavanaugh); Ex. 291 at Ex. A (Cavanaugh Direct); CEI Initial Br. at 26.
[1338] Minn. Stat. § 216B.2412 (2014); *In the Matter of the Application of CenterPoint Energy, a Division of CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota,* PUC Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 47-48 ((June 9, 2014).
[1339] Ex. 109 at 6-8 (Hansen Direct).
[1340] Tr. Vol. 3 at 274-275 (Nelson).
[1341] Ex. 417 at 33, 36, 40 (Davis Direct).

requirement at Minn. Stat. § 216B.2412, subd. 2 that decoupling proposals not adversely impact ratepayers. First, the RDM must be a full decoupling mechanism rather than a partial decoupling mechanism. Second, the RDM cap must be a hard cap of no more than 3 percent, based on total customer group revenue including fuel and riders. Finally, the RDM must be implemented as a pilot rather than a permanent program.[1342] The Company has agreed to the last change but disagrees with the other two proposed changes.

895. Both the OAG and AARP also recommend modifications to the Company's proposal if the Commission approves decoupling.[1343] Specifically, the OAG recommended full decoupling instead of partial decoupling, and also recommended changes to the Company's proposed cap.[1344] AARP recommended changes to the cap and the adoption of certain additional protections for ratepayers in the event decoupling is approved.[1345] These changes are opposed by the Company.

896. While supporting decoupling, ECC recommended changes to the RDM bill adjustment process.[1346] The Company also disagreed with this proposed change.

897. Each of these design issues is addressed below.

i. Full Versus Partial Decoupling

898. The Department recommended that the Commission order full decoupling rather than partial decoupling based on its conclusion that residential and small C&I customers covered by the program would be better off under full decoupling than partial decoupling.[1347]

In order to analyze whether to recommend full, partial or no decoupling, the Department requested the Company to provide estimates of the revenues for each of the Company's non-market rate customer classes, during the years 2004-2013, assuming: (a) no decoupling; (b) the Company's proposed partial revenue per-customer decoupling mechanism; and (c) full decoupling.[1348]

[1342] *Id.*
[1343] OAG Initial Br. at 70-71; AARP Initial Br. at 16-18.
[1344] Ex. 375 at 55-58 (Nelson Direct).
[1345] Ex. 310 at 17-18 (Brockway Direct); Ex. 311 at 19-20 (Brockway Rebuttal).
[1346] Ex. 234 at 28-29 (Colton Direct).
[1347] Ex. 419 at 16 (Davis Direct).
[1348] Ex. 417 at 27, CD-2 and CD-3 (Davis Direct); Ex. 419 at 12-13, CD-S-1 (Davis Surrebuttal). Originally, the Department requested and received information for the years 2009-2013. The Department later requested and received similar estimates for the years 2004-2008. *See* Ex. 419 at 12, CD-S-1. CD-S-1 is the Company's response to DOC IR 234 and includes Attachments A and B. Attachment A was calculated using test year numbers from 1993 for the calculations for the years 2004-2007. In Attachment B, the years 2004-2007 were calculated using numbers based on the assumption that the test year 1993 was updated with sales data from 2003 to show the effects of decoupling under a more consistent rate case schedule, given the unusual 13-year gap in the Company's rate cases between 1993 and 2006. The

899. The Company's estimates showed that the residential and small business customers covered by the Company's proposed partial RDM would have paid significantly more over the ten-year period from 2004-2013 than under a RDM employing full decoupling. The Department also observed that over the same time period, the customers covered by the Company's proposed partial RDM would have paid more under partial decoupling than no decoupling, but would have paid less with full decoupling than no decoupling.[1349] The Department summarized the results of its analysis in the table set forth below.[1350]

Table 25

2004-2013 Comparison of Partial and Full Decoupling

Customer Classes	**Increase/ (Decrease) in Revenues from No Decoupling**	**Average Annual Surcharge or (Refund)**
Residential Partial	$60,922,437	$56.81
Residential Full	($14,212,003)	($14.19)
Space Heating Partial	$4,405,657	$149.01
Space Heating Full	$5,363,540	$184.82
Small C&I Non-Demand Partial	($21,544,039)	($264.43)
Small C&I Non-Demand Full	($24,335,169)	($297.75)
Three Customer Classes Partial	$43,784,055	
Three Customer Classes Full	($33,183,631)	
Partial Costs Exceed Full Costs	$79,967,686	

900. Based on these results, the Department theorized that, during the period from 2003-2014, the Company's customers experienced non-normal weather in the form of a higher than usual temperature-humidity index (THI), boosting the Company's sales. The Department noted that weather-related sales are taken into account in full decoupling calculations, but not in the Company's proposed partial RDM. Because increased sales were not taken into account, the partial decoupling mechanism makes it appear as if revenues are lower than they are and thus customers are overcharged.[1351]

Department concluded that the numbers from Attachment B are more appropriate because the Commission likely would not have permitted a decoupling mechanism to continue for 13 years without a modification. Therefore, the Department chose to rely on the numbers from Attachment B. *See* Ex. 419 at 12-13, CD-S-1 (Davis Surrebuttal).

[1349] Ex. 419 at 13-14, CD-S-1 (Davis Surrebuttal).

[1350] Ex. 419 at 13 (Davis Surrebuttal).

[1351] Ex. 417 at 31 (Davis Direct).

901. To evaluate the extent to which actual use per customer (UPC) was higher than the weather-normalized UPC, the Department used data provided by the Company to create a table comparing actual UPC to weather-normalized UPC for the years 2005-2013. The table is set forth below.

Table 26

Comparison of Actual Use Per Customer to Weather-Normalized Use Per Customer (UPC), 2005-2013[1352]

Year	Actual UPC	WN UPC	Actual as Percent of WN
2005	8,321	8,116	103%
2006	8,288	8,150	102%
2007	8,387	8,170	103%
2008	7,921	7,980	99%
2009	7,690	7,918	97%
2010	8,099	7,854	103%
2011	8,069	7,851	103%
2012	8,010	7,824	102%
2013	7,938	7,684	103%

902. The Department reasoned that the information in the table above illustrates that, a significant majority of the time, the Company's weather-normalized use per customer (WN UPC) was lower than its actual UPC. If this pattern continues, the Department asserted that residential customers could be surcharged under the Company's partial RDM even if the Company has recovered its per-customer revenue requirement.[1353]

903. Based on its analysis of the Company's data, the Department concluded that the Company's proposed partial RDM would have an adverse impact on the Company's residential ratepayers, is not reasonable and should not be approved.[1354] Instead, the Department recommended the Commission approve a full RDM.

904. The OAG also recommended full decoupling rather than partial decoupling based on the Department's analysis of historical cost data.[1355]

905. In response to the Department's and OAG's recommended rejection of the Company's partial decoupling RDM proposal as unreasonable, the Company asserted inclusion or exclusion of weather in the RDM has no impact on meeting the statutory

[1352] *Id.* at 31-32.
[1353] *Id.* at 32.
[1354] *Id.* at 32; Ex. 419 at 13-14 (Davis Surrebuttal).
[1355] Ex. 375 at 55, 60 (Nelson Direct).

goal of reducing the disincentive to promote energy efficiency. In addition, the Company asserted that the Department's cost analysis is dependent on the pilot period sharing weather and economic conditions with the years analyzed by the Department.[1356]

906. The Department agreed that conditions during the pilot period might not be exactly the same as in the period examined by the Department. However, the Department pointed out that other factors such as economic downturn or significantly higher energy conservation could result in higher customer rates. Weather is the only factor that distinguishes between the Department's full and the Company's partial decoupling. Therefore, conditions such as an economic downturn or significantly higher energy conservation could lead to higher rates charged to customers, but would do so under either partial or full decoupling.[1357]

907. Furthermore, the Department asserted that the Company's own data demonstrated that from 2011 to 2013 partial decoupling would have cost residential ratepayers $52.9 million more than a full decoupling rate design.[1358] Because either full or partial decoupling would address the Company's incentive to sell more energy to meet its revenue requirement, the Department contended it is not reasonable to charge ratepayers $52.9 million more over a three year period.[1359]

908. The Department also pointed to the results of its analysis from 2004-2013 to support its conclusion that full decoupling provides more protection for ratepayers than does partial decoupling.[1360]

909. In response to the Department and OAG's recommendation that the Commission adopt full decoupling, CEI's expert noted that he had supported full decoupling in other states as a way to minimize risk to both utilities and their customers. Nonetheless, CEI supported the Company's proposed partial decoupling mechanism based on CEI's view that decoupling mechanisms work best when the utility supports the key design elements.[1361]

910. Based on the record in this case, the Administrative Law Judge concludes that full decoupling is a more reasonable approach than partial decoupling for the Company's residential and small business customers who would be subject to the RDM adjustments. The Department has demonstrated that the Company's partial decoupling RDM is likely to result in the Company's residential customers paying substantially more than under a full decoupling RDM, and could result in ratepayers being overcharged.[1362]

[1356] Ex. 110 at 5, 9 (Hansen Rebuttal).
[1357] Ex. 419 at 10 (Davis Surrebuttal).
[1358] *Id.* at 11.
[1359] *Id.* at 11.
[1360] *Id.* at 13-14.
[1361] Ex. 294 at 6 (Cavanagh Rebuttal).
[1362] Ex. 417 at 32 (Davis Direct).

Moreover, the record shows that either a full or a partial RDM would eliminate the Company's disincentive to encourage energy conservation and efficiency.[1363] To avoid an adverse impact on ratepayers subject to the new RDM, the Administrative Law Judge recommends that the Commission order the Company to implement its RDM with full decoupling.

ii. Type and Limit of Cap

911. As discussed above, the Company has proposed a soft cap as part of its RDM.[1364]

912. The Department, the OAG and AARP all support a hard cap on potential RDM billing adjustments rather than a soft cap.[1365] All contend that a soft cap is not an actual cap because amounts above the cap are deferred for future recovery.[1366]

913. AARP proposed a 2 percent cap, and the OAG proposed a hard cap set at less than 5 percent of total revenues.[1367]

914. AARP raised concerns about the impact of the proposed RDM on low-use, low-income and special needs customers. It asserted that these customers would face difficultly paying any surcharges applied as a result of RDM billing adjustments.[1368] AARP argued that the 2 percent hard cap was needed to protect customers from excessive rate increases if a RDM is approved.[1369]

915. The OAG's recommendation was based on its calculation that the Company's proposed 5 percent cap on RDM billing adjustments could increase residential rates from 4.75 percent to over 6 percent, depending on the customer's volumetric usage.[1370]

916. The Department objected to the Company's soft cap on RDM billing adjustments, asserting it would not adequately protect ratepayers.[1371]

917. Characterizing the Company's soft cap as "not a cap at all," the Department argued that the soft cap would not change the size of a given year's RDM

[1363] *Id.* at 18, 38-39.
[1364] Ex. 109 at 15 (Hansen Direct); Ex. 110 at 10 (Hansen Rebuttal).
[1365] Ex. 417 at 38 (Davis Direct), Ex. 377 at 39 (Nelson Rebuttal), Ex. 311 at 3 (Brockway Rebuttal).
[1366] Ex. 417 at 33 (Davis Direct), Ex. 310 at 21 (Brockway Direct), OAG Initial Br. at 70.
[1367] Exs. 311 at 3-6 (Brockway Rebuttal); Ex. 375 at 57-58 (Nelson Direct).
[1368] Ex. 311 at 6-8 (Brockway Rebuttal).
[1369] *Id.* at 3-6 (Brockway Rebuttal).
[1370] Ex. 375 at 57-58 (Nelson Direct).
[1371] Ex. 419 at 7 (Davis Surrebuttal).

billing adjustment but would only change the timing of the adjustment, shifting part of it from one year to the next.[1372]

918. Furthermore, the Department objected to the size of the Company's five percent cap with partial decoupling and 10 percent cap with full decoupling.[1373] Instead, the Department proposed a three percent hard cap.[1374]

919. In support of its position, the Department created the table set forth below, which illustrates the average monthly RDM billing adjustment that would have been paid under full decoupling by each RDM customer class in the years 2009-2013 assuming no cap:[1375]

Table 27

**Average Surcharge or (Refund) Under Full Decoupling
If Applied 2009-2013**

	Average Monthly Residential	**Average Annual Residential**	**Average Monthly Residential with Space Heat**	**Average Annual Residential with Space Heat**	**Average Monthly Small Commercial**	**Average Annual Small Commercial**
2009	$2.00	$23.94	$0.66	$7.88	($1.62)	($19.44)
2010	($0.02)	($0.23)	$1.77	$21.21	$0.54	$6.53
2011	($0.04)	($0.54)	$0.85	$10.25	$2.01	$24.12
2012	($0.05)	($0.55)	$5.36	$64.28	$0.64	$7.70
2013	($0.64)	($7.65)	($1.94)	($23.24)	($3.79)	($45.42)

920. As shown in the table, the Residential Customer class (without Space Heat) would have experienced an average RDM billing adjustment of $2 per month in 2009, or $24 per year, which would have been approximately 3 percent of annual residential bills.[1376] The remaining years would have provided residential customers with refunds.[1377]

921. The Residential with Space Heating customer class would have experienced a maximum RDM billing increase of $5.36 per month or $64.28 on an

[1372] Ex. 417 at 33 (Davis Direct).
[1373] *Id.*
[1374] *Id.* at 35.
[1375] *Id.* at 34.
[1376] *Id.* at 34-35.
[1377] *Id.* at 35.

annual basis in 2012. The 2012 RDM billing increase would have been approximately 5.4 percent of the Residential with Space Heating bills.[1378]

922. The average Small Commercial customers would have experienced a maximum RDM billing increase of $2.01 per month or $24.12 on an annual basis in 2011. The same class would have received an RDM billing refund of $45.12 in 2013.[1379]

923. The Department was concerned in particular about the size of the RDM billing increase for the Residential with Space Heating class in 2012 when the winter was mild and electric heating usage was low. The Department suggested that a hard cap on increased RDM billing adjustments with a full revenue decoupling mechanism could help mitigate the size of potential billing adjustments, if the cap is set at a reasonable percentage.[1380]

924. The Department compared the Company's 5 and 10 percent cap proposals to the Department's proposed 3 percent cap and AARP's proposed 2 percent cap.[1381] The Company's proposed caps were based on the percentage of base revenue, excluding fuel and applicable riders.[1382] The Department's proposed cap, and its interpretation of AARP's proposed 2 percent cap were calculated using base revenue, and including fuel and applicable riders.[1383]

925. The Department demonstrated that the Company's proposed caps of 5 percent for partial decoupling and 10 percent for full decoupling could result in RDM billing increases of approximately $48 million (five percent) and $97 million (10 percent) for the combined customer classes.[1384] The Department's analysis also indicated that the Residential customer class would have encountered a 2 percent cap under full decoupling in 2004 and 2009, but would not have encountered a 3 percent or higher cap.[1385] The Residential with Space Heating customer classes would have encountered 2 and 3 percent caps in 2006 and the 2, 3, and 5 percent caps in 2012 under full decoupling.[1386] The Small Commercial customers only would have encountered a cap once, and it would have been a 2 percent cap.[1387]

[1378] The Company's response to DOC IR No. 319 indicated that the average monthly residential space heating bill for October 2012 through September 2013 was $97.42, which translates into an average of $1,169 per year. Ex. 417 at 35 (Davis Direct).
[1379] Ex. 417 at 35 (Davis Direct).
[1380] *Id.* at 35-36.
[1381] Ex. 419 at 7-8, Table 3 (Davis Surrebuttal); Ex. 311 at 3 (Brockway Rebuttal).
[1382] Ex. 110 at 9 (Hansen Rebuttal).
[1383] Ex. 418 at 8 (Davis Rebuttal). In fact, AARP's proposed two percent cap excluded fuel and applicable riders. Ex. 311 at 3 (Brockway Rebuttal).
[1384] Ex. 419 at 7-8 (Davis Surrebuttal).
[1385] *Id.* at 8, CD-S-1.
[1386] *Id.* at 8.
[1387] *Id*.

926. The Department recommended that the Commission approve the Department's proposed cap of 3 percent of base revenues including fuel and applicable riders. The Department asserted that the 3 percent hard cap would limit ratepayers' exposure to potentially large surcharges. At the same time, the Department's analysis indicated that the 3 percent cap would rarely be encountered.[1388]

927. In its Rebuttal Testimony, the Company and CEI disagreed with the recommendations of the Department, OAG and AARP regarding the cap type and the size of the cap. Both the Company and CEI reasoned that if a hard cap limits the amount of a RDM billing adjustment, the Company faces the same disincentive to promote energy efficiency that it faced in the absence of the decoupling mechanism.[1389]

928. Nonetheless, the Company acknowledged that in the years when a hard cap is not exceeded the Company's disincentive to promote conservation and energy efficiency will be addressed by a decoupling mechanism.[1390]

929. The Company also maintained that the soft cap will adequately protect ratepayers from volatile RDM billing adjustments.[1391]

930. In response to the Company and CEI, the Department asserted that a hard cap would not reintroduce the Company's disincentive to promote energy savings because the Company's DSM financial incentive mechanism is set at a level that makes it cost-effective for the Company to achieve higher levels of energy savings, even with a 3 percent hard cap.[1392]

931. The Department presented a table showing the energy savings levels that the Company has achieved in recent years, and the corresponding incentive payments the Company received.[1393] The Department argued that, at the level of incentive payment the Company earns, it would be irrational for the Company to cut back on its energy savings achievements even if it appeared that a hard cap would impact the Company's RDM billing adjustments. This is because the Company can make more money by saving a marginal unit of energy than by making additional sales.[1394]

932. In addition, the Department pointed out that the Commission approved hard caps for MERC and for CenterPoint Energy as part of their decoupling pilot

[1388] *Id.* at 9.
[1389] Ex. 110 at 10 (Hansen Rebuttal); Ex. 294 at 5 (Cavanagh Rebuttal).
[1390] Tr. Vol. 3 at 96 (Hansen).
[1391] Ex. 110 at 12 (Hansen Rebuttal).
[1392] Ex. 419 at 6 (Davis Surrebuttal).
[1393] *Id.* at 4, Table 1.
[1394] Ex. 419 at 3-6 (Davis Surrebuttal).

programs.[1395] The Department asserted that the Commission should protect the Company's ratepayers in the same way.[1396]

933. The Administrative Law Judge concludes that the Company's proposed soft cap on RDM billing adjustments would place an unreasonable burden on ratepayers. The Administrative Law Judge also finds that the Company has not shown a need for more than a 3 percent cap. Based on data from 2009-2013, only the Residential with Space Heating ratepayers would have exceeded a 3 percent cap, and that cap would have been exceeded only in one year, 2012.

934. Therefore, the Administrative Law Judge recommends that the Commission adopt the Department's 3 percent hard cap on all revenues, including fuel and applicable riders, as part of the Company's RDM.[1397] This recommendation balances the need for the Company to earn its full authorized revenue with the requirement that ratepayers not be adversely affected, and is reasonable given that this electric RDM program would be the first for an electric utility in Minnesota.

iii. Measurement of the RDM Adjustment

935. The Company has proposed that the annual RDM billing adjustment be applied to the per-kWh variable charge based on monthly billings to specific customer groups.[1398]

936. ECC recommended that the Company instead calculate RDM billing adjustments as a percentage of the customer's total energy bill.[1399]

937. AARP recommended considering ECC's recommended modification to the RDM from the per-kWh to the percentage of the total energy calculation, and that the most equitable approach should be selected.[1400]

938. CEI supported ECC's recommended modification to the RDM from the per-kWh to the percentage of the total energy calculation.[1401]

939. The Company opposed ECC's recommended modification to the way in which the RDM billing adjustment is calculated. The Company explained that its proposed RDM billing adjustments would be applied to the variable portion of customer

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[1395] *Id.* at 7.
[1396] *Id.*
[1397] The Administrative Law Judge notes that, because the recommended three percent hard cap includes fuel and applicable riders, it is a larger cap than it would be if it excluded those amounts.
[1398] Ex. 109 at 14 (Hansen Direct); Ex. 110 at 13 (Hansen Rebuttal).
[1399] Ex. 234 at 33-34 (Colton Direct).
[1400] Ex. 311 at 3 (Brockway Rebuttal); *see* AARP Initial Br. at 18 (recommendation #8).
[1401] CEI Reply Br. at 16.

bills so low-use customers would receive smaller percentage increases to their bills than average-to higher-use customers.[1402]

940. The Administrative Law Judge concludes that ECC's recommendation that RDM billing adjustments be calculated as a percentage of the customer's total energy bill is not well supported in the record. The Company has demonstrated that its per kWh approach based on monthly billings to specific customer groups is most likely to minimize month-to-month variations in adjustments and to prevent cross-class subsidization. In addition, low-use customers would receive smaller increases under this method. Therefore, the Administrative Law Judge recommends that the Commission adopt the Company's proposed method of calculating RDM billing adjustments.

iv. Other Design Recommendations Suggested by AARP

941. In addition to the changes discussed above, AARP recommended certain other consumer protections, focusing in part on low-use customers. Included among AARP's recommended protections were additional demand-side management DSM programs and measures, prevention of cross-subsidization, establishment of performance requirements and application of RDM billing adjustments that benefit customers who use the least energy.[1403]

942. In response, the Company stated that it is committed to pursuing cost-effective DSM programs. The Company reiterated that decoupling is intended to remove the disincentive to promote conservation whereas other statutory provisions are designed to incent the Company to invest in DSM. The Company also explained that RDM is not susceptible to cross-subsidization because the proposed RDM calculates RDM billing adjustments within each applicable customer group, using only changes in usage per customer within that customer group. In addition, the Company produced a series of examples showing how the RDM might interact with residential customers' bills. The utility found that, all else being equal, "low use" customers (those who use 200 kWh or less per month) would experience lower percentage bill impacts from RDM surcharges than higher-use customers. The Company also found that the amount of conservation required to offset a bill impact associated with the maximum allowable RDM surcharge under the Company's proposal (5 percent of base rates) is attainable by, for example, replacing a single 60-watt incandescent light bulb with an equivalent compact fluorescent light bulb.[1404]

943. Based on the record, the Administrative Law Judge respectfully recommends that the programs advanced by AARP not be required as a condition of approving a decoupling pilot program for the Company. The Company has shown its proposal is designed in a manner that addresses AARP's concerns regarding cross-

[1402] Ex. 111 at 10 (Hansen Surrebuttal); CEI Initial Br. at 27.
[1403] Ex. 310 at 17-18 (Brockway Direct).
[1404] Ex. 109 at 8 (Hansen Direct); Ex. 110 at 12-13, 21-22 (Hansen Rebuttal); Ex. 111 at 5-10 (Hansen Surrebuttal).

subsidization and low-use customers. If the Commission believes the Company should increase its commitment to cost-effective DSM programs, the Administrative Law Judge recommends that the Commission require that issue be addressed as part of the Company's CIP filings.[1405]

v. Summary of Decoupling Recommendations

944. In summary, the Administrative Law Judge respectfully recommends the Commission authorize a revenue decoupling pilot program for the Company. The Administrative Law Judge further recommends that the pilot program include a RDM based on full decoupling rather than partial decoupling and that it include a 3 percent hard cap on upward bill adjustments, as proposed by the Department. These changes are necessary to help ensure ratepayers are not adversely affected by the new RDM. With regard to other aspects of the RDM design and implementation, the Administrative Law Judge recommends that the Commission adopt the Company's proposal including the agreements the Company reached with the parties during this proceeding.[1406]

X. Tariff Proposals

A. Coincident Peak Billing[1407]

945. Under the Company's existing tariff, a single business on contiguous properties that has multiple electric service metered locations is demand-billed separately for each metered location.[1408] If the maximum demand for each metered location occurs at different times during the month, the total of all billed demands for the month may exceed the amount that would have been billed if the entire business site was metered and billed through a single metered location.[1409]

946. Coincident peak billing is the practice of permitting synchronized interval-by-interval aggregated demand billing for all metered locations on a single business site, including meters on contiguous properties.[1410]

947. MCC has proposed that the Commission require the Company to modify its tariff to facilitate coincident peak billing for C&I demand-billed customers with demands of 500 kW or greater at one or more service points on a business site. Under MCC's proposal, each qualified customer would need to install interval recording meters at each electric service location as well as a totalizer on its qualified business site to take advantage of coincident peak billing.[1411]

[1405] *See* Minn. Stat. § 216B.2412 (2014).
[1406] *See* supra at paragraphs 855-871; Ex. 110 at 2-3 (Hansen Rebuttal).
[1407] Issue 71.
[1408] Ex. 340 at 24 (Schedin Direct).
[1409] Ex. 107 at 42-43 (Huso Rebuttal).
[1410] Ex. 340 at 24 (Schedin Direct).
[1411] *Id.* at 26 (Schedin Direct); Ex. 342 at 14 (Schedin Surrebuttal).

948. MCC argued that coincident peak billing is fair and reasonable because it will allow these large C&I customers to capture the demand diversity benefits they provide to the system, rather than allowing other customers to benefit from their diversity.[1412]

949. The Company opposed MCC's coincident peak billing proposal. According to the Company's data, there are only nine large C&I customers who would qualify for coincident peak billing under the definition proffered by MCC. In order to offer coincident peak billing, the Company would need to install a new billing system to aggregate all demand interval recording meter readings to bill peak demand.[1413] The Company urged rejection of the request by MCC for coincident peak billing due to the cost of implementing the new billing system.[1414] The Company also maintained that coincident peak billing is inappropriate for distribution capacity costs.[1415] The Company suggested that coincident peak billing is unnecessary because its current tariff already allows a C&I customer to change its wiring configuration to accommodate a single metered location on its business site for demand aggregation billing.[1416]

950. The Company noted that an experimental demand aggregation rider was previously used and cancelled in 2001 due to lack of interest.[1417]

951. MCC responded that coincident peak billing would be beneficial to the nine qualifying customers and noted that MCC is not "opposed to a reasonable meter charge to recover the billing process changes…."[1418]

952. In the last rate case, MCC also proposed that the Company be required to modify its tariff to allow coincident peak billing. The Commission did not adopt MCC's proposal. The Commission concluded that MCC's proposal was not sufficiently developed, especially in terms of cost implications, to demonstrate that it would result in reasonable rates.[1419]

953. While MCC's current coincident peak billing proposal has more specificity than its last proposal, the Administrative Law Judge concludes that its current proposal is still not sufficiently developed to show that it will result in reasonable rates. MCC has not addressed how the cost of implementing the new billing system would be recovered, other than to express its acceptance of a reasonable meter charge. MCC has not provided any evidence to demonstrate that it would be cost-effective for any of the nine customers to implement coincident peak billing if the customer is responsible for the cost of the new meters and also a reasonable meter charge. Finally, MCC has not

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[1412] Ex. 340 at 25 (Schedin Direct).
[1413] Ex. 107 at 44 (Huso Rebuttal).
[1414] *Id.*
[1415] *Id.* at 47.
[1416] Minnesota Electric Rate Book, Section No. 6, 1st Revised Sheet No. 17 (effective Date April 1, 2010).
[1417] Ex. 107 at 43 (Huso Rebuttal).
[1418] MCC Reply Br. at 12.
[1419] 12-961 ORDER at 13.

explained how its current proposal differs from the experimental demand aggregation rider program cancelled by the Company in 2001 due to lack of interest.

B. Definition of Contiguous[1420]

954. Under the Company's existing tariff, the term "contiguous" is used within the section in the General Service Rules governing Use of Service, as follows:

> The customer may combine the supply of electricity through one meter and one service to two or more buildings or occupancy units if they are located on the same or *contiguous* parcels of property and occupied by the same customer, solely for the customer's own use.[1421]

The tariff does not contain a specific definition of "contiguous."

955. MCC asked the Commission to require the Company to modify its tariff and adopt a definition of "contiguous" like that in Minn. Stat. § 216B.164, subd. 2a(e) (2014). Under the statute, "contiguous" is defined as "property owned or leased by the customer sharing a common border, without regard to interruptions in the contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way."[1422] According to MCC, the Company has been interpreting "contiguous" in a more limited manner. MCC maintained that the Company has been disallowing applications for combined electric service when property lines are interrupted by roadways and other rights of way.[1423] Under MCC's proposal, the new definition of "contiguous" would apply to the Use of Service section in the current tariff, future applications for solar power PPAs, and the coincident peak billing system suggested by MCC.[1424]

956. The Company opposed the request by MCC for formal adoption of a definition for "contiguous." According to the Company, there is no need to have a specific definition for the term as used in the current tariff; if a customer can wire a site in a way that presents one metered service location, then the customer can take advantage of demand aggregation and the structure of the parcel of property holding the metered service location is irrelevant.[1425] Moreover, the Company offered its interpretation of the term contiguous as generally referring "to a single physical customer site or location, as distinct from customer accounts at different geographical locations."[1426] In addition, because the Company opposed MCC's request for

[1420] Issue 72.
[1421] Minnesota Electric Rate Book, Sec. No. 6, 2nd Revised Sheet No. 19.3 (effective Date April 1, 2010) (emphasis added).
[1422] Minn. Stat. § 216B.164, subd. 2a(e).
[1423] Ex. 340 at 26 (Schedin Direct).
[1424] Ex. 342 at 15 (Schedin Surrebuttal).
[1425] Tr. Vol. 2 at 186-89 (Huso).
[1426] Ex. 136 (I.R. No. 251).

coincidental peak billing, the Company asserted a definition "contiguous" is not necessary.

957. MCC claimed the Company's current definition of "contiguous" lacks clarity and is subject to inconsistent application. By adopting the statutory definition of "contiguous" into the current tariff, MCC argued that customers will be able to more accurately plan metered service sites for their business locations.[1427]

958. The Administrative Law Judge concludes that MCC's request for adoption of the statutory definition of "contiguous" as part of the Company's current tariff is reasonable. Although the Administrative Law Judge has concluded that coincident peak billing is not appropriate under the facts in this record, MCC has shown that use of the statutory definition of "contiguous" would be beneficial. Formal application of the statutory definition in a revised tariff would provide uniformity and benefit to current customers looking to take advantage of demand aggregation.

C. Renewable Energy Purchase Tariff[1428]

959. XLI has asked the Commission to require the Company to develop a specific tariff for purchasing and selling renewable energy directly to qualifying large high-load factor customers.[1429]

960. The Company currently has a voluntary tariff referred to as the Voluntary Renewable and High Efficiency Energy Purchase Rider (the Windsource Program) where a customer can elect to purchase renewable energy in three ways: 100 kWh blocks; monthly; or for a single event.[1430] The Windsource Program allows customers to contribute to the development of renewable and high-efficiency energy resources.[1431] The Windsource Program, however, is not a viable option for large customers because its rates are set at a level that would result in a net increase in the cost of electricity for these customers. Therefore, the program provides little incentive for large C&I customers to purchase renewable energy.[1432]

961. In this case, XLI has recommended establishing a "Renew-A-Source" program pairing large high-load factor customers operating 24 hours a day with renewable energy resources available primarily during off-peak hours.[1433] Such a program could match the output of a defined portfolio of renewable resources with a qualifying large customer's load under a long-term agreement. If well structured, renewable energy could be made affordable to industrial customers while also driving down the price of renewable resources by creating a new and stable source of long-

[1427] MCC Reply Br. at 11.
[1428] Issue 77.
[1429] Ex. 260 at 60-62 (Pollock Direct).
[1430] *Id.* at 59.
[1431] *Id.*
[1432] *Id.*
[1433] Ex. 260 at 60-61 (Pollock Direct).

term demand.[1434] XLI has proposed guidelines for the tariff, including its applicability to non-residential customer meters with a minimum load standard and 75 percent minimum annual load factor, as well as a formula for calculating the energy rate.[1435] XLI believes the Company should be required to work with interested parties and develop the new tariff to be filed no later than the Company's next rate case.[1436]

962. The Company is interested in having discussions with XLI and other interested stakeholders regarding the development of a tariff program providing renewable energy to large high-load factor customers.[1437] The Company opposed imposition of a particular deadline, however, due to the time it will take to develop a proposal appropriate for all stakeholders.[1438]

963. The Administrative Law Judge concludes that XLI's concept of creating a new tariff program to provide renewable energy to large high-load factor customers is worthy of further review. If well structured, such a program could make renewable energy affordable to large C&I customers and further the state energy policy of encouraging use of renewable energy resources.[1439] Therefore, the Administrative Law Judge recommends that the Company be required to present a proposal for a "Renew-A-Source" tariff as part of its next rate case.

D. Definition of On-Peak Period[1440]

964. Under the Company's existing tariff, the term "on peak period" is defined within the rate schedule as follows:

> The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.[1441]

[1434] *Id.*
[1435] *Id.* at 61.
[1436] *Id.* at 62.
[1437] Ex. 100 at 47 (Clark Rebuttal); Tr. Vol. 2 at 131-135 (Clark).
[1438] Ex. 100 at 48 (Clark Rebuttal).
[1439] *See* Minn. Stat. §§ 216B.03; .1691, subd. 2.
[1440] Issue 78.
[1441] Minnesota Electric Rate Book, Sec. No. 5, 10th Revised Sheet No. 3 (effective Date December 1, 2013) (Residential Time of Day Service); Minnesota Electric Rate Book, Sec. No. 5, 12th Revised Sheet No. 24 (effective Date December 1, 2013) (Small General Time of Day Service); Minnesota Electric Rate Book, Sec. No. 5, 13th Revised Sheet No. 30 (effective Date December 1, 2013) (General Time of Day

965. XLI asked the Commission to require the Company to modify its tariff and limit the definition of “on peak period” to only the summer months (June, July, and August) instead of encompassing the entire year. According to XLI, limiting the “on peak period” to the summer months would be consistent with cost-causation principles because the Company is a predominantly summer-peaking utility and capacity-related costs are appropriately allocated relative to summer coincident peak demand.[1442] XLI pointed out that MISO[1443] determines resource adequacy using each load serving entity’s contribution to the annual summer peak.[1444] Moreover, according to XLI, limiting the definition of “on peak period” would send stronger price signals to customers.[1445]

966. The Company responded that XLI’s proposal is unnecessary because the Company already has seasonal demand charges that are higher during the summer peaking months.[1446] According to the Company, the “on peak period” is used principally to differentiate between energy and fuel cost charges by on-peak and off-peak periods during the day, not for differences in seasonal use.[1447]

967. The Administrative Law Judge concludes that XLI has not shown that a change in the definition of “on peak period” would result in more reasonable rates. XLI’s proposal fails to recognize that the current definition of “on peak” properly accounts for the hourly differences that occur in all months throughout the year. In addition, the Company’s existing seasonal demand charges reflect the cost difference associated with seasonal peak capacity differentials, making the proposed change unnecessary.[1448]

XI. Other Disputed Issues

A. Interest Rate on Interim Rate Refund[1449]

968. Minnesota Rules part 7825.3300 establishes the interest rate that a public utility is required pay on an interim rate refund. The rule states in part:

Service); Minnesota Electric Rate Book, Sec. 5, 10th Revised Sheet No. 46 (effective Date December 1, 2013) (Peak Controlled Time of Day Service).

1442 Ex. 260 at 57 (Pollock Direct).

1443 In 2002, the Company turned over functional control of certain facilities in order to join the regional transmission organization known as MISO. *See* Ex. 260 at 56.

1444 Ex. 260 at 56-57 (Pollock Direct).

1445 *Id.* at 57-58.

1446 Ex. 107 at 45 (Huso Rebuttal); *see also*, Minnesota Electric Rate Book, Sec. No. 5, 13th Revised Sheet No. 30 (effective Date December 1, 2013) (General Time of Day Service) (showing a June-September rate for On Peak Period Demand service that is higher than the October-May rate for On Peak Period Demand Service).

1447 Ex. 107 at 45 (Huso Rebuttal).

1448 *See id.* at 45; Ex. 260, Schedules 13-14 (Pollock Direct); Minnesota Electric Rate Book, Sec. No. 5, 13th Revised Sheet No. 29-31 (effective Date December 1, 2013) (General Time of Day Service).

1449 Issue 66.

> 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 set at the average prime rate, to reflect the fact that the Company in effect borrowed money from its customers during the pendency of the interim rate period.[1450]

969. Pursuant to Minn. R. 7829.3200 (2013), the Commission can vary its rules when its determines that the following requirements are met:

i. Enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;

ii. Granting the variance would not adversely affect the public interest; and

iii. Granting the variance would not conflict with standards imposed by law.

970. In the 2012 rate case, several parties requested that the Commission vary Minn. R. 7825.3300 and increase the interest rate on refunds issued in that case. The Commission agreed and ordered the Company to refund the interim rate over-collection using the Company's overall cost of capital, 7.45 percent, instead of the average prime rate of 3.25 percent.[1451]

971. The Commission found that the criteria for a variance were met based on the record in that case. With regard to the first prong of the variance test, the Commission found that refunding the over-collection of interim rates with interest at 3.25 percent would impose an excessive burden on ratepayers. The Commission focused on the magnitude of the over-collection in that case and in the Company's other recent cases, and concluded that the "rule's low interest rate relative to the Company's authorized return constitutes an excessive burden on ratepayers as captive lenders."[1452] With regard to the second prong of the variance test, the Commission found that there was no adverse effect on the public interest because varying the rule would promote equity between utility and ratepayer borrowing costs and would help discourage overstatement of interim rate requests in future rate cases. Finally, the Commission

[1450] Minn. R. 7825.3300.
[1451] 12-961 ORDER at 36-39.
[1452] *Id.* at 38.

found that the third prong of the variance test was met because granting the variance would not conflict with any legal requirement.[1453]

972. In this rate case, the OAG has again requested that the Commission vary Minn. R. 7825.3300 and require the Company to pay NSP's rate-of-return on any interim rate refunds ordered. The OAG asserted that the 3.25 percent prime interest rate provided for by the rule is too low and does not compensate ratepayers who may be subject to credit card debt interest of up to 15 percent or higher.[1454] The OAG maintained that the Company is "holding ratepayer funds that can be used to finance its operations at an unreasonably low cost if the prime rate is used."[1455] The OAG also argued that the Commission's reasoning for granting the variance in the last rate case applies equally to this case.[1456] The OAG maintained that the "only thing that has changed [since the last rate case] is that Xcel has asked for even more money this time around."[1457]

973. The Commercial Group supported the OAG's request for the Commission to vary its rule. The Commercial Group noted that the Company has timed its rate case filings to limit the effect of the Commission's decisions to short periods of time. The Commercial Group pointed out that final rates in the last rate case were only in effect for 33 days before interim rates went into effect in this case, and the Company was "able to reclaim $127 million of the approximately $182 million removed by the Commission from NSP's revenue requirement request."[1458] The Commercial Group maintained that varying the rule is necessary to protect ratepayers and to continue to remove the incentive a utility may have to overstate interim revenue requirements.[1459]

974. The Company opposed the OAG's request for the Commission to vary the rule governing the interest rate applied to any interim rate refund. 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.[1460]

975. According to the Company, this case differs from the last case because the Company took a conservative approach with its interim rate request in this case. The Company stated that it "took steps to assure that its interim rates would be approximately half" of its requested rate increase for the 2014 test year.[1461] These

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[1453] *Id*.
[1454] Ex. 370 at 59 (Lindell Direct).
[1455] *Id.*
[1456] OAG Initial Br. at 42-43.
[1457] *Id.* at 43.
[1458] Commercial Group Initial Br. at 13; Ex. 225 at 7-8 (Chriss Direct).
[1459] Commercial Group Initial Br. at 13-14.
[1460] Xcel Initial Br. at 106-107.
[1461] *Id.* at 106. While the Company states that the annual interim rate revenue requested is approximately half of its revenue requested rate increase for the test year, the Administrative Law Judge notes that the Company requested an interim increase of approximately $127,400,000 on an annualized basis and

steps included implementing the Company's proposed 50/30/20 amortization proposal for the TDG depreciation reserve surplus.[1462] Also, the Company did not seek an interim rate increase for the 2015 Step year.[1463]

976. Next, the Company claimed that it treats interim rate revenues as a substitute for short term debt because those revenues are typically available for a year or less.[1464] 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.[1465] The Company's cost of short term borrowing is 0.62 percent.[1466] The Average Prime Rate, which is the rate the Company will pay on interim rate refunds pursuant to Commission rule without a variance, is 3.25 percent.[1467] Thus, the Company asserted that even without a variance it will pay more in interest on any interim rate refunds (3.25 percent) than it would cost for replacement short term borrowing (0.62 percent).[1468]

977. Finally, the Company maintained that setting the interest rate equal to the Company's rate-of-return is not appropriate because any refund to customers already reflects application of the Company's rate-of-return. The interest on the interim rate refund is in addition to the refund of any excess return. The Company also stated that it obtains recovery of its current expenses but does not earn a return on those expenses. In the view of the Company, the OAG's recommendation would improperly apply a level of interest to the current expenses that is equal to the Company's rate-of-return.[1469]

978. The OAG disagreed with the Company's view that this case is distinguishable from the last rate case. The OAG asserted that there is likely to be a substantial over-collection of interim rates in this case just as in the last rate case and, thus, the refund should be set at the rate-of-return to equitably compensate ratepayers for foregone opportunities.[1470] With regard to the Company's other two arguments, the OAG maintained that the Commission rejected these contentions in the last rate case.[1471]

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requested an increase of $192,708,000 for the 2014 test year. Thus, the Company's interim rate request was approximately 66 percent of its 2014 test year request.

[1462] ORDER SETTING INTERIM RATES at 2-3.

[1463] Xcel Initial Br.at 106.

[1464] Ex. 31 at 23-24 (Tyson Rebuttal).

[1465] *Id*.

[1466] *Id.* at 24.

[1467] Minn. R. 7825.3300.

[1468] Ex. 31 at 24 (Tyson Rebuttal).

[1469] Ex. 90 at 38 (Heuer Direct).

[1470] OAG Reply Br. at 4-5.

[1471] *Id.*

979. In order for the Commission to grant a variance to the interim rate refund rule, Minn. R. 7825.3300, all three prongs of the variance test in Minn. R. 7829.3200 must be met.[1472]

980. The Administrative Law Judge will address the three prongs in reverse order.

981. The third prong of Minn. R. 7829.3200 requires a finding that granting the variance would not conflict with standards imposed by law. Minn. Stat. § 216B.16, subd. 3, provides:

> If, at the time of its final determination, the commission finds that the interim rates are in excess of the rates in the final determination, the commission shall order the utility to refund the excess amount collected under the interim rate schedule, including *interest on it which shall be at the rate of interest determined by the commission*.[1473]

This statute gives the Commission the authority to determine the interest rate applied to any interim rate refund. Thus, granting the variance would not conflict with standards imposed by law.

982. The second prong of Minn. R. 7829.3200 requires a finding that "granting a variance would not adversely affect the public interest."[1474] Because the Company seeks to impose a carrying charge on its customers for nuclear refueling outage costs that is equal to its rate-of-return, grossed up for taxes, the Administrative Law Judge concludes that the public interest would not be adversely affected if the Company were required to pay that same rate on interim rate refunds. Both rates are essentially payments for the use of money. The Company has failed to explain how the public interest is served by the Company paying only 3.25 percent interest on the interim rate refund at the same time imposing a much higher rate on its customers as a carrying charge.

983. The first prong of Minn. R. 7829.3200 requires a determination that "enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule."[1475]

984. Based on the Commission's decision in the last rate case, the Administrative Law Judge concludes that the determination of whether enforcement of the rule will impose an excess burden on ratepayers in this case depends largely on the magnitude of the over-collection of interim rates, if any, in this case. If the amount of over-collection is comparable to the last case, then the reasoning in the Commission's

[1472] Minn. R. 7829.3200.
[1473] Minn. Stat. § 216B.16, subd. 3 (emphasis added).
[1474] Minn. R. 7829.3200, subp. 1(B).
[1475] Minn. R. 7829.3200, subp. 1(A).

12-961 ORDER would apply equally to this case given the magnitude and frequency of the over-collections by the Company. On the other hand, if the over-collection is a much smaller amount, the burden on ratepayers from lending the Company funds at the 3.25 percent Average Prime Rate may not be excessive.

985. Therefore, a final determination on the first prong can only be made by the Commission after it makes the revenue requirement decisions in this case.

B. Fuel Cost Recovery Reform[1476]

986. The Company currently recovers fuel and purchased power costs through a Fuel Clause Adjustment (FCA) mechanism authorized by the Commission pursuant to Minn. R. 7825.2500 (2013).[1477] As a result, these costs are not included in the Company's base rates.[1478]

987. The Company's fuel costs are forecasted one month ahead of time, and then followed by an accounting true-up.[1479] Each year, the Company is required to file an annual fuel cost recovery report with the Department, which is later submitted to the Commission for final approval.[1480]

988. Fuel and purchased power costs represent a significant portion of the Company's revenue. The Company projected that approximately 30 percent of its 2014 revenue ($836 million out of $2.982 billion) will be recovered through the FCA mechanism.[1481]

989. In this case, XLI, MCC, and the Department all expressed concerns about the current FCA process for recovery of fuel and purchased power costs even though the costs are not included in the Company's revenue requirements for the 2014 test year or the 2015 Step.

990. XLI asserted that oversight of fuel cost accounting requires an immense commitment of time and personnel, and the current process affords little or no risk of a fuel cost disallowance for major plant outages.[1482] XLI pointed to the increased fuel costs resulting from an outage that occurred at the Company's Black Dog plant in late 2012 and early 2013 as an example of why reform of the FCA mechanism is needed.[1483] Because the costs recovered by the FCA mechanism are significant, XLI believes the Commission needs to give serious consideration to revising the design of

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[1476] Issue 67.
[1477] Ex. 343 at 41 (Maini Direct).
[1478] *Id.*
[1479] *Id.* at 41 (Maini Direct).
[1480] *Id.* at 25-26 (Pollock Direct).
[1481] *Id.* at 28 (Pollock Direct).
[1482] *Id.* at 25-26 (Pollock Direct).
[1483] XLI Reply Br. at 8-9.

the FCA mechanism and/or redefining the standards of proof required during the review process.[1484]

991. XLI asked that the Commission require the Company to propose a new FCA mechanism in the next rate case or within 90 days of the Commission's order in this case, whichever is earlier.[1485] XLI believes a new incentive-based FCA mechanism should be guided by four principles: (1) establish an effective incentive for the Company to control fuel and purchased energy costs in a manner that results in overall savings for customers; (2) avoid causing chronic over-or under-recovery of costs without necessarily guaranteeing a dollar for dollar recovery; (3) emphasize the burden of proof being on the Company to show the costs recovered are reasonable and prudent; and (4) allow for administratively efficient review of fuel recovery costs by the Department, the Commission, and customers.[1486]

992. MCC argued that reform of the current FCA mechanism is needed because the FCA mechanism places all of the risk of power outages on customers. MCC maintained it requires them to prove, after the fact, when fuel recovery costs are imprudently incurred.[1487]

993. The Department pointed out that the current FCA mechanism dilutes the Company's incentive to minimize energy costs because the costs are passed through to ratepayers. In addition, the Department noted that it is difficult for parties to demonstrate after-the-fact whether energy costs were prudently incurred. It provided examples involving its investigation of forced outages and wind curtailments in Docket No. E999/AA-11-792.[1488] The Department argued that the Company does not treat fuel and replacement power costs as part of the total cost of doing business.[1489] In the view of the Department, reformation of the current FCA mechanism is necessary.[1490]

994. Similar concerns have also been raised by parties in the AAA proceeding in Docket Number E999/AA-12-757.[1491] However, no action has been taken to date on reformation of the FCA mechanism.[1492]

995. XLI does not believe the AAA docket is the appropriate forum for fuel cost recovery reform because thus far, stakeholder discussions have not resulted in narrowing the relevant issues or achieving a common understanding about the components of a new incentive-based FCA mechanism.[1493] Moreover, XLI pointed out

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1484 Ex. 260 at 28-29 (Pollock Direct).
1485 *Id.* at 29.
1486 *Id.* at 26-27.
1487 Ex. 343 at 42 (Maini Direct).
1488 Ex. 412 at 12-14 (Ouanes Rebuttal).
1489 *Id.*
1490 *Id.*
1491 Ex. 412 at 12 (Ouanes Rebuttal).
1492 Ex. 343 at 42 (Maini Direct).
1493 Ex. 263 at 33 (Pollock Surrebuttal).

that inviting all utilities and interested parties to discuss FCA reform as part of the AAA docket significantly diminishes the likelihood of a consensus on the issue.[1494] As a result, XLI recommended that the Commission take action in this case to expedite resolution of the issue.

996. Similarly, MCC recommended that the Commission require the Company to file a proposal for a new FCA mechanism as part of the next rate case if no resolution is gained in the AAA proceeding by the time the next rate case is filed.[1495]

997. While the Department agreed with XLI and MCC that the current fuel cost recovery mechanism needs to be reformed, the Department believes the issue should be addressed in the AAA docket because it is not limited to the Company but also involves the other investor-owned utilities operating in Minnesota.[1496]

998. The Company agreed that all interested parties need to work toward an incentive-based FCA mechanism reasonably within the Company's control.[1497] However, the Company argued that the new FCA mechanism proposal should be commensurate with the existing regulatory framework and revised as part of the AAA docket.[1498] The Company believes the AAA docket is the best forum to ensure all interested parties are involved in the process.[1499]

999. XLI, MCC, and the Department all raise valid concerns regarding the current FCA mechanism and the need for reform. The Administrative Law Judge concludes, however, that FCA reform and proposals for a new incentive-based FCA mechanism are properly part of the AAA docket because the issues involve all electric utilities operating in the state. The Administrative Law Judge encourages the Commission to address reformation of the FCA in a timely fashion in order to meet the needs of interested stakeholders.

C. Annual Incentive Compensation Program[1500]

1000. The Company offers an annual incentive compensation program (AIP) to exempt non-bargaining employees.[1501] The AIP uses three components to determine the amount of incentive compensation awarded: individual; business area; and corporate.[1502] For the individual component, employees have performance goals tied to job functions and their leaders assess their performance against the goals at least twice

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1494 *Id.*
1495 *Id.*
1496 Ex. 412 at 12-13 (Ouanes Rebuttal).
1497 Ex. 100 at 43 (Clark Rebuttal).
1498 *Id.*
1499 *Id.*
1500 Issue 82.
1501 Ex. 78 at 29 (Figoli Direct).
1502 *Id.* at 35-36.

per year.[1503] The business area and corporate components use key performance indicators (KPIs) designed to measure performance of the relevant goals.[1504] Each business area uses a scorecard containing several KPIs specific to the relevant business function.[1505] Overall, the Company's employees can earn an AIP award when they individually, collectively, and organizationally meet the Company's AIP goals. [1506]

1001. The Company's AIP program is designed to incent superior employee performance towards core company objectives. These objectives include reliability, public safety, customer service, employee safety and engagement, and environmental leadership.[1507]

1002. The use of an incentive compensation program like AIP is common in the utility industry and the greater marketplace. According to a study conducted by Towers Watson in 2013, 99 percent of utility companies across the country maintain AIPs as part of their compensation packages.[1508] Companies use incentive compensation to promote superior employee performance and reduce labor costs.[1509]

1003. In the last rate case, the Commission approved the Company's AIP expense but also ordered the Company to "evaluate the goals set for its annual incentive program to determine if they are too lenient or if they actually require stretching to meet."[1510] The Commission required the Company to file the results of the evaluation in this rate case.

1004. The Company responded to the Commission's directive by re-evaluating all of its AIP targets.[1511] The Company presented AIP-related testimony from ten management-level employees: Darla Figoli (Corporate Services – Human Resources), David Harkness (Corporate Services – Business Services IT), Michael Gersack (Corporate Services – Customer Care), Stephen Foss (Distribution Operations), Steven Mills (Energy Supply), Amy Stitt (Financial Operations), Timothy O'Connor (Nuclear), Gary O'Hara (Supply Chain), David Sparby (Revenue Group), and Daniel Kline (Transmission).[1512] Each witness discussed the creation and assessment of the KPIs unique to their business area, as well as each business area's historical ability to meet the relevant KPIs.[1513] Overall, every witness maintained that the KPIs for the individual

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[1503] *Id.* at 36.
[1504] *Id.*
[1505] *Id.*
[1506] *Id.* at 40.
[1507] *Id.*
[1508] *Id.* at 33.
[1509] *Id.*
[1510] 12-961 ORDER at 9, 51.
[1511] Ex. 78 at 42 (Figoli Direct).
[1512] *Id.* at 44.
[1513] Ex. 71 at 40-44 (Gersack Direct); Ex. 69 at 48-51 (Foss Direct); Ex. 62 at 85-86 (Harkness Direct); Ex. 65 at 74-77 (Kline Direct); Ex. 78 at 45-50 (Figoli Direct); Ex. 51 at 130-33 (O'Connor Direct); Ex. 58 at

business areas are reasonable because the goals are appropriately set and sufficiently challenging.[1514]

1005. The Company included $17,584,311 in the 2014 test year for AIP expenses.[1515] This amount represents a four-year average of AIP expenses, and excludes amounts over 15 percent of any individual's base salary.[1516] The Company claimed that its AIP request will most likely be below actual AIP cost in 2014. This is due to the Company's conservative budgeting process, the 15percent cap of base salary, and the use of a four-year average capped at 100 percent.[1517]

1006. The Department agreed it is reasonable to allow the Company to recover AIP compensation from ratepayers up to the 15 percent cap proposed by the Company.[1518] The Department pointed out, however, that from 2009 through 2012 the Company's employees almost always met their KPIs.[1519] Moreover, actual AIP compensation paid out by the Company in 2009, 2010, and 2012 was more than 100 percent:[1520]

Table 28

Year	100% Target AIP ($000s)	Actual AIP ($000s)
2009	$24,708	$27,891
2010	$27,283	$28,218
2011	$28,995	$27,343
2012	$25,302	$29,731

The Department offered all of this testimony to provide perspective on the Company's AIP.[1521] Essentially, the Department suggested that the Company's KPIs for its AIP may not be not rigorous enough because the majority of employees meet their goals every year.

1007. The Company asserted that its "AIP goals strike the right balance between being difficult enough to challenge employees while not being so difficult as to serve as a disincentive."[1522] According to the Company, the intent of KPIs is to motivate

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86-88 (Mills Direct); Ex. 25 at 34 (Sparby Direct); Ex. 75 at 38 (O'Hara Direct); Ex. 86 at 70-71 (Stitt Direct).

[1514] *Id.*

[1515] Ex. 78 at 30 (Figoli Direct).

[1516] *Id.*

[1517] *Id.* at 31-32.

[1518] Ex. 437 at 59 (Lusti Direct).

[1519] *Id.* at 58.

[1520] Ex. 78 at 31 (Figoli Direct).

[1521] Ex. 437 at 59 (Lusti Direct).

[1522] Ex. 78 at 42 (Figoli Direct).

employees to provide excellent service at levels that can be met with the requisite amount of talent and effort.[1523] It is not necessary to make KPIs more challenging each year; instead, performance levels simply need to be sustained.[1524] The Company also asserted that the KPI goals are helping the Company to provide safe and reliable service at a reasonable price and therefore are achieving what they are intended to achieve.[1525] In addition, the Company claimed AIP is not a "bonus" because anything less than 100 percent of the full AIP compensation puts the employee at a compensation level below the relevant market.[1526] Finally, the Company pointed out that its 15 percent cap is less than the 25 percent cap approved by the Commission in the recent CenterPoint Energy gas rate case.[1527]

1008. No other parties besides the Department and the Company provided testimony on the issue of whether the Company's existing AIP goals are sufficiently challenging.[1528]

1009. The Administrative Law Judge concludes that the Company has complied with the Commission's directive from the last rate case and has demonstrated that its existing KPIs provide a proper incentive for its employees to perform well in key areas. The Company has also shown its proposed AIP expense is reasonable because it is based on a four-year average and includes a 5 percent cap.

D. FERC Cost Comparison Study – KPI Benchmarks[1529]

1010. Each year, Xcel Energy Inc. conducts a benchmark study (Study) using publicly available data from FERC reports to compare the Company and other Xcel operating companies to investor-owned peer utility companies in the Edison Electric Institute (EEI) Index.[1530] The Study focuses on retail revenues, fuel, and purchased power costs, as well as non-fuel O&M costs including production, transmission, distribution, customer care, and administrative.[1531] In the 2013 Study, the Company's performance fell below the second quartile in comparison to peer utility companies with respect to two benchmarks: (1) non-fuel O&M costs (percent of retail revenue by total, per customer, per retail MWh sales, and per Mwh generated); and (2) transmission

[1523] *Id.* at 42-43.
[1524] Ex. 80 at 7 (Figoli Rebuttal).
[1525] *Id.* at 5.
[1526] Ex. 78 at 43 (Figoli Direct).
[1527] Ex. 80 at 4 (Figoli Rebuttal).
[1528] While not commenting on this issue, MCC raised separate issues (Issues 69 and 70) relating to O&M and transmission cost controls and recommended new KPIs to address these costs. *See infra* at ¶¶ 1101-1102, 1019-1120.
[1529] Issue 70.
[1530] Ex. 67 at 37 (Kline Rebuttal).
[1531] Ex. 100 at 45 (Clark Rebuttal); Ex. 67 at 38 (Kline Rebuttal).

O&M costs (transmission O&M per line-mile and transmission O&M per Mwh throughout).[1532] The 2013 Study used Xcel Energy Inc.'s costs from 2012.[1533]

i. MCC's Proposal

1011. Based on the 2013 Study, MCC has recommended that the Commission require the Company to add the two lowest benchmarks from the 2013 Study, non-fuel O&M costs and transmission O&M costs, as KPIs to its AIP.[1534] MCC recommended the addition of the two benchmarks from the 2013 Study based on the Company's performance as compared to peer utility companies.[1535] The Department agreed with MCC's recommendation.[1536]

ii. The Company's Position

1012. The Company opposed both additional KPIs recommended by MCC.

1013. With regard to the Company's proposal for non-fuel O&M, the Company pointed out that it has already implemented a KPI related to non-fuel O&M growth management.[1537] Specifically, the Company's KPI goal in 2014 is to limit recoverable non-fuel O&M cost growth to no more than 2.2 percent.[1538] Unlike the benchmark from the 2013 Study, the Company's KPI is tied to costs recoverable from ratepayers and takes into account variations that may occur between cost categories.[1539] The Company believes its O&M growth management KPI sufficiently addresses the concerns of MCC, making implementation of an additional KPI for non-fuel O&M costs is unnecessary.[1540]

1014. Regarding the transmission O&M costs benchmark from the Study, the Company argued that it is overly simplistic because the benchmark from the Study compares the Company to a broad group of utilities in the EEI index, some of which are not comparable.[1541] The Company asserted that the transmission O&M costs benchmark in the Study fails to account for a variety of factors, including geographic differences in line-mile calculations and membership in an RTO.[1542] According to the Company, adding a transmission O&M costs KPI is unnecessary. If a transmission

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[1532] Ex. 343 at 43-44 (Maini Direct).
[1533] Ex. 100 at 45 (Clark Rebuttal).
[1534] Ex. 343 at 45 (Maini Direct).
[1535] *Id.* at 43-45.
[1536] Ex. 412 at 16 (Ouanes Rebuttal).
[1537] Ex. 100 at 46 (Clark Rebuttal).
[1538] *Id.* at 47.
[1539] *Id.* at 46-47.
[1540] *Id.* at 47.
[1541] Ex. 67 at 40-41(Kline Rebuttal).
[1542] *Id.*

O&M cost KPI is deemed necessary, however, the Company requested a broader, more balanced set of metrics be utilized to measure transmission function performance.[1543]

1015. In response, MCC revised its position and instead suggested that in the next rate case, the Company identify which peer utility companies should be used for comparison in the Study and justify its selection.[1544]

iii. Analysis

1016. The Administrative Law Judge concludes that the Company's KPI for non-fuel O&M growth management sufficiently addresses concerns raised by MCC and the Department relating to non-fuel O&M costs. Unlike the benchmark proposed by MCC from the 2013 Study, the Company's KPI for non-fuel O&M growth management is tied to costs recoverable from ratepayers and takes into account cost variations between Xcel Energy Inc.'s four operating companies.[1545] Therefore, the additional non-fuel O&M costs benchmark from the Study is not necessary.

1017. The arguments relating to the addition of a KPI for transmission O&M costs, however, raise valid cause for concern and justify further study. Therefore, the Administrative Law Judge recommends that, in the next rate case, the Company be required to present a new KPI for transmission O&M costs, including appropriate peer companies for comparison.

E. Transmission Business Area Cost Control[1546]

1018. In addition to the specific transmission O&M cost issue discussed above, MCC has raised general concerns regarding cost controls for the Company's transmission business unit.[1547] According to MCC, transmission costs, on a dollar per KW per month basis, are a fast-growing element in the Company's rate structure. It maintains that adequate cost controls are lacking.[1548] Specifically, MCC believes transmission cost control should be a major stated responsibility for the Vice-President of Transmission.[1549] Currently, transmission cost control is primarily addressed through the Company's employee performance review process.[1550]

1019. To address the situation, MCC recommended that a new transmission KPI be developed for the Vice-President of Transmission.[1551] In addition, MCC

[1543] *Id.* at 44-45.
[1544] *Id.*
[1545] Ex. 100 at 46-47 (Clark Rebuttal).
[1546] Issue 69.
[1547] Ex. 340 at 16-21 (Schedin Direct).
[1548] *Id.* at 17.
[1549] *Id.*
[1550] *Id.*
[1551] *Id.*

recommended that price caps be established for new transmission projects.[1552] For each transmission project requiring a CON, MCC suggested that the Commission impose a firm cost cap which cannot be exceeded for ratemaking purposes without Commission approval.[1553] For projects that do not require a CON, MCC recommended that the Company and other MISO transmission owners establish a reasonable cost control mechanism at MISO.[1554]

1020. The Company opposed MCC's request, maintaining that it has sufficient cost management controls in place for the transmission business unit.[1555] In addition, the Company asserted that a firm cost cap for transmission projects based on the cost estimates provided at the CON stage is inappropriate because there are a significant number of uncertainties that impact the final cost of a project, which are not resolved until a final project route is determined.[1556] Moreover, imposing a cost cap based on CON cost estimates is inconsistent with the purpose of the CON process to determine the most appropriate way to meet the project need through a comparison of reasonable alternatives.[1557] The Company noted that detailed design and engineering is not preferred at the CON stage because the scoping estimates are sufficient to decide between alternative resources.[1558] Lastly, the Company stated that there are ample opportunities for parties to review and challenge the prudence of transmission project costs, either during rate case proceedings or the Transmission Cost Recovery Rider proceedings.[1559]

1021. For projects that do not require a CON, the Company believes sufficient processes are already in place at MISO to control transmission costs. Specifically, MISO and interested stakeholders have the power under the MISO tariff and the formula rate protocols to review and monitor transmission owner cost data.[1560] Moreover, MISO has a robust stakeholder process in which many entities actively participate.[1561] Through this process, employees from the Company participate in MISO's regional planning efforts to ensure transmission expansion plans are fully vetted and appropriately sized.[1562] The Company also pointed out that MISO is likely to develop additional cost control mechanisms in light of FERC Order No. 1000, but development of these additional mechanisms may take time.[1563]

1022. No other parties have taken a position on this issue.

[1552] *Id.*
[1553] *Id.*
[1554] *Id.*
[1555] Ex. 67 at 29-33 (Kline Rebuttal).
[1556] *Id.* at 20-29.
[1557] *Id.* at 19.
[1558] *Id.*
[1559] *Id.*
[1560] *Id.* at 36.
[1561] *Id.*
[1562] *Id.*
[1563] *Id.*

1023. MCC has raised valid concerns about whether the Company has sufficient overall cost control mechanisms in place in its transmission business area. To address this issue, the Administrative Law Judge recommends that in the next rate case, the Company be required to propose a new cost control KPI at the Vice Presidential level for overall transmission costs. The new KPI should include a subcategory for transmission O&M costs to meet the recommendation in paragraph 1018 above.

1024. The Administrative Law Judge, however, agrees with the Company that the CON process is not designed to provide final cost estimates and, therefore, it would not be appropriate to establish price caps for transmission projects on that basis.

CONCLUSIONS OF LAW

1. The Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. §§ 14.50, 216B.08 (2014).

2. The public and the parties received proper and timely notice of the hearing and the Applicant complied with all procedural requirements of statute and rule.

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, .241, 216C.05.[1564]

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.[1565] Similarly, the burden of proof is on the utility to show that a multi year rate plan is just and reasonable.[1566]

5. The record supports the resolution of the settled, resolved, and uncontested matters set forth in Attachment A. 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 in the Commission's ORDER SETTING INTERIM RATES, issued January 2, 2014, and a refund ordered to the extent that the interim rate exceeds the final rates for 2014 and 2015, subject to any true-up that is ordered.

[1564] Minn. Stat. § 216B.03.
[1565] Minn. Stat. § 216B.16, subd. 4.
[1566] Minn. Stat. § 216B.16, subd. 9(a).

8. Any Findings of Fact more properly designated as Conclusions are hereby adopted as such.

Based upon these Conclusions of Law, the Administrative Law Judge makes the following:

RECOMMENDATION

The Administrative Law Judge recommends that:

1. The Company is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. By January 9, 2015, the Company shall file with the Commission and serve on all parties in this proceeding, financial and rate design schedules that reflect the 2014 test year and 2015 Step revenue requirements and rate design recommended by the Administrative Law Judge.

3. The Commission incorporate the agreements made by the parties in the course of this proceeding into its Order.

4. The Commission adopt the recommendations set forth in the Findings above.

5. The Company make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: December 26, 2014

__s/Jeanne M. Cochran____________
JEANNE M. COCHRAN
Administrative Law Judge

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2013), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Part 7829.2700, Subpart 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

OAH 68-2500-31182
PUC E-002/GR-13-868

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

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

ATTACHMENT A
RESOLVED ISSUES AND UNDISPUTED CORRECTIONS

The following issues were resolved in the course of the proceeding or involve corrections that are undisputed. The adjustments related to these issues are reflected in the Company's revised requested increase of $142.2 million for 2014 and $106.9 million in 2015, for a total combined increase of $249.0 million:

1. Sales Forecast (2014 and 2015 Step) (Issue 13)[1567]

2. Property Tax Amount (2014) (Issue 14)

3. Emissions Control Chemicals (2014) (Issue 15)

4. Insurance – Surplus Distributions from Industry Mutual Insurance Pools (2014) (Issue 16)

5. Treatment of Capitalized Pension and Related Benefit Costs – Rate Based Factor Method (Issue 17)

6. Qualified Pension Measurement Date (Issue 18)

7. Retiree Medical Expenses (FAS 106) – Measurement Date Update (2014) (Issue 19)

8. Non-Qualified Pension-Restoration Plan (2014) (Issue 20)

9. Post-Employment Benefits – Long-term Disability and Workers' Compensation (Issue 21)

[1567] The issue number refers to the number in the Final Issues List filed by the Company on October 7, 2014 (eDockets No. 201410-103651-01). The facts in the record supporting the resolution or undisputed correction of each issue are set forth in that document, as well as in the proposed Findings of Fact of the Department and the Company.

10. Active Health Care and Welfare Costs (2014) (Issue 22)

11. Nuclear Cash-Based Retention Program (2014) (Issue 23)

12. Customer Care O&M Expenses – Miscellaneous O&M Credits (Issue 24)

13. Nuclear Fees (Issue 25)

14. Investor Relations Costs (Issue 26)

15. Business Systems General Ledger System (Issue 28)

16. Prairie Island Administration Building (Issue 29)

17. Ratepayer Protection Mechanism for Company Owned Wind Farms (Issue 31)

18. Property Tax Amount (2015 Step) (Issue 32)

19. Emissions Control Chemical Costs (2015 Step) (Issue 33)

20. MYRP Refund Mechanism Due to Postponed or Cancelled Capital Projects (Issue 35)

21. MYRP: Compliance for 2015 Step Projects (Issue 36)

22. Service Agreement between NSP and Xcel Energy Services Inc. (Issue 37)

23. Withdrawal of Hollydale Transmission Project (Issue 38)

24. Prairie Island EPU/LCM Split Correction (Issue 39)

25. Xcel Energy Foundation Administration Cost Correction (Issue 40)

26. Big Stone Brookings Cost Correction (Issue 41)

27. Bargaining Unit Wage Increase Correction (Issue 42)

28. Theoretical Reserve for Intangible Plant Correction (Issue 43)

29. Net Operating Loss Correction (2014) (Issue 44)

30. Monticello Cyber Security Correction (Issue 45)

31. Alliant Wholesale Billing Revenues (Issue 46)

32. Cost of Capital Impact (2014 and 2015 Step) (Issue 47)

33. Net Operating Loss Impact (2014 and 2015 Step) (Issue 48)

34. Cash Working Capital Impact (2014 and 2015 Step) (Issue 49)

35. Interest Synchronization Methodology and Calculation (2014 and 2015 Step) (Issue 49A)

36. Low-Income Discount Program (Issue 55)

37. Level of Economic Development Discounts (Issue 56)

38. FCA Rider/ Base Cost of Energy – Nuclear Disposal Fees (2014) (Issue 57)

39. CIP Rider: CCRC and CAF (Issue 58)

40. Windsource Rider (Issue 59)

41. Time-of-Day Energy Charges/Energy Charge Credit (Issue 60)

42. Firm Service Demand Charges (Issue 61)

43. Voltage Discounts (Issue 62)

44. Base Energy Charges for the C&I Demand Class (Issue 62A)

45. Standby Service Tariff – Manner of Service (Issue 73)

46. DG Tariff Change (Issue 74)

47. Low-Income Renter Conservation Program (Issue 81)

48. Sherco Unit 3 Insurance Claims and Litigation Reporting[1568]

[1568] This issue was not assigned a number but is identified here because the 12-961 ORDER required compliance filings relating to Sherco Unit 3. No party disputes that the Company made the required filings in accordance with the order. *See* Department's Proposed Findings of Fact at 187-191.

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

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

ATTACHMENT B
SUMMARY OF PUBLIC COMMENT

Public hearings were held at the following times and places:

June 23, 2014, at 1:00 p.m. at the Earle Brown Heritage Center, Minneapolis, Minnesota;

June 23, 2014, at 7:00 p.m. at the Sabathani Community Center, Minneapolis, Minnesota;

June 24, 2014, at 1:00 p.m. at the West Minnehaha Recreation Center, St. Paul, Minnesota;

June 24, 2014, at 7:00 p.m. at Woodbury Central Park, Woodbury, Minnesota;

June 25, 2014, at 7:00 p.m. at the Civic Center, Mankato, Minnesota;

June 26, 2014, at 7:00 p.m. at the Eden Prairie City Center, Eden Prairie, Minnesota; and

June 27, 2014, at 1:00 p.m. at the Lake George Municipal Complex, St. Cloud, Minnesota.

The following persons appeared at the public hearings on behalf of the parties and the Commission:

Aakash Chandarana, Lead Assistant General Counsel Attorney; Christopher Clark, Regional Vice President of Rates and Regulatory Affairs; Al Krug, Associate Vice President of State Regulatory Policy; Paul Lehman, Manager, Compliance and Filings; Jody Londo, Policy Specialist, on behalf of Northern States Power (NSP, Xcel Energy or Applicant);

Samir Ouanes, Susan Peirce, Christopher Shaw, Rates Analysts; Angela Byrne, Nancy Campbell, and Dale Lusti, Financial Analysts, on behalf of the Department of Commerce, Division of Energy Resources;

Ryan Barlow and Ian Dobson, Assistant Attorneys General; John Lindell, Financial Analyst; Ron Nelson, Utilities Economist, on behalf of the Office of the Attorney General – Antitrust and Utilities Division (OAG);

Jim Scheibel, Seth Boffeli, Will Phillips, Jay Haapala, Mary Jo George, on behalf of the AARP;

Will Nissen, Fresh Energy, on behalf of the Minnesota Center for Environmental Advocacy, Izaak Walton League of America-Midwest Office, Fresh Energy, Sierra Club and Natural Resources Defense Council;

James Strommen, Esq., Kennedy & Graven, on behalf of the Suburban Rate Authority;

Jorge Alonso, John Brown, Clark Kaml, Susan Mackenzie, and Sean Stalpes on behalf of the Public Utilities Commission staff.

In addition to the public hearings, there was an opportunity for the public to submit written public comments. The public comment period closed on July 7, 2014 as provided in the NOTICE OF PUBLIC HEARINGS approved by the Commission on April 4, 2014.[1569] Written comments were filed in the electronic docket system.

SUMMARY OF PUBLIC COMMENT

1. Over 900 written public comments were received by the July 7, 2014 deadline set by the Public Utilities Commission.[1570] In addition, over 90 individuals provided oral comments at the public hearings held throughout the Company's service territory.

2. All comments made at the public hearings or submitted in writing were fully considered. The following accurately summarizes the topics raised, although not all persons raising the topic are cited.[1571]

[1569] NOTICE OF APPROVAL OF PUBLIC HEARING NOTICE (April 4, 2014) (eDocket No. 20144-97980-01).

[1570] An additional 25 comments were received by the Commission and the Administrative Law Judge after the July 7, 2014 deadline. Those late-filed comments are not included in this Summary.

[1571] The citations in the footnotes below are to written comments filed in the Commission's e-Dockets system except where a public hearing transcript citation is provided. Most of the written comments received were in e-mail format. A relatively small number of mailed letters were received. All written comments were e-filed in the e-Dockets system either by the Commission or the Office of Administrative Hearings.

General Opposition to the Proposed Rate Increases

3. The vast majority of the public comments expressed serious concern about the size of the proposed rate increases. A large number of customers are opposed to any rate increase.[1572] Others suggested that any rate increase should be much smaller than that requested by the Company, and should be no greater than the rate of inflation or the Social Security annual cost-of-living increase.[1573]

4. Many individuals noted that they cannot afford the rate increases proposed by the Company.[1574] Others explained that a rate increase of the size requested by the Company would impose a hardship.[1575] For example, Maureene Lee stated she is at the point "of having to choose between food and medication or food and a utility bill."[1576] Similarly, Susan Rose stated that if Xcel's proposed 12.5% rate increase for residential customers is approved, seniors will have to choose between food, medicine and electricity.[1577] Marilyn Wegscheider, the president of a senior apartment building association, commented that she represents a "low-income based community and raising the rates for energy will affect us greatly."[1578] She explained that many of the residents of her building have health issues that require air conditioning and/or the use oxygen machines, both of which require electricity.[1579] She noted that these residents are already struggling financially and they will be tempted to turn off the needed equipment if Xcel increases its rates.[1580] Likewise, Louise Bergeron stated that she needs electricity for her oxygen machine, which runs constantly, and cannot afford the proposed rate increases. She fears she might end up living in a homeless shelter.[1581]

5. Others expressed concern that Xcel's proposed rate increases would force them to sell their homes. Sharon and Thomas Dean stated that they try to conserve as much electricity as possible. Their monthly Xcel budget bill is currently $100 and their total monthly income is $770. They noted that they are "barely making it now" and stated "we will have to sell our house if our monthly utility bills increase."[1582]

[1572] *See, e.g.*, Ker Thoa (May 27 and 29, 2014); Luke Rasmussen (May 27, 2014); Patricia Lagerquist (June 10, 2014); Nancy Fagerstrom (June 30, 2014); David Brown (Transcript (Tr.) Woodbury Hearing (Hrg.) at 28, June 24, 2014).

[1573] *See*, *e.g.*, Robert Palmero (May 17, 2014); Anthony Zaleski (May 21, 2014); Clare Gallagher (May 26, 2014); Tim Knellwolf (May 29, 2014); Robert Buselmeier (June 7, 2014).

[1574] *See, e.g.*, Michael Weber (February 2, 2014); Tim Overweg (March 21, 2014); Janet Murray (May 14, 2014); Adam Lagerquist (May 31, 2014); Lois Hornick (June 20, 2014); Mara Lewandowski (June 23, 2014).

[1575] *See*, *e.g.*, Tim Knellwolf (May 29, 2014); Maureene Lee (June 9, 2014); Susan Rose (June 12, 2014); Marilyn Wegscheider (July 3, 2014).

[1576] Maureene Lee (June 9, 2014).

[1577] Susan Rose (June 12, 2014).

[1578] Marilyn Wegscheider (July 3, 2014).

[1579] *Id.*

[1580] *Id.*

[1581] Louise Bergeron (June 18, 2014).

[1582] Sharon and Thomas Dean (July 1, 2014).

Likewise, Mavis Havlish stated that Xcel's repeated rate increases are a "major factor contributing to those of us on fixed incomes being driven out of our homes."[1583] Sharon Hinrichs also expressed concern about losing her house due to Xcel's proposed rate increases. She stated that she works two jobs and has a daughter with a chronic illness who needs the house to be warm in the winter. Ms. Hinrichs does not qualify for bill assistance, and fears she will lose her house if Xcel raises its rates again.[1584] Similarly, Joclyn Poehler stated that her "family is a struggling middle class household with two small children. The increase in utility costs are putting us in a tough position and we will not be able to continue to stay in our home if corporations like Xcel Energy are able to receive these enormous rate increases every single time they ask."[1585]

6. Many residential customers also expressed concern that the Company is seeking an increase of 12.5 percent for the residential class over the next two years, yet most residential customers have had only very small raises in the last few years, if any.[1586] Similarly, a number of retirees noted that the increase sought by the Company is much larger than the small annual cost-of-living increase that they receive from Social Security.[1587]

7. Many other retirees also warned that they cannot afford to pay the increase in electric rates proposed by the Company.[1588] For example, A.R. Leckband, an 83 year-old Korean War veteran, stated that his pension has not gone up at the same rate as his expenses. He noted that electricity is not the only expense that has increased. He stated: "I will be left with very little heat if these increases continue."[1589] Likewise, customers who have limited incomes due to unemployment, underemployment, or other financial difficulties expressed concerns about being able to afford the proposed increases.[1590] Several residential customers described Xcel's 12.5 percent proposed residential rate increase request as "unfair" and "unreasonable."[1591]

[1583] Mavish Havlish (June 24, 2014); s*ee also e.g.*, Dorothy Powell-Porrazzo (June 24, 2014); Bill Kubes (June 24, 2014).
[1584] Sharon Hinrichs (June 18, 2014).
[1585] Joclyn Poehler (June 23, 2014).
[1586] *See, e.g.*, Val Kosky (June 23, 2014); Mary Gearin (July 4, 2014); Lori Johnson (May 19, 2014); Craig Bell (June 22, 2014); Erik Mortenson (June 29, 2014).
[1587] *See*, *e.g.*, Stephen and Barbara Vanderbilt (January 31, 2014); Ida C. Blair-Erickson (June 30, 2014); Jo Angela Maniaci (June 9, 2014); Lane Larson (June 9, 2014); Judith Treise (February 14, 2014).
[1588] *See, e.g.*, Jack Kuppich (May 17, 2014); Dorthy Alsleben (May 29, 2014); James Thommes (June 9, 2014); Harvey Parker (June 24, 2014); Barbara Stillinger (Tr. Earle Brown Hrg. at 32, June 23, 2014).
[1589] A.R. Leckband (May 29, 2014).
[1590] *See*, *e.g.*, Adam Lagerquist (May 31, 2014); Sheri McPherson (June 10, 2014); Julie Andrzejewski (Tr. St. Cloud Hrg. at 23, June 27, 2014) (speaking on behalf of her students who have graduated and are unable to find jobs); Barbara Cavanaugh (Tr. Woodbury Hrg. at 45-46, June 24, 2014) (speaking on behalf of recent immigrants); Jeanette LaVerne (Tr. Earle Brown Hrg. at 55-56, June 23, 2014)
[1591] *See*, *e.g.*, Jeanne Walker (June 9, 2014); Susan Zemke (June 25, 2014); Kathy Eggers (July 4, 2014); Ronald Loi (July 5, 2014).

Other residential customers described the proposed rate increase as "excessive,"[1592] "severe,"[1593] "exorbitant,"[1594] and "outrageous."[1595]

8. Many customers noted that Xcel has had several rate increases over the last ten years.[1596] One customer commented: **"**This trend reminds me of the double digit increases we've seen in college costs for the past two decades and the result is students who cannot afford college unless they take on massive debt."[1597] A number of other customers commented that they cannot afford these frequent increases.[1598]

Conservation Efforts Resulting in Higher Rates

9. A number of Xcel customers expressed their frustration that increased conservation efforts have led the Company to propose increased rates.[1599]

10. For example, Dennis Chishom stated: "I have made all possible upgrades and insulating recommendations, and anytime there is a possibility of seeing a savings on my end, [Xcel] takes the benefit with a rate hike."[1600]

11. Similarly, Larry and Linda Kettner stated that they have done everything they can think of to conserve energy. "We keep our home at 58 to 62 degrees in the wintertime," and use energy-efficient light fixtures and appliances. "We think we're saving money … and yet every month and every year our energy bill keeps going up and keeps going up." The Kettners are retired and live on a fixed income.[1601]

12. Susan Mayer, a small business owner, expressed similar concerns. She stated: **"**I have done everything possible to 'go green,' conserve energy and save money in my hairstyling salon. I replaced all the lighting in the entire salon (cost $1500.00), put timers on all outdoor signage and use them for less time. I have maintained climate control systems efficiently and run them at barely comfortable temperatures when clients are in the salon. At night the HVAC is turned off in the summer and turned down just enough to keep the pipes from freezing in the winter. I have added insulation and changed the outside door on my rented business space. Any money I have saved by being a responsible business owner and energy consumer will be lost with these increases. I will also never recoup my investment in energy efficient

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[1592] Michael Weber (February 2, 2014).
[1593] Tim Overweg (March 21, 2014).
[1594] Janet Murray (May 14, 2014).
[1595] Ida C. Blair-Erickson (June 30, 2014).
[1596] *See*, *e.g.*, Gaeland Priebe (June 9, 2014); Dennis Morin (June 9, 2014); Robert Allen (June 25, 2014); Sherry Williams (June 28, 2014); Darrell Spaeth (July 3, 2014).
[1597] Don Magnuson (June 2, 2014).
[1598] *See*, *e.g.*, Pamela Nielson (June 9, 2014); Robert Anderson (May 31, 2014); T.J. Davis (June 26, 2014); Annie Zimbel (July 4, 2014).
[1599] *See, e.g.,* Douglas Verdier (June 9, 2014); Jeanine Smegal (July 4, 2014); Helen Friedlieb (June 26, 2014); Mary Ann Lundquist (Tr. Sabathani Center Hrg. at 47, June 23, 2014).
[1600] Dennis Chisholm (June 10, 2014).
[1601] Larry and Linda Kettner (Tr. Mankato Hrg. at 23-24, June 25, 2014).

lighting, as I was promised by Xcel. In reality, any savings will be taken back by Xcel."[1602]

13. Susan Richter stated that Xcel's proposed rate increase "penalize[s]" customers who conserve, and suggested that conservation efforts should be rewarded with lower rates.[1603]

Comments by Business Customers

14. While the vast majority of the public comments were received from residential customers, some small business customers also provided public comments.[1604] Small business customers expressed concern that the proposed rate increases would adversely affect their business operations and could force them to close.

15. World Aerospace Corporation, a small business, commented that it has had to cut its costs to its customers by six percent per year and cannot afford a 10.4 percent rate increase. World Aerospace noted that the proposed rate increase will "result in an extreme hardship to our business at a time when we are struggling to stay afloat."[1605]

16. Similarly, Kevin Hirman of Denny's 5th Avenue Bakery stated that "[th]e cost of energy is of the top concerns of small business owners." He also noted that small business owners are not able to adjust their prices quickly enough to match the potentially steep energy cost increases without hurting their customer base. Also, he indicated that most small business owners are not able to buy new, more energy efficient equipment fast enough to offset the price increases.[1606]

17. Karl Artmann owns a convenience store, gas station, and auto repair shop in Lester Prairie, Minnesota. He stated that he cannot afford the rate increase proposed by Xcel.[1607]

18. A representative of the St. Paul Area Chamber of Commerce, on the other hand, spoke in favor of Xcel's proposed rate increases.[1608] Matt Kramer, president of the St. Paul Area Chamber of Commerce, stated that "we would all be happier if we didn't have a rate increase. We also understand that from a business perspective, the

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[1602] Susan Mayer (July 3, 2014).
[1603] Susan Richter (July 9, 2014).
[1604] *See, e.g.,* Karl Artmann (May 6, 2014); Ike Phelps, World Aerospace Corporation (May 16, 2014); Kevin Hirmann, Denny's 5th Avenue Bakery (May 27, 2014); Susan Mayer (July 2, 2014).
[1605] Ike Phelps, World Aerospace Corporation (May 16, 2014).
[1606] Kevin Hirmann, Denny's 5th Avenue Bakery (May 27, 2014).
[1607] Karl Artmann (May 6, 2014).
[1608] Matt Kramer (Tr. St. Paul Hrg. at 39-40, June 24, 2013).

investments Xcel Energy makes are in the efficacy and reliability of the energy grid. Things that benefit us not just today, but ten years in the future."[1609]

19. Similarly, representatives of the local Chambers of Commerce in Bloomington, Minneapolis, and St. Cloud commented about the value that Xcel provides to their members in terms of reliability, affordability, and alternative energy sources.[1610] For example, Todd Kingel, president of the Minneapolis Chamber of Commerce, stated that reliability is especially important to Minneapolis Chamber members because "[n]one of them can afford downtime."[1611] Mr. Kingel noted that Xcel is "expert in making sure customers have continued reliable energy…."[1612] With regard to affordability, Mr. Kingel stated that "even with the proposed increase, Xcel's rate will still remain below the national average."[1613] He also commented that Minneapolis Chamber members are pleased with Xcel's efforts to utilize renewable energy.[1614] Representatives of the Bloomington and St. Cloud Chambers provided very similar comments.[1615]

20. In addition, Patrick Baker with Greater Mankato Growth, a local development group, spoke about "Xcel's outstanding track record as a good corporate citizen in our community."[1616] He noted that Xcel has been a great collaborative partner in helping Mankato businesses find affordable solutions to their energy needs.[1617] Mr. Baker also noted Xcel's sponsorship of Mankato's "Songs on the Lawn" series and Economic Summit.[1618]

Xcel Should Control Costs Rather Than Raise Rates

21. Many members of the public suggested that, rather than raising rates, Xcel should do a better job of managing its expenses.[1619] They pointed out that Xcel's customers have had to cut costs in recent years, and believe Xcel should be expected to do the same.[1620]

[1609] *Id.*
[1610] Maureen Scallen Failor (Tr. Eden Prairie Hrg. at 28-30, June 26, 2014); Todd Klingel (Tr. Sabathani Center Hrg. at 26-29, June 23, 2014); John Herges (Tr. St. Cloud Hrg. at 23-26, June 27, 2014).
[1611] Todd Klingel (Tr. Sabathani Center Hrg. at 27, June 23, 2014).
[1612] *Id.*
[1613] *Id.* at 28.
[1614] *Id.*
[1615] Maureen Scallen Failor (Tr. Eden Prairie Hrg. at 28-30, June 26, 2014); John Herges (Tr. St. Cloud Hrg. at 23-26, June 27, 2014).
[1616] Patrick Baker (Tr. Mankato Hrg. at 48, June 25, 2014).
[1617] *Id*. at 48-50.
[1618] *Id*. at 48-49.
[1619] *See*, *e.g.*, Ronald Loi (June 5, 2014); Kay Kramer (June 23, 2014); Molly Fletcher (Tr. Eden Pairie Hrg. at 55-56, June 26, 2014); Louise Quast (Tr. Earle Brown Hrg. at 61-62, June 23, 2014).
[1620] *See, e.g.,* Pauline Cahalan (June 24, 2014); Kay Kramer (June 23, 2014); John Robertson-Smith (June 10, 2014); Roger Davidson (Tr. Mankato Hrg. at 33, June 25, 2014).

22. William Tiemann, who formerly worked for Xcel, asserted that there is a lot of "waste" at Xcel. He stated that Xcel does not need a rate increase but instead should cut its costs, particularly its management costs.[1621]

23. The level of executive compensation was especially troubling to members of the public.[1622] Several members of the public suggested that CEO and other executive pay be reduced.[1623] Michael Justin, an AARP member, commented that he believes Xcel's executives are paid too much given that they have not been able to balance the company's budget without raising rates a number of times in the last ten years.[1624] Others suggested that corporate jet expenses and executive travel costs be controlled better.[1625]

24. Several members of the public also stated that Xcel does not have an incentive to reduce its costs because it is a monopoly provider of an essential service.[1626] They noted that Xcel's customers have no ability to change to another provider if they believe the rates are too high.[1627]

25. A few customers also commented that Xcel should be subject to competition to help control its costs.[1628] Another suggested that Xcel should be owned by its customers rather than shareholders.[1629] Others suggested that an independent audit be conducted into Xcel's spending to examine whether its increased expenses are necessary.[1630]

26. Some customers also questioned the Company's need for any rate increase, noting that the Applicant's parent company has been performing well recently.[1631] Others suggested that Xcel reduce its dividends paid rather than increase its rates.[1632]

[1621] William Tienmann (June 24, 2014).
[1622] *See*, *e.g.,* Norm and Sharon Ledeboer (February 18, 2014); Randy Cunliffe (June 1, 2014); Dennis Morin (June 9, 2014); Ida C. Blair-Erickson (June 30, 2014); Shada Buyove Hammond (Tr. Sabathani Center Hrg. at 66, June 23, 2014).
[1623] *See, e.g.*, Dennis Chisholm (June 10, 2014); Jane McEvoy (June 24, 2014); Jerry Walden (Tr. Woodbury Hrg. at 42, June 24, 2014).
[1624] Michael Justin (June 19, 2014).
[1625] *See*, *e.g.*, Adam Lagerquist (May 31, 2014); Fred Richardson (June 23, 2014); Kim Halverson (June 19, 2014); Tom Clayton (Tr. St. Paul Hrg. at 45, June 24, 2014).
[1626] *See*, *e.g.*, Tim Knellwolf (May 29, 2014); Terry Pettipiece (June 20, 2014); Michael Dunn (July 1, 2014); Vikki Steward (July 3, 2014).
[1627] *See, e.g.*, Randy Cunliffe (June 1, 2014); Gary Wright (June 9, 2014).
[1628] *See, e.g.,* Katie Simon-Dastych (July 7, 2014); Lee Olson (June 19, 2014).
[1629] Willard Shapira (June 22, 2014).
[1630] *See*, *e.g.*, Deborah Kitzman (July 1, 2014); Lois Hornick (June 16, 2014).
[1631] *See, e.g.*, Douglas Verdier (July 7, 2014); Paul Beery (June 5, 2014); Craig Bell (June 22, 2014).
[1632] *See*, *e.g.*, Steve Gray (Tr. Woodbury Hrg. at 24, June 24, 2014); Douglas Verdier (July 7, 2014).

Residential Customer Charge Increases

27. A number of residential customers stated their opposition to the Company's proposal to increase the residential customer charge. Many believe that increasing the customer charge will disproportionately affect low-income customers and take away incentives for conservation.[1633]

28. For example, Duane Willenbring noted that customer charges are an impediment to cost effectiveness for customers on fixed incomes.[1634]

29. With respect to conservation, Andrew Holewa stated: "I have spent a lot of money insulating my house, using solar, turning down the heat and changing to low energy bulbs." He stated that he is willing to pay more for electricity but not for "the base charge."[1635]

Residential versus Business Class Increases

30. There was great opposition by residential customers to the Company's proposal to impose a greater percentage increase on the residential class than on the business and industrial classes. A number of AARP members noted that "residential customers are being asked to pay 12.5% over the next two years while corporations see just a 9.2% increase."[1636]

31. Mark Have proposed that the percentage increase for business customers be greater than the increase for residential customers because "[w]ages of the average worker, pensions, and Social Security have not been keeping up with the growth of the economy. Corporations, on the other hand, have been doing well; this is evidenced by the salaries and bonuses given to executives."[1637]

32. Similarly, Janet Leadholm stated: "Corporate profits have risen steadily, while average American's income has been losing ground for years. It's time for companies to pay their fair share."[1638]

[1633] *See*, *e.g.*, Nancy Miller (June 19, 2014); Julie Andrzejewski (June 23, 2014); Robert Witter (June 24, 2014); Jessica Tritsch (Tr. Sabathani Center Hrg. at 37, June 23, 2014); Rick Tallman, Citizens for Fair Utility Rates (Tr. St. Cloud Hrg. at 33, June 27, 2014, and July 6, 2014 written comments).
[1634] Duane Willenbring (Tr. St. Cloud Hrg. at 43-44, June 27, 2014).
[1635] Andrew Holewa (June 23, 2014).
[1636] *See*, *e.g.*, Lori Bestler (June 9, 2014); Ralph Frye (June 9, 2014); Melvin Hendrickson (June 10, 2014); William Anderson (June 10, 2014); Rose Anna Murray (Tr. Eden Prairie Hrg. at 47, June 26, 2014).
[1637] Mark Have (June 27, 2014); *see also* Gary Gohman (Tr. St. Cloud Hrg. at 34-35, June 27, 2014) (stating that the business community should pay a greater share of the total rate increase).
[1638] Janet Leadholm (July 3, 2014).

Decoupling

33. A number of members of the public provided comments in support of Xcel's decoupling proposal. Julie Andrzejewski, a professor at St. Cloud State University and member of the Beyond Coal Organization, stated that she supports decoupling because it "break[s] the link between energy sales and revenue so that Xcel Energy is not incentivized to sell more energy and discouraged from supporting energy efficiency and rooftop solar."[1639] Others expressed similar reasons for supporting Xcel's decoupling proposal.[1640]

Inclining Block Rates

34. The Clean Energy Intervenors' proposal for an Inclining Block Rate (IBR) structure also generated a number of public comments. As detailed above, some members of the public supported the IBR proposal, and others opposed it.

35. Many people expressed support for the IBR proposal based on their belief that the proposal will promote conservation and benefit low-income customers.[1641] Two organizations also expressed their support for the proposed IBR for similar reasons. Charles Dayton, of Minnesota Interfaith Power & Light, stated that his organization supports the IBR proposal because "it is designed to create incentives for reduction of energy use" and favors "low use customers, who will often be low income."[1642] Similarly, Buddy Robinson, of the Minnesota Citizens Federation Northeast, stated: "The proposed IBR in the Xcel Energy rate case will provide more affordable electric service to those who can least afford it."[1643]

36. On the other hand, customers who oppose the IBR proposal expressed their belief that the proposal is unfair. Tom Bergerson stated that: "By definition fairness means the *rate* is the same for everyone. You use more you pay more even if the rate is the same."[1644] Likewise, James Gagne noted that "[i]f a person uses more electricity they are already paying more than someone else that doesn't use as much."[1645]

37. Others expressed opposition to the proposed IBR because their homes use electricity for heat.[1646] One customer suggested that the Commission consider

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[1639] Julie Andrzejewski (Tr. St. Cloud Hrg. at 23, June 27, 2014, and July 23, 2014 written comments).
[1640] *See*, *e.g.*, Nancy Miller (June 19, 2014); Cecelia Newtown (June 25, 2014); Jessica Tritsch (Tr. Sabathani Hrg. at 37, June 23, 2014); Louise and Allan Campbell (July 1, 2014).
[1641] *See*, *e.g.*, Mark Nelson (June 9, 2014); David Kelly (June 10, 2014); Louise and Allan Campbell (July 1, 2014); Kelly Halpin (July 7, 2014); John Krenn (July 7, 2014).
[1642] Charles Dayton, Minnesota Interfaith Power & Light (July 7, 2014).
[1643] Buddy Robinson, Minnesota Senior Federation (July 1, 2014).
[1644] Tom Bergerson (June 6, 2014) (emphasis in the original).
[1645] James Gagne (June 6, 2014).
[1646] John McNally (June 7, 2014); Norm and Sharon Ledeboer (July 7, 2014).

"total energy use" rather than just electricity use.[1647]

New Rate Design Proposals

38. In addition to the rate design proposals presented by the parties in pre-filed testimony, a few members of the public proposed alternative rate design proposals.

39. One member of the public suggested that there be no rate increase for seniors. He noted that most seniors are disabled and need air conditioning.[1648]

40. Another member of the public suggested that people over the age of 75 with income less than $30,000 pay a flat rate for "all utilities." The individual did not specify an amount for the flat rate.[1649]

41. Similarly, Drew Campbell, a Blue Earth County Commissioner, proposed that all customers get a "certain number of kilowatt hours for free" to help people who are living on limited incomes. He stated that "in a well-developed country like [the United States] … we should be able to provide access to electricity."[1650]

42. George Crocker, Executive Director of the North American Water Office, recommended that the Commission not approve any rate increase until Xcel's rates have been redesigned to recognize the benefits received from customers who "are participating in the behaviors that saves society money and saves pollution …."[1651]

Service Quality Issues

43. Several customers expressed concern with the level of service they are receiving and do not believe a rate increase is warranted unless service quality improves.[1652] For example, Shellie Spector, Office Manager of Lear-Annoni Appraisals, stated that the real estate appraisal company that she works for in Eden Prairie experiences frequent outages. She noted that a recent outage caused the company's computer network to fail, resulting in both lost time and money to the small business. She requested that Xcel be required to upgrade its service quality in the area if it is granted a rate increase. [1653]

44. Tim Sather reported that the power goes out frequently at his house in Plymouth. He asks that service quality be improved before any rate increase is

[1647] John McNally (June 7, 2014).
[1648] Jerry Ciresi (Tr. St. Paul Hrg. at 38, June 24, 2014).
[1649] Alice Griser (June 9, 2014).
[1650] Drew Campbell (June 25, 2014).
[1651] George Crocker (Tr. St. Paul Hrg. at 30, June 24, 2014).
[1652] *See, e.g.*, Shellie Spector (April 11, 2014); Ronald Reosler (June 10, 2014); Susan Zemke (June 25, 2014); Tim Sather (June 23, 2014).
[1653] Shellie Spector (April 11, 2014).

granted.[1654] Rita Wenner stated that she was forced to buy a generator for her house because Xcel's electric power is unreliable and her husband has a medical device that requires constant electricity.[1655] Barbara Schmidt reported that it took Xcel a long time to respond to a call regarding a problem with her meter.[1656]

45. Other customers have been pleased with Xcel's service.[1657] Bill Steinbicker stated: "Xcel Energy provides us with dependable electric power at what I consider to be reasonable rates compared to some parts of the country."[1658]

Comments Regarding Electric Generation Sources

46. Several members of the public expressed their views about sources of electric generation. A number of customers encouraged the Commission to increase the use of alternative energy sources such as wind, solar, and biomass.[1659] Some also requested that the Commission require Xcel to reduce its use of coal power.[1660]

47. Other customers felt that they were being asked to pay higher rates because renewable energy costs more than other types of energy.[1661] At least one customer encouraged the Company to use more coal power.[1662] Another recommended that Sherco Units 1 & 2 not be retired early because they are cost effective generation sources.[1663]

48. Some customers questioned whether the proposed rate increases are really necessary given that the price of natural gas, which is used as a fuel to generate electricity, has been going down recently.[1664]

49. Others objected to paying higher rates due to cost overruns and other issues with the Company's nuclear plants.[1665] Michael Weber stated that the cost

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[1654] Tim Sather (June 23, 2014).
[1655] Rita Wenner (June 20, 2014).
[1656] Barbara Schmidt (Tr. Eden Prairie Hrg. at 49-50, June 26, 2014).
[1657] *See, e.g.,* Bill Steinbicker (July 2, 2014); Drew Campbell (Tr. Mankato Hrg. at 38, June 25, 2014); Roger Davidson (Tr. Mankato Hrg. at 33, June 25, 2014).
[1658] Bill Steinbicker (July 2, 2014).
[1659] *See*, *e.g.,* Eleanor Wagner (June 15, 2014); Cecelia Newton (June 25, 2014); Deborah Kitzman (July 1, 2014); Katie Simon-Dastych (July 7, 2014).
[1660] *See*, *e.g.,* Eleanor Wagner (June 15, 2014); Cathy Geist (Tr. Sabathani Center Hrg. at 33-35, June 23, 2014); Jessica Tritsch (Tr. Sabathani Center Hrg. at 36, June 23, 2014); Kathy Heyden (June 15, 2014).
[1661] *See*, *e.g.,* David Campbell (July 3, 2014); Floyd Hagen (Tr. Eden Prairie Hrg. at 44-46, June 26, 2014).
[1662] *See*, *e.g.,* Dan Rector (July 5, 2014).
[1663] Torin Kelly (April 3, 2014).
[1664] *See, e.g.,* Paul Beery (June 5, 2014); Mark Wackerfuss (Tr. Woodbury Hrg. at 38-40, June 24, 2014); Jane McEvoy (Tr. St. Paul Hrg. at 45-46, June 24, 2014).
[1665] *See, e.g.,* Helen E. Proechel (January 1, 2015); Michel Weber (February 10, 2014); Lynn Kidder (Tr. Mankato Hrg. at 42-43, June 25, 2014); Cathy Geist (Tr. Sabathani Center Hrg. at 33-35, June 23, 2014).

overruns “should not be put on the backs of the average citizens....”[1666] Lynn Kidder objected to having to pay increased rates for costs associated with maintaining Xcel’s nuclear power plants.[1667] Cathy Geist, a professor who teaches about sustainable energy, also expressed concern about the use of nuclear energy because there is no permanent solution for nuclear waste. [1668]

50. Purves Todd, on the other hand, supports the Company’s extension of the operating life of the Monticello nuclear plant. He noted that electricity is necessary for the success of the United States and carbon dioxide “helps forests.”[1669]

Support for Xcel’s Proposed Rate Increases

51. A small number of individuals provided comments supporting Xcel’s proposed rate increases,[1670] but these comments were far outweighed by the number of those opposed to Xcel’s proposed rate increases.

Xcel’s Public Notice

52. Some members of the public felt that Xcel’s notice to its customers regarding the proposed rate increases did not provide sufficient information for an individual customer to determine how the proposal would affect that particular customer’s cost of service. There was also a concern that the notice failed to adequately explain the need for the increased revenue.[1671] One customer suggested that the notice include a comparison of current rates to proposed rates on a per kwH basis.[1672] Another suggested that the notice include a comparison of Xcel’s proposed rates to those of other utilities in the surrounding area.[1673] A third customer suggested that Xcel display its proposed rate increases on all of its electronic and social media and provide a link to the Commission website, with instructions on how customers can provide comments.[1674]

[1666] Michel Weber (February 10, 2014).
[1667] Lynn Kidder (Tr. Mankato Hrg. at 42-43, June 25, 2014).
[1668] Cathy Geist (Tr. Sabathani Center Hrg. at 34-35, June 23, 2014).
[1669] Purves Todd (Tr. St. Cloud Hrg. at 27-28, June 27, 2014).
[1670] *See, e.g.,* Donald Drusch (June 26, 2014); Douglas Jones (June 26, 2014); James Regan (July 2, 2014); Greg Mowry (July 1, 2014).
[1671] Ron Johnson (May 5, 2014); Tim Knellwolf (May 29, 2014).
[1672] Vikki Casey Steward (Tr. Eden Pairie Hrg. at 34-42, June 26, 2014, and July 3, 2014 written comments).
[1673] Ron Johnson (May 5, 2014).
[1674] Steve Washburn (June 18, 2014).

Interim Rates

53. Customers questioned why Xcel is allowed to increase its rates before the Commission has made a final decision. These customers maintain such a practice is unfair and unusual.[1675]

Other Issues

54. Several members of the public suggested that Xcel stop spending money on naming rights, such as the rights for the Xcel Energy Center in St. Paul.[1676] Others questioned why Xcel has a need to advertise when it is a monopoly provider.[1677]

55. Mary Ann Lundquist questioned why Xcel spends a large amount of money on lobbying.[1678] Patricia Wasser suggested that Xcel redirect some of its lobbying funds towards customer education for the purpose of encouraging customers to use electricity during off-peak hours.[1679]

56. Jerry Canfield commented that he believes that the Home Energy Report is not useful and suggested that Xcel stop spending money on the report.[1680] Rose Vaught also suggested that Xcel stop producing the report.[1681]

57. John Nielson commented that he does not believe that ratepayers should pay for market losses on the Company's pension plan.[1682]

[1675] *See, e.g.*, Jack Dalin (January 12, 2014); Carlotta Cannon (Tr. St. Paul Hrg. at 41, June 24, 2014).
[1676] *See, e.g.,* Jerry Canfield (June 19, 2014); David Bjorklund (June 19, 2014); Lee Martin (Tr. Eden Prairie Hrg. at 26-27, June 26, 2014); Mark Sprangler (Tr. Mankato Hrg. at 28-29, June 25, 2014).
[1677] See, *e.g.*, Dustin Ericson (Tr. St. Cloud Hrg. at 37, June 27, 2014); Jill Reiter (Tr. St. Cloud Hrg. at 40, June 27, 2014); Patrick Heffernan (June 9, 2014); Steve Gray (Tr. Woodbury Hrg. at 24, June 24, 2014).
[1678] Mary Ann Lundquist (Tr. Sabathani Hrg. at 47, June 23, 2014).
[1679] Patricia Wasser (Tr. Sabathani Hrg. at 72-73, June 23, 2014).
[1680] Jerry Canfield (June 19, 2014).
[1681] Rose Vaught (Tr. St. Paul Hrg. at 27, June 24, 2014).
[1682] John Nielson (June 19, 2014).