OAH 68-2500-30266
PUC E-002/GR-12-961

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

TABLE OF CONTENTS

STATEMENT OF THE ISSUES 2
FINDINGS OF FACT 3
I. Summary of the Application 3
II. The Parties 3
III. Procedural Background 5
IV. Comments from the Public 8
V. Legal Standards 8
VI. Disputed Revenue Requirement Issues 9
A. Monticello LCM/EPU 10
i. Background 10
ii. Project Implementation and Status 11
iii. Cost Increases 12
iv. The Objections of MCC, XLI and the Department 13
v. Conclusions – Monticello LCM/EPU Project Costs 15
B. Sherco 3 17
i. Background 18
ii. Sherco 3 Costs 19
iii. The Company's Request 20
iv. The Department's Position 20
v. The OAG and ECC Positions 22
vi. The ICI Group Position 22
vii. MCC's Position 22

viii. Conclusion – The "Used and Useful" Question 23
ix. Conclusion - Other Arguments Regarding Sherco 3 Costs 25
x. The Company's Rebuttal Proposal 26
C. Qualified Pension Expense 28
i. Background 28
ii. The Parties' Positions 30
iii. Value of the Pension Assets 32
iv. Qualified Pension Assumptions 32
a. The Earned Return on Assets (EROA) Assumption 32
b. SFAS 87 Discount Rate 33
c. Wage Rate Increase Assumption 34
v. 2008 Market Losses 35
vi. Employee Contributions 38
D. Incentive Compensation 38
i. The Department's Position 40
ii. The OAG's Position 41
iii. MCC's Position 41
iv. ECC Position 41
v. Prior Commission Decisions on AIP Costs 41
vi. Conclusion 42
E. Sales 43
i. Forecast Design 43
ii. Disputes as to Forecast Design Characteristics 44
a. Customer Counts 45
b. Forecasting Energy Prices 46
c. Demand-Side Management 47
d. Sales to Large Commercial and Industrial (LC&I) Customers 48
iii. Conclusions 49
iv. Improving the Practice for the Next Rate Case 49
F. Return on Equity and Capital Structure 50
i. Return on Equity 50
a. The Company's Initial ROE Analysis 52
b. The Department's Initial ROE Analysis 60

c. The Company's Updated ROE Analysis 71
d. The Department's Updated ROE Analysis 76
e. ROEs Proposed by ECC, the Commercial Group, and ICI Group and the Responses of the Company and the Department 79
f. ROE Conclusions and Recommendation 82
ii. Capital Structure 83
iii. Hypothetical Capital Structure 85
G. Prairie Island Extend Power Uprate (PI EPU) 86
i. Background 86
ii. The Department's Objections 87
iii. The OAG's Objections 88
iv. The Company's Response 88
v. Conclusion – PI EPU Costs 89
H. Nobles Wind Capital Costs Over RES Amount 91
i. Background 91
ii. Current Request for Recovery of Nobles Capital Costs 92
iii. Conclusion – Nobles Capital Costs over RES Amount 94
I. Nuclear Employee Cash-Based Retention Program 95
J. Non-Qualified Pension Expenses 97
K. Directors and Officers Insurance 98
L. Active Health Care Costs 100
M. Base Salary Increase – Non-Bargaining Employees 101
N. Additional Energy Assistance Funding 102
O. Other Operating Revenues 104
i. Depreciation Change 104
ii. Nuclear Outage Amortization 105
iii. 2012 Transmission Transaction 106
P. Rate Case Amortization Expense 106
Q. Investor Relations Costs 107
R. Transmission Studies 108
S. FERC 921 Fluctuations 109
T. Nuclear Fees 110
U. Property Tax Expense 111
i. The Company's 2013 Property Tax Forecast and Adjustments 112

ii. Reasonableness of the Forecast 114
iii. MCC's Proposal 115
iv. Conclusion 115
V. Prairie Island Steam Generator/Rate Base Adjustment 115
W. Depreciation Expenses and Reserves 116
i. Depreciation Methods 117
ii. Nuclear Asset Reserve 118
iii. TD&G Asset Reserve 120
X. Corporate Aviation 122
Y. FAS 106, 112 – Amoritization of Prepaid Asset 123
Z. Nuclear Refueling Outage Costs 124
AA. CWIP/AFUDC 128
i. The Objections of the OAG and the Commercial Group 129
ii. Conclusion 130
BB. Bad Debt – Credit and Collection Expense 130
VII. Rate Design Issues 131
A. Rate Design Principles 131
B. Class Cost of Service Study 132
i. The OAG Objections to the CCOSS 133
ii. The Department's Objections to the CCOSS 133
a. Use of Winter Peak in Allocation of Capacity-Related Production Plant Costs 134
b. Allocation of CIP CCRC Costs 134
iii. XLI and MCC Objections to the CCOSS 135
a. Other Operation and Maintenance Costs 135
b. Allocation of Economic Development Discounts 137
c. Allocation of Fixed Production Plant 137
d. Average and Excess Demand (AED) CCOSS Method 139
e. Counting Average Demand in Demand Allocator 140
f. Allocation of Transmission 140
g. Allocation of Interruptible Credits 141
iv. Street Lighting 142
C. Revenue Apportionment 144

i. The Company's Proposed Revenue Apportionment 146
ii. The Department's Proposed Revenue Apportionment 148
iii. OAG's Proposed Revenue Apportionment 150
iv. MCC and XLI Proposed Revenue Apportionments 150
v. The Commercial Group's Proposed Revenue Apportionment 152
vi. Final Revenue Apportionment 152
vii. Conclusion 152
D. Residential Customer Charge 153
i. Company's Proposed Customer Charge 154
ii. The Department's Proposed Customer Charge 155
iii. SRA Proposed Customer Charge 156
iv. The OAG's and ECC's Responses 156
v. Conclusion 157
E. Inverted Block Rate 157
i. ECC's Proposed IBR 157
ii. Impact of Proposed IBR on Customers' Bills 159
iii. The Company's Opposition to ECC's Proposed IBR 160
iv. The Department's Opposition to ECC's Proposed IBR 162
v. The OAG's Opposition to ECC's Proposed IBR 164
vi. Conclusion 165
F. Competitive Response Rider 165
i. Support for and Opposition to the Proposed Rider 166
ii. "Competitive Market Conditions" Language 166
iii. Deferred Accounting of the Revenue Deficiency Provision 168
iv. Conclusion 168
G. Business Incentive and Sustainability Rider 169
H. Standby Service Tariff 170
I. Coincident Peak Billing 171
J. Interruptible Service Rates 172
K. Distributed Generation (DG) Tariff Change 174
VIII. Other Disputed Issues 174
A. Interest Rate on Interim Rate Refund 174
B. Interim Rates in the Next Rate Case 177
C. Fuel Clause Adjustment Incentive 179

D. Historical Test Year 180
E. Bad Debt Expense Study 181
F. Momentary Average Interruption Frequency Index 182
G. End-of-Month Billing 184
H. Wind Integration Study 185
I. In General 185
CONCLUSIONS OF LAW 185
RECOMMENDATION 186
NOTICE 187
Attachment A – Resolved Issues and Undisputed Corrections
Attachment B – Summary of Public Comment

OAH 68-2500-30266
PUC E-002/GR-12-961

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

FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATIONS

An evidentiary hearing was held before Administrative Law Judge Jeanne M. Cochran on April 18-19, 2013 and April 22-24, 2013, at the Public Utilities Commission, St. Paul, Minnesota in the above-captioned matter. Public hearings were held in Minneapolis, Woodbury, St. Paul, Mankato, Eden Prairie, and St. Cloud between March 4, 2013 and March 22, 2013. Written public comments were received until April 1, 2013.

Post-hearing briefs were filed on May 15, 2013, and responsive briefs were filed on May 30, 2013.

On May 29, 2013, the Department of Commerce filed a motion to strike a portion of the initial brief of Northern States Power Company.[1] On June 5, 2013, the Company filed its reply. The hearing record closed on June 11, 2013, with the issuance of the Order Granting the Motion to Strike.

Appearances:

Aakash H. Chandarana,[2] James P. Johnson, Kari L. Valley, Alison C. Archer, James R. Denniston and Mara N. Koeller, all of Xcel Energy Services, Inc., and Richard J. Johnson, Moss and Barnett, appeared on behalf of Northern States Power Company.

Andrew P. Moratzka, 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).

---

[1] Also referred to in the record as the Applicant, NSP, Xcel or "the Company".
[2] At the time of the evidentiary hearing, Mr. Chandarana was with the law firm of Briggs and Morgan. Mr. Chandarana is now in-house counsel with Northern States Power Company.

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).

Brian M. Meloy, Leonard, Street and Deinard, appeared on behalf of the ICI Group.

Kevin Reuther, Attorney at Law, appeared on behalf of the Minnesota Center for Environmental Advocacy, Izaak Walton League, Sierra Club, and Fresh Energy (the Environmental Intervenors).

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

Ronald M. Giteck, Ian Dobson, and Christopher Shaw, Assistant Attorneys General, appeared on behalf of the Office of the Attorney General – Antitrust and Utilities Division (the OAG).

Robert Harding, Jerry Dasinger, Susan Mackenzie, Dorothy Morrissey and Clark Kaml, staff of the Public Utilities Commission (PUC or Commission), also attended the hearing.

STATEMENT OF THE ISSUES

1. On November 2, 2012, the Company filed a petition to increase its electric rates in Minnesota. The company requested an annual rate increase of $285.476 million - an increase of approximately 10.7 percent.

2. On December 26, 2012, the PUC 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:

   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?

Based on the evidence in the hearing record,[3] 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 annual rate increase of $285.476 million, or approximately 10.7 percent over current rates, effective January 1, 2013. The Application was based on a 2013 test year.[4]

2. Over the course of the proceeding, several of the financial issues were resolved among the parties. The Company also updated its cost of service as new information became available. During the evidentiary hearing, the Company revised its requested increase down to $215.442 million, or an 8.2 percent increase over current rates, to reflect the agreements and changes as of that time.[5] During the post-hearing briefing period, the Company and the parties resolved two additional financial issues, which further reduced the Company's requested increase down to $208.946 million, or an increase of approximately 7.8 percent.[6]

3. At the close of the evidentiary hearing, based on issues resolved during the proceeding and its position on the remaining issues, the Department recommended that the Company receive a $98.606 million increase to the revenue requirement in 2013.[7]

4. The issues affecting the Company's revenue requirement that were fully resolved by the parties are listed in Attachment A. Also listed in Attachment A are undisputed corrections made by the Company.[8]

II. The Parties

5. Northern States Power Company is a Minnesota corporation serving Minnesota customers. NSP is a subsidiary of Xcel Energy Inc. (XEI), a public utility

---

[3] A Master Exhibit List, including links to all exhibits received into evidence, was efiled by the court reporter on May 8, 2013 (Edocket No. 20135-86808-01).
[4] Exhibit (Ex.) 5 (Application, Volume 1); Ex. 56 at 1 (Heuer Direct).
[5] Ex. 88 at 3 (Heuer Opening Statement); *see also*, Ex. 56 at AEH-1, Schedule 3 (showing Retail Related Revenue under present rates).
[6] *See* Financial Adjustment Summary and Final Issues List (June 5, 2013) (Edocket No. 20136-87866-01) (showing adjustment down to $208.946 million, which is attributable to the resolution of Issue 23 (NSP-Minnesota Wholesale Customer) and Issue 24 (NSP-Wisconsin Wholesale Customers)).
[7] Ex. 184 at DVL-HE-2 (Lusti Hearing Exhibit); Initial Post Hearing Brief of the Minnesota Department of Commerce (Department Initial Brief).
[8] *See also*, Final Issues List (June 5, 2013) (Edocket No. 20136-87866-01).

holding company with four utility subsidiaries that serve electric and natural gas customers in eight states.

6. 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.

7. 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.

8. 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.

9. 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.

10. The Xcel Large Industrials include Flint Hills Resources, Gerdau Ameristeel US Inc. and USG Interiors, 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.

11. 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. MCC is involved in policy issues that affect business, including energy policy, on behalf of its members.

12. The Environmental 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.

13. 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.

14. 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[9]

15. On November 2, 2012, the Company filed its application to increase its electric rates in Minnesota.

16. The Commission issued its Notice and Order for Hearing on December 26, 2012. On that same date, it issued two other orders, one finding the rate case filing was substantially complete,[10] and one setting an interim rate schedule for the duration of this proceeding.[11] In its order finding the application substantially complete, the Commission ordered the Company to make a supplemental filing within 30 days of the date of the order:

a) explaining why it has not refinanced higher-cost bonds given the current low-interest-rate environment;

b) discussing the effect of adjusting the Company's capital structure to allocate a higher percentage to debt (one to five percent);

c) addressing the effect of adjusting the Company's capital structure to allocate a higher percentage to debt (one to five percent) on a Minnesota jurisdictional basis; and

d) reporting for each of the past five years (2007 – 2011) the Company's authorized return on equity and its actual return on equity as reported on its form 10-K on a jurisdictional, total-company, and regulated-company basis.[12]

17. On December 26, 2012, when the Commission issued its Notice and Order for Hearing, the only parties to this proceeding were the Company and the Department.[13]

18. On January 10, 2013, a Prehearing Conference was held at the Public Utilities Commission. The First Prehearing Order was issued on January 16, 2013, 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, and SRA.[14]

---

[9] All Documents referred to in this section are filed with the eDocket system, Docket Number 12-961, and are listed at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=eDocketsResult&userType=public#{F06FB39B-ACD6-41BC-9B0B-A2F424889400}.

[10] ORDER ACCEPTING FILING, SUSPENDING RATES, AND REQUIRING SUPPLEMENTAL FILING (December 26, 2012).

[11] ORDER SETTING INTERIM RATES (December 26, 2012).

[12] ORDER ACCEPTING FILING, SUSPENDING RATES, AND REQUIRING SUPPLEMENTAL (December 26, 2012).

[13] NOTICE AND ORDER FOR HEARING (December 26, 2012).

[14] FIRST PREHEARING ORDER (January 10, 2013).

19. On January 18, 2013, the petitions to intervene of the ICI Group and the OAG were granted.[15]

20. On January 23, 2013, the petition to intervene of XLI was granted.[16]

21. On January 25, 2013, the Company filed its Supplemental Direct Testimony in compliance with the Commission's Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing.

22. On February 6, 2013, the petitions to intervene of MCC and the Environmental Intervenors were granted.[17]

23. On February 28, 2013, the Intervenors filed Direct Testimony.

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

March 4, 2013, Earle Brown Heritage Center, and Sabathani Community Center, Minneapolis;

March 7, 2013, Woodbury Central Park, Woodbury;

March 8, 2013, West Minnehaha Recreation Center, St. Paul;

March 18, 2013, Civic Center, Mankato;

March 19, 2013, Eden Prairie Community Center; and

March 22, 2013, Lake George Municipal Complex, St. Cloud.

25. The parties filed Rebuttal Testimony on March 25, 2013.

26. On April 12, 2013, the parties filed Surrebuttal Testimony.

27. On April 15, 2013, a status 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.[18]

28. On that same date, the Department filed a Motion to Strike Testimony. The Department also requested leave to file the motion because the motion was filed seven days after the deadline set forth in the First Prehearing Order. On April 16, 2013, the Company filed its response to the Department's motion.

---

[15] ORDER GRANTING INTERVENTION TO THE ICI GROUP AND THE OFFICE OF THE ATTORNEY GENERAL (January 18, 2013).
[16] ORDER GRANTING INTERVENTION TO THE XCEL LARGE INDUSTRIALS (January 23, 2013).
[17] ORDER GRANTING INTERVENTION TO THE MINNESOTA CHAMBER OF COMMERCE AND TO THE IZAAK WALTON LEAGUE, FRESH ENERGY, THE SIERRA CLUB, AND THE MINNESOTA CENTER FOR ENVIRONMENTAL ADVOCACY (February 6, 2013).
[18] Transcript of April 15, 2013 Status Conference.

29. On April 17, 2013, the Administrative Law Judge held a telephone hearing on the Department's motion and request for leave to file the motion. At the conclusion of the telephone hearing, the Administrative Law Judge orally denied the Department's request for leave to file the motion because the Department failed to demonstrate good cause for filing the motion a week after the deadline.[19]

30. The evidentiary hearing was held on April 18-19, 2013 and April 22-24, 2013 at the Public Utilities Commission.

31. On May 1, 2013, the Company filed an Issue Outline Summary identifying all issues raised in the course of the rate proceeding and specifying which issues had been resolved and which issues remained in dispute. The Company also filed a Financial Adjustment Summary, and Rate Base and Income Statement Bridge Schedule.[20]

32. On May 2, 2013, the Company filed a revised Issue Outline Summary because the Company realized that the May 1, 2013 filing had inadvertently omitted a full description and discussion of issues related to the Prairie Island Extended Power Uprate.[21]

33. On May 15, 2013, the parties filed Initial Briefs along with any comments on the Issue Outline Summary filed by the Company.

34. On May 22, 2013, the Company filed an updated version of the Issue Outline Summary, incorporating the comments of the other parties.[22]

35. On May 29, 2013, the Department filed its "Motion to Strike Portion of Xcel's Initial Brief or, Alternatively to Disregard Xcel's New Claimed Fact and ROE Proposal and Department's Offer of Proof."[23]

36. On May 30, 2013, the parties filed Reply Briefs and Proposed Findings of Fact.

---

[19] *See* Transcript of the April 17, 2013 Motion Hearing at 8-9, 17-19; FIRST PREHEARING ORDER at 6 ¶ 26; ORDER DENYING DEPARTMENT OF COMMERCE REQUEST FOR LEAVE TO FILE MOTION. While the Department's request for leave to file the Motion to Strike was denied, the Company voluntarily agreed to strike the testimony of Kent Larson and the testimony of Anne Heuer that was at issue in the Motion to Strike. *See* Exs. 187-188. The Company did not agree, however, to strike the testimony of Mark Moeller, which was also at issue in the Motion to Strike. *See* Xcel's Response to Motion to Strike Testimony (April 16, 2013).

[20] Cover Letter with attached Financial Adjustment Summary, Rate Base and Income Statement Bridge Schedule, and Issue Outline Summary (May 1, 2013) (Edocket number 20135-86624-01).

[21] Revised Issue Outline Summary (May 2, 2013) (Edocket number 20135-86661-01).

[22] Updated Issue Outline Summary (May 22, 2013) (Edocket No. 20135-87287-01).

[23] Department's Motion to Strike Portion of Xcel's Initial Brief or, Alternatively to Disregard Xcel's New Claimed Fact and ROE Proposal and Department's Offer of Proof (May 29, 2013) (Edocket No. 20135-87508-01).

37. On June 5, 2013, the Company filed a final version of the Issue Outline Summary, reflecting the resolution of three issues during the briefing period.[24]

38. On that same date, the Company filed its response to the Department's motion to strike.[25]

39. On June 11, 2013, the undersigned Administrative Law Judge issued an order granting the Department's motion to strike.[26]

IV. Comments from the Public

40. Over 1,000 written public comments were filed by the April 1, 2013 deadline. In addition, a number of individuals provided oral comments at the seven public hearings held in March 2013 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. A full summary of the public comments is included as Attachment B to this report.

41. While the public raised a variety of specific concerns, there was widespread concern about the size of the proposed rate increases. Customers with fixed and low-incomes expressed concern about their ability to pay for an increase of more than ten percent in their electric rates when they are experiencing little or no increase in their incomes. 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. Business customers expressed a concern that higher rates would adversely affect their ability to compete or remain profitable.

V. Legal Standards

42. The Commission must set rates that are just and reasonable, balancing the interests of the utility and its customers.[27] 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 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.[28]

---

[24] Cover letter with attached Final Issues List and updated Financial Adjustment Summary and Rate Base and Income Statement Bridge Schedule (June 5, 2013) (Edocket No. 20136-87866-01).
[25] Xcel Energy's Reply to the Department's Motion to Strike a Portion of Xcel's Brief or, Alternatively to Disregard Xcel's New Claimed Fact and ROE Proposal, and the Department's Offer of Proof (June 5, 2013) (Edocket No. 20136-87882-01)
[26] ORDER GRANTING MOTION TO STRIKE (June 11, 2013).
[27] Minn. Stat. § 216B.03. Minnesota Statutes are cited to the 2012 Edition.
[28] Minn. Stat. § 216B.16.

43. The utility seeking an increase in its rates has the burden of proving by a preponderance of the evidence that its proposed change is just and reasonable.[29] 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."[30] Any doubt as to reasonableness of the proposed rates is to be resolved in favor of the consumer.[31]

44. The Commission acts in both a quasi-judicial and quasi-legislative capacity in setting rates. It evaluates the facts, including the claimed costs, and also evaluates the reasonableness of placing the burden of the costs on the ratepayers.[32]

45. When developing a proposed set of rates, the utility will select a test year and look at its rate base, revenue, expenses and reasonable rate of return to determine if it will have a revenue deficiency. As part of this process, the utility may also propose to move funds collected through riders into its rates. It will conduct a study of costs by customer class, and allocate revenue by class to determine the portion of the deficiency each class should bear. Then, it designs rates to collect the appropriate portion from each class.[33] In constructing its rate proposal, the Company must follow standard accounting principles and comply with prior orders of the Commission.[34]

VI. Disputed Revenue Requirement Issues

46. 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.

47. 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, 2013). 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.[35]

---

[29] Minn. Stat. § 216B.16, subd. 4.
[30] *In re Northern States Power Co.,* 416 N.W.2d 719, 722 (Minn. 1987).
[31] Minn. Stat. § 216B.03.
[32] *In re Northern States Power Co.,* 416 N.W.2d at 722-23.
[33] For general discussion, *see* Ex. 56 (Heuer Direct).
[34] *See* Ex. 11 at 36, JMP-1, Schedule 2 (Poferl Direct) (addressing the Company's compliance with prior Commission Orders).
[35] This is portrayed in the revenue requirements summary exhibits of both the Company and the Department. *See e.g.*, Ex. 56, Schedule 3 (Heuer Direct) and Ex. 181, DLV-2 (Lusti Direct Attachments).

48. This section of the report addresses revenue requirement issues that are disputed among the parties involving the rate base, test year expenses and revenues, and rate of return. The seven most controversial revenue requirement issues are addressed first, followed by the remaining issues. The remaining disputed revenue requirement issues are addressed in the order that they appear on the Final Issues List filed by the Company on June 5, 2013.[36]

A. Monticello LCM/EPU[37]

49. The Company included costs for its Life Cycle Management/Extended Power Uprate (LCM/EPU) project at its Monticello nuclear power plant in the rate base for its 2013 test year. The Company agreed that recovery of these costs would be subject to a prudence review in its next rate case.[38]

50. MCC, XLI, and the Department all opposed the Company's proposed treatment of these costs and recommended alternatives.

i. Background

51. The Monticello nuclear power generating plant (Monticello) is a 585 MW baseload plant that has been in operation since 1971.[39]

52. 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. That same year, the PUC authorized the storage of spent fuel at Monticello until 2030.[40] The Life Cycle Management (LCM) portion of the project involves the work undertaken so that the plant can operate beyond its prior license period.[41]

53. The Extended Power Uprate (EPU) portion of the project is designed to add approximately 71 MW of additional capacity at the plant.[42] In 2008, the Company filed a License Amendment Request with the NRC for the EPU.[43]

54. That same year, the Company filed a Certificate of Need (CON) application with the Commission for the EPU. The application requested authority from the Commission to increase the generating capacity from a nominal capacity of 585 MW to a nominal capacity of 656 MW to meet its customers' growing needs.[44] The

---

[36] Final Issues List (June 5, 2013) (Edocket No. 20136-87866-01).
[37] Issue 1, Final Issues List (Edocket No. 20136-87866-01) (hereinafter only the issue number will be provided).
[38] Ex. 48 at 24 (O'Connor Direct).
[39] *Id.* at 2.
[40] *Id.*
[41] *Id.*
[42] *Id.*
[43] *Id.;* Ex. 49 at 8 (O'Connor Rebuttal).
[44] Petition to the Minnesota Public Utilities Commission for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate, Docket No. E0002/CN-08-185 (February 14, 2008) (Monticello EPU CoN Application).

Monticello EPU will increase the generating capacity of the plant by: (1) increasing the amount of steam produced in the reactor; and (2) improving the balance-of-plant equipment that converts the steam into electricity.[45]

55. In its CON application, the Company estimated the total cost of the EPU and LCM activities at $320 million. Of that amount, the Company estimated that $133 million, or 41.6 percent, was attributable to the EPU alone. The estimate was not based on an incremental cost study. Instead, costs for activities that changed the output of the plant were assigned to the EPU and costs relating to aging equipment were assigned to the LCM. The Company also asserted in its application that the EPU was $169 million less expensive than the next best alternative for meeting its customers' needs. [46]

56. In February 2009, the Commission approved the EPU based on the findings of the Administrative Law Judge.[47] In his report, the Administrative Law Judge concluded that the forecasts and cost analyses presented by the Company were reasonably reliable and appropriate for determining the need for the EPU.[48]

ii. Project Implementation and Status

57. The Company managed the LCM and EPU components as an integrated project.[49] The work was implemented in three phases corresponding to three planned refueling outages in 2009, 2011, and 2013. All LCM and EPU program components have been installed and will be in use following completion of the Spring 2013 outage, but the plant will not be generating power at the increased EPU levels.[50]

58. The NRC has not yet authorized the Company to operate the Monticello plant at its EPU power level. Until the Company receives a license amendment from the NRC, the Company will not be allowed to produce the additional 71 MW from the EPU. The plant can continue to operate at its existing level until the license amendment is approved.[51]

59. The Company applied for the EPU license amendment from the NRC in 2008, but there have been delays due to the NRC's response to developments at other

---

[45] Ex. 48 at 3 (O'Connor Direct).
[46] Ex. 49 at 14-16 (O'Connor Rebuttal); Monticello EPU CoN Application at 1-1.
[47] Ex. 48 at 12 (O'Connor Direct); *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, ORDER GRANTING CERTIFICATE OF NEED AND ACCEPTING ENVIRONMENTAL ASSESSMENT, Docket No. E0002/CN-08-185 (January 8, 2009) at 22.
[48] *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION, Docket No. E0002/CN-08-185 (November 19, 2008) at 22.
[49] Evidentiary Hearing Transcript Volume (Tr. Vol.) 2 at 126 (O'Connor).
[50] Ex. 48 at 13-14 (O'Connor Direct); Ex. 49 at 8, 24 (O'Connor Rebuttal).
[51] Ex. 49 at 8 (O'Connor Rebuttal); Ex. 48 at 2 (O'Connor Direct) (noting that the NRC has authorized the Monticello plant to operate at existing levels until 2030).

plants that have undergone EPUs and the NRC's response to the nuclear accident that occurred at the Fukushima Diichi nuclear plant in Japan.[52]

60. The Company expects to receive NRC approval for the EPU in the fall of 2013, but the current federal government sequester could delay the approval timeline. The Company noted that it is also possible that the NRC could request more information from the Company relating to the EPU. The NRC is permitted to take as long as it believes is necessary to ensure the safe operation of the plant at the EPU level when reviewing an EPU license amendment.[53]

61. 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.[54] Certain equipment had be replaced, designed differently, or increased in size to accommodate the EPU portion of the project.[55]

iii. Cost Increases

62. The current estimated cost of the Monticello LCM/EPU project is much higher than the original $320 million estimate. As of October 2012, the Company estimated that the LCM/EPU project would cost $586.7 million. In Rebuttal Testimony, the Company provided an updated and increased estimate, but the Company is not seeking to include the additional amount over the $586.7 million estimate in its 2013 rate base.[56]

63. The Company explained, in Direct Testimony, that the increases in cost were due to: (1) changes by the NRC in the criteria applicable to EPUs; (2) project design changes; and (3) discovery of unknown conditions. The Company noted that other utilities implementing LCM/EPU projects have also experienced final costs that are significantly higher than initial estimates. The Company stated that the major cost increases related to four modifications: (1) steam dryer acoustic monitoring and replacement of the steam dryer; (2) installation of 13.8 kV electric distribution system upgrades; (3) replacement of reactor feedwater pumps, valves, flow transmitters, and feedwater heaters; and (4) replacement of the condensate pump and demineralizer system. The Company provided a detailed description of each of these modifications.

---

[52] Ex. 49 at 8-9 (O'Connor Rebuttal).
[53] *Id.* at 8, 11, 13 (O'Connor Rebuttal).
[54] Ex. 122 at 16 (Pollock Surrebuttal) (citing November 22, 2011 Notice of Changed Circumstances in the Monticello EPU CoN docket).
[55] *See*, *e.g.*, Ex. 48 at 20-23 (O'Connor Direct) (NRC changed criteria for steam dryers during the EPU application process resulting in the purchase of a new steam dryer for EPU approval; feedwater heaters sized slightly larger to support EPU; replacement of condensate pumps to meet increased demand for water to the reactor feed water pumps); Ex. 50 at TJO-2 (O'Connor Rebuttal) (Schedule 5 at 5 of 48 (MNGPU EPU Condensate Pump Impeller, stating that the new pumps are sized to provide sufficient feedwater flow when the EPU is approved), at 6 of 48 (MN EPU Expansion Joints, stating that the new expansion joints are sized to accommodate plant operations at the EPU levels), at 7 of 48 (EPU Condensate Demineralizer System Replacement, stating that the new demineralizer vessels are sized to provide sufficient feedwater flow when the EPU is approved).
[56] Ex. 49 at 7 (O'Connor Rebuttal).

The Company maintained that extensive oversight was in place to ensure that all project costs are appropriate and that the changes made during the course of the project were reasonable and necessary.[57]

64. In response to concerns raised by the Department, the Company included in its Rebuttal Testimony additional information about the increased costs for the Monticello LCM/EPU project. Similar to its Direct Testimony, the Company explained that the increases were due to three main factors: (1) NRC changes and delays; (2) project design changes; and (3) emergent work. The Company provided additional information about each of these factors beyond that provided in its Direct Testimony. The Company also included a detailed spreadsheet entitled "LCM/EPU Modifications In-Service Table" that identifies each sub-project for the LCM/EPU project, the modification (if any), the in-service date, the in-service cost and the justification for the sub-project. The spreadsheet provides a total estimated cost for the project of $586.7 million.[58]

iv. The Objections of MCC, XLI and the Department

65. MCC and XLI objected to the Company's proposal to include the full $586.7 million in Monticello LCM/EPU project costs in its 2013 rate base because the plant is not operating at the increased EPU levels.

66. MCC recommended holding the EPU portion of the project (41.6%) in Construction Work In Progress (CWIP), with an Allowance for Funds Used During Construction (AFUDC) offset, until the prudence review is complete.[59] MCC argued that the Company should not be allowed to recover the cost of and a return on the EPU portion of the project because the Monticello plant is not producing power at the increased EPU levels and it is questionable whether the plant will be licensed to do so during the 2013 test year. According to MCC, the EPU portion of the project is not currently "used and useful" under Minnesota law. MCC asserted that ratepayers should not be required to pay for the added EPU costs when they are not receiving the benefit of the added 71 MW.[60]

67. MCC's suggestion that 41.6 percent of the costs be attributed to the EPU portion of the project was based on the Company's original estimate for the CON, which allocated 41.6 percent of the LCM/EPU project costs to the EPU. MCC also noted that it had requested an updated breakdown of costs from the Company but the Company maintained that it was not able to provide one because the EPU and LCM were implemented as an integrated project. MCC asserted that the costs of the two components can be separated as shown by the Company's original filing and the

[57] Ex. 48 at 18-23 (O'Connor Direct).
[58] Ex. 49 at 8-25 (O'Connor Rebuttal); Ex. 50 at TJO-2, Schedule 5 (Trade Secret Attachment).
[59] Ex. 108 at 9-10 (Schedin Rebuttal).
[60] MCC Initial Brief at 6-9; Ex. 108 at 9-10 (Schedin Surrebuttal); Ex. 107 at 17 (Schedin Direct); Minn. Stat. § 216.16, subd. 6.

Company's separation of the Prairie Island LCM/EPU costs in this rate case. MCC argued that the Company failed to make any effort to separate the costs. [61]

68. MCC also stated that there is no accounting reason why the EPU portion of the costs cannot be held in CWIP. MCC noted that classification of the project as CWIP will protect shareholders.[62] The Company calculated MCC's proposal as resulting in a $16.585 million reduction to the initial 2013 test year amount.[63]

69. XLI offered another alternative to recognize that the EPU is not yet in use. XLI proposed removing the EPU costs from rate base until the NRC license is received. XLI calculated that this would reduce the test year revenue requirement by $26.1 million.[64] XLI also argued that the EPU portion of the LCM/EPU project is not "used and useful" because the Company is not yet authorized to generate at the higher MW capacity levels made possible by the EPU. XLI also noted that its proposal only results in a temporary denial of recovery of the costs because the Company can seek recovery of the costs in its next rate case.[65]

70. The Department also objected to the Company's proposal to recover the Monticello LCM/EPU costs in its 2013 test year, but for a different reason. The Department asserted that the Company failed to provide sufficiently detailed information in its Direct Testimony to demonstrate that the proposed Monticello LCM/EPU cost increases are reasonable. The Department acknowledged that the Company provided more detailed information in responses to the Department's information requests and in its Rebuttal Testimony, but asserted that the information was provided too late in the process to allow the Department sufficient time to fully analyze this information.[66]

71. The Department noted that nuclear costs are a major cost driver in this rate case. According to the Department, the costs associated with the Monticello LCM/EPU project and the Prairie Island Plant are approximately 25 percent of the total revenue requirement initially sought by the Company. The Department argued that because the Company did not provide sufficient information to support the cost increases, the Commission should disallow a large portion of the overrun. The Department recommended limiting the amount in rate base to the initial $320 million estimate plus an increase for inflation and an increase to reflect additional regulatory requirements resulting from the Fukushima Daiichi nuclear plant disaster. The Department's recommendation was for this rate case only. Based on this analysis, the Department recommended reducing the nuclear plant rate base by $39.217 million.[67]

---

[61] Ex. 108 at 9 (Schedin Rebuttal); Ex. 107 at Attachment 11, 12, 14 (MCC IRs No. 406, 416, and 409); Tr. Vol. 3 at 202 (Schedin).
[62] Ex. 108 at 10 (Schedin Surrebuttal); Ex. 107 at 17-18 (Schedin Direct).
[63] *See* Financial Adjustment Summary (May 1, 2013) (Edocket number 20135-86624-01).
[64] Ex. 119 at 28 (Pollock Direct).
[65] XLI Initial Brief at 4-9.
[66] Ex. 166 at 94-106 (Campbell Direct).
[67] *Id.* at 95, 106-107 (Campbell Direct); Ex. 173 at 96 (Campbell Surrebuttal) (the Department originally recommended a reduction of $47.013 million, but revised the number to $39.217 million in its surrebuttal testimony to reflect corrections to the calculation).

72. The Company countered that the entire LCM/EPU project is currently "used and useful" because the investments and upgrades are in service and are being used to produce power, albeit at existing levels. The Company maintained that the lack of an NRC license for the EPU is not relevant to whether the Monticello LCM/EPU investments are "used and useful." With regard to the Department's argument, the Company contended that it had met its burden of proof as to the costs included in rate base by providing detailed information about the costs and the reasons for the increases.[68]

73. In response to the issues raised by these parties, the Company offered to reduce its request for the Monticello LCM/EPU project costs in the current rate case. The Company proposed that the NRC licensing costs for August and November of 2013 remain in CWIP, with an AFUDC offset for all of 2013, because the NRC has not yet granted the EPU license amendment for the plant. The Company also proposed to defer the 2013 depreciation expense associated with the May 2013 plant addition until the prudence review is completed in the 2014 rate case. The Company noted that to implement its proposal, it would need authorization from the Commission to create a regulatory asset to defer the depreciation expense and amortize it over the remaining life of the plant.[69] The Company's rebuttal proposal would result in an $8.261 million reduction to the 2013 revenue requirement.[70]

74. MCC, XLI, and the Department all opposed the Company's rebuttal position. MCC and XLI opposed the Company's rebuttal proposal because the EPU is not yet operational.[71] MCC did agree that 2013 EPU licensing costs should remain in CWIP, but maintained that the Company's proposal does not go far enough. MCC continued to recommend that the Commission remove all EPU costs from rate base by placing 41.6% of the combined LCM/EPU costs in CWIP.[72] The Department opposed the new proposal arguing that the Company should not be allowed to defer 2013 costs to its next rate case because the Company had failed to meet its burden of proof in this rate case.[73]

v. Conclusions – Monticello LCM/EPU Project Costs

75. Minnesota law requires utilities to charge "just and reasonable" rates.[74] When determining "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

[68] Xcel Energy Initial Brief (Xcel Initial Brief) at 31-33; Ex. 50, Schedule 5 (O'Connor Rebuttal).
[69] Ex. 19 at 12-14 (Robinson Rebuttal); Ex. 52 at 11, 13 (Perkett Rebuttal).
[70] *See* Financial Adjustment Summary (May 1, 2013) (Edocket number 20135-86624-01).
[71] Ex. 108 at 9-10 (Schedin Surrebuttal); Ex. 122 at 14 (Pollock Surrebuttal).
[72] MCC Reply Brief at 7.
[73] Ex. 173 at 103-104 (Campbell Surrebuttal).
[74] Minn. Stat. § 216B.03.

rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.[75]

76. By the terms of this statute, only capital projects that are "used and useful" are included in the Company's rate base.[76] The Commission has discretion in determining whether property is "used and useful."[77]

77. 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."[78]

78. The record in this case demonstrates that the Monticello LCM/EPU capital project is "in service" **but only** for LCM purposes. The equipment installed as part of the LCM/EPU project is being used to generate electricity at existing levels, not at the higher EPU level.[79]

79. The EPU portion of the project is not "in service" because the Company does not yet have the NRC license amendment required to operate at uprated EPU level. As a result, the Company cannot generate the additional 71 MW that the EPU is designed to provide. The Company can only operate at its current licensed capacity. The Company will not be able operate at its uprated power level until it receives authorization from the NRC.[80]

80. In addition, it is not reasonable to expect that the NRC will issue the license amendment for the EPU during the 2013 test year. The record in this case shows a history of delays by the NRC and the current federal government sequester calls into serious question the likelihood that the license amendment will be issued this year. Thus, the Company has failed to demonstrate by a preponderance of the evidence that the property will be "in service" for EPU purposes during the 2013 test year.

81. In addition, the EPU required installation of equipment that was specifically designed to allow the plant to generate at the increased level. As a result, some of the equipment installed is larger than would otherwise be necessary and some equipment would not have been required but for the EPU. Because the plant has not yet operated at its increased level, the EPU-related equipment is not being used for its intended purpose and is not benefitting ratepayers at this time.

82. Thus, contrary to the assertion of the Company, the fact that the project investments are being used to generate electricity at current levels for LCM purposes does not mean that the entire LCM/EPU project is "in service" or "used and useful" for purposes of Minn. Stat. § 216.16, subd. 6. Because the plant is only generating power

---

[75] Minn. Stat. § 216B.16, subd. 6 (emphasis added).
[76] *Id.*
[77] *In re Request of Interstate Power for Authority to Change its Rates for Gas Service in Minnesota*, 559 N.W.2d 130, 133 (Minn. 1997).
[78] *Senior Citizens Coalition of Northern Minnesota v. MPUC*, 355 N.W.2d 295 (Minn. 1984).
[79] Ex. 49 at 8 (O'Connor Rebuttal).
[80] *Id.*; Ex. 19 at 16 (Robinson Rebuttal).

at existing levels, the EPU portion of the project is not "in service" or "used and useful."[81] Any other interpretation of Minn. Stat. § 216B.16 would improperly allow the Company to recover EPU costs, with a return, before ratepayers ever receive the benefit of the additional 71 MW of EPU capacity. To allow recovery of the EPU costs before the plant provides the additional power would result in unreasonable rates for ratepayers.

83. Because the EPU portion of the project is not "used and useful," the Administrative Law Judge recommends that the Commission adopt MCC's proposal to hold the EPU capital costs in CWIP (with an AFUDC offset) in this rate case. MCC's proposal appropriately balances the interests of the ratepayers and the Company by recognizing that the ratepayers are not currently receiving the benefits of the EPU while also allowing the Company a future return on the EPU investment at the time when the plant is actually providing the additional power to ratepayers.

84. The Administrative Law Judge also concludes that MCC's proposal to keep 41.6 percent of the combined LCM/EPU project costs in CWIP, with an AFUDC offset, is reasonable.[82] The 41.6 percent apportionment of costs between the EPU and LCM represents the Company's own estimate of the proportion of costs attributable to the EPU part of the project. While the Company maintains that the estimate was an early, high level figure, the Company has not produced an incremental cost study or any other reliable accounting study to show that the estimate is no longer reasonable. Thus, a preponderance of the evidence in the record demonstrates that MCC's proposal is reasonable and should be adopted.

85. Given the conclusions and recommendations above, the Administrative Law Judge does not believe it is necessary to address the alternative proposals of XLI and the Department.[83]

B. Sherco 3[84]

86. The parties dispute the amount of direct costs that the Company should be allowed to recover for the Sherco 3 generating unit (Sherco 3). The amount in dispute is over $34 million in test year expenses.[85] The dispute stems from the fact that Sherco 3 has not been operating since November 2011 due to an unexpected, catastrophic failure.

---

[81] The Company's reliance on precedent to support its "used and useful" argument is not persuasive. None of the cases cited presents a situation like that in this matter where the project costs to be recovered were, in part, for an EPU but the plant was not yet operating at the increased EPU levels.

[82] It is the Administrative Law Judge's understanding that the 41.6% amount would include the 2013 NRC licensing costs that the Company proposed to keep in CWIP and no separate adjustment is necessary for those costs.

[83] The Administrative Law Judge notes that the Department raised valid concerns regarding the timing of information provided by the Company regarding the Monticello LCM/EPU cost increases. The record, as a whole, however, shows that the Company provided sufficient information to support its proposed recovery of the LCM related costs in this rate case, subject to a later prudency review.

[84] Issue 8.

[85] *See* Ex. 166 at 33 (Campbell Direct); Ex. 58 at 25 (Heuer Rebuttal).

i. Background

87. Sherco 3 is the largest generating unit in the NSP-System.[86] Sherco 3 is a 900 MW coal-fired plant first put into service in November 1987.[87]

88. Xcel owns approximately 59 percent of Sherco 3 (531 MW), and the Southern Minnesota Municipal Power Agency owns the remainder of the unit (369 MW).[88]

89. Sherco 3 has been included in the Company's rate base in each rate case since the plant was approved by the Commission.[89] It is part of a portfolio of generation that purposefully includes additional capacity to assure reliable service in the event of a forced outage.[90]

90. In November 2011, there was a significant failure at Sherco 3, which led to an extended outage. The event occurred at the end of a planned overhaul outage, which included completion of an uprate project for the unit. During the start-up testing procedure, the turbine and generator instrumentation reported vibration levels significantly above normal and the unit shut down. The vibration damaged many of the steam oil and hydrogen seals in the turbines and generator, and caused a fire. The turbine generator, rotor and exciter (among other components) suffered significant damage, requiring the Company to consider a total replacement (a multi-year process) or extensive repairs.[91]

91. Engineering experts determined that the outage was caused by the failure of the mechanical connections between the low pressure blade and the rotor. The connections were deep inside the turbine and could only be accessed by completely disassembling the turbine. The failure was not one that the Company could have predicted or prevented.[92]

92. The Company has been working to repair the unit. In the course of the repair work, the Company discovered that the damage was more extensive than initially anticipated. At this time, all of the major equipment repair work has been completed and the unit is now being reassembled.[93]

93. When the Company filed its Direct Testimony in November 2012, the Company estimated that Sherco 3 would be back on-line at the end of the first quarter of 2013. In its Rebuttal Testimony (filed in March 2013), the Company revised its estimate to on or before September 30, 2013. At the time of the evidentiary hearing in

---

[86] Tr. Vol. 1 at 58 (Larson).
[87] Ex. 52, Perkett Rebuttal at 10.
[88] Ex. 166 at 15 (Campbell Direct).
[89] Ex. 19 at 8 (Robinson Rebuttal).
[90] Tr. Vol. 1 at 55-56 (Larson).
[91] Ex. 13 at 29-30 (Larson Direct); Ex. 15 at 7 (Larson Rebuttal).
[92] Ex. 17, Schedule 1 (Larson Surrebuttal); Tr. Vol. 1 at 47 (Larson).
[93] Ex. 15 at 8 (Larson Rebuttal); Tr. Vol. 1 at 47 (Larson).

April, 2013, the Company stated that it still expects the unit to return to service by September 30, 2013. The Company agreed that there is no guarantee that Sherco 3 would return to service in 2013, but the Company is very confident that it will be back in service by this date. The Company noted that it has confidence in the September 30, 2013 return date because the Company is now reassembling the turbine, a process that is more predictable than repair of such units.[94] Once back on-line, Sherco 3 is expected to provide many years of additional service.[95]

94. While planned outages are part of plant operations, it is unusual to have a catastrophic outage that lasts almost two years. The outage at the Sherco 3 unit is the longest outage of this type in the Company's history.[96]

95. Sherco 3 was accredited for capacity purposes with Midwest Independent Transmission System Operator (MISO) through 2012 but the Company made the decision to forgo MISO capacity accreditation for Sherco 3 in 2013. Even so, when it is operational again, Sherco 3 will be eligible to be dispatched into the MISO energy market as an energy resource, and the fuel savings will be passed on to customers. In other words, even without the MISO capacity accreditation, Sherco 3 can generate power for use by the Company's customers once it is back on-line.[97]

ii. Sherco 3 Costs

96. Because the outage resulted from an accident, most of the cost of the repair work is covered by insurance. The cost of the deductible was recorded in 2011 and is not included in the 2013 test year. No costs related to the repair have been included in the current test year. The cost of improvements that have been accelerated to take advantage of the current outage are included in the test year.[98]

97. The Company agreed to provide a full accounting of Sherco 3 repair costs and insurance recovery in its next rate case. The accounting is intended to demonstrate that no costs related to the Sherco 3 that have been reimbursed by insurance are included in the next test year and is intended to provide accounting for costs not covered by insurance.[99]

98. The costs at issue in this proceeding are the direct costs of Sherco 3 including depreciation expense, property taxes, payroll taxes, fuel handling, insurance, operations and maintenance (O&M), rate of return and a tax gross-up.[100]

---

[94] Ex. 13 at 30 (Larson Direct); Ex. 15 at 6 (Larson Rebuttal); Tr. Vol. 1 at 53-54 (Larson).
[95] Ex. 19 at 7-8 (Robinson Rebuttal).
[96] *Id.* at 8-9; Tr. Vol. 1 at 151 (Robinson).
[97] Tr. Vol. 1 at 55 (Larson); Ex. 17 at 2 (Larson Surrebuttal).
[98] Ex. 15 at 30-31 (Larson Direct); Tr. Vol. 1 at 60-61 (Larson).
[99] Ex. 29 at 6-7 (Stitt Rebuttal).
[100] Ex. 166 at 33 (Cambpell Direct); Ex. 167 at NAC-10 (Campbell Direct Attachments) (based on Xcel response to DOC Information Request 193 showing the Minnesota jurisdictional amounts).

99. Because the Company operates a portfolio of generation that includes excess reserves, so as to account for the possibility of outages, the Company did not need to add additional generating capacity during the outage.[101]

100. The Company, however, has had higher fuel costs for the replacement power provided during the outage. According to the Department, from November 2011 to October 2012, ratepayers paid an additional $22.7 million in fuel costs as a result of the extended outage at Sherco 3.[102] The fuel costs are recovered through the Fuel Clause and will be addressed in a separate Commission proceeding.[103]

iii. The Company's Request

101. The Company initially included the following direct costs for Sherco 3 in its test year: depreciation expense; property tax; payroll taxes; fuel handling; insurance; O&M; emissions control chemicals; a return on rate base; and tax gross-up. According to the Department, this amount totaled approximately $39.9 million on a Minnesota jurisdictional basis.[104]

102. In Rebuttal Testimony, the Company offered a rate mitigation proposal that would lower Sherco 3 test year costs by approximately $35 million. This proposal reflects the fact that Sherco 3 is not expected to be operational until September 2013. First, the Company agreed not to seek recovery of the approximately $4.4 million (Minnesota jurisdictional amount) in variable operating and maintenance costs, including chemicals costs, for the test year. Second, the Company proposed to lower its operating costs by deferring property taxes related to Sherco 3 incurred in 2012 and 2013 and by deferring the depreciation expense associated with Sherco 3 for 2012 and 2013. The property tax and depreciation expense (totaling $31.45 million on a Minnesota jurisdictional basis) would then be amortized over the 21 year remaining life of the unit beginning in January 2014. This would require that the remaining life of Sherco 3 be suspended and restarted when the unit is back in service. It would also require the Commission to finally authorize the creation of a regulatory asset to allow for the deferral and amortization.[105] Finally, the Company agreed to provide accounting information on the insurance coverage for the Sherco 3 repairs, as described above.[106]

iv. The Department's Position

103. The Department recommended a reduction of approximately $36.6 million to the test year expenses for Sherco 3. While the dollar amount recommended by the

---

[101] Tr. Vol. 1 at 55-56 (Larson); Ex. 19 at 5 (Robinson Rebuttal).
[102] Ex. 166 at 25 (Campbell Direct).
[103] *See* Xcel Initial Brief at 26.
[104] Ex. 167 at NAC-10 (Cambpell Direct Attachments); Ex. 166 at 33 (Campbell Direct). This amount includes emissions chemical costs for Sherco 3. If those costs are excluded, the amount is approximately $36.6 million.
[105] Ex. 19 at 5-6 (Robinson Rebuttal); Ex. 52 at 7 (Perkett Rebuttal).
[106] Ex. 29 at 6-7 (Stitt Rebuttal).

Department is similar to that requested by the Company on rebuttal, the substance of the Department's proposed adjustment is very different than that proposed by the Company.[107]

104. The Department recommended that all direct costs for Sherco 3 be removed from the 2013 test year. The Department noted that ratepayers have paid $22.7 million extra in fuel costs for power since Sherco 3 failed in November 2011 and are expected to pay approximately $40 million by the time the unit is back on-line. In addition, the Department asserted that ratepayers have paid $14.2 million for O&M costs for Sherco 3 included in 2011 and 2012 rates, which the Company has not incurred. The Department also maintained that the Sherco 3 costs should be removed from the 2013 test year because ratepayers also overpaid for costs associated with Black Dog Units 2 and 5, located in Burnsville, Minnesota.[108]

105. The Department agreed to the Company's proposal for deferred accounting of the 2013 depreciation expense, but not to the deferred accounting of the 2013 tax expenses or the 2012 depreciation or tax expenses. The Department asserted that it is not appropriate for the Company to defer 2012 costs because ratepayers already paid those costs in their 2012 rates and have also paid for replacement power. The Department also stated that the Company's request for deferral of the 2012 tax expense is in conflict with the Commission's order in Docket No. E002/M-11/1263 where the Commission denied the Company's request for deferred accounting of 2012 property taxes.[109]

106. The Department also recommended that the Commission accept the Company's proposed 21-year remaining life as a placeholder for the Sherco 3 plant, but suggested that the Company have an engineer evaluate Sherco 3 to determine the actual remaining life due to the significant upgrades and restoration work.[110]

107. Finally, the Department agreed with the Company's proposal to provide, as a compliance filing in the next rate case, the insurance information discussed by the Company in its rebuttal testimony.[111]

---

[107] Ex. 175 at 3 (Campbell Opening Statement); Ex. 173 at 43-44 (Campbell Surrebuttal with errata). The $36.6 million does not include Sherco 3 chemical control costs, which amount to an additional reduction of $3,369,262. These costs will need to be included in the adjustment for Sherco 3 if the Commission adopts the Department's position. *See* Ex. 166 at 33 (Campbell Direct); Financial Adjustment Summary at Line 28 (Emissions Control Chemicals).

[108] Ex. 166 at 32-33 (Campbell Direct); Ex. 175 at 3 (Campbell Opening Statement); Ex. 173 at 43-44 (Campbell Surrebuttal with errata).

[109] *Id.*

[110] *Id.*

[111] Ex. 175 at 4 (Campbell Opening Statement).

v. The OAG and ECC Positions

108. Both the OAG and the ECC, in post hearing briefs, supported the position of the Department.[112]

vi. The ICI Group Position

109. The ICI Group proposed that the fixed costs associated with Sherco 3 be removed from the 2013 test year. The ICI Group claimed that Sherco 3 is not "used and useful" because the plant experienced a catastrophic failure in November 2011 and is not currently operating. The ICI Group noted that Sherco 3 lost its capacity accreditation from MISO, and asserted that the Company has been forced to buy higher cost replacement energy on the MISO market as a result of the outage. For these reasons, the ICI Group maintained that it is not appropriate for Xcel's customers to continue paying for the costs associated with Sherco 3. According to the ICI Group, to allow recovery of Sherco 3 costs would send incorrect price signals to utilities and encourage "over- and mis-investment."[113]

vii. MCC's Position

110. MCC also objected to the inclusion of Sherco 3 costs in the 2013 rate base, arguing that Sherco 3 is not currently "used and useful." MCC initially proposed that Sherco 3 be removed from "Plant In Service" and placed in CWIP with an AFUDC offset. After the Company responded that accounting rules did not permit the transfer of Sherco 3 to CWIP, MCC proposed that the Commission authorize the Company to create a regulatory asset that would serve the same purpose. MCC recommended that Sherco 3 remain out of rate base until it is back on-line and fully accredited by MISO. According to MCC, this would result in a $20.7 million adjustment on a Minnesota jurisdictional basis.[114]

111. MCC also agreed with the Company that no depreciation on Sherco 3 should be recorded in 2013, and that no property taxes for Sherco 3 should be recovered in 2013. In addition, MCC recommended that 2012 depreciation and 2012 property taxes be returned to ratepayers, and that all of these items be deferred and recovered in the future as set out by Xcel. According to MCC, this proposal amounts to a $31.45 million adjustment.[115]

112. MCC also proposed that 2013 legal costs, administrative costs, employee and overhead costs be removed from the 2013 test year. MCC noted that Xcel has agreed to an adjustment of $4.4 million for these expenses, but questioned if this is the

---

[112] Initial Brief of the Office of the Attorney General (OAH Initial Brief) at 45-46; Initial Brief of ECC (ECC Brief) at 2.
[113] Initial Brief of the ICI Group (ICI Group Initial Brief) at 4-6; Ex. 105 at 9 (Glahn Direct).
[114] Initial Brief of the Minnesota Chamber of Commerce (MCC Initial Brief) at 3-5; Reply Brief of the Minnesota Chamber of Commerce (MCC Reply Brief) at 5.
[115] Reply Brief of the Minnesota Chamber of Commerce at 5.

correct amount. MCC also recommended removing chemical costs for Sherco 3, which are approximately $3.3 million.[116]

viii. Conclusion – The "Used and Useful" Question

113. Several parties have argued that Sherco 3 is not currently "used and useful" because the Unit has not produced electricity since November 2011, and therefore rate base costs related to Sherco 3 should be excluded from the 2013 test year. These parties would exclude these costs even though Sherco 3 has been included in rate base in past rate cases.

114. As discussed above, only property that is "used and useful" is included in the Company's rate base. [117] 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."[118]

115. The Minnesota Supreme Court has held that a cancelled plant that has not and never will provide electricity to ratepayers is not "in service." [119] The Commission has determined that a plant that has not produced power for "several years" and is not expected with reasonable certainty to return to production is considered *no longer* "in service."[120] Moreover, to be "reasonably necessary," facilities must provide value to the paying customers.[121]

116. No party has identified any Minnesota precedent examining the "used and useful" standard in a context similar to this one where an electric generating unit has experienced a prolonged outage, but is expected to come back into service in the near future.

117. The Connecticut Department of Public Utility Control, however, addressed a similar situation in 1997. The Connecticut case involved three generating units at the Millstone nuclear generating facility. The facility had been generating electricity for a number of years before all three units went off-line. Millstone Unit 1 was shut down for

---

[116] *Id.*

[117] Minn. Stat. § 216B.16, subd. 6. (2012). As noted by the Company, the "used and useful" standard only applies to rate base costs, not operating costs like property taxes. Xcel Initial Brief at 23 (citing *In re Interstate Power Company*, 574 N.W.2d 408, 413-14 (Minn. 1998)).

[118] *Senior Citizens Coalition of Northern Minnesota v. MPUC*, 355 N.W.2d 295 (Minn. 1984).

[119] *In re Petition of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, 417 N.W.2d 677 (Minn. 1988) *review denied* (Mar. 23, 1988) (designating a cancelled facility as not "used and useful" because the planned project would never provide electricity to ratepayers).

[120] *See In the Matter of the Petition of Minnesota Power & Light Company, d/b/a/ Minnesota Power, for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota*, Docket No. E015/GR-87-223, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 14–18 (Mar. 1, 1988). ("1988 Hibbard Order") (finding Hibbard plant was not "used and useful" because the plant had been out of service for seven years, was out of service during the test year, and the utility had only tentative, long-term plans to return the plant to service).

[121] *See Senior Citizen*, 355 N.W.2d at 300 (holding recreational facilities at a hydroelectric facility were used and useful and should be included in rate base because they were required by FERC as a condition of its license).

a refueling outage in November 1995. Millstone Units 2 and 3 were shut down for an unplanned outage due to equipment deficiencies in February 1996 and March 1996, respectively. All three units were expected to come back on-line, but there was less certainty as to when Unit 1 would be generating power again than there was for Units 2 and 3.[122]

118. In determining whether the Millstone units were "used and useful" for purposes of setting rates, the Connecticut DPUC considered: (1) the length of time that the unit would be out of service; (2) the degree to which the outage could be expected to occur during the normal operation of the plant; and (3) the certainty with which resumption of service could be predicted. Because there was no dispute that the outage at the three units was not part of normal operations, the Connecticut DPUC focused on whether each unit would be in service during the period in which the rates were to be in effect in determining whether the unit was "used and useful." In particular, the DPUC focused on "the certainty and imminence" with which each unit would again be producing electricity.[123]

119. The Connecticut DPUC held that Milestone Unit 1 was not "used and useful" and removed it from rate base because major work remained before the unit could be restarted and the Company was not aggressively seeking to restart Unit 1. With regard to Units 2 and 3, however, the Connecticut DPUC held that those units remained "used and useful" and allowed Units 2 and 3 to remain in rate base because it was reasonably certain that those units would be restarted within three to six months after the Department's order. The Connecticut DPUC rejected the view that absolute certainty of the restart date was required for each unit, and instead required reasonable certainty, which it found in the record. With regard to Unit 3 in particular, the Connecticut DPUC noted that significant progress had been made toward the restart of the unit and significant new issues were unlikely. The Connecticut DPUC also put the utility on notice that it would review the status of both Units 2 and 3 at a later date and could re-examine its decision if circumstances changed.[124]

120. The test applied by the Connecticut DPUC to determine whether the Millstone units were "used and useful" provides a sound basis for determining whether Sherco 3 is "in service" and "used and useful" for purposes of Minnesota law.

---

[122] *In re Connecticut Light & Power Co*., Connecticut Department of Public Utility Control Docket, No. 97-05-12 1997 WL 866679 ** 8-9, 19-21 (December 31, 1997) (also available at http://159.247.49.194/__85255F2C005B9480.nsf/0/DA73A3EF251AD86F8525657E0060C3B6?Open&Highlight=2,97-05-12) (last viewed on June 29, 2013).
[123] *Id.* at 9.
[124] *Id.* at 8-9, 11-12, 19-21.

121. Applying that test to Sherco 3, the Administrative Law Judge concludes that Sherco 3 will be "in service" and "used and useful" during the 2013 test year. While the prolonged outage at Sherco 3 was unexpected, it is reasonably certain that Sherco 3 will be back on-line by September 2013, during the current test year.[125] The Company has completed all of the repairs at Sherco 3 and is in the reassembly phase. The Company is working diligently to return the plant to operation. This is not a plant that faces an uncertain future. Because the plant has been in rate base for a number of years and there is reasonable certainty that the plant will be producing power during the 2013 test year, Sherco 3 is "used and useful" for purposes of the 2013 rate case.[126]

122. Moreover, the conclusion that Sherco 3 is "used and useful" is fully consistent with the conclusion that the Monticello EPU is not "used and useful." The varying conclusions are explained by the differing facts. First, Sherco 3 had been generating electricity for many years prior to the outage, whereas as the Monticello EPU has never been operational. Second, the Company has control over when Sherco 3 will be operating again and the Company has shown it is reasonably certain that the unit will be generating electricity during the 2013 test year. There is no certainly, on the other hand, as to when the Monticello EPU will be operating. The determination as to when the Monticello EPU can begin operations is in the hands of the NRC, not the Company. Thus, the facts show that Sherco 3 will be "in service" and "used and useful" during the 2013 test year but no such showing has been made for the Monticello EPU.

ix. Conclusion - Other Arguments Regarding Sherco 3 Costs

123. The Department argued that it is unfair to include Sherco 3 costs in 2013 rates because the Company has been recovering direct costs related to Sherco 3 in existing rates even though the unit has not been operating since November 2011, and because ratepayers have also been paying for replacement power through the Fuel Clause.[127]

124. The Department's argument regarding existing rates does not provide a basis for excluding 2013 costs for Sherco 3 in the new rates. The Commission's decision about rates is prospective, not retroactive.[128] Moreover, it is not consistent with traditional ratemaking principles to look at one cost in isolation in examining whether

---

[125] In the Connecticut case, it was determined that the outages at Millstone were caused by mismanagement. Here there has been no allegation by any party that the outage at Sherco 3 was due to mismanagement. The record is clear, however, that that outage at Sherco 3 is highly unusual and was not expected to occur during normal operations.

[126] Because Sherco 3 was not back in service as of April 2013 but is expected to be in service on or before September 30, 2013, the Commission could find that Sherco 3 is "used and useful" for only a portion of the 2013 test year. However, the Commission has not historically removed generating plants from rate base due to planned or unplanned outages. *See* Ex. 19 at 8-9 (Robinson Rebuttal).

[127] Ex. 175 at 3 (Campbell Opening Statement); Ex. 173 at 43-44 (Campbell Surrebuttal with errata); Ex. 166 at 32 (Campbell Direct).

[128] Minn. Stat. § 216B.16, subd. 5.

existing rates are reasonable.[129] With regard to replacement power costs, the Department raises a valid question as to whether the Company should be allowed to recover the additional replacement power costs, but that issue is not part of this rate case. The Company has not included the cost of replacement power in the current test year. The issue will be addressed in a separate proceeding before the Commission. Thus, the Department's arguments regarding recovery of Sherco 3 costs in existing rates and the cost of replacement power do not provide a basis for finding the 2013 Sherco 3 costs unreasonable.

125. The Department also argued that the Sherco 3 costs should be denied because ratepayers were required to pay for O&M and capital costs of Black Dog Units 2 and 5 during the extended outages at those units and ratepayers also paid higher fuel costs during those outages.[130] The Administrative Law Judge does not find the Department's argument persuasive. First, this argument addresses costs at other facilities, not Sherco 3. Second, as discussed above, focusing on one cost in isolation is not a proper method of determining the reasonableness of existing rates. In fact, the record shows that the Company did not earn its authorized rate of return in 2012.[131]

126. Finally, the ICI Group argued that Sherco 3 costs should be removed because Sherco 3 is not currently accredited for capacity purposes. This argument also is not persuasive. The ICI Group ignores the fact that when Sherco 3 is back on-line it will be generating power for use by Xcel's customers.[132] Thus, even without the capacity accreditation, Sherco 3 will be "used and useful" during the 2013 test year.

x. The Company's Rebuttal Proposal

127. In its Rebuttal Testimony, the Company agreed that all avoidable O&M costs related to Sherco 3 should be removed from the test year. The Company identified approximately $4.4 million on a Minnesota jurisdictional basis in variable O&M costs, including chemical costs, for the test year.[133]

128. A review of Sherco 3 expenses appears to show that the avoidable O&M costs, including chemical costs, are greater than $4.4 million on a Minnesota jurisdictional basis. According to Department Exhibit NAC-10, the O&M costs and chemical costs for Sherco 3 are approximately $7.453 million on a Minnesota jurisdictional basis.[134] Unless the Company can explain the discrepancy, it appears that the actual avoidable O&M expenses, including chemicals, for Sherco 3 included in the 2013 test year are $7.453 million.

---

[129] *See In the Matter of the Complaint by Myer Shark et al, Regarding Xcel Energy's Income Taxes*, MPUC Docket No. C-03-1871, ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 4 (Oct. 1, 2004).
[130] Ex. 166 at 32-33 (Campbell Direct).
[131] *See* Ex. 11 at 5 (Poferl Direct); Ex. 12 at 10 (Poferl Rebuttal).
[132] Tr. Vol. 1 at 55 (Larson); Ex. 17 at 2 (Larson Surrebuttal).
[133] Ex. 19 at 5-6 (Robinson Rebuttal).
[134] Ex. 167 at NAC-10 (Campbell Direct Attachments) (listing Sherco 3 expenses on a Minnesota jurisdictional basis including $4,083,976 for O&M expenses *without chemicals* and $3,369,262 for chemicals), (this exhibit is based on Xcel's response to DOC Information Request No. 193).

129. Because Sherco 3 is not expected to be back on-line until September 30, 2013, the Administrative Law Judge agrees that it is reasonable to remove all avoidable O&M costs, including chemical costs, for Sherco 3 that are included in the 2013 test year.

130. In addition, the Company proposed to defer collection of $31.45 million of Sherco 3 costs through the creation of a regulatory asset. This amount would be removed from the 2013 test year, and instead amortized over 21 years (the remaining life of the plant) beginning in 2014. The Company proposed this adjustment to recognize the fact that the plant will continue to be off-line until the restoration work is complete, and at the same time, preserve recovery of the costs to a later date.[135]

131. In Rebuttal Testimony, the Company proposed that the $31.45 million be comprised of deferred 2012 and 2013 depreciation expense and property tax expense.[136]

132. The Department agreed to the deferral of the 2013 depreciation expense, but objected to the deferral of the 2013 property tax expense. The Department also objected to the deferral of any 2012 expenses because those expenses were paid in 2012 rates and the Commission denied the Company's request for deferred accounting of 2012 property taxes in Docket No. E002/M-11-1263.[137]

133. The Administrative Law Judge concludes that it is reasonable to defer certain 2013 expenses through the creation of a regulatory asset in recognition that Sherco 3 is under restoration and is not expected to be operating until later in the 2013 test year. The Administrative Law Judge also agrees with the Department that it is not reasonable to include 2012 expenses in the amount deferred because those expenses have been recovered in 2012 rates.[138]

134. For these reasons, the Administrative Law Judge recommends that the Commission authorize the Company to defer its 2013 depreciation expense ($11.218 million), its 2013 property tax expense ($5.301 million), and its 2013 return on rate base for Sherco 3. If permissible from an accounting perspective, the Administrative Law Judge also recommends that the Commission authorize deferral of the 2013 payroll taxes ($296,876), 2013 fuel handling costs ($462,842),[139] and 2013 insurance costs ($485,920).[140] In effect, the Administrative Law Judge recommends that all 2013 direct

---

[135] Ex. 19 at 6 (Robinson Rebuttal).
[136] *Id.*
[137] *Id.*
[138] In its Reply Brief, the Company maintained that its proposal to create a regulatory asset does not implicate expenses "outside of the test year." This position is inconsistent with the Company's Rebuttal Testimony of Mr. Robinson where Mr. Robinson specifically suggested including a "depreciation adjustment for 2012" and deferring property taxes of "$7.0 million for 2012." Ex. 19 at 6 (Robinson Rebuttal).
[139] It is unclear if "fuel handling costs" are a variable cost or a fixed cost. If "fuel handling" costs are variable, then the Administrative Law Judge instead recommends that they be considered an avoided cost and be excluded rather than deferred.
[140] *See* Ex. 167 at NAC-10 (based on Xcel Energy Response to DOC Information Request No. 193).

Sherco 3 costs, other than the variable costs that the Company has agreed to exclude, be deferred and amortized beginning in 2014.

135. Deferral and amortization of these 2013 expenses is reasonable. This approach properly balances the interests of the ratepayers and the Company by mitigating the rate impact to current ratepayers and allowing the Company to recover its costs at a later time.

136. Because the net effect of the Administrative Law Judge's recommendations is to remove all of the direct 2013 costs related to Sherco 3 from the 2013 test year, adoption of these recommendations would result in a reduction of approximately $39.9 million to the 2013 test year revenue requirement.[141]

137. The Administrative Law Judge further recommends that the Commission accept the Company's proposed 21-year remaining life as a placeholder, but that it require the Company have an engineer evaluate Sherco 3 to determine the actual remaining life of the upgraded facilities.[142] Also, the Administrative Law Judge recommends that the Company's provide, as a compliance filing in the next rate case, the insurance information discussed by the Company in its Rebuttal Testimony and the engineer's report.[143]

C. Qualified Pension Expense[144]

138. The Company has requested recovery of its 2013 qualified pension expense. The Department objected to the Company's request on the grounds that the amount requested is not reasonable. The Department challenged two of the assumptions used by the Company in calculating the expense, and also objected to the inclusion of 2008 stock market losses in the expense.[145]

i. Background

139. As part of its overall compensation package, the Company provides a defined benefit pension. This pension benefit is known as a "qualified pension."[146] The Company's qualified pension is not intended to provide an employee's total retirement income. Employees can also contribute to a 401(k) plan. The qualified pension and the 401(k) plan together provide retirement income to employees.[147]

140. The test year expense includes costs for employees of NSP-Minnesota (NSPM) and costs for employees of Xcel Energy Services (XES), its service company

---

[141] According to NAC-10, the total Sherco 3 costs included in the 2013 test year are $39,970,192. Ex. 167 at NAC-10 (based on Xcel Energy Response to DOC Information Request No. 193).
[142] *Id.*
[143] Ex. 175 at 4 (Campbell Opening Statement).
[144] Issues 13-15 (qualified pension update, assumptions, and 2008 market loss amortization).
[145] *See* Initial Post Hearing Brief of the Department (Department Initial Brief) at 79-80.
[146] Ex. 35 at 12, 29-31 (Figoli Direct); Ex. 38 at 14 (Moeller Direct).
[147] Ex. 38 at 4 (Moeller Direct); *see also*, *id.* at 4-14 (detailed discussion of the design of the Company's retirement plan and an explanation as to why employees are not required to contribute to their pension).

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. Approximately 73 percent of the Company's test year pension costs relate to the NSPM Plan, and 27 percent relate to the XES Plan.[148] Because the XES Plan was created after the NSPM plan, the Company uses two different accounting methods to determine the total qualified pension expense. For the NSPM Plan, the Company uses the aggregate cost method (ACM). For the XES Plan, the Company uses the SFAS 87 method.[149]

141. The accounting methods used by the Company are actuarial methods that take a long term view of pension expenses. The Company has used the same approach to calculating its pension expense for more than 40 years.[150]

142. The pension expense under both plans is calculated in a similar manner. The 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 and reflects the time value of money; (3) the earned return on assets (EROA), which is what the pension asset is expected to earn; (4) the prior service cost, which includes adjustments to benefit levels; and (5) actual pension asset gains and losses.[151] Pension earnings and amortization of pension gains (earnings above the EROA) reduce pension expense. Pension losses increase that expense.

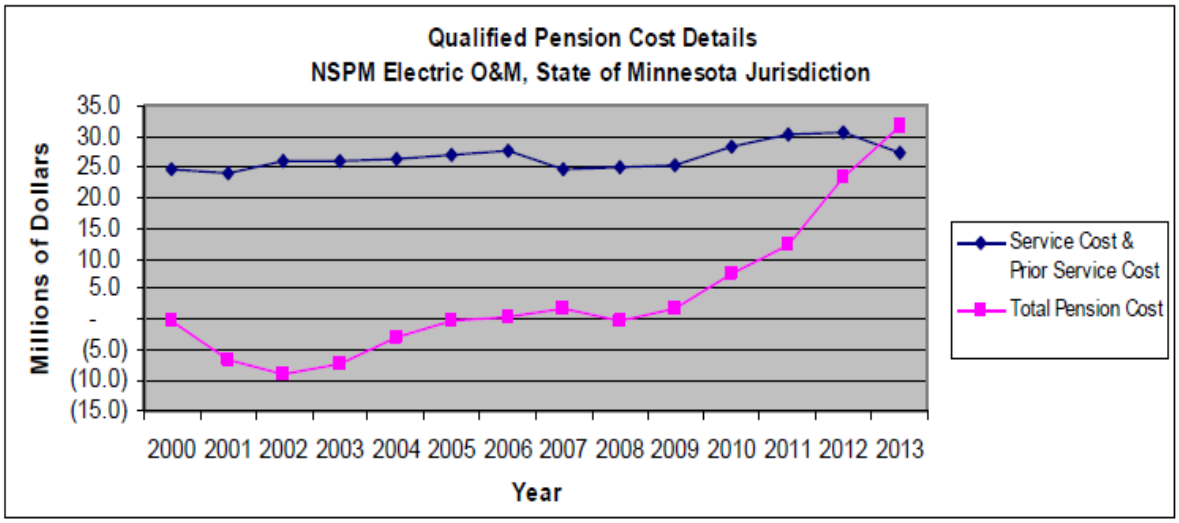
143. The pension expense included in rates is different than the Service Cost, (the actual cost of providing the pension benefit to Company employees), because the amount included in rates is adjusted to reflect the interest cost, pension earnings, and unrecognized gains and losses.[152]

144. As a result of recognizing pension earnings and losses, actual pension costs were much lower than annual Service Costs from 2000 to 2012 as shown in the table below.[153]

---

[148] *Id.* at 14 (Moeller Direct).
[149] Ex. 38 at 14, 24 (Moeller Direct).
[150] Ex. 39 at 13 (Moeller Rebuttal).
[151] Tr. Vol. 2 at 57-62 (Moeller); Ex. 38, Schedule 6 (Moeller Direct).
[152] *See* Ex. 38 at 19 (Moeller Direct); Ex. 39 at 17 (Moeller Rebuttal).
[153] Ex. 39 at 17 (Moeller Rebuttal).

Table 1



145. From 2000 to 2013, the Company's qualified pension has provided a cumulative benefit of approximately $320 million to customers, even after incorporating the recognized portion of the 2008 market loss. The current test year, 2013, is the first time the recognized pension cost (as calculated by the Company) has exceeded the annual Service Cost. The Company expects that pension costs will once again be below Service Costs in 2015, provided that the Company's current assumptions and method remain in place.[154]

ii. The Parties' Positions

146. The Company initially proposed recovery of approximately $35.1 million in pension expenses in its 2013 test year. This amount is comprised of approximately $27.9 million for pension O&M expense in the Minnesota electric jurisdiction, and recovery of approximately $7.2 million for capitalized pension costs. The amount the Company requested is based on estimates of its actuarially determined 2013 pension costs.[155]

147. The approximately $27.9 million qualified pension O&M expense requested by the Company in its 2013 test year is more than double the approximately $12.05 million qualified pension O&M expense that the Company requested in its 2011 test year.[156]

148. The increase from 2011 to 2013 is primarily the result of three factors: 1) the 2008 stock market losses, which account for approximately 66 percent of the pension cost increase; 2) decreased discount rates, which account for about 17 percent

[154] Ex. 39 at 17 (Moeller Rebuttal).
[155] *Id.* at 4-5.
[156] Ex. 166 at 44 (Campbell Direct).

of the pension cost increase; and 3) decreased EROA, which accounts for about 17 percent of the pension cost increase.[157]

149. Recognizing the impact to rates from the increased qualified pension expense, the Company proposed two methods to smooth recovery of the expense and mitigate the rate impacts. The first method would extend the NSPM amortization period for unrecognized pension costs from 10 to 20 years. The second method would cap the XES pension expense at the 2011 level, and defer the difference into future years. According to the Company, the net effect of adopting both methods would be an approximately $9.9 million reduction to the Company's proposed 2013 test year revenue requirement.[158]

150. The Department objected to the Company's calculation of its 2013 qualified pension expense on the grounds that: (1) the 2008 market losses should not be included: (2) the discount rate for the XES Plan did not match the EROA for the XES plan; and (3) the 4 percent assumed wage increase used by the Company in calculating the pension expense was too high and should be 2.6 percent.[159]

151. The Department recommended reducing the qualified pension O&M expense by approximately $23.4 million and reducing capitalized pension costs by approximately $6.0 million. The Department's recommendation reflected elimination of any recovery of the 2008 market loss, increasing the discount rate used for the XES Plan from 5 percent to 7.5 percent, lowering the wage increase assumption from 4.0 percent to 2.6 percent, and using year-end 2012 data for the measurement of asset value.[160]

152. In its Rebuttal Testimony, the Company proposed: 1) including updated pension expenses and costs to reflect the final actuarial determinations for 2013; 2) using a three-year average (2010-2012) for the discount rate and EROA assumptions that are used in the actuarial determination; and 3) adopting the same smoothing methods as proposed in its Direct Testimony.[161] Making these adjustments would result in the qualified pension O&M expense being reduced to approximately $19.060 million and the corresponding capital cost would be reduced to approximately $4.518 million, on a Minnesota jurisdictional basis.[162]

153. In Surrebuttal Testimony and at the evidentiary hearing, the Department opposed the Company's revised qualified pension expense recommendation. The Department raised a number of concerns regarding the Company's rebuttal position, including that: 1) the assumptions are not independent; 2) the Company failed to provide support for its updated assumptions; and 3) the Department did not have sufficient time to evaluate the updated assumptions. The Department also continued to

---

[157] Ex. 38 at 15-16 (Moeller Direct).
[158] *Id.* at 21-26.
[159] Ex. 166 at 47-56 (Campbell Direct).
[160] Ex. 173 at 47-48 (Campbell Rebuttal); Ex. 166 at 40-41 (Campbell Direct).
[161] Ex. 39 at 5-22 (Moeller Rebuttal); Ex. 58 at 38 (Heuer Rebuttal).
[162] Ex. 39 at 9 (Moeller Rebuttal); Ex. 58 at Schedule 14, 1 of 3 (Heuer Rebuttal).

recommend that the Commission adopt the adjustments set forth in the Department's Direct Testimony.[163]

iii. Value of the Pension Assets

154. On February 1, 2013, the Company provided the Department with the year-end value of its pension assets. The year-end value results in a reduction of the pension expense of $623,126. The Department recommended that the measurement date for the value of the plan assets be updated from July 30, 2012 to December 31, 2012, the year end.[164] The Company did not object.

155. The Administrative Law Judge concludes that it is reasonable to measure the value of the pension asset using the December 31, 2012 year end date.

iv. Qualified Pension Assumptions

156. The pension expense for both plans is based on three primary assumptions: 1) the EROA; 2) the Discount Rate; and 3) the salary scale.[165] In Direct Testimony, the Company included the following assumptions for the NSPM Plan and the XES Plan:[166]

Table 2

Total Impact					
	2013	2014	2015	2016	2017
Impact From Extending ACM Amortization	($7,324,270)	($5,927,523)	($4,749,018)	($3,838,208)	($2,848,079)
Impact From Capping XES at 2011 Level	($2,564,699)	($870,063)	$134,927	$1,047,428	$1,914,876
Total	($9,888,969)	($6,797,585)	($4,614,092)	($2,790,780)	($933,203)

a. The Earned Return on Assets (EROA) Assumption

157. In its Direct Testimony, the Company used a 7.5 percent EROA assumption. The Company noted that the 7.5 percent EROA is lower than EROA used in its last rate case because the Company has moderated its investment risk profile for the pension assets. The 7.5 percent is also slightly lower than the Edison Electric Institute (EEI) average of 7.78 percent.[167] The higher the EROA, the lower the pension expense.[168]

158. On Rebuttal, the Company updated the EROA to 7.25 percent. The Company did not provide any supporting schedules to show how the updated EROA

[163] Ex. 173 at 51-61 (Campbell Surrebuttal).
[164] Ex. 166 at 41, 50-51 (Campbell Direct); Ex. 174 at 61 (Campbell Surrebuttal).
[165] Ex. 38 at 15 (Moeller Direct).
[166] *Id.* at 26.
[167] *Id. at* 27, Schedule 9 at page 3 of 3.
[168] *See* Ex. 39 at 17 (Moeller Rebuttal).

number was derived or why it is lower. The only explanation for the change was that the new EROA number was updated as of December 31, 2012.[169]

159. The Department did not object to the use of the 7.5 percent EROA, but it did object to the use of the updated 7.25 percent EROA. The Department asserted that the Company has not provided a reasonable and independent basis for this updated number.[170]

160. The Administrative Law Judge agrees with the Department that the Company has failed to demonstrate that its updated EROA number is more accurate than its original number. Given that any doubt as to reasonableness is to be resolved in favor of the consumer, the Company's original 7.5 percent EROA should be used.

b. SFAS 87 Discount Rate

161. The Company also updated the SFAS 87 Discount Rate from 5.0 percent to 4.03 percent.[171] The Discount Rate has an inverse relationship to pension cost, meaning that the lower the discount rate, the higher the pension cost.[172] The Company did not provide an explanation for the lowering of the discount rate other than to simply state that the Discount Rate was updated as of December 31, 2012.[173]

162. The Department objected to the Company's proposed SFAS 87 Discount Rate, both as originally proposed and the rebuttal proposal. The Department maintained that the SFAS 87 Discount Rate should match the EROA rate, which is higher. The Department noted that the Discount Rate and the EROA rate used by the Company to calculate the NSPM pension expense are the same (7.5% in Direct Testimony). The Department asserted that the Company should also match the SFAS 87 Discount Rate to the EROA for the XES plan. The Department maintained that this 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 and unnecessarily increase the liability to be addressed. The Department estimated that increasing the SFAS 87 Discount Rate used for the XES Plan from 5 percent to 7.5 percent (the EROA amount) would result in an $870,450 reduction to the pension expense.[174]

163. The Company countered that if the Department's recommendation on the SFAS 87 Discount Rate were adopted for the XES Plan, it would lead to permanent under recovery of costs by the Company because there are significant differences between the accounting method used for the XES plan and the accounting method used

[169] Ex. 39 at 4-5 (Moeller Surrebuttal); Tr. Vol. 2 at 64 (Moeller).
[170] Ex. 173 at 60 (Campbell Surrebuttal).
[171] Ex. 39 at 4-5 (Moeller Surrebuttal).
[172] *See* Ex. 166 at 47 (Campbell Direct).
[173] Ex. 39 at 4-5 (Moeller Surrebuttal); Tr. Vol. 2 at 64.
[174] Ex. 166 at 46-48 (Campbell Direct).

for the NSPM plan. The Company did not explain in any detail why the differences in accounting methods would lead to an under recovery of costs.[175]

164. The Administrative Law Judge concludes that the Department's recommendation to use a 7.5 percent Discount Rate for the XES plan is reasonable. This approach is consistent with the approach used by the Company for the NSPM plan and appropriately matches the discount rate to the EROA. The Company has not adequately explained why a different Discount Rate should be used for the XES Plan for ratemaking purposes. Accordingly, the Administrative Law Judge recommends that the Discount Rate for the XES Plan be set at 7.5 percent, the same level as is recommended for the EROA rate.

c. Wage Rate Increase Assumption

165. The wage increase assumption is a long-term assumption that represents all pay increases over the expected years to retirement. The application of a long-term raise assumption is a requirement of the aggregate accounting method (ACM) and the SFAS 87 accounting methods used for the NSPM plan and XES plan, respectively.[176]

166. The wage increase assumption is made up of two components. The first component is an inflation factor and is meant to approximate the long-term rate of inflation. The second component reflects compensation increases resulting from productivity or merit increases, and promotions.[177]

167. In Direct Testimony, the Company assumed a 4.0 percent wage rate increase in the calculation of the pension expense. In its Rebuttal Testimony, the Company updated this number to 3.75 percent. Both the 4.0 percent and 3.75 percent wage rate increase assumptions are within the range of wage rate increase assumptions used by other companies. Utility and non-utility companies use wage rate assumptions that fall within this range.[178]

168. The Department recommended instead that the Commission require the Company to use a 2.6 percent wage increase assumption. The 2.6 percent assumption is comprised of a 2.10 increase for inflation (based on the 2013 inflation rate) and a 0.5 percent productivity increase (based on the productivity increase from 1999 to 2008). The Department also criticized the Company's wage rate increase assumption as not being independent.[179]

169. A lower wage rate assumption lowers the pension expense.[180]

170. The Administrative Law Judge concludes that the Company's rebuttal assumption of 3.75 percent is the most reasonable wage rate increase assumption.

---

[175] Ex. 166 at 8-9 (Moeller Rebuttal).
[176] Ex. 38, Schedule 9 at page 2 of 3 (Moeller Direct).
[177] *Id.*
[178] Ex. 39 at 4-5, 7-8 (Moeller Rebuttal); Ex. 38 at 27 (Moeller Direct).
[179] Ex. 166 at 48 (Campbell Direct); Ex. 173 at 53 (Campbell Redirect).
[180] Ex. 38 at 27 (Moeller Direct).

The Company has provided evidence from other companies to demonstrate that the use of this updated number is reasonable.[181] The Department's recommendation is not as reasonable because its uses the current inflation rate, not the long-term rate of inflation, and includes a productivity factor but does not account for promotions.

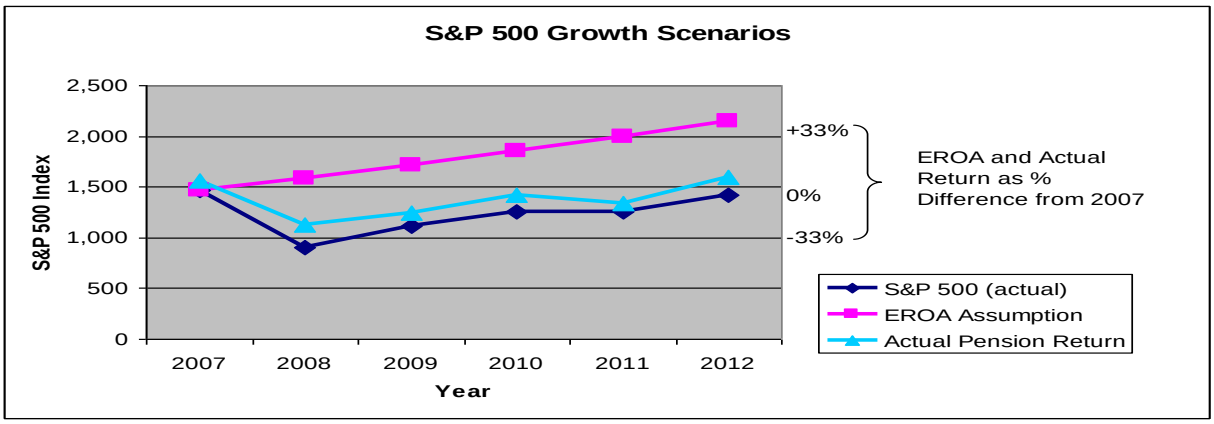
v. 2008 Market Losses

171. In addition to factoring in the EROA, the Discount Rate, and the Wage Rate Increase when calculating the pension expense, the Company also considers unrecognized market gains and losses.[182]

172. The NSPM Plan and XES Plan together lost pension assets of about $248 million (or 32.8 percent) on a jurisdictional basis due to the 2008 stock market decline. The Company has recovered approximately $39 million of the $248 million loss (2008 Market Loss).[183]

173. While recent market gains have helped to offset the 2008 Market Loss, these gains are insufficient to restore the value of the qualified pension asset. The Company lost not only 32.8 percent of its asset but also the expected return. The financial markets would need to grow by 51 percent in order for the asset to be restored to its expected value. The chart below depicts the Company's expected return on assets in the years 2007 through 2012 and the Company's actual returns during the same time period with the corresponding return of the S&P 500.[184]

Table 3

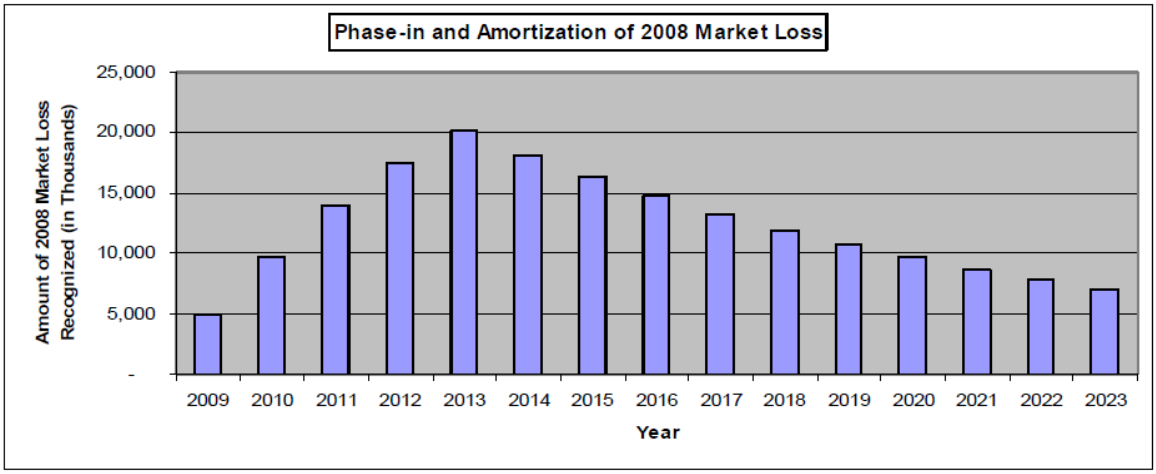


174. To account for the 2008 Market Loss, the Company has phased-in the loss as reflected in the chart below, showing jurisdictional amounts:[185]

---

[181] *See* Ex. 40 at 7-8 (Moeller Rebuttal).
[182] Tr. Vol. 2 at 57-60 (Moeller); Ex. 38 at 19 (Moeller Direct).
[183] Ex. 39 at 10 (Moeller Rebuttal).
[184] *Id.* at 10-11.
[185] *Id.* at 13, 15.

Table 4



175. The phase-in is a smoothing mechanism that is used to average gains and losses for both the NSPM Plan and the XES Plan over a five-year period. As a result, the calculation of the qualified pension expense reflects only 20 percent of the 2008 Market Loss in the first year (2009) and 100 percent by the fifth year (2013). The amount of loss phased in for each year is then amortized, which provides further levelization of the expense.[186]

176. In the first year (2009), the Company had included $50 million of losses and began to amortize that $50 million over a period of about ten years. As a result, in 2009 the Company recognized about $5 million of loss amortization. The loss amortization increased in 2010 when another $50 million of losses was brought into the amortization, which increased the amortization another $5 million. For 2009 through 2013, there was about a $5 million step-up each year in the loss amortization. After 2013, the amortization will gradually decline.[187]

177. This approach applies actuarial methods. The Company has consistently used this approach for both gains and losses for over 40 years.[188]

178. In its last rate case (Docket No. E002/GR-10-971), the Company reflected the 2008 Market Loss using this same method. The Company also forecasted, in its last rate case, that it would have a pension expense of approximately $25 million in 2013 as compared to the 2011 test year expense of approximately $12 million.[189]

---

[186] Ex. 38 at 17 (Moeller Direct).

[187] Tr. Vol. 2 at 51-53 (Moeller); Ex. 39 at 12-13 (Moeller Rebuttal). The Company also claimed that if recovery based on this approach is denied in this case, it would create regulatory uncertainty about the Company's ability to recover the remaining $209 million of unrecognized 2008 Market Loss. As a result, the Company maintained that it might have to report a financial impairment of $209 million. Ex. 39 at 15 (Moeller Rebuttal).

[188] Ex. 39 at 12 (Moeller Rebuttal).

[189] *Id.* at 15.

179. Using this method, the Company's initial 2013 test year includes approximately $19 million for the 2008 Market Loss.[190]

180. The Department opposed the Company's request to include approximately $19 million for the 2008 Market Loss in the test year. The Department argued that the Company's proposal should be rejected because: (1) the market has returned to 2007 levels; (2) the amortization is not levelized; (3) the Company's has not shown why ratepayers should be responsible for the 2008 Market Loss; and (4) the Company's method of recognizing gains and losses is asymmetrical, because in years when the gains exceeded the expenses, the Company did not give a refund to ratepayers.[191]

181. The Administrative Law Judge concludes that the Company's proposed inclusion of approximately $19 million for the 2008 Market Loss in its qualified pension expense for the 2013 test year is reasonable. The Company has demonstrated that its approach for recovery 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 an increase to the pension expense in the 2013 test year, ratepayers have received significant benefits from this approach in prior years. The pension expense (after consideration of the EROA and pension gains) has typically been well below the Service Cost. As noted above, customers received about $320 million of benefits (even after amortizing part of the 2008 Market Loss) in reduced Service Costs between 2000 and 2013.[192]

182. While the market has recovered to pre-2007 levels, the Company has demonstrated that its pension assets have not returned to their expected value.[193]

183. With the smoothing mechanism suggested by the Company in Rebuttal Testimony, the 2013 test year pension expense is approximately $8 million lower than the Service Cost for the 2013 test year.[194]

184. The Company's approach fairly allocates both the gains and the losses to customers. Where there is a market gain, it is used to offset the Service Cost. If the market gain exceeds the pension obligation in a particular year, it is reflected as a negative expense (for the XES plan) or retained in the pension fund (for the NSPM Plan) to offset future pension expense.[195] The Department's argument that the Company's approach is not symmetrical fails to recognize the benefit to customers 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.

---

[190] Ex. 166 at 52 (Campbell Direct).
[191] *Id.* at 52-54; Ex. 173 at 58-61 (Campbell Surrebuttal); Ex. 175 at 5 (Campbell Opening).
[192] Ex. 39 at 17 (Moeller Rebuttal).
[193] *Id.* at 11.
[194] Ex. 80 (Moeller Opening Statement).
[195] Tr. Vol 2. at 67-68 (Moeller); Tr. Vol. 5 at 210 (Campbell).

185. For these reasons, 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 2013 test year expense.

186. To mitigate the rate impact, the Administrative Law Judge also recommends the adoption of both of the normalization methods suggested by the Company. Accordingly, the Administrative Law Judge recommends that the Commission require the Company to: (1) extend the NSPM Plan amortization period for unrecognized pension costs from 10 to 20 years; and (2) cap the XES pension expense at the 2011 level of $6.1 million and defer the difference in excess of this level to future years.[196]

vi. Employee Contributions

187. The Commission directed the Company to address the reasonableness of not requiring pension contributions from employees. While employees do not contribute to the XES or NSPM plan funds, ratepayers are not funding 100 percent of retirement costs for Company employees. This is true because the Company's pensions provide only part of a reasonable level of retirement income. Company employees need both their pensions and significant levels of 401(k) plan income to provide a reasonable level of retirement income. Company employees must contribute to their 401(k) plans in order to obtain that retirement income level.[197]

188. The Company's approach to employee contributions is consistent with other private sector employers.[198]

D. Incentive Compensation[199]

189. The Company included $22.02 million in its 2013 test year for incentive compensation under its annual incentive program (AIP). This test year amount includes a 25 percent cap on amounts over base salary. In its Rebuttal Testimony, the Company proposed calculating its AIP costs using a 4-year average of target AIP costs, and limiting its recovery in rates to 100 percent of its performance target. The Company also proposed lowering the cap on amounts over base salary to 15 percent for ratemaking purposes. This proposal would reduce the AIP test year expense by $1.3 million to $20.7 million.[200] The Company also agreed that if it recovers more in rates than it pays out in incentive compensation for the year, it would refund the surplus to ratepayers.[201]

---

[196] *See* Ex. 38 at 21-25 (Moeller Direct).
[197] The Commission stated: "In its next rate case filing the Company shall provide support for the reasonableness of asking ratepayers to fund 100% of pension costs." *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota,* E-002/GR-10-971, Order of May 14, 2012, ordering point 22; Ex. 38 at 5-6 (Moeller Direct).
[198] Ex. 38 at 11 (Moeller Direct).
[199] Issue 20 at 11.
[200] Ex. 56 at 88-89 (Heuer Direct); Ex. 35 at 26-27 (Figoli Direct); Ex. 58 at 31 (Heuer Rebuttal).
[201] Ex. 37 at 19 (Figoli Rebuttal).

190. The Department, the OAG, MCC, and ECC all objected to the Company's proposed AIP expense.

191. The Company's AIP provides a targeted cash incentive to each of its eligible employees, calculated as a percentage of base salary. The percentage is determined by the employee's position or level within the organization. Levels of payout are based on performance of the individual employee, the business area, and the Company.[202]

192. The Company's AIP is not limited to executives. It covers all exempt employees that are not represented by a bargaining unit.[203]

193. The use of incentive compensation programs like the AIP is common in the utility industry and the greater marketplace. According to an Aon Hewitt survey of 1,494 large U.S. companies, 92 percent of employers had performance-based awards programs in 2011. Similarly, according to a 2012 Towers Watson study, 97 percent of companies in a national sample had an annual incentive plan, with 100 percent of companies in the revenue-based sample maintaining such a plan.[204] Companies use incentive compensation to promote employee performance and reduce labor costs.[205]

194. The Company's AIP program is designed to incent superior employee performance towards core company objectives. These objectives include customer satisfaction, reliability, safety, and the environment. In 2012, the Company met or exceeded its goals in these areas. Achievement of these goals benefits both the Company and its customers.[206]

195. The Company retained Towers Watson, an independent human resources consulting firm, to conduct a study of its total cash compensation as compared to the total cash compensation offered by other utilities. The study reflects pay rates as of March 1, 2012, the most recent information available at the time. The study shows that, without the AIP compensation, the Company's cash compensation would be 20 percent below that paid by utilities with similar revenues and 14 percent below that paid by utilities across the country. With AIP compensation capped at 25 percent (the Company's initial proposal), the Company's compensation levels are 9 percent below that of utilities with similar revenues and 2 percent below that of utilities across the county.[207] Finally, when base salary and target AIP compensation with no cap is considered, the Company's compensation is close to market levels for utilities nationally and 7 percent below utilities with similar revenues.

---

[202] Ex. 35 at 25, DAF-1, Schedule 3 (Figoli Direct).
[203] *Id.*
[204] *Id.* at 23-24.
[205] *Id.*
[206] Ex. 37 at 10-13 (Figoli Rebuttal).
[207] Ex. 35 at 28-29, DAF-1, Schedule 5 (Figoli Direct); Ex. 36 at DAF-1, Schedule 5 (Trade Secret Version of the Towers Watson study).

196. The Company maintained that because incentive pay is not a permanent fixed cost like base pay, the AIP helps to control total employee compensation costs. Total compensation costs are also lower with incentive compensation because some employee benefit programs are tied to base salary and do not include incentive compensation.[208]

197. The Company has not requested recovery of the full costs of its AIP expense for 2013. The cap on incentive compensation used for ratemaking purposes serves to limit the amount included in rates.[209] The actual cost to the Company includes amounts exceeding the cap.

198. The Company asserted that it uses a conservative budgeting process in calculating its AIP expense. This process has resulted in AIP budgets that have been lower than the actual level of AIP paid in the last several years.[210] The Company calculated its 2013 AIP expense in the same manner as it has done in prior rate cases, wherein its AIP expense has been approved.[211]

199. The Company maintained that if it did not offer incentive compensation, it would need to increase its base salaries commensurate to a market-competitive level in order to attract and retain talented employees.[212]

i. The Department's Position

200. The Department initially took the position that the entire AIP expense should be excluded. The Department agreed with the methodology used by the Company to calculate its AIP expense, but recommended exclusion of the AIP expense because the Company failed to provide the underlying financial support for its calculation in response to a Department information request. The Company later provided additional detail and explained that the sought-after information was not provided when originally requested because the Company misunderstood the Department's information request.[213]

201. In Rebuttal Testimony, the Department recommended that the Commission allow recovery of 25 percent of the amount proposed in its rebuttal testimony, or $5.18 million. The Department suggested that AIP compensation should be limited in this manner to address concerns by the public regarding executive compensation and to reflect the fact that the Company did not provide the underlying factual support for its request in a timely manner.[214]

---

[208] Ex. 35 at 24 (Figoli Direct); Ex. 37 at 14 (Figoli Rebuttal).
[209] Ex. 35 at 26-7 (Figoli Direct); Tr. Vol. 5 at 220 (Lusti).
[210] Ex. 37 at 18 (Figoli Rebuttal); Ex. 35 at DAF-1, Schedule 4 (Figoli Direct).
[211] Ex. 37 at 16 (Figoli Rebuttal); Ex. 180 at 27-28 (Lusti Direct).
[212] Ex. 37 at 14 (Figoli Rebuttal).
[213] Ex. 180 at 27-30 (Lusti Direct); Ex. 37 at 17 (Figoli Rebuttal).
[214] Ex. 183 at 18-19 (Lusti Surrebuttal).

ii. The OAG's Position

202. The OAG recommended that the Commission exclude the entire $22.0 million AIP expense. The OAG argued that recovery of the expense should not be permitted by the Company because the Company has not managed its costs properly. The OAG pointed to cost increases in the Monticello LCM/EPU project and the cancelation of the PI EPU as examples. The OAG asserted that the Company should only be allowed to recover expenses for AIP if the Company can show it has provided high quality service at a low cost. The OAG suggested several benchmarks that could be used to measure the Company's performance.[215]

iii. MCC's Position

203. MCC maintained that the Company has not adequately demonstrated that its total compensation expenses are reasonable. Similar to the OAG, MCC suggested that the reasonableness of the Company's compensation should be measured by cost benchmarks. MCC suggested different cost benchmarks for possible use. MCC noted that Xcel's Minnesota operations do not compare favorably to others in the industry or even to other Xcel subsidiaries when measured by certain cost benchmarks. MCC also noted that the Towers Watson study only considered cash compensation. MCC asserted that the Company should provide support for its total compensation package, not just cash compensation. MCC did not suggest a specific adjustment to the Company's AIP expense.[216]

iv. ECC Position

204. ECC recommended that the Commission exclude at least $15.5 million of the AIP expense.[217]

v. Prior Commission Decisions on AIP Costs

205. The Commission has established in past rate cases that reasonable AIP costs are properly included in the Company's revenue requirement. Since 1993, the Commission has approved recovery of AIP costs in every electric rate case brought by the Company.[218]

206. In its 1993 Order After Reconsideration, the Commission determined that recovery of incentive compensation costs in rates was reasonable and appropriate at that time because: (1) incentive compensation was widely used in the industry; (2) it was shown to help the Company reduce overall compensation costs; and (3) the

[215] Ex. 126 at 10-11 (Lindell Surrebuttal); Ex. 127 (Lindell Hearing Statement).
[216] Ex. 113 at 12-13 (Maini Direct); Ex. 115 at 18 (Maini Surrebuttal); Trans. Vol. 5. at 36 (Figoli).
[217] Initial Brief of Energy CENTS Coalition at 2.
[218] *See* Ex. 37 at 11 (Figoli Rebuttal); Tr. Vol. 5 at 218 (Lusti).

Company should be allowed to use its business judgment to structure and adjust compensation levels to be within a reasonable range of the market.[219]

vi. Conclusion

207. The Company has demonstrated that its rebuttal AIP proposal, which includes a 15 percent cap on amounts over base salary and a commitment to return any amounts not paid to ratepayers, is reasonable. First, the Company's request is consistent with previous AIP requests approved by the Commission.[220] Second, the Company has shown that without the AIP compensation, its employee total cash compensation would be well below that offered by other utilities. To provide safe and reliable service, the Company needs to be able to offer competitive compensation packages to its employees. Third, the 15 percent cap helps to address concerns regarding executive compensation by limiting the amount of executive pay that can be recovered from ratepayers. Fourth, the program aids in reducing employee compensation expenses by limiting fixed costs. Fifth, the Company has shown that its AIP is aligned with customer interests by focusing employee performance on reliability, safety and customer satisfaction.

208. The Department's recommendation to limit the Company's AIP expense to 25 percent of the amount requested by the Company is not supported by the record. While customer concerns regarding the level of executive compensation are understandable, the Department has failed to provide any financial analysis to support its recommended reduction in the AIP expense. The only specific evidence in the record regarding employee compensation is the Tower Watson study, which shows that the Company needs to provide the AIP compensation, or an equivalent increase in base pay, in order to attract and retain qualified employees. In addition, in the Company's last rate case, the Department acceded to a 15 percent cap on AIP, recognizing that AIP compensation at such a level provides incentives for Company employees without placing an undue burden on ratepayers.[221]

209. The OAG and MCC both raise an important concern regarding the Company's efforts to effectively manage its overall cost of service.[222] Denial of the AIP expense on this basis, however, would not be reasonable because eliminating the AIP would put future service levels at risk. The Tower Watson study shows that the Company would not be able to hire the workforce that it needs to provide safe and reliable electric service without offering the AIP or an equivalent base pay increase. Rather than denying recovery of the AIP expense altogether on this ground, the Administrative Law Judge recommends that the Commission instead require the

---

[219] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. G002/GR-92-1186, ORDER AFTER RECONSIDERATION (December 30, 1993) at 6-7.
[220] Ex. 58 at 31 (Heuer Rebuttal).
[221] ALJ REPORT in Docket 10-971 at Finding 150.
[222] This concern was raised by a number of members of the public as well. *See* Attachment B (Summary of the Public Comments).

Company to include one or more cost management benchmarks in its AIP starting in 2014 or as soon as is practicable.

E. Sales[223]

210. The determination of sales volumes is an important feature in ratemaking because the costs that are to be recovered are divided by the amount of sales. Thus, the sales volume directly impacts the overall test year revenue requirement; and ultimately, the rates that are charged to ratepayers.[224]

211. A sales forecast that underestimates future sales results in a utility collecting more revenues for each unit sold than is warranted by its costs and results in customers paying more for energy than is reasonable.[225]

212. A sales forecast that overestimates future sales results in a utility collecting fewer revenues for each unit sold than is warranted by its costs and denies the utility an opportunity to recover its costs.[226]

213. The Company asserted that over the course of the last five years it has over-forecasted sales by an average of 1.9 percent.[227]

214. The Company maintained that, based upon average revenues per kilowatt hour, the over-forecast equated to an under-collection of $30 million in revenues per year.[228]

i. Forecast Design

215. The Company used regression analysis, a statistical tool for forecasting future results, to estimate test year sales volumes and number of customers. The Company used different model specifications for the different rate classes. Its overall approach, however, is the same across all sales and customer count models. In general, for the sales models the Company estimated sales based on demographic factors, price, monthly bill days, heating degree days (HDD) or temperature-humidity index (THI) weighted by customers and month, binary factors to account for other impacts, and autoregressive and moving-average terms to correct for model specification issues.[229]

---

[223] Issue 25.
[224] Ex. 145 at 2-3 (Heinen Direct).
[225] *Id.*
[226] Tr. Vol. 5 at 47 (Heinen).
[227] Ex. 21 at 8-9 (Dybalski Direct).
[228] *Id.*
[229] Ex. 145 at 7 (Heinen Direct).

216. The Company's test year normal weather is based upon daily average temperatures for the most recent 20-year historical period. The 2013 test year forecast used historical data from 1992 to 2011 to determine test year "normal weather."[230]

217. The Company also adjusted test year sales for projected Demand Side Management (DSM) savings and expected changes in usage by certain large commercial and industrial customers – which the Company termed "the DSM Adjustment."[231]

218. In general, the Company used the same forecasting methodology in this rate case as it used in its last rate case. In the interval between the two rate cases, the Company updated certain input data, changed the independent factors that are included in some models, and added a price variable in the models for its commercial and industrial rate classes.[232]

219. In its Rebuttal Testimony, the Company updated its forecast with actual customer count, sales and weather data through December 2012. Additionally, the Company added a set of updated economic assumptions from IHS Global Insight's December 2012 economic forecast. The Company also added a second binary variable to account for the incremental loss of sales due to the June 2012 closure of the Verso Paper plant. Finally, the Company offered to provide a refund to customers if weather-normalized actual sales revenues are higher than the Company's revised forecast, but only if the Commission adopts the Company's forecast model.[233]

220. The Department recommended adjustments to the Company's regression analysis based on examination of the Company's method, including the use of the DSM Adjustment, and developed an alternative sales forecast for use in this proceeding. [234]

ii. Disputes as to Forecast Design Characteristics

221. There are four key disputes as to the reasonableness of the Company's sales forecast model: (a) the calculation of customer counts; (b) the price forecast for the test year; (c) use of the DSM Adjustment; and (d) the Large Customer and Industrial forecast. The Department proposed adjustments for each of these items.[235]

222. The Company asserted that its forecast reflects a weakness in growth during 2012 and 2013, and slow growth in households, as has been seen over the past few years. The Company estimated that customer growth in 2013 will fall below the lowest level experienced for any year during the recession.[236]

---

[230] *Id.* at 8.
[231] *Id.* at 6.
[232] *Id.* at 5.
[233] Ex. 26 at 2-3 (Marks Rebuttal); Ex. 23 at 26 (Dybalski Rebuttal).
[234] Ex. 145 at 44-45 (Heinen Direct).
[235] *Id.* at 9-10.
[236] *Id.* at 15.

223. The Department asserted that the Company's treatment of these factors results in a sales forecast that is too low to set reasonable rates for electricity.[237]

a. Customer Counts

224. An accurate forecast of a utility's test year customer count is a key factor in determining test year revenues. The number of customers paying for service during the test year (the customer count) affects sales and revenues, particularly revenues from the fixed customer charge for the test year.[238]

225. The historical graphs of the Company's residential customer counts together with the Company's forecasted counts illustrate a positive change in the trends of customer growth around the beginning of 2005. Moreover, notwithstanding the Company's change in its methods for counting and billing its customers, occurring in mid-2005, the positive trend in customer growth continues from that period – albeit with a different growth shape.[239]

226. The Company asserted that it would be erroneous to rely upon customer counts that pre-date the 2007 recession. The Company maintained that the growth in customer counts during the period between January 2007 and June 2012 was anemic, but still higher than the actual growth in customer counts near the end of this period. According to the Company, if this trend line were continued forward in time, it would result in a customer count forecast that is similar (albeit 300 customers smaller) than the one the Company urges the Commission to adopt for the test year.[240]

227. The Company predicted that it will add approximately 3,000 customers during the test year.[241]

228. The Company's customer count forecast from February 2012 projected significantly higher customer growth in 2013 than it did in its test year projections used for this rate case.[242]

229. Moreover, notwithstanding the fact that local housing data indicates growth in new housing starts within a significant portion of the Company's service area, the Company's proposed Residential—Non-Heating rate class count shows fewer average customer additions than any year since 2007.[243]

230. Because the projections for new housing, electric metering and construction permits all point to higher customer counts than an additional 3,000

---

[237] *Id.* at 9-10.
[238] *Id.* at 10.
[239] *Id.* at 13-14.
[240] Ex. 26 at 12-13 (Marks Rebuttal).
[241] Ex. 21 at 21 (Dybalski Direct).
[242] Ex. 145 at 15 (Heinen Direct); Ex. 146 at AJH-3 (Heinen Direct Attachments—Public); Ex. 21 at 21 (Dybalski Direct).
[243] Ex. 145 at 19-21 (Heinen Direct); Ex. 149 at 18 (Heinen Surrebuttal); Ex. 146 at AJH-11 (Heinen Direct Attachments-Public); Transcript, Vol. V at 59-60.

customers for the test year, the Company has not established the reasonableness of its customer count forecast.[244]

231. As demonstrated by the Department, a better approach is to utilize the average growth factor, updated with actual data from January of 2007 through December of 2012, to calculate test year Residential Non-Heating customer counts. When this analysis is undertaken, the result shows an average of .04 percent growth over the course of this review period and an addition of 5,786 residential customers.[245]

232. This calculation, which draws data from months in which there was genuine economic difficulty and months in which performance was good, provides a balanced and more reliable forecast of the rate of customer additions for the test year. For these reasons, a test year residential customer addition of 5,786 customers is both reasonable and supported by the record.[246]

b. Forecasting Energy Prices

233. An accurate forecast of a utility's energy price is a key factor in determining test year revenues. If the price of electricity increases, there can be corresponding decreases in both consumption and revenue.[247]

234. In this rate case, the Company used data from its resource planning model to forecast future prices. In earlier rate cases, the Company drew energy price data from the producer price index for these forecasts.[248]

235. The Company argues that drawing data from its resource planning and budgeting systems produces a superior forecast because this data reflects the upward cost and price experience that is specific to the Company's service area.[249]

236. Xcel's estimated energy prices are higher than the average change in prices during the years between 1998 and 2011.[250]

237. Moreover, the actual prices of more recent years, 2011 and 2012, reveal significantly smaller rises than the price escalators urged by the Company.[251]

---

[244] *Compare,* DOC Ex. 145 at 16-21 (Heinen Direct) *with* Xcel Ex. 23 at 4 (Dybalski Rebuttal).
[245] DOC Ex. 149 at 20-21 (Heinen Surrebuttal); DOC Ex. 150 at AJH-S-7 (Heinen Surrebuttal Attachments-Public).
[246] DOC Ex. 149 at 20 (Heinen Surrebuttal); DOC Ex. 150 at AJH-S-7 (Heinen Surrebuttal Attachments-Public).
[247] Ex. 145 at 21-22 (Heinen Direct).
[248] Ex. 23 at 18 (Dybalski Rebuttal); Ex. 145 at 23 (Heinen Direct).
[249] Ex. 23 at 18 (Dybalski Rebuttal); Ex. 26 at 10-11 (Marks Rebuttal); *see also,* Ex. 4 at Information Request No. 20 (Sales Forecast Data—Non-Public Part 2).
[250] Ex. 23 at 18 (Dybalski Rebuttal); Ex. 26 at 10-11 (Marks Rebuttal); *see also,* Ex. 4 at Information Request No. 20 (Sales Forecast Data—Non-Public Part 2).
[251] Ex. 147 at 26, lines 5 through 7 (Heinen Direct—Trade Secret); Ex. 149 at 16 (Heinen Surrebuttal); and Ex. 151 at AJH-S-5, (unnumbered Page 5 of 5, "Strategist 2012 Growth and Strategist 2013 Growth") (Heinen Surrebuttal Attachments—Trade Secret).

238. The Company did not update its price factor for the last six months of 2012.[252]

239. The data provided by the Company in response to Information Request No. 528 suggests that its upward slope of prices is overstated.[253]

240. The Company has not established that it is reasonable to use its long-term resource planning forecasts to estimate short-term, test year prices.[254]

241. The Company has not established that it is reasonable to use growth factors for prices that were higher than actual growth in prices.[255]

242. The Company has not established the reasonableness of the price escalators resulting from the Strategist forecasting model.[256]

243. In conclusion, the Company has not established the reasonableness of its price forecast.

244. As shown by the Department, using the monthly average price changes during the period between January 1998 and June 2012, drawn from the Company's Pre-Filed Forecast Data, results in a lower, more accurate and reasonable set of price escalators.[257]

c. Demand-Side Management

245. The Company asserted that its efforts to curb the demand for electricity – including its work to support use of more efficient appliances and electric devices – has resulted in DSM achievements that exceed historical averages.[258]

246. Because the historical data that the Department used to estimate the embedded DSM uses only the "first-year" energy savings – the energy savings expected in the 12-month period immediately following the installation of a new DSM measure – the cumulative impacts of prior years are not included in the calculation of "embedded DSM." The Company argued that this method does not measure the true and continuing impact of these measures.[259]

---

[252] Ex. 149 at 27-28 (Heinen Surrebuttal).
[253] Ex. 151 at AJH-S-4 (Heinen Surrebuttal Attachments—Non Public).
[254] Ex. 145 at 23-25 (Heinen Direct).
[255] Ex. 149 at 16 (Heinen Surrebuttal).
[256] Ex. 145 at 26 (Heinen Direct); Ex. 148 at AJH-14 (Heinen Direct Attachments--Trade Secret); *see also*, Ex. 149 at 28 (Heinen Surrebuttal).
[257] Ex. 145 at 28-29 (Heinen Direct).
[258] Ex. 23 at 13 (Dybalski Rebuttal).
[259] *Id.* at 11-13.

247. To calculate the wider impact of its DSM successes, the Company urged the use of a five-year average of historical DSM achievements to approximate the "steady-state, or assumed constant level, of DSM present within the forecast."[260]

248. Applying the Company's DSM adjustment would decrease the Department's sales forecast by 225,186 MWh.[261]

249. Because the Company's historical sales data already include energy savings that have occurred following the enactment of Next Generation Energy Act (NGEA) in 2007, the Company's proposed addition of a DSM adjustment risks double-counting some of the same savings in the sales forecast.[262]

250. Incremental DSM savings in the 2013 test year and beyond are expected to level off significantly from levels that have been achieved in recent years.[263]

251. In addition, when compared with the actual 2012 sales experience, the Company's sales forecast (with DSM) was lower than actual weather normalized sales in five of the six most recent months.[264]

252. As shown by the Department, the best method of accounting for DSM-related savings beyond the first year of a device's implementation, while avoiding an over-estimation of the impact of these savings, is to use a four-year average to calculate embedded DSM. This approach would increase the sales forecast by 51,161 MWh or $3.0 million in revenue, above the forecast resulting from the five-year average advocated by the Company.[265]

d. Sales to Large Commercial and Industrial (LC&I) Customers

253. Following the closing of the Ford Motor Company facility in Saint Paul, Minnesota, and the explosion at the Verso Paper plant in Sartell, Minnesota, the Company adjusted its sales forecasts to reflect the loss of these large customers.[266]

254. The Company's approach was to include a binary factor (MNLCI_Closings) in its LC&I sales model to represent facility closings and production cut-backs for several large customers that occurred during December 2011.[267]

---

[260] Ex. 26 at 8 (Marks Rebuttal); Ex.25 at 7 n.3 (Faruqui Rebuttal); Tr. Vol. 5 at 52-53 (Heinen).
[261] Ex. 23 at 10, 12 and 15-16 (Dybalski Rebuttal).
[262] Ex. 145 at 32 (Heinen Direct).
[263] Ex. 145 at 31-32 (Heinen Direct).
[264] Ex. 149 at 6-7 (Heinen Surrebuttal); Ex. 23 at 8 (Dybalski Rebuttal). Because a full year of historical DSM achievements was not yet available for 2012, the Company doubled the 5-year average for 2012 to estimate embedded 2013 (test year) DSM.
[265] Ex. 145 at 33-34 (Heinen Direct) (22,035 MWh Residential + 29,126 MWh C&I).
[266] *See, Id.* at 38-43.
[267] *See,* Ex. 1 at Information Request No. 5 (Sales Forecast Data—Public Part 1); Ex. 146 at AJH-22 (Heinen Direct Attachments).

255. The more appropriate approach, as recommended by the Department, is to estimate sales in the first instance, and then make exogenous adjustments, based upon historical data relating to these former customers, to reach a final sales figure.[268]

256. The Company has actual historical data for these large customers to use for these types of exogenous adjustments. This approach allows for greater precision in the adjustment because it avoids other impacts that may follow from use of the binary factors.[269]

iii. Conclusions

257. The Department's recommendations result in a sales forecast that is reasonable, well-designed and appropriate for ratemaking in this case.

258. The Department's recommendations increase the test year retail revenue by $26,163,000.[270]

iv. Improving the Practice for the Next Rate Case

259. The Administrative Law Judge likewise recommends that the Commission establish requirements for the now-anticipated rate case to be filed by the Company in 2014.

260. As suggested by the Department, the Commission should require the Company to provide:

A. forecasting data at least 30 days prior to the initial rate case filing;

B. a comparison to the forecast information in this docket and the Baseload Diversification Study that will be filed on or around July 1, 2013;

C. large industrial customer account data in a format that allows interested parties to readily access historical data for all customers;

D. a spreadsheet, with all links intact, identifying any data inconsistencies with the Company's raw weather data and any modifications made to the raw weather data;

E. a detailed step-by-step explanation as to how test year revenue was calculated and what commands should be changed if a party wishes to adjust test year sales, adjust customer counts or calculate revenue;

---

[268] Ex. 145 at 40 (Heinen Direct); Ex. 149 at 23-24 and 26 (Heinen Surrebuttal).
[269] *Id.*
[270] Ex. 184 at DVL-HE-7, column (aj) (Lusti Hearing Exhibit).

F. detail the changes the Company has made to simplify its test year revenue calculation so that persons outside of the Company may verify the accuracy of the calculation; and,

G. a report on the meetings Company representatives have had, prior to filing, with interested parties to explain its revenue calculation process and to cooperatively discuss methods for streamlining the revenue calculation.[271]

F. Return on Equity and Capital Structure[272]

261. 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.[273]

262. 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 multiplied by the rate base, will give the utility enough, but no more than, a reasonable return on its total investment.[274]

263. 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, preferred stock, short-term debt and long-term debt. These amounts are represented as dollar amounts and as percentages of the total capital.[275]

264. In this case, there is no dispute as to the Company's proposed capital structure, the cost of short-term debt or the cost of long-term debt.[276] The parties disagree, however, about the cost of equity or return on equity (ROE).

i. Return on Equity

265. Minnesota law requires the Commission to set electric rates at a level that allows the public utility to earn a fair and reasonable ROE.[277] 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)

---

[271] Ex. 145 at 58-60 (Heinen Direct).
[272] Issues 26 and 50 (Issue 50 is not disputed but is discussed in the body of the report because the Commission specifically required supplemental testimony on the capital structure).
[273] Ex. 134 at 2 (Amit Direct).
[274] *Id.*; Minn. Stat. § 216B.16, subd. 6; *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923); *Federal Power Commission, et al. vs. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[275] Ex. 134 at 55 (Amit Direct).
[276] *See* Ex. 138 at 10-11 (Amit Surrebuttal). The Department was the only party that provided testimony on the issues of capital structure, the cost of long term debt, and the cost of short term debt.
[277] Minn. Stat. § 216B.16, subd. 6.

commensurate with returns being earned on other investments having equivalent risks.[278]

266. 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.[279] 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.[280]

267. 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 they may be subject to limiting assumptions or other methodological constraints, multiple analytical approaches are often used.[281]

268. The Discounted Cash Flow (DCF) model is a market-oriented method that is widely used in regulatory proceedings to determine the cost of equity for regulated utilities. The DCF model is 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.[282]

269. Under the constant growth DCF method, if annual dividends grow at a constant rate over an infinite period, the required rate of return on common equity capital is estimated using the following formula: the expected dividend yield + the expected growth rate in dividends = the expected (required) rate of return on equity.[283]

270. Another DCF method is the Two Growth Rates DCF (TGDCF). That approach is used when the short-term projected dividend growth rate for a company is unlikely to be sustained in the long run. The TGDCF 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.[284]

271. 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"

---

[278] Ex. 134 at 3 (Amit Direct); Ex. 45 at 5-6 (Hevert Direct); *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Company* 320 U.S. 591 (1944).
[279] Ex. 134 at 3 (Amit Direct).
[280] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER *In re Petition of Otter Tail Power Company,* Docket No. E017/GR-07-1178 at 55 (Aug. 1, 2008).
[281] Ex. 45 at 36 (Hevert Direct).
[282] Ex. 134 at 4 (Amit Direct); Ex. 45 at 37 (Hevert Direct).
[283] Ex. 134 at 4-5 (Amit Direct); Ex. 45 at 39 (Hevert Direct).
[284] Ex. 134 at 5-6, 38-39 (Amit Direct); Ex. 135 at EA-29 (Amit Direct Att.).

risk of that security.[285] 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.[286]

272. As described in detail below, the parties disagreed concerning the appropriate ROE in this matter. The Company recommended a 10.60 percent ROE throughout this proceeding. The Department initially proposed a ROE of 10.24 percent and an overall ROR of 7.71 percent, but subsequently updated its DCF/TGDCF analysis to reflect more current data and thereafter recommended a 9.83 percent ROE and a 7.45 percent overall ROR. ECC, the Commercial Group, and the ICI Group supported the Department's final recommendation or an even lower ROE.

a. The Company's Initial ROE Analysis

273. The Company determined that the Company's cost of equity currently is in the range of 10.25 percent to 10.90 percent. Based on quantitative and qualitative analyses, the Company concluded that a ROE of 10.60 percent is reasonable and appropriate. The Company's analysis was based primarily on the DCF model (including the use of the TGDCF 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 the DCF analysis, as well as the effect of flotation costs, including the costs of both public and non-public equity issuances.[287]

274. According to the Company, current market conditions continue to reflect a high degree of risk aversion on the part of investors. The Company indicated that, as Treasury yields have decreased, both the equity risk premium for the electric utility industry and the spread between higher and lower rated utility debt have increased. As a result, while the estimated cost of equity has declined by certain measures, the Company concluded that decline has been far less than the decline in yields on Treasury bonds or utility debt.[288]

275. The key factors considered in the Company's ROE analysis were: (1) the standards for determining a fair and reasonable ROE; (2) the effect of the current capital market conditions on investors' return requirements, including the increased return requirements for investors to accept the added risks of equity investments; and (3) the overriding importance of the Company's electric operations and the decisions to be made by the Commission. The Company emphasized that over 90 percent of the Company's total operations involve electric service. In addition, the Company

[285] Ex. 45 at 45-46 (Hevert Direct).
[286] Ex. 134 at 17, 47 (Amit Direct).
[287] *Id.* at 2-4, 21, 35-36.
[288] *Id.* at 3.

maintained that its access to both debt and equity capital is even more important in light of the Company's extensive multi-year capital improvement program.[289]

276. The Company asserted that the historical relationships between Treasury yields, utility interest rates, and the cost of equity for utilities have changed significantly since the time of the Company's last rate case. The Company noted that Treasury yields have decreased to historically low levels, and indicated that utility interest rates have also decreased but not to the extent of Treasury yields. This has increased the spreads between utility interest rates and Treasury yields. During this period, the cost of equity for utilities has remained far more stable, reflecting an increase in the premium investors require to make an equity investment in utilities (the equity risk premium).[290] In the Company's view, the increase in the equity risk premium is the result of: (1) the Federal Reserve's policy under its "maturity extension program" of buying longer-dated Treasury securities and selling short-term securities, which has had the effect of decreasing long-term Treasury yields and corporate borrowing rates; and (2) the continuing aversion of investors to the added risk of equity investments.[291]

277. Based on an analysis of data for 1,357 electric utility rate proceedings between January 1980 and July 2012, the Company concluded that the equity risk premium is inversely related to the level of interest rates. Specifically, the Company found that 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.[292]

278. The Company also analyzed the relationship between authorized ROEs and 30-year Treasury yields during the time period of June of 2011 to June of 2012. The Company found that authorized returns remained relatively stable during that time period even though interest rates sharply declined.[293]

279. The Company prepared a chart showing the relationship between the equity risk premium for utilities and the Treasury yields during the period of January of 2010 through July of 2012. The Company determined that, during that time period, the equity risk premiums for utilities have increased approximately 1.4 percent (from approximately 6.0 percent in January, 2010, to approximately 7.4 percent in July, 2012).[294]

280. According to the Company, three additional measures also provide support for its position that the cost of equity has not fallen in lock step with the decrease in Treasury yields: (1) credit spreads, including incremental credit spreads between various debt ratings; (2) the relationship between utility dividend yields and

---

[289] *Id.* at 3-4, 7.
[290] *Id.* at 7-8.
[291] *Id.* at 9-12.
[292] *Id.* 13-14, Chart 1.
[293] *Id.* at 14-15, Chart 2.
[294] *Id.* at 15-16, Chart 3.

30-year Treasury yields; and (3) measures of both market volatility and the correlation in returns between utility stocks and the broad market.[295]

281. Because the Company is an operating subsidiary of Xcel Energy and is not a publicly-traded entity, the Company selected a group of 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. Use of a proxy group serves to moderate the effects of anomalous, temporary events that may be associated with any one company. The use of proxy group companies also eliminates any possible effects of NRG Energy, Inc. on the Company's ROE.[296]

282. 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).[297] Based on the Company's very high concentration of electric operations, the Company primarily relied on the results of the XECG in making its recommendation for the ROE to be used in this proceeding. The Company acknowledged that the Commission has considered the returns of combined electric and gas utility companies in recent cases, and has applied a 60 percent weighting to electric proxy groups and a 40 percent weighting to combination proxy groups. However, the Company applied an 80/20 percent weighting to the XECG and the XCCG, respectively, because the Company did not believe that the weighting of the combination proxy group should exceed 20 percent.[298]

283. The XECG was composed of companies with mostly electric utility operations. The Company began with the 38 U.S. utilities that 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. Selected proxy companies that are vertically integrated utilities (i.e., utilities that own and operate regulated generating assets);

e. 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;

[295] *Id.* at 16-27, Charts 4-8.
[296] *Id.* at 28.
[297] The Department's expert witness, Dr. Eilon Amit referred to the "XECG" and the "XCCG" as the "HEGC" and the "HCCG." *See* Ex. 134 at 65 (Amit Direct).
[298] *Id.* at 30.

f. 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

g. Eliminated companies that were known to be involved in a merger or other significant transaction.[299]

284. The Company then examined the operating profile of each of the fourteen 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 three companies: Edison International, which experienced significant unregulated operating losses in 2009 and 2011; Integrys Energy Group, Inc., which experienced a 2009 operating loss of $114.6 million in its Natural Gas Utility Segment; and PNM Resources Inc., whose long-term issuer rating was below investment grade prior to April 13, 2012.[300] The final XECG included the following eleven companies: American Electric Power Company, Inc.; Cleco Corporation; Empire District Electric Company; Great Plains Energy, Inc.; Hawaiian Electric Industries, Inc.; IDACORP, Inc.; Otter Tail Corporation; Pinnacle West Capital Corp.; Portland General Electric Company; Southern Company; and Westar Energy, Inc.[301]

285. The XCCG consisted of utility companies that have combined electric and gas operations. To select the XCCG, the Company began with the 49 U.S. utilities that Value Line classifies as Electric 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;

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

[299] *Id.* at 30-31.
[300] *Id.* at 31-32.
[301] *Id.* at 32-33.

g. Eliminated companies that were currently known to be party to a merger or other significant transaction.[302]

286. The Company did not include Xcel Energy in its analysis in order to avoid the circular logic that would otherwise occur.[303]

287. The XCCG included the following 13 companies: Alliant Energy Corporation; Avista Corporation; Black Hills Corporation; CMS Energy Corporation; Consolidated Edison, Inc.; Dominion Resources, Inc.; DTE Energy Company; PG&E Corporation; SCANA Corporation; Sempra Energy; TECO Energy, Inc.; Vectren Corporation; and Wisconsin Energy Corporation.[304]

288. The Company applied the DCF model to the proxy group of integrated electric utility companies using the average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days ended July 31, 2012, and the proxy companies' current annualized dividend per share as of July 31, 2012. The Company then calculated the DCF results using 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. The Company also applied the TGDCF model when the mean growth rate of a particular company was atypically high or low compared to the proxy group.[305]

289. In conducting its analysis, the Company used three averaging 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 averaging periods it used take this concern into account while still being reasonably representative of expected capital market conditions over the long term.[306]

290. 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 twelve-month period, and does not overstate the dividends to be paid during that time.[307]

291. When using the TGDCF approach, the Company applied the Zacks, First Call, and Value Line earnings growth rates to the first five years of its analysis and, for

---

[302] *Id.* at 33-34.
[303] *Id.* at 34.
[304] *Id.* at 34.
[305] *Id.* at 38, 40-41, Schedule 2.
[306] *Id.* at 38-39.
[307] *Id.* at 39.

the second stage, used the proxy group average growth rate, excluding the growth rates determined to be outliers.[308]

292. 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.[309]

293. In accordance with Commission decisions,[310] the Company made the flotation cost adjustment by dividing the expected dividend yield by: 1 minus percentage flotation costs. The Company included the costs of both public and non-public issuances in its calculation. Based on the weighted average issuance costs, the Company concluded that a reasonable estimate of flotation costs is approximately 0.14 percent (14 basis points).[311]

---

[308] *Id.* at 40-41, Schedule 2 at 7-8.
[309] *Id.* at 41-43.
[310] *In the Matter of Great Plains Natural Gas Co. for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G004/GR-04-1487, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (May 1, 2006) at 12.
[311] Ex. 45 at 44-45, Schedule 3 (Hevert Direct).

294. The results of the Company's DCF analysis are summarized below:[312]

Table 5

	Low Growth Rate	Mean Growth Rate	High Growth Rate
Electric Proxy Group Results (XECG)			
30-Day Average	9.43%	10.34%	11.45%
90-Day Average	9.61%	10.52%	11.65%
180-Day Average	9.68%	10.59%	11.72%
Weighted Average Results (80% Electric / 20% Combination)			
30-Day Average	9.34%	10.19%	11.22%
90-Day Average	9.51%	10.36%	11.41%
180-Day Average	9.58%	10.43%	11.49%

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

296. 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 described in several of the attachments to the Direct Testimony of its expert, Mr. Hevert.[313] The results of the CAPM analysis were highly 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.[314]

297. The Company also performed a Bond Yield Plus Risk Premium analysis to test the reasonableness of its 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. That is, since returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that risk. Risk premium approaches

[312] *Id.* at 45, Schedule 2 at 1-6, Table 4.
[313] *Id.* at 47, Schedules 4-7.
[314] *Id.* at 48.

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.[315]

298. 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. As discussed above, the Company examined data from 1,357 electric utility rate proceedings between January of 1980 and July of 2012 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 4.33 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 10.28 to 10.87 percent.[316]

299. The Company also considered two other factors in determining the Company's cost of equity and its recommended ROE. First, the Company considered investors' ongoing aversion to the risk of equity ownership in the context of the Company's need to fund substantial capital expenditures. The Company emphasized that it expects that it will engage in a significant capital expenditure program during the period of 2012 – 2016. The Company asserted that these capital investments will require ongoing access to both debt and equity markets, and investors will pay attention to the levels of regulatory support for investments. 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.[317]

300. Second, the Company considered its method of fuel cost recovery. Because the Company recovers the commodity cost of fuel used to generate electricity through its Fuel Clause Adjustment, the Company indicated that its earnings are not directly affected by changes in fuel costs. As a result, the Company determined that fuel costs do not affect the Company's cost of equity. The Company further asserted that its Fuel Clause Adjustment is similar to the fuel cost recovery mechanism employed by the proxy group companies and, therefore, the effect of changes in fuel costs are already incorporated in the results of its DCF analysis.[318]

301. Finally, the Company calculated the average capital structure of the operating utility subsidiaries for the XECG and XCCG groups over the last eight

[315] *Id.* at 48-49.
[316] *Id.* at 48-49, Schedule 8.
[317] *Id.* at 49-51.
[318] *Id.* at 51-52.

quarters. The Company found that the mean equity ratio of the operating utility subsidiaries of the XECG proxy group was 51.35 percent, and the range was 47.59 percent to 57.67 percent.[319] The mean equity ratio of the operating utility subsidiaries of the XCCG group was 51.85 percent, and the range was 47.60 percent to 57.73 percent.[320] Based on that review, the Company concluded that its proposed capital structure is generally consistent with both proxy groups and is appropriate.[321]

302. The Company concluded that a ROE in the range of 10.25 percent to 10.90 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 10.60 percent. Although its recommended ROE is above the midpoint of the range of results, the Company asserted that it is appropriate to establish a ROE that is above the mean DCF results of the weighted results of the XECG and the XCCG. The Company contended that the results of the XECG analysis are "far more important" because this proceeding will set the rates for the Company's electric service operations only. In addition, the Company maintained that it is important that there be a supportive regulatory environment to enable the Company to maintain access to the capital markets to finance its capital expenditures at a reasonable cost. In its view, a ROE of 10.60 percent reasonably represents the return required to invest in a company with a risk profile comparable to the Company.[322]

b. The Department's Initial ROE Analysis

303. The Department initially proposed a ROE of 10.24 percent and an overall ROR of 7.71 percent. The Department used both the constant growth DCF model and the TGDCF model in estimating the required ROE for the Company. The Department also used the CAPM to support those analyses.[323]

304. As part of its initial analysis, the Department assessed what impact lower yields of Treasury bills would likely have on investors' expectations of the cost of equity capital. The Department determined that the yields on mid- and long-term Treasury bills in 2012 were significantly lower than in 2011, and also were significantly lower than their respective average yields over the period of 1993-2012. In addition, the yield spreads between long-term Treasury bills and one-year Treasury bills were significantly higher in 2012 than their respective averages for the period of 1993 to 2012.[324] The primary reasons for the much lower yields in 2012 than in 1993 to 2012 were the increased economic and financial uncertainties that caused investors to purchase fixed income

---

[319] *Id.* at Schedule 9, p. 1.
[320] *Id.* at Schedule 9, p. 4.
[321] *Id.* at 52-53.
[322] *Id.* at 53-54.
[323] Ex. 134 at 2, 6, 7 (Amit Direct). As discussed in further detail below**,** Dr. Amit later updated his DCF/TGDCF analysis to reflect more current data and, based on the updated analysis, finally recommended a 9.83 percent ROE and a 7.45 percent overall ROR. Ex. 138 at 2, 11, 13-14 (Amit Surrebuttal); Ex. 139 (Amit Summary Statement) at 2.
[324] Ex. 134 at 7-9 (Amit Direct).

assets such as long-term Treasury bills rather than more risky common equity assets; and the increased demand for long-term Treasury bills that occurred after the Federal Reserve's announcement that it intended to sell or redeem approximately $667 billion of short-term Treasury bills by the end of 2012 and use the proceeds to purchase long-term Treasury bills.[325]

305. The Department concluded that the lower yields on long-term Treasury bills are not accompanied by a similar decline in the required rate of return on common equity because (1) the lower yields are highly correlated with higher risk premiums; and (2) the lower yields result in part from funds flowing away from common equity into fixed income assets due to higher investment risks. The Department estimated based on its empirical analysis, that a decline by 100 basis points in the yields on 30-year Treasury bills would result in a decline of only approximately 15 basis points in the required rate of return on common equity. Thus, while the Department found that "the significantly lower yields on long-term Treasury bills result in lower required rates of return on equity," it concluded that "the decline in the required rate of return on common equity is of much smaller magnitude than the decline in the yields on long-term Treasury bonds due to the higher risk premium."[326]

306. Because the Company is a division company of Xcel Energy and is not publicly traded on any of the stock exchanges, no DCF analysis can be directly performed on the Company.[327] Instead, the Department performed a DCF analysis on a group of companies that have investment risk comparable to that of the Company.[328] The Department used two sets of comparable groups: the Final Electric Comparison Group (FECG), which consisted of all-electric utilities; and the Combination Comparison Group (CCG), which consisted of combination gas-and-electric utilities.[329] The Department did not include Xcel Energy Inc., NSPM's parent company, for reasons similar to those given by the Company.[330]

307. The Department applied a set of risk screens to eliminate companies that do not have comparable risk. The Department included companies with similar Standard Industrial Classification (SIC) codes (4911 for electric utilities and 4931 for combination utilities). The Department excluded foreign companies as well as companies whose main line of business is not regulated retail services. The Department applied a financial risk measure to the companies that survived the above screens by looking at the bond rating each company had been assigned by S&P. The Department used the beta and the Standard Deviation of Price Changes (SDPC) methods as additional measures of investment risk, and the common equity ratios and long-term debt ratios as additional measures of the financial risk of the companies.[331]

---

[325] *Id.* at 9-10.
[326] *Id.* at 14-15.
[327] *Id.* at 6-7.
[328] *Id.* at 7, 15.
[329] *Id.* at 17-28.
[330] *Id.* at 17-28.
[331] *Id.* at 16-17; Ex. 135 at EA-2 (Amit Direct Att.).

308. The initial universe for the FECG included all electric utilities that were listed in the October 31, 2012, 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-). Thirty-two companies met these criteria.[332]

309. The Department thereafter eliminated seven foreign companies from the group because foreign companies operate under significantly different economic and regulatory environments and may have investment risks that differ significantly from those of the Company.[333] The Department then applied additional screens to the remaining group of 25 electric companies before performing its DCF analysis to ensure that the companies in the final group have risks that are similar to those of the Company. These screens: (1) eliminated companies whose main operations do not consist of regulated retail electric services; (2) eliminated companies that do not pay dividends or that just started to pay dividends and have no reliable dividend history; (3) eliminated companies whose 2011 regulated revenues and regulated operating incomes were less than 60 percent of total revenues and total net income, respectively; and (4) eliminated companies for which both beta and SDPC deviated by more than one standard deviation from the group's mean. Seventeen companies remained after these screens were applied.[334] The Department 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 16 companies.[335]

310. The Department performed a DCF analysis for each of the sixteen companies and used a risk premium analysis as a criterion for checking the reasonableness of its DCF results. 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 four companies in the group had expected ROEs of less than 8 percent and thus did not pass the financial reasonableness test.[336]

311. The Department's FECG is composed of the 12 companies that remained after the DCF analysis: Dominion Resources, Inc., DTE Energy Co., Empire District Electric Co., FirstEnergy Corp., Great Plains Energy, Inc., Hawaiian Electric Industries, NextEra Energy, Inc., Northeast Utilities, Pepco Holdings, Inc., Pinnacle West Capital Corp., Portland General Electric Co., and UIL Holdings Corp.[337]

312. The Department chose a group of combination electric, gas, and other service utilities as a second comparison group for its DCF analysis. The initial universe

---

[332] Ex. 134 at 17-18 (Amit Direct); Ex. 135 at EA-2 (Amit Direct Att.).
[333] Ex. 134 at 18 (Amit Direct); Ex. 135 at EA-3 (Amit Direct Att.).
[334] Ex. 134 at 18-19 (Amit Direct); Ex. 135 at EA-4 – EA-7 (Amit Direct Att.).
[335] Ex. 134 at 20 (Amit Direct); Ex. 135 at EA-8 (Amit Direct Att.).
[336] *Id.* at 20-23; Ex. 135 at EA-10 (Amit Direct Att.).
[337] *Id.* at 23; Ex. 135 at EA-8, page 2 (Amit Direct Att.).

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.[338] The Department thereafter applied additional screens to eliminate foreign companies, companies with less than 60 percent regulated revenues and regulated net income, companies with no dividends, companies for which both beta and standard deviation of stock price changes deviated by more than one standard deviation from the group's mean, and companies that were in the process of merging with another company. The Department also eliminated one company because its mean expected growth rate was negative. The remaining ten companies comprised the CCG: ALLETE, Inc., Alliant Energy Corp., Avista Corp., CenterPoint Energy, Inc., CMS Energy Corp., NiSource, Inc., Northwestern Corp., OGE Energy Corp., SCANA Corp., and Westar Energy, Inc.[339]

313. The Department assessed the investment risk of the FECG, CCG, Xcel Energy, Inc., and the Company by applying direct market-oriented risk measures (beta and SDPC and financial risk measures (common equity ratio, long-term debt ratio, and S&P bond rating). The Department concluded that the FECG and CCG groups had very similar investment risks. Based on beta and bond ratings, it determined that Xcel Energy Inc. had a somewhat smaller investment 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 CCG.[340]

314. Application of the DCF analysis requires an estimate of both the expected growth rate and the expected dividend yield. Because the Department determined that historical growth rates may be poor indicators of future growth rates, the Department based its estimated growth rates only on projected growth rates.[341] The Department used the projected five-year growth rates provided by Zacks Investment Research and the Value Line Investment Survey. The Department also used the First Call Consensus long-term earnings growth rate estimate provided by Thomson Financial Network.[342] In its initial analysis, the Department used the four-week period closing prices for the period of November 6, 2012, to December 4, 2012, to estimate the expected dividend yield. These were the most current available prices at the time the Department submitted its Direct Testimony.[343]

---

[338] Ex. 134 at 24-25 (Amit Direct); Ex. 135 at EA-15 (Amit Direct Att.).
[339] Ex. 134 at 24-26; Ex. 136 at EA-16 – EA-18 (Amit Direct Att.).
[340] Ex. 134 at 26-28 (Amit Direct).
[341] *Id.* at 28-29, 33, 43.
[342] *Id.* at 29.
[343] *Id.* at 30.

315. At the time of its initial analysis, the Department's best point estimate of the growth rate for the FECG group was 5.72 percent and the range of the growth rates was from a low of 4.76 percent to a high of 6.81 percent.[344] Its best point estimate of the growth rate for the CCG group was 5.74 percent, and the range of the growth rates for that group was from a low of 4.87 percent to a high of 6.76 percent.[345]

316. 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 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.[346] However, the Department also examined the reasonableness of analysts' projected earnings.[347]

317. The Department used the average daily closing prices for the period of November 6, 2012 to December 4, 2012, to calculate the dividend yields for its DCF analysis for the FECG and CCG.[348] 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.[349] The Department determined that the average expected dividend yield for the FECG group is 4.66 percent, and the dividend yield ranges from a low of 4.64 percent to a high of 4.68 percent.[350] The average expected dividend yield for the CCG group was 4.34 percent, and the dividend yield for CCG group ranged from a low of 4.32 percent to a high of 4.36 percent.[351]

318. 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 9.40 percent to a high of 11.49 percent, and found that the best point estimate for the required ROE for that group was 10.38 percent.[352] The Department further found that the required ROE for the CCG ranged from a low of 9.19 percent to a high of 11.12

---

[344] *Id.* at 31-32, 43; Ex. 134 at EA-11 (Amit Direct). The low expected growth rate shown in Attachments EA-11 and EA-19 for each company is the lowest growth rate among Zacks, Thomson, 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. 134 at 32, 43 (Amit Direct).
[345] *Id.* at 43; Ex. 135 at EA-19 (Amit Direct Att.).
[346] *Id.* at 32-33, 43.
[347] *Id.* at 33.
[348] *Id.* at 34-35, 44; Ex. 135 at EA 11 and EA-20 (Amit Direct Att.).
[349] Ex. 134 at 34.
[350] *Id*. at 20-21;(Amit Direct) EA-14.
[351] Ex. 134 at 44 (Amit Direct); Ex. 135 at EA-20 (Amit Direct Att.).
[352] Ex. 134 at 35 (Amit Direct).

percent, with the best point estimate for the required ROE for the CCG at 10.08 percent.[353]

319. The Department did not use the above DCF results for the FECG and the CCG to recommend a ROE for the Company, however, because the Department determined that some of the analysts' projected growth rates were not reasonable to be used as proxies for the DCF's long-term, sustainable growth rates.[354] Where analysts' projected growth rates were unsustainable, the Department used the group's projected five-year average EPS growth rates as a proxy for the sustainable long-term growth rates.[355]

320. The Department applied the TGDCF analysis to five companies in the FECG with an expected growth rate outside the range of 4.11 percent to 7.33 percent, based upon its determination that an expected growth rate outside that range may not be sustainable. Those companies were Empire District Electric Co., FirstEnergy Corp., Great Plains Energy, Hawaiian Electric, and Portland General Electric. Based on a TGDCF analysis, the Department calculated the following ROEs for the FECG group: a low ROE of 9.72 percent; a mean ROE of 10.15 percent; and a high ROE of 10.67 percent.[356] The Department also performed a TGDCF analysis on two companies in the CCG (Avista Corp. and NiSource Inc.) that had mean expected growth rates outside the range of 4.51 percent to 6.97 percent.[357]

321. Finally, the Department adjusted the dividend yields for flotation costs and agreed that this adjustment is appropriate even if no new issuances of common stock are planned in the near future. To arrive at the adjustment, the Department divided the expected dividend yield by 1 minus F, where F is the percentage of issuance costs. For the value of F, the Department used 3.096 percent, in accordance with the Company's calculation of the value of flotation costs.[358]

322. The following table summarizes the initial results of the Department's DCF (including the TGDCF) analyses:[359]

[353] Ex. 134 at 44-45 (Amit Direct); Ex. 135 at EA-20 (Amit Direct Att.).
[354] Ex. 134 at 35-36 (Amit Direct).
[355] Ex. 134 at 36-37 (Amit Direct); Ex. 135 at EA-12 (Amit Direct Att.).
[356] Ex. 134 at 39-40 and Tables 6 and 7(Amit Direct); Ex. 135 at EA-13 and EA-14 (Amit Direct Att.).
[357] Ex. 134 at 45 and Table 8 (Amit Direct); Ex. 135 at EA-23 (Amit Direct Att.).
[358] Ex. 134 at 41-42, 46 (Amit Direct); Ex. 135 at EA-31 and EA-22 (Amit Direct Att.).
[359] Ex. 134 at 46, Table 9 (Amit Direct).

Table 6

	Low	Average	High
FECG	9.86%	10.30%	10.82%
CCG	9.44%	10.16%	19.92%

323. The Department conducted a CAPM analysis as a check on the reasonableness of its DCF analyses.[360] 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.[361]

324. In performing the CAPM check, the Department used the yield on 20-year Treasury bonds as a proxy for the risk-free asset, but acknowledged that it is not, in fact, a risk-free asset. In particular, it noted that the yield on twenty-year Treasury bonds incorporates a risk-premium associated with interest risk (i.e., the risk of capital losses to which investors are exposed as a result of changing interest rates) and using it in a CAPM analysis may result in an upward bias of the ROE.[362] The Department calculated the yield on 20-year Treasury bonds by starting with the 3.15 percent yield on 30-year Treasury bonds for 2013 as set forth in the Blue Chip Financial Forecast dated November 1, 2012, and subtracting from that 35 basis points (the difference between the yields on 30- and 20-year bonds in 2012), to arrive at a yield of 2.80 percent. The Department used the S&P 500 Index as a proxy for the market portfolio, calculated a dividend yield of 2.15 percent, and determined that the required rate of return on the S&P 500 was 11.31 percent.[363] The Department used a beta of 0.717 for the FECG group and a beta of 0.735 for the CCG group.[364]

325. The Department's CAPM result for the FECG group, adjusted for flotation costs, was 9.05 percent. Its CAPM result for the CCG group after adjustment for flotation costs was 9.19 percent. The Department referred to this analysis as the "Ex-Ante CAPM analysis."[365]

326. The Department also applied another version of the CAPM--the Empirical CAPM (ECAPM)—which attempts to account for the deficiencies of the CAPM. Using the ECAPM, and adjusting for flotation costs, the Department arrived at ROEs of 9.62 percent for FECG and 9.75 percent for CCG. The ECAPM ROEs were significantly higher than the ROEs the Department calculated under the CAPM and reasonably close to the lower end of the DCF ROEs calculated by the Department. The Department did not, however, conclude that the results of its DCF/TGDCF analyses were too high

[360] *Id.* at 47.
[361] *Id.* at 47.
[362] *Id.* at 48-50.
[363] *Id.* at 50-51.
[364] *Id.* at 51.
[365] *Id.* at 51, Ex. 135 at EA-18 (Amit Direct Att.).

based on the CAPM and ECAPM results because CAPM analysis may not be reliable, particularly when interest rates are extremely low relative to their historical averages.[366]

327. The Department's initial recommendation regarding the required ROEs for the FECG and the CCG can be summarized as follows:[367]

Table 7

DCF

	Low	Average	High
FECG	9.86%	10.30%	10.82%
CCG	9.44%	10.16%	10.92%

Ex-Ante CAPM

FECG	9.62%
CCG	9.75%

328. The Ex-Ante CAPM's results were inside the range of the Department's DCF results for the CCG group and fairly close to the low end of its DCF estimated ROE for the FECG. The Department concluded that the results of the Ex-Ante CAPM analysis confirmed the reasonableness of its DCF results.[368]

329. Based on the Department's DCF and TGDCF analyses for the FECG and FCCG groups, it estimated that the required ROE for the Company ranged from a low of 9.44 percent to a high of 10.92 percent.[369]

330. Because the focus of the current proceeding is to estimate the required rate of return for the electric operations of the Company, the Department acknowledged that the most significant weight must be assigned to the DCF analysis for the FECG group. It noted, however, that the DCF analysis for the CCG group also provides additional important information and concluded that some weight must be assigned to those results as well. Accordingly, it assigned a weight of 60 percent to the FECG group and 40 percent to the CCG group.[370]

331. Based on these weights, the Department concluded that the required ROE for the Company ranged from a low of 9.69 percent to a high of 10.86 percent. Using the same weights for the mean ROEs of FECG and FCCG, the Department determined that a reasonable required ROE for the Company was 10.24 percent.[371]

332. The Department also responded to the analysis contained in the Company's Direct Testimony. It agreed with many aspects of the Company's analysis,

[366] *Id.* at 47, 52-53.
[367] *Id.* at 53, Table 10 (Amit Direct), as corrected (*see* Tr. Vol. 4. at 180-181 (Amit Testimony)).
[368] *Id.* at 53.
[369] *Id.* at 54.
[370] *Id.* at 54-55.
[371] *Id.* at 54, 55.

but not with its final recommendations.[372] For example, the Department agreed with the Company's calculation of its expected growth rates based on the projected five-year EPS growth rates by Zacks, Value Line, and used the same methodology in its own DCF analysis.[373]

333. The Department expressed concern about or disagreed with the following aspects of the Company's DCF 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 that may reflect irrelevant information and result in biased dividend yields. The Department emphasized that the 90- and 180-day average dividend yields in the Company's initial analysis were 18 basis points and 24 basis points higher, respectively, than its 30-day average dividend yield. 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."[374]

b. The Department disagreed with the Company's decision to assign 80 percent weight to the estimated ROEs for its XECG and only 20 percent weight to the estimated ROEs 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. The Department further noted that, while the Company screened the companies for both groups based on different measures of their percentage of electric operation, 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. For these reasons, the Department concluded that the Company's assignment of four times more weight to the XECG

[372] *Id.* at 66.
[373] *Id.* at 67.
[374] *Id.* at 66-67.

than to the XCCG may inappropriately bias its estimated ROEs towards its estimates for the XECG.[375]

334. 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 9.43 percent to 11.45 percent, with an average of 10.34 percent, for the XECG. For the XCCG, it resulted in ROE ranges of 9.34 percent to 11.22 percent, with an average of 10.19 percent.[376] Using a weighted average of 60/40 for the XECG and XCCG groups, respectively, the required rate of return would be 10.28 percent. This result is only four basis points higher than the Department's initial recommended ROE of 10.24 percent.[377]

335. The Department raised concerns about two aspects of the Company's CAPM analysis:

a. The Department acknowledged that the Company's choice of the 30-year Treasury bond yield as a proxy for the risk-free yield may be reasonable, but cautioned that it includes an interest rate risk premium and may bias the CAPM estimated ROE upward. The Department substituted the 20-year Treasury bond yield in its own analysis to minimize the interest risk impact the risk-free yield.[378]

b. The Department also contended that the Company failed to adjust its risk premium accordingly when it used the projected 30-year Treasury bond yield. The Department noted that the Company used a risk premium of 10.49 percent in all of its CAPM calculations, but indicated that, for the projected 30-year yield, the risk premium should be 9.92 percent to reflect the projected 2013 yield rather than the 30-day average yield.[379]

336. The Department adjusted the Company's CAPM analysis by substituting the December 2012 average yield on 20-year Treasury bonds for the Company's current yield on 30-year Treasury bonds; substituting the projected yield on 20-year Treasury bonds for the Company's projected yields on 30-year Treasury bonds; and using the average of the betas the Company used. The results of the Company's CAPM analysis as adjusted by the Department are set forth below:[380]

Table 8

Group	Low ROE	Mean ROE	High ROE
XECG	10.26%	10.30%	10.33%
XCCG	10.20%	10.27%	10.28%
60/40% weights	10.24%	10.29%	10.31%

[375] *Id.* at 69-71.
[376] *Id.* at 68.
[377] *Id.* at 68.
[378] *Id.* at 71, 72.
[379] *Id.* at 73.
[380] *Id.* at 73-74, Table 13.

337. The Department also disagreed with the risk premium calculations made by the Company in its additional Sharp Ratio (SR) CAPM analysis on the following grounds:

a. The Department asserted that the appropriate historical risk premium is 5.70 percent, not the 6.60 percent used by the Company. According to the Department, the Company inappropriately used the difference between the total equity return and the income-only bond return to calculate its risk premium and contended that the appropriate risk premium is the difference between the total return of two assets.

b. The Department maintained that the Company incorrectly converted the historical risk premium to the expected risk premium using the Sharp Ratio. According to the Department, it is necessary to estimate the expected standard deviation in order to estimate the expected risk premium. However, after the Company calculated the historical standard deviation, it substituted the expected VXV for the expected standard deviation. Although the Department argued that this was inconsistent and improper, it indicated that there was no need to engage in further discussion of this model given that the Company's estimates for its SR CAPM are very low compared to its other estimates.[381]

338. Finally, the Department disagreed with the Company's Bond Yield Plus Risk Premium analysis. The Department pointed out that the Company's regression analysis assumed that both coefficients (c = -0.0316 and a = -0.0298) are stable over time and do not depend on investors adjusting their expectations depending on different federal monetary and fiscal policies. The Department asserted that, to the degree that investors adjust their behavior to adapt to changing federal policies, both coefficients are not stable and cannot be used to estimate the expected risk premium. The Department also argued that the recent economic environment has two significant impacts on the risk premium. First, even though the risk premium as measured by historical data declined, the expected risk premium may have increased due to the increased risks of investing in common equity relative to investment in Treasury bonds. Second, due to the increased risk of investing in common equity, investors substituted investment in fixed income securities such as Treasury bonds for investment in common equity and, as a result, the current yields on risk-free assets are lower than they would have been in the absence of the economic crisis. The Department asserted that these factors may have caused the estimated values of the two coefficients to change, contrary to the Company's assumption that the coefficients are stable over time.[382]

339. In Direct Testimony, the Department modified the Company's estimated ROEs as follows:

---

[381] *Id.* at 76-77.
[382] *Id.* at 78-79.

Table 9

DCF				CAPM		
Group	Low	Mean	High	Low	Mean	High
XECG	9.43%	10.34%	11.45%	10.26%	10.30%	10.33%
XCCG	9.34%	10.19%	11.22%	10.20%	10.27%	10.28%
Weighted Average	0.39%	10.28%	11.35%	10.24%	10.29%	10.31%

The Department did not update the Company's DCF analysis using more recent data in arriving at the above DCF results. Based on the Department's modifications of the Company's analysis, the ROE for the Company was 10.28 percent, not 10.60 percent as recommended by the Company.[383]

c. The Company's Updated ROE Analysis

340. In Rebuttal Testimony, the Company responded to the testimony relating to ROE and capital structure provided by the Department, the Commercial Group, and ICI Group.[384]

341. The Company also updated the ROE analyses contained in its Direct Testimony and found that the updated results were quite consistent with the earlier results. The Company continued to recommend a 10.60 percent ROE, within a slightly modified ROE range of 10.25 percent to 10.80 percent. 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 were 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.[385]

342. The Company noted several areas in which it and the Department are in agreement, including: their primary reliance on DCF and TGDCF results in arriving at their ROE recommendations; their adjustment of current dividend yields to reflect expected growth rates; their use of earnings projections as a measure of long-term growth; their use of Zacks, Value Line, and Thomson/First Call as appropriate sources of consensus earnings growth projections; their use of electric and combination comparison groups in their DCF and TGDCF analyses; the need to include an adjustment for flotation costs and the approximate amount of that adjustment; and their use of the CAPM as a check on their DCF results. The Company agreed with the

[383] *Id.* at 80, Table 14.
[384] *Id.* at 1 (Hevert Direct). The Company's responses to the testimony of Mr. Chriss and Mr. Glahn are discussed below.
[385] Ex. 46 at 1-2 (Hevert Rebuttal).

Department that the Empirical CAPM is a reasonable analytical approach and included it in the Department's updated results and analyses.[386]

343. The Company and the Department agreed that the low level of Treasury yields have been due in large part to the tendency of investors to seek the safety of Treasury securities as a means of avoiding equity risk. The Company agreed with the Department's conclusion that the increase in the risk premium may offset the corresponding downward pressure on the ROE due to lower yields on Treasury securities. The Company indicated that the Department's observation that declines in Treasury yields do not result in corresponding declines in the cost of equity finds support in accepted theory as well as observable data.[387]

344. The Company and the Department disagreed on the composition of their electric and combination comparison groups and the appropriate weight that should be given to each of their comparison groups when arriving at a recommended ROE for the Company. The Company used an 80%/20% weighting and the Department used a 60%/40% weighting.[388] There were also differences between them with respect to certain elements of the CAPM analyses and the application of the Bond Yield Plus Risk Premium analysis.[389]

345. In selecting their comparison groups, the Company and the Department used similar screening criteria based on the consistency of dividend payments and credit ratings. They also established criteria to eliminate companies that derive a significant portion of their financial performance from non-regulated operations. The Company asserted that its screening criteria narrowed the comparison groups to more closely reflect the operations and risks of the Company.[390]

346. The Company agreed that the Department's FECG reasonably reflected the Company's electric and gas business composition. The Company indicated that, in 2009-2011, the Company derived an average of 90.07 percent of its net income from electric utility operations and 7.74 percent from natural gas utility operations, and Xcel Energy derived an average of 86.25 percent of its regulated net income from electric utility operations and 13.75 percent from natural gas utility operations. The Department's FECG was comprised of companies which, on average, derived 84.92 percent of regulated net income from regulated electric utility operations and 74.97 percent of total net income from regulated electric utility operations. Consequently, the Department's FECG already incorporates companies that reflect regulated natural gas operations and non-regulated operations.[391]

347. The Company asserted that (on average) the electric operations portion of the Department's FECG was within two percent of the portion of regulated net income

[386] *Id.* at 4-6, 25.
[387] *Id.* at 6-9, Chart 1.
[388] *Id.* at 5-6, 18.
[389] *Id.* at 18, 23-27.
[390] *Id.* at 19-21.
[391] *Id.* at 22.

that is derived from Xcel Energy's electric operations. In its view, those findings support a focus on the results of FECG and suggest that a weighting greater than 60 percent should be applied to that group. In the Company's opinion, the Department's initial 10.24 percent ROE recommendation, which was based on only a 60 percent weighting of the FECG, represented the low end of the range of reasonable results.[392]

348. The Department's average CAPM result was 9.66 percent to 9.79 percent, while the Company's mean results ranged from 9.90 percent to 10.33. Both ultimately found that the CAPM results were secondary to the DCF and TGDCF results in estimating the Company's ROE.[393]

349. The Department and the Company were not in complete agreement regarding two elements of their 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 Department used a recent average of the 20-year Treasury note yield as its risk-free rate. The Company found it appropriate to use the 30-year Treasury bond because it is the longest duration risk-free security. The Company noted that the average equity duration for its proxy group is 26.38 years, and the average useful life of the Company's transmission, distribution, and general other assets is approximately 33 years. The Department based its Equity Risk Premium estimate on the difference between Ibbotson's long-term S&P 500 index return and the total return on intermediate term government bonds. In contrast, the Company estimated the *ex-ante* Market Risk Premium by using two methods. The first was derived from the expected return on the S&P 500 Index, less the current 30-year Treasury bond yield. The second was based on the historical Sharpe Ratio. The Department's calculation of the Market Risk Premium was similar to the Company's first approach. The Department expressed disagreement with components of the Company's calculation of the Sharpe Ratio Derived Market Risk Premium. In the interest of reducing the scope of the contested issues, the Company did not update in its Rebuttal Testimony the CAPM results that relied on the Sharpe Ratio Derived Market Risk Premium.[394]

350. The Company agreed that the Empirical CAPM analysis used by the Department is a theoretically valid model and therefore included that approach in its updated analyses.[395]

351. The Company 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. The Company acknowledged that its regression coefficients did not change over the study period, but asserted that the intent of its study was to measure the effect of the Equity Risk Premium over a long-term average, including interest rates and authorized ROEs that are quite high during one period and quite low during another. To account for that variability, the Company used a semi-log regression in which the relationship is

[392] *Id.* at 22-23.
[393] *Id.* at 23.
[394] *Id.* at 24.
[395] *Id.* at 24-25.

measured based on a proportionate, rather than linear, change in Treasury yields. It contended that this analysis is useful in measuring an absolute change in the dependent variable (the Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield), especially at the extremes (i.e., when Treasury yields are at historically low levels). In addition, because the data covers a number of economic cycles, the analysis also may be used to assess the stability of the Equity Risk Premium.[396]

352. The Company performed an additional analysis to specifically measure the effect of volatility and incremental changes in interest rates. The Company defined the Risk Premium as the dependent variable, and the prevailing 30-year Treasury yield as an independent variable. As explanatory variables, the Company also included the Chicago Board Options Exchange's one month volatility index and the credit spread between the 30-year Treasury yield and the Moody's Baa Utility Index (as a measure of incremental risk). In both instances, the same statistically significant inverse relationship between Treasury yields and the Risk Premium was demonstrated and the results were generally consistent with those of its original Bond Yield Plus Risk Premium analysis.[397]

353. In Rebuttal Testimony, the Company updated all of the analyses presented in its Direct Testimony with data as of February 15, 2013. The Company continued to rely on the Constant Growth DCF model with the TGDCF approach to moderate the effects of substantially high or low growth rate estimates. Consistent with the Department's approach, the Company applied the TGDCF to any company with an average growth rate outside of one standard deviation from the XECG and XCCG groups. In addition, the Company included PNM Resources, Inc., in its revised XECG because its long-term issuer rating was upgraded causing it to meet the screening criteria.

[396] *Id.* at 25-27, Chart 4.
[397] *Id.* at 27, Schedule 10.

354. The results of the Company's DCF analysis for its revised XECG, including an adjustment for flotation costs, are summarized below:[398]

Table 10

	Low Growth Rate	Mean Growth Rate	High Growth Rate
Revised Electric Proxy Group Results			
30-Day Average	9.62%	10.58%	11.84%
90-Day Average	9.70%	10.67%	11.94%
180-Day Average	9.70%	10.68%	11.96%
Weighted Average Results (80% Revised Electric / 20% Combination)			
30-Day Average	9.41%	10.33%	11.49%
90-Day Average	9.50%	10.42%	11.60%
180-Day Average	9.49%	10.42%	11.0%

355. In updating its CAPM analysis, the Company used the same inputs described in its Direct Testimony, updated through February 15, 2013. However, the Company did not update the CAPM results that relied on the Sharpe Ratio Derived Market Risk Premium. For the risk-free rate, it continued to refer alternatively to: (1) the 30-day average of the 30-year Treasury yield; and (2) a consensus forecast of the average 30-Year Treasury yield for the coming six quarters. For the MRP, it continued to refer to the expected return on the S&P 500 Index less the current 30-year Treasury yield. For the beta coefficient, it continued to rely on results from Bloomberg, Value Line, and 12-month Calculated Beta coefficient. Based on updated market information, its CAPM analyses produced a range of ROE estimates from 9.90 percent to 10.33 percent. In addition, it included an Empirical CAPM analysis which produced a range of ROE estimates from 10.66 percent to 11.03 percent. The Company did not place any specific reliance on its CAPM results but used it to corroborate the results of its DCF analysis.[399]

356. The Company's updated Bond Yield Plus Risk Premium analysis included authorized ROEs as reported by Regulatory Research Associates through February 15, 2013. To calculate the expected risk premium and ROE, it used the current and projected 30-year Treasury yield. Its updated result was 10.23 percent to 10.76

[398] *Id.* at 33, Table 1, Schedule 1.
[399] *Id.* at 34, Schedule 4.

percent. As with the CAPM analysis, it used the Bond Yield Plus Risk Premium analysis to corroborate the results of its DCF analysis.[400]

357. The results of the Company's updated DCF analysis applied to the original XECG and XCCG for both the time period of the Department's initial analysis and for the period ending February 15, 2013, are set forth below:[401]

Table 11

	Low Growth Rate	**Mean Growth Rate**	**High Growth Rate**
Xcel Original Electric Proxy Group Results – 30-Day Average Results			
As filed in Direct	9.43%	10.34%	11.45%
Updated February 15, 2013	9.61%	10.46%	11.59%
Xcel Weighted Average Results (80% Electric / 20% Combination) - 30-Day Average Results			
As filed in Direct	9.34%	10.19%	11.22%
Updated February 15, 2013	9.41%	10.23%	11.29%
Department Results (as filed)			
FECG Results (Dec. 4, 2012)	9.86%	10.30%	10.82%
Weighted Average (60% FECG / 40% CCG) (Dec. 4, 2012)	9.69%	10.24%	10.86%

358. The Company continued to believe that it is appropriate to place primary weight on the DCF analysis for the XECG. For that reason, and taking into consideration the Company's substantial capital investment plan and the implications for investors, the Company concluded that the reasonable range of ROE estimates is from 10.25 percent to 10.80 percent, and continued to recommend a ROE of 10.60 percent.[402]

d. The Department's Updated ROE Analysis

359. In Surrebuttal Testimony, the Department updated its initial ROE analysis using more current closing prices and more recent projected growth rates based on the view that "it is important to use the most recently available dividend yields when relying on a DCF analysis."[403] The Department used the same methodology and sources of

[400] *Id.* at 34-35, Schedule 5.
[401] *Id.* at 35, Table 2. Mr. Hevert's original Electric Proxy Group did not include PNM Resources, Inc., but the revised Electric Proxy Group did. All other companies remained the same.
[402] *Id.* at 36.
[403] *See* Ex. 138 at 1-2 (Amit Surrebuttal).

information in calculating the updated ROE as it had used in calculating the initial ROE.[404]

360. In its updated analysis, the Department included American Electric Power and Cleco Corporation in the FECG because their mean expected rate of return exceeded 8.00 percent.[405] The Department excluded OGE Energy Corporation from the CCG because its mean expected rate of return was less than 8.00 percent, and called the final version of the CCG the "FCCG."[406]

361. Based on the Department's updated analysis, the Department recommended a return on common equity capital of 9.83 percent and an overall ROR of 7.45 percent for the Company.[407]

362. The Department calculated updated dividend yields using the closing prices from the most recently available four-week period (February 25, 2013 – March 24, 2013). The updated average dividend yields for FECG and FCCG were 4.22 percent and 4.09 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.[408]

363. 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, Thomson, and Value-Line projected EPS growth rates, following the same methodology described in his prefiled Direct Testimony.[409] The updated expected growth rates are summarized below:[410]

Table 12

Group	Low Expected Growth Rates	Mean Expected Growth Rates	High Expected Growth Rates
FECG	4.32%	5.37%	6.27%
FCG	4.88%	5.59%	6.30%

364. As in its initial analysis, the Department substituted TGDCF analyses for DCF analyses 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 companies for which it applied TGDCF analyses also changed. In the updated analysis, the TGDCF method was applied to the

[404] *Id.* at 2-6.
[405] *Id.* at 2. These companies had been previously excluded because they did not survive Dr. Amit's screen for financial reasonableness. Ex. 134 at 21 (Amit Direct).
[406] *Id.* at 3 and n.1.
[407] *Id.* at 2.
[408] *Id.* at 3, EA-SR-3, and EA-SR-8; *see also* Ex. 134 at 34 (Amit Direct).
[409] Ex. 138 at 3-4, EA-SR-1, and EA-SR-7 (Amit Surrebuttal).
[410] *Id.* at 4, Table 1, EA-SR-3, and EA-SR-8.

following five companies: American Electric Power Company, First Energy Corporation, Northeast Utilities, Pinnacle West Capital Corporation, and UIL Holdings Corporation.[411]

365. The results of the Department's updated DCF/TGDCF analysis, as adjusted for flotation costs of 13 basis points, are summarized below:[412]

Table 13

Group	Low	Mean	High
FECG	9.03%	9.89%	10.66%
FCCG	9.18%	9.73%	10.23%

366. The Department again assigned a weight of 60 percent to the FECG results and 40 percent to the FCCG results. The Department concluded that, based on these weights, a reasonable ROE for the Company ranges from a low of 9.09 percent to a high of 10.49 percent, with a midpoint of 9.83 percent. The Department recommended a ROE of 9.83 percent for the Company.[413]

367. The Department also updated its CAPM estimates by using the most recently-available betas from the February- March 2013 Value-Line Investment Survey (0.70 for the FECG and 0.72 for the FCCG) and the March 2013 daily average of the yield on 20-year Treasury bonds (2.78 percent). It also used an 8.89 percent projected growth rate for the S&P 500 Index and a 2.00 percent dividend yield based on information as of April 1, 2013. For the DCF analysis, the dividend yield was increased by one half of the growth rate of 8.89 percent to arrive at a dividend yield of 2.09 percent. It determined that the required market rate of return on the S&P 500 is 10.98 percent. Its updated *ex-ante* CAPM estimates, including flotation costs, were 8.66 percent for the FECG and 8.82 percent for the FCCG.[414]

368. The Department updated its ECAPM analysis as well. The results, including flotation costs, were 9.28 percent for the FECG and 9.26 percent for the FCCG. The Department concluded that, when using expected risk premiums, the *ex-ante* ECAPM was useful in confirming the reasonableness of its DCF estimates for the required ROE for the Company.[415]

369. In its Surrebuttal Testimony, the Department also 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. The Department modified the Company's DCF analyses by using only the 30-day period; substituting the average prices over the period of February 25, 2013 – March 24, 2013; using the most recent available project growth rates as of March 25,

[411] *Id.* at 4-5, Table 2, and EA-SR-6.
[412] *Id.* at 5-6, Table 3, EA-SR-5, EA-SR-9.
[413] *Id.* at 6.
[414] *Id.* at 7-8.
[415] *Id.* at 8.

2013; and updating its TGDCF analyses. The Department's updates of the Company's DCF analyses result in a mean ROE of 9.96 percent for the XECG and 9.19 percent for the XCCG, including a 13 point flotation cost adjustment. Assigning weights of 60 percent to the XECG and 40 percent to the XCCG results in a ROE of 9.66 percent rather than the 10.60 percent recommended by the Company. If the Company's proposed weights of 80/20 percent were used, the resulting ROE is 9.81 percent. That result is very close to the Department's recommended ROE of 9.83 percent.[416]

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

Table 14 - ROE

Group	Low	Mean	High
Electric			
Department (FCCG)	9.03%	9.89%	10.66%
Company (XCCG)	8.94%	9.96%	11.05%
Combination			
Department (FCCG)	9.18%	9.73%	10.23%
Company (XCCG)	8.62%	9.19%	9.79%
Weighted (60/40)			
Department (FCCG)	9.09%	9.83%	10.49%
Company (XCCG)	8.81%	9.66%	10.55%

The Department concluded that the above updated DCF/TGDCF results confirmed the reasonableness of its recommended ROE for the Company.[417]

e. ROEs Proposed by ECC, the Commercial Group, and ICI Group and the Responses of the Company and the Department

371. ECC agreed with the Department's recommendation of a 9.83 percent ROE.[418]

372. The ICI Group asserted that the record in this matter does not support the Company's proposal for a 10.6 percent ROE. It recommended that the Commission grant the Company a ROE no greater than it awarded the Company in its last electric rate case and, preferably, allow a ROE that is "more in line with recent regulatory decisions in other jurisdictions." It indicated that recent decisions by other state utility commissions have been in the range of 9.8 percent to 10.45 percent. The ICI Group argued that any ROE granted to the Company should reflect the most recent financial

[416] *Id.* at 13-14.
[417] *Id.* at 14, Table 6.
[418] ECC Initial Brief at 2, 32.

data available. It urged that the Commission either maintain the Company's existing 10.37 percent ROE or adopt the Department's recommended 9.83 percent ROE.[419]

373. Regarding the ICI Group's recommendation, the Company agreed that recent ROE decisions in other states provide a "meaningful benchmark to assess the reasonableness of the Company's request." The Company contended that its ROE range and recommendation are supported by relevant data and consistent with those observed in other jurisdictions.[420] The ICI Group disagreed and indicated that the Company's recommended 10.6 percent ROE was greater than those recently approved in other jurisdictions.[421]

374. The Department objected to the ICI Group's recommendation on several grounds. First, it asserted that the regulatory process has a significant effect on the allowed ROEs for regulated companies, and argued that non-regulated companies must be included in any analysis comparing ROEs in order to avoid circularity. Second, the Department argued that the decisions upon which the ICI Group relied were based on analyses that were completed six to nine months before the decisions were issued, and thus were outdated. Finally, the Department contended that it is not appropriate to base a recommended ROE solely on ROE decisions in prior cases despite the fact that such comparisons may help provide a check on the reasonableness of an ROE analysis.[422]

375. The ICI Group agreed with the Department's comments generally but not with its conclusion. The ICI Group clarified that it was not suggesting that the Commission rely on ROEs authorized by other commissions as a substitute for a traditional rate of return analysis but instead use such information as supporting evidence. Ultimately, the ICI Group noted that the ROEs determined in other jurisdictions supported the Department's initial recommendation of a 10.24 percent ROE.[423]

376. The Commercial Group argued that the 10.60 percent ROE proposed by the Company is "unreasonably high" and found the Department's recommendation of 9.83 percent to be "much more reasonable." It asserted that the ROE "should be adjusted downward toward the low end of any reasonable ROE range determined by the Commission, or below the 9.83 percent ROE target" of the Department. Like the ICI Group, the Commercial Group urged the Commission to consider the ROEs authorized in 2012 and early 2013 in other states in evaluating the appropriate ROE for the Company. It emphasized that, according to a January 17, 2013, report by Regulatory Research Associates, the ROEs that were authorized for electric utilities in 2012 averaged 10.15 percent. Moreover, according to data from SNL Financial, the ROEs authorized by commissions to investor-owned electric utilities in 55 reported electric utility general rate cases between January 25, 2012, and February 22, 2013, averaged

[419] Ex. 105 at 10 (Glahn Direct); Ex. 106 at 5 (Glahn Surrebuttal); ICI Initial Brief at 7-8, 11-13; ICI Reply Brief at 3-4.
[420] Ex. 46 at 32 (Hevert Rebuttal).
[421] Ex. 106 at 5 (Glahn Surrebuttal).
[422] Ex. 137 at 2-3 (Amit Rebuttal).
[423] Ex. 106 at 5-7 (Glahn Surrebuttal).

10.0 percent. The Commercial Group also maintained that including construction work in progress (CWIP) in the base rate reduces the Company's risk and should result in a lower ROE for the Company.[424]

377. 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 provide a specific ROE recommendation. The Company also emphasized that it is a vertically integrated electric utility that owns and operates generation, transmission and distribution assets, while 13 of the 55 cases in other jurisdictions that were the subject of the SNL report pertained to companies that are transmission- and distribution-only utilities.[425]

378. In addition, the Company asserted that it is facing substantial capital expenditures, and that its credit rating and outlook will depend on whether and to what extent rating agencies view the regulatory environment to be credit-supportive. Given the Company's need to access external capital, and in light of the weight that both Moody's and S&P place on the nature of the regulatory environment, the Company contended that it is important to consider the extent to which the jurisdictions included in the SNL data are considered by rating agencies to be credit-supportive. The Company indicated that Minnesota is considered to be "Credit Supportive" by S&P, which is the mid-level tier. The Company conducted additional analysis of the SNL data and determined that the median ROE for the companies operating in "More Credit Supportive" or "Credit Supportive" jurisdictions is 10.25 percent rather than the 10.00 percent cited by the Commercial Group.[426]

379. 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, and indicated that the Commercial Group had not done so. The Company determined that eight of the 12 companies in its Revised Electric Proxy Group were permitted to use forecasted test-years or partially forecasted test years in at least one regulatory jurisdiction. It also found that 8 of the 12 companies in that 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.[427]

380. The Department responded 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. As a result, the Department concluded that no additional adjustment in ROE is necessary.[428]

---

[424] Commercial Group Brief at 2, 3-6; Ex. 81 at 6-9 and Exhibits SWC-2 and SWC-3 (Chriss Direct); Ex. 83 at 1 (Chriss Summary Statement).
[425] Ex. 46 at 28-29 (Hevert Rebuttal).
[426] Ex. 46 at 2-3, 28-30 and Schedule 11 (Hevert Rebuttal).
[427] *Id.* at 31.
[428] Ex. 137 at 8, 11 (Amit Rebuttal).

f. ROE Conclusions and Recommendation

381. The primary reason for the difference between the recommendations of the Company and the Department stems from the different periods to which they applied their DCF and TGDCF analyses. The Company based its analysis on average prices over 30-, 90-, and 180-day periods. In contrast, the Department based its analysis on a 30-day period only.[429] The 90-day and 180-day average dividend yields used by the Company are 18 and 24 basis points higher, respectively, than the 30-day average dividend yield.[430] Moreover, the use of 90- and 180-day average dividend yields may create a mismatch between such yields and more recent projected growth rates.[431]

382. In addition, the Company calculated the dividend yields for its updated 30-day period analysis using the average prices over the period of January 15, 2013, to February 15, 2013, while the Department's updated dividend yields are based on the average prices over the more recent period of February 25, 2013, to March 24, 2013.[432]

383. Finally, the Company assigned 80 percent weight to the ROE results of its electric comparison group (XECG) and only 20 percent to its combination group (XCCG). While the Department also assigned a somewhat greater weight to the ROE results of its FECG group because that group contained electric utilities, the Department recognized that important information could also be obtained from the combination FCCG group. Consequently, the Department assigned 60 percent weight to the ROE results of the FECG and 40 percent to the FCCG.

384. The Department demonstrated that, if the Company had used more recent 30-day data only and had applied a 60/40 weighting for XECG and XCCG, respectively, the required ROEs would have been nearly the same as those recommended by the Department (4 basis points higher than the Department's initial recommendation, and 2 basis points lower than its revised recommendation).[433]

385. After careful consideration, the Administrative Law Judge recommends that the Commission adopt the Department's recommended ROE of 9.83 percent, including flotation costs. The Company has not shown that it is reasonable to use average prices over a 90-day or 180-day period or that such outdated market information is relevant to the forward-looking DCF analysis. The Administrative Law Judge is persuaded that the Department's use of a 30-day period to calculate the dividend yield is consistent with the basic financial principle that current stock prices fully reflect all publicly available information. Moreover, the Department's updated DCF and TGDCF analyses are a better reflection of current market expectations because they are based on more recent information. Finally, the Company has not shown that it is reasonable to assign 80 percent weight to the XECG (which has a higher ROE) and

---

[429] Ex. 139 at 3 (Amit Summary Statement); Tr. Vol. 4 at 186.
[430] Ex. 134 at 67 (Amit Direct).
[431] *Id.*
[432] Ex. 139 at 3-4 (Amit Summary Statement); Tr. Vol. 4 at 186.
[433] Ex. 134 at 80 (Amit Direct); Ex. 138 at 13-14 (Amit Surrebuttal).

only 20 percent weight to the XCCG. Such a significant difference in weighting has not been shown to be warranted where the comparison groups operate under similar economic and regulatory environments, have similar investment risks, and have only small differences in equity ratios and betas. The Department's assignment of 60 percent to the group containing only electric utilities and 40 percent to the combination group is more reasonable.

ii. Capital Structure

386. While this issue is not disputed, it is addressed here because the Commission requested supplemental testimony on the issue.

387. The components of the capital structure may include long-term debt, preferred stock, common equity and short-term debt. The overall cost of capital (or ROR) is determined by the amount of long-term debt, short-term debt, preferred stock and common equity held by the Company. These amounts are represented as dollar amounts and as percentages of the total capital, and are called the capital structure.[434]

388. The Company is a separate legal entity from its parent company, Xcel Energy Inc., and has its own capital structure. The Company issues its own debt securities, which are credit-rated by the various rating agencies such as Standard and Poor and Moody's.[435]

389. The Company's proposed capital structure is the actual capital structure of the Company. In Direct Testimony, the Company proposed the following capital structure for its 2013 test year:[436]

Table 15 NSP's Initially Proposed Capital Structure

Category	Total Amount ($1,000s)	Percent of Capitalization
Long-Term Debt	$3,667,701	44.96%
Short-Term Debt	$202,538	2.48%
Common Equity	$4,288,643	52.56%
Total	$8,158,882	100.00%

390. In Rebuttal Testimony, the Company updated its proposed capital structure to reflect a number of changes. The updated numbers are as follows:[437]

[434] Ex. 134 at 55 (Amit Direct).
[435] Ex. 41 at 27 (Tyson Direct); Ex. 134 at 56 (Amit Direct).
[436] Ex. 134 at 56 (Amit Direct).
[437] Ex. 138 at 10 (Amit Surrebuttal); Ex. 43 at Schedules 1-3 (Tyson Rebuttal).

Table 16 Updated NSP Test Year Capital Structure

Component	Total Amount ($1,000s)	Percent of Total Capitalization
Long-Term Debt	$3,667,701	45.30%
Short-Term Debt	$173,270	2.14%
Total Debt	$3,840,971	47.44%
Common Equity	$4,255,604	52.56%
Total Capitalization	$8,096,575	100.00%

391. The update reflects:

- the issuance of ten-year long-term debt of $265 million in 2013 at an interest rate of 2.65 percent, replacing the planned 30-year long-term debt issuance of $425 million at an interest rate of 4.25 percent;
- the increased balance of short-term debt in the updated capital structure, based on actual balances for January through February 2013, and updated forecast for the remaining months of 2013; and
- the more recent forecast of the cost of short-term debt.[438]

392. As a result of the updates, the cost of short term debt went down from 0.75 percent to 0.68 percent.[439]

393. The Department agreed that the Company's updated capital structure (including the Company's amounts of long-term debt, short term debt, and common equity) is reasonable. No other party provided any testimony or recommendation regarding the issue.[440]

394. The Company's capital structure is generally comparable to the capital structures of other similar utilities. The Company needs to raise capital for its significant planned infrastructure investments. The Company's updated capital structure is appropriate to support those investments.[441]

395. If the Commission adopts the Department's 9.83 proposed ROE as recommended by the Administrative Law Judge and the Commission also adopts the Company's updated capital structure and recommended cost of debt, the result is an overall ROR of 7.45 percent. The table below summarizes the calculation.

[438] Ex. 138 at 9 (Amit Surrebuttal); Ex. 43, Schedules 2 and 3 (Tyson Rebuttal).
[439] Ex. 138 at 9 (Amit Surrebuttal); Ex. 43, 6, Schedules 2 and 3 (Tyson Rebuttal).
[440] *See* Ex. 138 at 10-11 (Amit Surrebuttal).
[441] Ex. 45 at 52-53 (Hevert Direct); Ex. 47 at 2-3, 4-6 (Hevert Supplemental Direct); Ex. 42 at 6-7 (Tyson Supplemental Direct); Ex. 134 at 58-59, 87 (Amit Direct); Ex. 138 at 10-11 (Amit Surrebuttal).

Table 17 DOC's Recommended Cost of Capital for NSP[442]

Component	Capitalization Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	45.30	5.02	2.27
Short-Term Debt	02.14	0.68	0.01
Common Equity	52.56	9.83	5.17
Total	100.00%		7.45%

iii. Hypothetical Capital Structure

396. In its December 26, 2012 Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing, the Commission required the Company to provide supplemental testimony:

- explaining why it has not refinanced higher-cost bonds given the current low interest rate environment;
- discussing the effect of adjusting the Company's capital structure to finance with a higher percentage of debt (one to five percent);
- addressing the effect of adjusting the Company's capital structure to allocate a higher percentage (one to five percent) to debt on a Minnesota jurisdictional basis; and
- reporting for each of the past five years (2007 – 2011) the Company's authorized return on equity and its actual return on equity as reported on its form 10-K on a jurisdictional, total-company, and regulated-company basis.

397. On January 25, 2013, the Company filed the required supplemental testimony.[443]

398. Imputing an additional 1 to 5 percent of long-term debt would decrease the revenue requirement in the range of $7 million to $39 million.[444]

399. Both the Company and the Department agreed, however, that doing so would not be justified for a number of reasons. First, the Company's investment plans require the Company to maintain its existing equity ratios. Second, increasing the Company's imputed debt ratio is likely to negatively impact the Company's credit rating

[442] Ex. 138 at 10-11 (Amit Surrebuttal).
[443] Ex. 42 (Tyson Supplemental Direct); Ex. 47 (Hevert Supplemental Direct).
[444] Ex. 42 at 13-14 (Tyson Supplemental Direct).

and would likely increase the Company's costs of capital. Third, the Company may not be able to earn its authorized rate of return if a hypothetical debt ratio is used.[445]

400. Accordingly, it would not be reasonable to use an increased hypothetical debt ratio in calculating the Company's authorized rate of return. While its use may benefit ratepayers in the short-run, it could harm ratepayers in the long-run through higher financing costs. The Company's actual debt ratio is reasonable.

G. Prairie Island Extend Power Uprate (PI EPU)[446]

401. The Company initially included PI EPU costs in its 2013 test year. In Rebuttal Testimony, the Company agreed to remove the PI EPU costs from the 2013 test year due to the termination of the PI EPU project in December 2012.[447]

402. The parties agreed to the removal of the PI EPU costs from the 2013 test year. The parties dispute, however, whether the Company should be allowed to request recovery of PI EPU costs in its next rate case.[448]

i. Background

403. On May 16, 2008, the Company filed a Certificate of Need application with the Commission requesting authority to increase the power output at its PI nuclear facility by a total of 164 MW. On December 18, 2009, the Commission issued an order granting the Certificate of Need for the PI EPU.[449]

404. On March 30, 2012, the Company filed a Notice of Changed Circumstances with the Commission, proposing to delay the implementation date and to reduce the capacity of the PI EPU. On October 22 and 25, 2012, the Company filed comments stating that continued pursuit of the PI EPU was no longer in its customers' interests.[450]

405. On November 7, 2012, the Commission issued an Order to Show Cause, asking interested persons to present arguments as to why the Commission should not terminate the Certificate of Need for the PI EPU. [451]

---

[445] Ex. 42 at 13-14 (Tyson Supplemental Direct); Ex. 42 (Tyson Supplemental Direct); Ex. 47 (Hevert Supplemental Direct); Ex. 134 at 85-87 (Amit Direct).
[446] Issue 5, Item 2
[447] *See* Ex. 58 at 51-52; Ex. 175 at 7 (Campbell Opening Statement).
[448] *Id.*; Xcel Initial Brief at 92; Department Initial Brief at 48; OAG Initial Brief at 42-43.
[449] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, MPUC Docket No. E002/CN-08-509, ORDER ACCEPTING ENVIRONMENTAL IMPACT STATEMENT, AND GRANTING CERTIFICATE OF NEED AND SITE PERMIT WITH CONDITIONS (Dec. 18, 2009) (ORDER GRANTING CERTIFICATE OF NEED).
[450] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, MPUC Docket No. E002/CN-08-509, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY (Feb. 27, 2013) at 1 (ORDER TERMINATING CERTIFICATE OF NEED).
[451] *Id.*

406. On December 11, 2012, the Company filed Reply Comments stating, among other things, that it had terminated all work on the PI EPU project. The Company also stated that "[i]f it becomes probable that the Certificate of Need will be terminated, the PI EPU accumulated costs will be recorded as a regulatory asset in FERC account 182.2–Unrecovered Plant and Regulatory Study costs, pending further accounting evaluation and review in our next rate case."[452]

407. At an agenda meeting on December 20, 2012, the Commission voted to terminate the Certificate of Need for the PI EPU. [453]

408. In December 2012, the Company transferred $64 million (total company amount) in PI EPU costs to a regulatory asset account for future cost recovery. The Company's auditors, Deloitte and Touche, approved creation of the regulatory asset and deferral of the costs under Generally Accepted Accounting Principles (GAAP).[454]

409. On February 27, 2013, the Commission issued its Order Terminating Certificate of Need Prospectively. [455]

410. The order only briefly addressed the issue of recovery of costs associated with the cancelled PI EPU project. It states: "Nor does the decision [to terminate the Certificate of Need] address the prudence of Xcel's investments or the recovery of those costs; those judgments may be made in the context of Xcel's rate case." At the end of the sentence, there is a footnote which provides: "See *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota,* Docket No. E-002/GR-12-961." The docket referenced is the current rate case docket.[456]

411. Based on the Commission's decision, the Company and the Department adjusted the proposed 2013 test year revenue requirement to remove costs associated with the cancelled PI EPU project.[457]

ii. The Department's Objections

412. The Department agreed to the removal of the PI EPU costs from the test year, but objected to the transfer of PI EPU costs to a regulatory asset. The Department maintained that because the Company stopped work on the PI EPU project in December 2012, the Company was required under GAAP either to request

---

[452] Ex. 74 at 2 and Schedule 1 (Robinson Supplemental attaching Reply Comments).
[453] *See In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, MPUC Docket No. E002/CN-08-509, ORDER TERMINATING CERTIFICATE OF NEED PROSPECTIVELY (Feb. 27, 2013) (ORDER TERMINATING THE CERTIFICATE OF NEED).
[454] Ex. 55 at 7-8 (Weatherby Rebuttal); Ex. 74 at 1 (Robinson Supplemental Examination).
[455] ORDER TERMINATING THE CERTIFICATE OF NEED at 1.
[456] *Id.* at 4.
[457] Ex. 174 at 16 (Campbell Surrebuttal); Ex. 183 at DVL-S-4 (Lusti Surrebuttal).

Commission approval of deferred accounting treatment of the costs or write-off the costs of the cancelled project.[458]

413. Deferred accounting is generally reserved for costs that occur outside of a rate case and are: 1) related to utility operations for which ratepayers have incurred costs or received benefits; 2) significant in amount; and 3) unusual or extraordinary. In addition, such costs are subject to review for reasonableness and prudence.[459]

414. The Department asserted that the Company had not addressed, much less met, the criteria for deferred accounting of the PI EPU costs. The Department maintained that deferred accounting is not permissible for these costs given that the Company decided to cancel the PI EPU project "despite showing benefits in the Company's IRP and CN." The Department also claimed that because the EPU was not "used and useful," the costs were not prudently incurred.[460]

415. Finally, the Department asserted that the Commission's Order Terminating the Certificate of Need provides that the prudency of the costs for the PI EPU project will be addressed in this docket, not the next rate case.[461]

416. For these reasons, the Department recommended that the Commission not approve deferred accounting of the PI EPU costs which are approximately $48 million on a Minnesota jurisdictional basis. If the Commission does allow the Company to seek recovery of its PI EPU costs in the next rate case, the Department recommended that the Commission require the Company to provide information explaining certain PI EPU plant transfers in its initial filing in the next rate case.[462]

iii. The OAG's Objections

417. The OAG also objected to the transfer of PI EPU costs to a regulatory asset without Commission approval. The OAG asserted that, according to GAAP, the Company was required to write-off the PI EPU costs because the project was cancelled in 2012.[463]

iv. The Company's Response

418. The Company countered that it should be allowed to seek recovery of its PI EPU costs in its 2014 rate case. The Company maintained that it would not have been possible to do a full prudence review in the current proceeding because it did not know until after the rate case was filed that the PI Certificate of Need would be terminated.[464] The Company claimed that, given the Commission made its decision

---

[458] Ex. 176 at 2-3 (Campbell Supplemental Response).
[459] Ex. 173 at 117 (Campbell Surrebuttal).
[460] *Id.* at 117-119; Ex. 176 at 3.
[461] Ex. 176 at 7; DOC Initial Brief at 49.
[462] Ex. 173 at 117-119 (Campbell Surrebuttal); Ex. 176 at 3 (Campbell Supplemental Response); Department Reply Brief at 47.
[463] OAG Initial Brief at 42-43.
[464] Ex. 74 at 3 (Robinson Supplemental Testimony).

orally on December 20, 2012 and issued its order on February 27, 2013, adding the issue at that time would have increased the burden on the parties and the Commission in a case that already had an extremely large number of disputed issues.[465]

419. The Company maintained that GAAP allows it to record the PI EPU costs as a regulatory asset without Commission approval. The Company asserted that relevant GAAP provisions were amended in 1986 to allow creation of a regulatory asset when construction for a project is cancelled.[466]

420. The Company also argued that the Department applied the wrong standard when it concluded that the PI EPU costs were not prudently incurred because the EPU was not used and useful.[467]

421. The Company disagreed with the Department's interpretation of the Commission's February 27, 2013 order terminating the PI EPU Certificate of Need. The Company maintained that the Order allows the Company to address the issue in a future rate case.[468]

422. The Company also asserted that it would be contrary to the public interest to deny recovery of the PI EPU costs without allowing the Company an opportunity to present evidence in the next rate case as to whether such costs are prudent. The Company asserted that such a decision would create incentives for utilities to finish projects that should be abandoned.[469]

423. Finally, the Company argued that the issue is not ripe because the Company is not requesting recovery of the PI EPU costs in this rate case and it has not requested deferred accounting treatment in this docket.[470]

v. Conclusion – PI EPU Costs

424. The Administrative Law Judge concludes that the issue of whether the Company should be barred from seeking recovery of its PI EPU costs in its next rate case is not ripe. It would be premature to decide the issue in this case.

---

[465] *Id.*; Xcel Initial Brief at 58.
[466] Ex. 74 at 1 (Robinson Supplemental Testimony); Xcel Reply Brief at 59.
[467] Xcel Reply Brief at 57-58.
[468] Ex. 74 at 2 (Robinson Supplemental Testimony); Xcel Reply Brief at 58.
[469] Ex. 74 at 3 (Robinson Supplemental Testimony).
[470] Xcel Initial Brief at 98.

425. Under the ripeness doctrine, an issue need not be decided unless there is some injury or harm to be addressed.[471] In past dockets, the Commission has applied the ripeness doctrine and declined to address issues that are not ripe.[472]

426. Here, there is no need for the Commission to make a decision at this time regarding the PI EPU costs because there is no injury or harm to be addressed. The Company has not requested that the Commission take any action in this docket regarding these costs. It has not requested recovery of any of the costs in its revised 2013 test year. Nor has it requested that the Commission authorize deferred accounting of its PI EPU costs.

427. Moreover, there is no reason why the parties cannot make the same arguments in the next rate case as they did in this matter as to whether the Company acted in accordance with GAAP when it transferred the PI EPU costs to a regulatory asset account, without Commission approval. Likewise, the parties can raise their arguments regarding the reasonableness of the costs in the next rate case.

428. Finally, contrary to the Department's suggestion, the Commission's February 27, 2013 order does not require that a determination regarding prudency or recovery of the PI EPU costs be made in this docket. The Commission's order states "those judgments *may* be made in the context of Xcel's rate case."[473] The use of the word "may" allows, but does not require, a decision in this case. Moreover, there is no language in the Commission's Order requiring the Company to request deferred accounting in this rate case if it intends to seek recovery of the PI EPU costs in its next rate case.[474]

429. For these reasons, the Administrative Law Judge recommends that the Commission take no action at this time on the question of whether the Company should have sought deferred accounting or written-off the PI EPU costs as asserted by the Department and OAG. Instead, the Commission should allow the Company the opportunity to request recovery of its PI EPU costs in the next rate case, and the other parties should be afforded an opportunity to raise their same objections, and any new objections, in that docket. The Company, of course, will have the burden in the next rate case to show that the PI EPU costs are eligible for recovery in rates and that they were prudently incurred.

---

[471] *Friends of the Riverfront v. City of Minneapolis*, 751 N.W.2d 586, 592 (Minn. Ct. App. 2008).

[472] *See*, *e.g.*, *In re Application of the City of Hutchinson (Hutchinson Utilities Commission) for a Certificate of Need to Construct a Large Natural Gas Pipeline*, No. A03-99, 2003 WL 22234703 (Minn. Ct. App. Sept. 23, 2003) (affirming Commission decision that it was not necessary for the Commission to determine whether the proposed pipeline would be an intrastate pipeline in its decision on whether to grant a certificate of need to the project); *In re Petition by Xcel Energy for Approval of Revisions to the Solar*Rewards Program*, ORDER APPROVING MODIFICATIONS TO XCEL'S SOLAR*REWARDS PROGRAM, MPUC Docket No. E002/M-10-1278 (March 1, 2013) (noting that the issue of whether to revise the tariff was not ripe for Commission action).

[473] ORDER TERMINATING CERTIFICATE OF NEED at 4 (emphasis added).

[474] *Id.*

430. The Administrative Law Judge also recommends that the Commission require the Company, in the initial filing in its next rate case, to provide the information requested by the Department regarding the transfers of Plant from the cancelled PI EPU project to the PI LCM project and to other nuclear projects.

H. Nobles Wind Capital Costs Over RES Amount[475]

431. The Company has incurred costs for the Nobles Wind Farm Project (Nobles) that exceed the amount that the Commission approved for recovery through the Renewable Energy Standards (RES) Rider. The Company has requested recovery of approximately $5.5 million in additional capital costs, which results in an increase to the 2013 revenue requirement of $644,000.[476] In rebuttal testimony, the Company proposed an alternative that would treat the $5.5 million of additional capital costs as an investment in cancelled plant. Under that proposal, the Company would be allowed to recover a return of the investment (i.e. depreciation) but not a return on its investment over a reasonable period of time, such as 10 years.[477] Under this alternative, the revenue requirement for Nobles would decrease from $644,000 to $514,000.[478]

i. Background

432. In 2009, the Commission approved the Company's plan to include Company-owned wind generation as part of its renewable generation mix.[479]

433. Nobles is part of the Company's wind-owned generation. Nobles was selected through an RFP process where the Company sought bids for the construction of a company-owned wind project. The RFP sought bids only for projects that would be constructed by another company and then transferred to Xcel to own and operate.[480]

434. On June 10, 2009, the Commission approved the Company's acquisition of Nobles, finding that the Company needed the energy from Nobles to meet its renewable energy obligations. The Commission did not address the issue of rate recovery in that proceeding.[481]

---

[475] Issue 7.
[476] Ex. 58 at 54 (Heuer Rebuttal).
[477] Ex. 15 at 41 (Larson Rebuttal); Ex. 58 at 55 (Heuer Rebuttal).
[478] Ex. 58 at Schedule 28 (Heuer Rebuttal).
[479] ORDER APPROVING TARGET PORTFOLIO ALLOCATION WITHIN XCEL'S RENEWABLE ENERGY PLAN, Docket No. E002/M-07-1558 at 4, 9 (June 19, 2009).
[480] Ex. 15 at 35, 37 (Larson Rebuttal); *In the Matter of the Petition of Northern States Power Company, A Minnesota Corporation for Approval of Two Wind Energy Projects*, Petition at 9 (December 8, 2008).
[481] *Id.* at 34 (Larson Rebuttal); ORDER APPROVING INVESTMENTS AND EXPENDITURES, FINDING THE NOBLES PROJECT EXEMPT FROM OBTAINING A CERTIFICATE OF NEED, AND ADDING REQUIREMENTS, Docket No. E002/M-08-1437, (June 10, 2009).

435. The Company first requested recovery of its additional costs for Nobles through its 2009 RES Rider filing.[482] In that docket, the Department argued against recovery of capital costs in excess of the original estimate provided by the Company in the RES eligibility filing.[483] After considering the Department's arguments, the Commission denied recovery of the additional capital costs at that time, and limited recovery through the RES Rider to the previously approved estimates. However, in its April 22, 2010 order, the Commission left the door open for the Company to recover the additional costs in "its next rate case, upon a showing that it is reasonable to require ratepayers to pay for any such additional costs."[484]

436. In its next rate case, filed in November 2010, the Company sought recovery of its costs in excess of those identified in the RES docket. The Department and MCC opposed recovery of the additional Nobles costs. In her report, the Administrative Law Judge concluded that the Company had failed to demonstrate that additional capital costs for Nobles should be included in rate base. The Administrative Law Judge also found that if the Commission determined that recovery is permissible, then certain of the costs (landowner payments, overhead and contingency costs) were reasonable costs of the project.[485] Ultimately, the Commission did not decide the issue on the merits because the Commission approved a settlement in that docket.

ii. Current Request for Recovery of Nobles Capital Costs

437. In this rate case, the Company has again requested recovery of Nobles costs in excess of those approved in the RES Rider docket. The approximately $5.5 million in additional capital costs included by the Company in this rate case is less than the amount requested in the last rate case because the current amount is based on actual rather than estimated numbers.[486]

438. The final cost for the Nobles project is 1.6 percent greater than the original Nobles estimate.[487] The additional capital costs include costs for overhead, higher than expected land costs and contingency costs.[488]

439. The Company asserted that recovery should be allowed because: (1) the Commission had authorized it to include company-owned wind resources in its mix of

---

[482] *In the Matter or the Petition of Northern States Power for Approval of the 2010 Renewable Energy Standard Cost Recovery Rider and 2009 Renewable Energy Standard Tracker Report,* Order Approving 2010 RES Rider and 2009 RES Tracker Report, Establishing 2010 RES Charge, and Requiring Revised Tariff (April 22, 2010) (2010 RES Rider Order), Docket No. E002/M-09-1083.
[483] *Id.* at 4.
[484] *Id.* at 5.
[485] *In the Matter of the Application of Northern States Power Co. for Authority to Increase Rates for Electric Service in Minnesota*, Docket 10-971, FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION (February 22, 2012) at ¶¶ 396-416 (10-971 FINDINGS).
[486] Ex. 168 at NAC-27 (IR 1139 Response) (Campbell Direct Attachments).
[487] *See* Ex. 15 at 34 (Larson Rebuttal).
[488] Ex. 166 at 90 (Campbell Direct).

generation; (2) Nobles was acquired with Commission approval in furtherance of that generation mix; and (3) the Nobles costs are reasonable and were prudently incurred.[489]

440. In this rate case, the Department and MCC again opposed recovery of costs in excess of those approved in the RES docket.[490] The Department argued that the Company should not be allowed to recover the additional costs because Nobles was competitively bid and the Company has not shown the reasonableness of the excess costs. For example, the Department noted that the Company failed to include its own project management costs when it presented the budget for Nobles to the Commission. The Department maintained that the Company should only be allowed to recover excess costs if the costs are a result of an unforeseen or extreme event, and that no such showing has been made in this case. The Department asserted that allowing the Company to recover cost overruns after a competitive bidding process would harm the integrity of the competitive bidding process and result in unreasonable rates. [491]

441. The Company responded that the costs in the current case were not cost overruns or increased project-specific costs. The Company maintained that the additional costs were project costs that would have been incurred under any build/transfer scenario. The Company also asserted that because Nobles was not competing with independent power producer proposals, the recovery of the additional costs does not harm the bidding process. The Company maintained that Company ownership of wind projects is beneficial to customers.[492]

442. The Department also specifically challenged the reasonableness of the increased landowner payments, based on what it claimed was inconsistent testimony by Company witnesses in the last rate case. The Department noted that, in the last rate case, one witness for the Company testified that the increase in costs was due to more landowners than expected selecting the lump-sum payment method, which resulted in increased capitalized costs. However, another witness testified that O&M costs increased due to increases in lease payments.[493]

443. The Company responded that there is no inconsistency in the testimony on land owner payments. Rather, the testimony reflects the fact that there are two different payment options available for landowners – a lump sum payment or annual rental payments - and only actual costs of each were included. The increases reflect the fact that Nobles did not become operational until December 2010. The Company also maintained that the payments were not double-counted. The Company noted that in the last rate case, the Administrative Law Judge found the landowner costs to be prudent and necessary costs of the project.[494]

---

[489] Xcel Initial Brief at 102-106; Xcel Reply Brief at 61-63.
[490] Ex. 166 at 87 (Campbell Direct); Ex. 173 at 58-59; (Department Initial Brief) at 58-59; Ex. 107 at 12 (Schedin Direct).
[491] *Id.* at 87, 93; (Department Initial Brief) at 58-59.
[492] Ex. 15 at 35-38 (Larson Rebuttal); Xcel Reply Brief at 63; Tr. Vol. 1 at 80 (Larson).
[493] Ex. 166 at 90 (Campbell Direct); Ex. 173 at 94 (Campbell Rebuttal).
[494] Ex. 14 at 25-26 (Larson Direct); Ex. 15 at 40 (Larson Rebuttal).

iii. Conclusion – Nobles Capital Costs over RES Amount

444. The Administrative Law Judge concludes that the Company's request for recovery of additional costs over the amount approved in the RES Rider Docket appears to be time-barred by the Commission's April 22, 2010 Order in the RES Rider Docket.

445. In that Order, the Commission "allowed" the Company "to seek recovery, on a prospective basis, of additional costs *at the time of its next rate case*."[495] The Company filed its next rate case in November 2010. In that rate case, the Company sought recovery of the Nobles costs in excess of the RES amount. The Company, however, then elected to enter into a settlement. As a result, the Commission did not reach the merits of the issue.

446. Because the Commission's April 22, 2010 order authorized the Company to seek recovery in "*its next rate case*," which was its 2010 rate case, and there is no language in the Order authorizing the Company to seek recovery in a later rate case, the Company's request for recovery of the excess Nobles costs in the current rate case is inconsistent with the Commission's April 22, 2010 Order. For this reason, the Administrative Law Judge recommends that the Commission deny the request.

447. The Administrative Law Judge, however, recognizes that the Commission is in the best position to interpret its own orders. If the language in the April 22, 2010 Order authorizing the Company to request recovery of the additional Nobles costs "in its next rate case" was not intended foreclose recovery of the additional costs in subsequent rate cases, then the question of recovery remains.

448. In the last rate case, the Administrative Law Judge addressed this question. The Administrative Law Judge concluded that if the Commission addressed recovery of the costs, the record demonstrated that the additional costs were reasonable.[496] The record in this case also supports that conclusion.

449. With regard to the landowner payments, the Company demonstrated that there was no double-counting and that the increase was due to more landowners than expected choosing the lump-sum option. With regard to overhead and contingency costs, there was no specific challenge to these costs in this rate case. In addition, the total project costs exceed the original estimate by only 1.6 percent.[497]

450. The Company, however, failed to disclose all known costs of the Nobles project when it originally sought approval from the Commission. The Company failed to include any of its own costs in the estimate that it provided to the Commission. The

---

[495] 2010 RES RIDER ORDER at 5 (emphasis added).
[496] ALJ REPORT, Docket 10-971, at ¶¶ 406-416.
[497] Ex. 14 at 25-26 (Larson Direct); Ex. 15 at 34, 40 (Larson Rebuttal).

forecast provided to the Commission was based solely on the costs of the wind developer.[498]

451. To address this lack of disclosure by the Company when the project was originally approved but at the same time recognize the costs were reasonably incurred, the Administrative Law Judge recommends that the Commission adopt the Company's rebuttal position if the Commission allows the Company to seek recovery in this docket.[499] The Company's rebuttal proposal would allow a return of the investment (i.e. depreciation) but not a return on the investment, and, thus, appropriately balances the interests of the ratepayers and the Company in these circumstances.

I. Nuclear Employee Cash-Based Retention Program[500]

452. Xcel initially proposed to recover expenses from three new Nuclear Employee Retention programs in its 2013 test year. These programs were developed in the fall of 2012.[501] The Department opposed recovery of these expenses.[502] The Company, in its rebuttal testimony, agreed to withdraw the expenses associated with two of the programs – the Restricted Stock Units program and the Long Term Incentive program – from this rate case.[503] The Company continued to seek recovery of the $1.032 million Minnesota jurisdictional expense for its Nuclear Employee Cash-Based Retention Program.[504] The Department, in its Surrebuttal Testimony, maintained its opposition to the expense for this program.[505]

453. The nuclear industry is facing increased competition for experienced workers due to additional regulation, worldwide growth in the nuclear industry, an aging workforce, and a lack of entry-level candidates.[506]

454. Retaining a qualified work force is necessary for safe, reliable, and efficient electricity production at the Company's nuclear facilities.[507]

455. The Company has had trouble retaining employees in key nuclear positions. In September 2012, the Chief Nuclear Officer and the Prairie Island Site Vice President both resigned. In addition, the Company has identified more than 36 changes at the senior level, manager and above, in the past two years.[508] The Company currently has 114 unfilled full time positions in its Nuclear Business Unit even with

---

[498] Ex. 24 at 22 (Larson Direct).
[499] Ex. 15 at 41 (Larson Rebuttal); Ex. 58 at 55 (Heuer Rebuttal).
[500] Issue 12.
[501] Ex. 49 at 47 (O'Connor Direct).
[502] Ex. 181 at 34-37.
[503] Ex. 12 at 18 (Poferl Rebuttal).
[504] Ex. 58 at 34 (Heuer Rebuttal).
[505] Ex. 183 at 22 (Lusti Surrebuttal).
[506] Tr. Vol. 4 at 15 (Schedin); Ex. 48 at 37-39 (O'Conner Direct); Ex. 37 at 24-25 (Figoli Rebuttal).
[507] Ex. 48 at 38 (O'Conner Direct).
[508] Ex. 37 at 25 (Figoli Rebuttal); Ex. 49 at 48 (O'Connor Rebuttal).

significant hiring efforts.[509] The Company's compensation for certain nuclear positions is currently below market levels.[510]

456. In October 2012, the nuclear plant in Kewaunee, Wisconsin closed. The Company has attempted to hire employees who worked at the Kewaunee plant to fill openings at Xcel but has had little success. The Company has interviewed about 250 Kewaunee employees, extended 24 offers to qualified candidates, but only 5 offers have been accepted.[511]

457. The Company developed the Nuclear Cash-Based Retention Program to address the significant turnover in key leadership positions experienced during 2012 and to stabilize existing leadership in the division. The Company has had prior success with similar retention programs and such programs are common in the nuclear industry.[512]

458. The Department objected to recovery of the expense for the Nuclear Employee Cash-Based Retention Program. The Department noted that the Company developed the program just prior to filing its rate case and asserted that the Company failed to provide sufficient information to demonstrate the reasonableness of the expense for the program.[513] The Department stated that the Company could provide additional support for the program when it files its next rate case in the fall of 2013.[514]

459. The Company has shown a clear need for some type of retention program, given the hiring and retention challenges that it faces in the nuclear energy division. The Company has also shown that cash-based retention programs assist in holding key talent. The Company has not, however, shown that the $1.032 million requested for its new Nuclear Employee Cash-Based Retention Program is a reasonable amount. There is no information in the record explaining how the Company arrived at the $1.032 million budget for its new Nuclear Employee Retention Program.[515] Without specific financial information supporting the amount requested, there is no basis upon which to determine that the amount requested for this new program is reasonable.

460. Accordingly, the Administrative Law Judge concludes that the Company has failed to demonstrate that the $1.032 million requested for its new Nuclear Employee Retention Program in the 2013 test year is reasonable.

---

[509] Ex. 37 at 25-26 (Figoli Rebuttal).
[510] Ex. 48 at 39 (O'Connor Direct); Ex. 35 at 7 (Figoli Direct).
[511] Ex. 37 at 30 (Figoli Rebuttal).
[512] *Id.* at 25-27.
[513] Ex. 180 at 36 (Lusti Direct); Ex. 181 at Schedule 12 (Lusti Direct Attachments); Ex. 183 at 20-22 (Lusti Surrebuttal).
[514] Ex. 183 at 22 (Lusti Surrebuttal).
[515] *See* Ex. 37 at 26-27 (Figoli Rebuttal); Ex. 180 at 36 (Lusti Direct); Ex. 181 at Schedule 12 (Lusti Direct Attachments); Ex. 183 at 20-22 (Lusti Surrebuttal).

J. Non-Qualified Pension Expenses[516]

461. The Company initially included approximately $1.243 million in the 2013 test year for non-qualified pension expenses. This amount includes approximately $577,133 for its Supplemental Executive Retirement Plan (SERP) and $646,116 for its Restoration Plan.[517]

462. The Department objected to the inclusion of both the SERP and the Restoration Plan costs. The Department recommended that the Commission exclude the approximately $1.243 million in non-qualified pension expense from the 2013 test year and also exclude the Company's proposed capitalized non-qualified or supplemental costs of $213,359.[518]

463. The Company, in its Rebuttal Testimony, agreed to remove the SERP costs.[519] The Company did not agree to remove the costs associated with the Restoration Plan.[520]

464. The Department, in its Surrebuttal Testimony, continued to recommend exclusion of both the SERP and the Restoration Plan costs, leaving the Restoration Plan costs in dispute at the end of the hearing.[521]

465. The Restoration Plan makes up for any benefits lost under the qualified pension plan as a result of IRS compensation limits. The Restoration Plan provides benefits to highly-paid employees of the Company whose compensation exceeds IRS thresholds.[522]

466. The Company asserted that Restoration Plans are common in the utility industry and other industries.[523]

467. The Company maintained that Restoration Plan benefits are necessary to attract and retain talented employees. The Company also claimed that Restoration Plan benefits ensure that employees with wages exceeding the IRS-covered compensation limits receive a wage replacement benefit equal to the pay replacement for all Xcel employees.[524]

468. The Department countered that the Restoration Plan benefits are essentially tax payments made on behalf of highly compensated individuals. The Department noted that there is no evidence in the record to show that the Company

---

[516] Issue 16.
[517] Ex. 37 at 20 (Figoli Rebuttal).
[518] Ex. 166 at 58-63 (Campbell Direct).
[519] Ex. 12 at 15 (Poferal Rebuttal); Ex. 58 at 38-39 (Heuer Rebuttal).
[520] *Id.*
[521] Ex. 173 at 65 (Campbell Surrebuttal); Issue Outline Summary at 13 (May 22, 2013) (Edocket No. 20135-87287-01).
[522] Ex. 37 at 20 (Figoli Rebuttal); Ex. 166 at 61 (Campbell Direct).
[523] Ex. 37 at 20 (Figoli Rebuttal).
[524] *Id.*

would not be able to find talented employees without this benefit. The Department did not object to the Company providing this benefit, but maintained that ratepayers should not be responsible for the costs because it has not been shown to be reasonable.[525]

469. The record is insufficient to conclude that the Restoration Plan expenses included by the Company are a reasonable or necessary cost of providing utility service. There are no studies or other specific information in the record to support the Company's claim that the Restoration Plan is necessary to retain these employees. In addition, the Company's suggestion that the Plan is needed to equalize compensation with other Xcel employees is not persuasive given that the employees who receive this benefit are already the most highly paid employees of the Company. Accordingly, the Administrative Law Judge concludes that the Company has failed to demonstrate the reasonableness of the Restoration Plan expense and recommends that both the Restoration Plan and SERP costs be disallowed.

K. Directors and Officers Insurance[526]

470. The Company included approximately $1.6 million in the 2013 test year revenue requirement for Directors & Officers (D&O) and Fiduciary insurance costs.[527]

471. Insurance premiums for the D&O and Fiduciary insurance policies are paid by Xcel's service company, Xcel Energy Services, and allocated to Xcel subsidiaries, including NSP-Minnesota, through work orders using the general allocator.[528]

472. D&O insurance provides liability coverage to protect employees and the Company against claims related to actions taken within the scope of directors' and officers' normal duties. Depending on the type of coverage purchased, policies can offer several layers of protection for the Company and the individual directors and officers.[529]

473. Fiduciary liability insurance provides personal liability protection for anyone who is considered to have breached his or her fiduciary duties. "Fiduciaries" include persons who are expected to act solely on behalf of his or her representatives and may not seek personal benefits from any related transactions. A fiduciary may include retirement or benefit plan administrators, trustees, or directors and officers of a corporation.[530]

474. According to the Department, publicly held companies commonly carry D&O insurance. D&O insurance may be required by investors as a way to protect their investment. The Department did not provide any instances of fiduciary insurance being

---

[525] Ex. 166 at 61 (Campbell Direct); Ex. 173 at 64 (Campbell Surrebuttal).
[526] Issue 17.
[527] Ex. 162 at ACB-12 (Bryne Direct).
[528] *Id.* at 41.
[529] *Id.* at 40.
[530] *Id.*

required by investors, but inferred that such insurance would provide similar benefits to investors as D&O insurance.[531]

475. The Department opposed full recovery of the D&O and Fiduciary insurance expense from ratepayers because shareholders also benefit from such insurance. Instead, the Department proposed that only 50 percent, or $812,618, of the expense be allowed in test year costs.[532]

476. The Company responded that it is required by law to indemnify its directors, officers and employees under Minnesota law.[533] In the absence of this coverage, the Company would be unnecessarily exposing its customers to risks arising from running its operations and providing service.[534]

477. The Company also has fiduciary duties regarding the benefits it offers employees. The Employee Retirement Income Security Act of 1974 (ERISA) imposes liabilities for a breach of these duties.[535] In the absence of Fiduciary insurance coverage, the Company would run the risk of losses.[536]

478. Because the Company is required by law to indemnify its Directors and Officers and has fiduciary duties under ERISA, the D&O and fiduciary insurance coverage is directly related to providing utility service. These policies provide protection for particular categories of risk and provide necessary protections in the same manner as other type of insurance. As a result, the Administrative Law Judge concludes that the cost of D&O and Fiduciary insurance is a necessary and reasonable part of the cost of providing utility service and the full Minnesota jurisdictional amount is properly included as a test year expense.

479. To ensure that the Company is properly managing this expense, in its next rate case filing the Company should make the informational filing requested by the Department. This filing would address the reasons for recent increases in insurance premiums, the degree of such increases, and Xcel's efforts to mitigate increases in insurance costs. The filing would include, at a minimum, a description of the coverage for each policy that the Company holds, the amount of coverage under each policy, the steps the Company has taken to mitigate its costs, and a discussion of the relative benefits to ratepayers and shareholders. It would also provide detailed, quantitative support for recovering the expense from ratepayers.[537]

---

[531] *Id.* at 41.
[532] *Id.* at 42.
[533] Minn. Stat. § 302A.521, subd. 2.
[534] Ex. 43 at 13 (Tyson Rebuttal).
[535] *Id.* at 14.
[536] *Id*.
[537] Ex. 162 at 43 (Bryne Direct); 164 at 21 (Byrne Surrebutal).

L. Active Health Care Costs[538]

480. The Company initially proposed recovery of approximately $39.8 million for Active Health Care O&M costs in its 2013 test year.[539] The Company calculated this amount by averaging actual costs from 2008 through 2011, broken out on a per employee basis to account for varying sizes of the workforce. The Company described the result as a linear trend line, which it used to arrive at a per employee gross amount. This amount was then increased by a projected 8.00 percent annual health care cost inflation factor. The Company based this annual health care cost inflation factor on an article from PricewaterhouseCoopers, which estimated private health care costs will increase by 7.50 percent in 2013. The Company used the higher 8.0 percentage inflation factor to reflect the higher than average age of the Company's workforce.[540]

481. In Rebuttal Testimony, the Company updated its Active Health Care cost forecast based on year-end 2012 data. This update reduced its test year expense to approximately $36.2 million, which is approximately $3.6 million less than its initial test year amount. The reduction was attributed to a decline in the number of employee claims.[541]

482. The Department disputed the validity of the Company's forecast of its 2013 Active Health Care costs. The Department asserted that the Company over-recovered Active Health Care O&M and capital costs in both 2011 and 2012 as compared to its 2011 test year amount. The Department calculated the over-recovery of Active Health Care O&M costs as 13.9 percent per year on average for 2011 and 2012 on average. The Department calculated the over-recovery of capital costs in 2011 and 2012 as 31 percent per year on average.[542] The Department noted that forecasting costs "involves either using an average-cost method for situations in which costs fluctuate on a year-to-year basis or, if costs are trending upward, using an average increase inflation factor method." The Department described the Company's use of both methods as "not appropriate."[543]

483. The Department used a three-year average of health care costs to arrive at its proposed Active Health Care expense for the 2013 test year. The Department calculated the expense as approximately $34.9 million for the Active Health Care O&M cost and $7,188,290 for the Active Health Care capital cost.[544]

484. The Company responded to the Department's critique of its forecasting method for Active Health Care costs as follows:

---

[538] Issue 18.
[539] Ex. 166 at 64-65 (Campbell Direct).
[540] Ex. 38 at 38-41 (Moeller Direct).
[541] Ex. 39 at 23 (Moeller Rebuttal).
[542] Ex. 166 at 66 (Campbell Direct).
[543] *Id.* at 68.
[544] *Id.* at 69-71; Ex. 173 at 65-66 (Campbell Surrebuttal).

> Our budgeting process accounts for incorporates [sic] the historical variability of costs and persistent upward pressure on health care costs. To do so, we use two factors to budget for our health care costs: (1) the four-year linear trend line which normalizes year-to-year fluctuations in actual historical claims experience, and (2) an inflation factor, because health care costs continue to rise. I believe the unexpected decline in health care claims that I noted is a good case study supporting the use of these two factors instead of just an inflation factor.[545]

485. The record fails to support the use of the Company's forecast method to calculate its test year Active Health Care costs. The Company has not justified the use of an inflationary factor on top of the four-year linear trend. The Department has demonstrated that the historical average method is an appropriate method of calculating Active Health Care costs for ratemaking purposes. Accordingly, the Administrative Law Judge concludes that the Active Health Care costs as calculated by the Department are reasonable and should be included in the test year revenue requirement.

M. Base Salary Increase – Non-Bargaining Employees

486. The Company included an expense for the base salary costs of its employees in its 2013 test year. There is no dispute regarding the expense for Xcel employees covered by collective bargaining agreements. The Department, however, disputes the amount of the expense included in the test year for non-bargaining employees.

487. For non-bargaining employees, the Company proposed rate recovery of base salaries equal to 2012 base salary amounts, excluding a 2012 merit increase. To this amount the Company added an amount budgeted for merit increases in 2013, calculated as 2.5 percent of the total base salary of non-bargaining employees.[546] In the course of the proceeding, the Company offered an alternative which budgeted 2013 merit increases equal to 2.32 percent for non-bargaining employees, reducing the test year revenue requirement by $244,000.[547]

488. The Company contended that a 2.5 percent increase is consistent with the current market and failing to increase base salaries would result in difficulty attracting and retaining qualified employees. The Company also asserted that failing to recognize such salary increases in rates would result in under-recovery of its costs. The Company offered internal data showing the amounts forecast are likely to be incurred in 2013. The Company also demonstrated that there has been significant under-recovery of base salary costs in each of the last three years.[548]

489. The Department objected to the amount requested by the Company and instead recommended calculating the increase to base salaries of non-bargaining

[545] Ex. 39 at 24 (Moeller Rebuttal).
[546] Ex. 37 at 4 (Figoli Rebuttal).
[547] Ex. 11 at 17-18 (Poferl Rebuttal); Ex. 58 at 30 (Heuer Rebuttal).
[548] Ex. 37 at 5-7 (Figoli Rebuttal).

employees using salary data from the Company's 2008 rate case, inflated by the increases reflected in the XCEL ENERGY CORPORATE ESCALATION FACTORS Trend Forecast developed by IHS Global Insight (Global Insight data) for 2010, 2011, and 2013. The Department asserted that this approach is superior because it begins with a Commission-approved salary amount and uses historical averages to arrive at the test year forecast amount. The Department did not address the under-recovery of actual salary costs in the last three years. The Department proposed adjustments would decrease the Company's test year expenses by $2,131,791, and test year rate base by $354,757.[549]

490. The Company's approach uses current data and better reflects the Company's actual experience in paying non-bargaining employee salaries. There has been no showing that the Company's test year expenses for this item are unreasonable. The Company has shown significant under-recovery in this category for the past three years. For these reasons, the Company has demonstrated that its alternative proposal, which budgets non-bargaining base salary increases at 2.32 percent in 2013, is reasonable and prudent.

N. Additional Energy Assistance Funding[550]

491. ECC initially recommended that additional assistance be provided for customers with high usage medical equipment, for customers in emergency financial situations, and as a supplement for the Company's POWER On program. ECC proposed that late payment fees (approximately $3.2 million) be used to fund this effort.[551]

492. The Company's POWER On program provides energy assistance to high usage Low Income Home Energy Assistance Program (LIHEAP) recipients.[552] POWER On also works to increase the long-term ability of the lowest income customers to pay for electric service.[553] The POWER On program has been in operation for several years and the Company files POWER On status reports with the Commission.[554]

493. The Company and the Department both opposed ECC's original proposal for a variety of reasons.[555]

494. At the evidentiary hearing, ECC instead proposed a $3.2 million increase solely to the POWER On program. The ECC noted that the demand for the program

[549] Ex. 180 at 13-17 (Lusti Direct); Ex. 183 at 5 (Lusti Surrebuttal).
[550] Issue 21.
[551] Ex. 101 at 3, 31 (Marshall Direct).
[552] Ex. 54 at 5 (Gersack Rebuttal); Ex. 101 at 14 (Marshall Direct); Tr. Vol. 5 at 173 (Marshall).
[553] Ex. 104 at 1 (Marshall Opening Statement).
[554] *Id.*
[555] Ex. 54 at 7-9 (Gersack Rebuttal); Ex. 156 at 8 (Peirce Rebuttal).

exceeds supply.[556] Providing support in this manner would lower Other Revenues and increases the 2013 revenue requirement by $3.2 million.[557]

495. The Company and Department agreed with ECC's revised proposal.[558]

496. The MCC agreed with the concept of increasing funding for POWER On, but recommended that the amount included in base rates be prorated to reflect that the additional funding will not be in effect for the entire 2013 calendar year.[559] The MCC did not oppose full funding for the 2014 test year.[560]

497. The Commercial Group recommended the Company pay for half the additional funds for the POWER On expansion.[561]

498. The OAG did not oppose this proposed increase to low-income energy assistance. The OAG noted, however, that what started as a proposal to help low-income customers with in-home medical equipment by using late payment fee revenue, changed into an expansion of the POWER On program paid for entirely by ratepayers over and above the Company's requested revenue requirement.[562]

499. The Company stated that MCC's recommendation to prorate the 2013 funding is unnecessary. The additional funding is expected to be fully disbursed to customers annually. Also, any funds not distributed in a year will be available for disbursement in the following year.[563] The Company agreed that it will report the amounts spent as part of the existing report on low-income and affordability programs.[564]

500. The Company also disagreed with the Commercial Group's proposal. Once approved, the additional funding becomes part of the cost of service.[565]

501. The record demonstrates a need for additional energy assistance.[566] POWER On is an efficient means of delivering assistance to the Company's low-income customers. The proposal to increase POWER On funding is reasonable. The tracking mechanism to be implemented by the Company ensures the additional funds will be spent for low-income customers. Finally, allowing cost recovery of the program is

---

[556] *See e.g.*, Ex. 101 at 31 (Marshall Direct) (stating the POWER On program closed as of September, 2012 and that over 3,500 households have been denied assistance because of lack of funding); Ex. 101 at 16 (Marshall Direct).
[557] Ex. 104 at 1 (Marshall Opening Statement); Tr. Vol 3 at 183-84 (Marshall); Ex. 58 at 60-61 (Heuer Rebuttal).
[558] Tr. Vol. 5 at 236-240 (Heuer); Tr. Vol. 5 at 124 (Peirce).
[559] MCC Initial Brief at 13.
[560] *Id.*
[561] Commercial Group Initial Brief at 2.
[562] OAG Proposed Findings of Fact and Conclusions of Law at ¶ 59.
[563] Tr. Vol. 5 at 240 (Heuer).
[564] Ex. 88 at 1-2 (Heuer Opening Statement); Tr. Vol. 5 at 240 (Heuer).
[565] Tr. Vol. 5 at 241 (Heuer) and at 245-246 (Peppin).
[566] Ex. 101 at 16, 31 (Marshall Direct) (stating the POWER On program closed as of September, 2012 and that over 3,500 households have been denied assistance because of lack of funding).

consistent with state law.[567] The additional funding for the POWER On program as proposed by ECC is reasonable and should be adopted.

O. Other Operating Revenues[568]

502. Other Operating Revenues are an offset to the Company's revenue requirement, and thereby serve to lower rates.[569] The Company's rate case filing reflected the 2013 test year budget amounts for Other Operating Revenues. Based on the Department's recommendation,[570] the Company agreed to replace the budgeted amounts with a figure calculated using a 2010-2012 historical average.[571]

503. In its calculation of the historical average, the Company excluded four items: Depreciation Change; Nuclear Outage Amortization; Windsource; and Service Quality.[572] The Company excluded these items because, according to the Company, they are not part of the Company's revenue requirement or they are recovered elsewhere in the test year amounts.[573]

504. The Department agreed that it was reasonable to exclude the Windsource and Service Quality revenues.[574] The Department objected, however, to the exclusion of the Depreciation Change and the Nuclear Outage Amortization.[575] The Department also asserted that the Company should have returned all wholesale revenues from a 2012 transmission transaction to ratepayers, but did not do so because the transaction occurred outside a rate case test year. For these reasons, the Department argued that the Company's proposed amount for Other Operating Revenues is unreasonably low. The amount in dispute between the Company and the Department is $529,000.[576]

i. Depreciation Change

505. According to the Company, the Depreciation Change was necessary to neutralize a deferral of Interchange Agreement revenues due from NSP-Wisconsin and was related to the settlement in the last rate case. The Company stated that the Depreciation Change is an accounting adjustment and does not reflect additional revenue available to the Company.[577] Additionally, the Company claimed that including the Depreciation Change would result in double-counting because the change to depreciation is already reflected in the 2013 test year.[578] Therefore, the Company

---

[567] *See* Minn. Stat. § 216B.16, subd. 15(d) (stating utilities are allowed to recover the cost of affordability programs).
[568] Issue 22.
[569] Xcel Initial Brief at 117.
[570] Ex. 169 at 11-14 (Campbell Direct); Ex. 170 at Schedules 4-6 (Campbell Direct); Ex. 180 at 46 (Lusti Direct).
[571] Ex. 29 at 8-11 (Stitt Rebuttal); Ex. 58 at 40 (Heuer Rebuttal).
[572] Ex. 29 at 9-10 (Stitt Rebuttal).
[573] *Id.* at 8-9.
[574] Ex. 173 at 27-28 (Campbell Surrebuttal).
[575] *Id.*
[576] Department Initial Brief at 150-154.
[577] Ex. 29 at 9-10 (Stitt Rebuttal).
[578] *Id.*

contended the Depreciation Change should be excluded from the calculation of Other Operating Revenues.[579]

506. The Department maintained that the Depreciation Change should be included in the calculation of the historical average. The Department asserted that because depreciation is included in rates, and therefore related revenue should be included in "Other Operating Revenue" as an offset.[580] The Department also claimed that the revenue associated with the Depreciation Change may have facilitated Commission approval of the Company's settlement of the depreciation issue in the last rate case.[581]

507. The Company has demonstrated that the Depreciation Change does not reflect additional operating revenue. Therefore, the Administrative Law Judge concludes that the Company's adjustment to exclude the Depreciation Change from the calculation of Other Revenues is reasonable and appropriate.

ii. Nuclear Outage Amortization

508. At the time the Commission approved the Company's change to the deferral and amortization method for nuclear outage costs, the Company booked a prepaid expense for nuclear outage costs. This prepaid expense was amortized and repaid beginning with the Company's 2008 rate case.[582] The prepaid expense was fully amortized at the end of 2012.[583] Because the expense has been fully amortized, the Company contended that including Nuclear Outage Amortization in the calculation of the historical average of Other Operating Revenues would result in crediting the prepaid expense to customers twice.[584]

509. Similar to its position on the Depreciation Change, the Department asserted that nuclear outage expenses are included in rates and therefore the associated revenue should be credited to customers.[585] The Department also stated that the revenue associated with this item may have facilitated approval of the Company's nuclear outage amortization.[586]

510. Because including the Nuclear Outage Amortization in the historical average would result in double-counting of this item, the Company's proposal to exclude the item from the calculation of Other Operating Expenses is reasonable.

---

[579] *Id.*
[580] Ex. 173 at 28 (Campbell Surrebuttal).
[581] *Id.*
[582] Ex. 18 at 7-8 (Robinson Direct); *In the Matter of a Petition by Northern States Power Company, a Minnesota Corporation, for Accounting Treatment for Nuclear Refueling Outage Costs*, ORDER APPROVING CHANGE IN ACCOUNTING METHODOLOGY WITH CONDITIONS, Docket No E002/M-07-1489 at Order Point 3 (September 16, 2008).
[583] Ex. 29 at 9-10 (Stitt Rebuttal).
[584] Xcel Initial Brief at 119.
[585] Ex. 173 at 28 (Campbell Surrebuttal).
[586] *Id.*

iii. 2012 Transmission Transaction

511. The Department argued that the entire amount associated with the Company's 2012 sale of certain transmission assets should be included in Other Operating Revenues.[587] The Department maintained that if the transaction would have occurred in 2011 or 2013 (both of which were test years), all the proceeds would have been returned to customers.[588]

512. The Company asserted that by calculating Other Operating Revenues using a three-year average of the amounts from 2010-2012, a portion of the 2012 transaction proceeds will be returned to customers.[589] The Company also stated that its proposed transmission revenue and expense tracker account would have addressed the volatility associated with such revenues, but that proposal was rejected by the parties.[590]

513. It is reasonable to estimate the 2013 Other Operating Revenues using a three year historical average (2010-2012) that excludes four items: Depreciation Change; Nuclear Outage Amortization; Windsource; and Service Quality.[591] No adjustment is necessary for the 2012 Transmission Transaction.

P. Rate Case Amortization Expense[592]

514. No party disputed the amount of the rate case expense. The only remaining question is the appropriate time frame for amortization of the expense.

515. The Company and the Department agreed that the rate case expense should be amortized either over one or two years because the Company plans to file another rate case later this year. If a two year amortization period is used, the Company proposed that it be allowed to recover the cost of the second year in the next rate case or by reducing the interim rate refund in this case.[593]

516. The Administrative Law Judge concludes that a one year amortization period is reasonable because the Company has stated repeatedly that it plans to file another rate case before the end of 2013.[594] Accordingly, the Administrative Law Judge recommends that the Commission adopt a one year amortization period for the rate case expense.

---

[587] Department Initial Brief at 150-151.
[588] Ex. 166 at 14 (Campbell Direct).
[589] Ex. 15 at 43 (Larson Rebuttal).
[590] *Id.* at 42.
[591] Ex. 29 at 9-10 (Stitt Rebuttal).
[592] Issue 27.
[593] Ex. 56 at 90-91 (Heuer Direct); Ex. 180 at 37-40 (Lusti Direct); Ex. 58 at 10-12 (Heuer Rebuttal); Ex. 183 at 23-25 (Lusti Surrebuttal).
[594] *See*, *e.g.*, Ex. 12 at 7, 21 (Poferl Rebuttal).

Q. Investor Relations Costs[595]

517. The Company requested recovery of $821,971 in the 2013 test year revenue requirement for investor relations costs.[596] The Department recommended limiting recovery to 50 percent of the costs.[597]

518. Investor relations costs include the following activities:

- Communications to investors and the financial community;
- Coordinating transactions with the transfer agent;
- Shareholder record-keeping functions; and
- Planning for annual shareholder meetings.[598]

519. In Direct Testimony, the Department asserted that the Company had failed to provide evidence demonstrating that it is reasonable for ratepayers alone to pay for the Company's investor relations costs. The Department noted that the Company acknowledged that shareholders also benefit from investor relations activities through the performance of the Company's stock. For these reasons, the Department recommended that 50 percent of the investor relations costs be excluded from the test year.[599]

520. In response to the Department's testimony, the Company asserted that investor relations activities are necessary to raise both debt and equity in a cost-effective manner. The Company stated that the activities help achieve positive credit ratings and strong investor demand for its long-term debt securities and sales of its shares. Access to public markets is especially important in light of the Company's significant investment plans. These activities help the Company manage its financing costs.[600]

521. In Surrebuttal Testimony, the Department recognized that investor relations expenses provide some benefit to ratepayers, but asserted that ratepayers do not cause all of the costs. Some of the expenses, such as the costs of the Company's annual shareholder meeting and providing on-line services, are provided for shareholders. In addition, the Department noted that the Company did not provide a means to determine which costs are incurred to support ratepayers. For these reasons, the Department continued to recommend that the Commission allow recovery of only 50 percent of the costs of investor relations activities.[601]

---

[595] Issue 32.
[596] Ex. 28 at 38-40 (Stitt Direct).
[597] Ex. 162 at 39 (Byrne Direct); Ex. 164 at 18 (Bryne Surreubttal).
[598] Ex. 28 at 39 (Stitt Direct).
[599] Ex. 162 at 38-39 (Byrne Direct).
[600] Ex. 43 at 8-12 (Tyson Rebuttal); Ex. 11 at 1 (Poferl Direct).
[601] Ex. 164 at 17-18 (Bryne Surrebuttal).

522. The Company has demonstrated that investor relations costs generally benefit both ratepayers and shareholders. Some costs, however, such as the annual meeting are of no or partial benefit to ratepayers. Absent a more exact method of allocation, the Department's position to allow 50 percent of the investor relations costs is reasonable. This recommendation is consistent with the recommendation made by the Administrative Law Judge in the last rate case.[602]

R. Transmission Studies[603]

523. The Company requested recovery of costs for transmission studies. These studies were included as an expense of providing service.

524. The Department did not challenge the reasonableness of the costs, but rather recommended that 50 percent of the test year expense for transmission studies be capitalized on the grounds that about half of the projects would result in a future capital project.[604] The Department's proposed adjustment would increase rate base by $366,595 and reduce revenue requirements by $733,189.[605]

525. In Rebuttal Testimony, the Company asserted that it had reviewed each transmission study in the test year and concluded the study costs were appropriately treated as an expense under the Company's capitalization policy because the studies do not yet have the probability of resulting in a specific future capital project.[606]

526. In Surrebuttal Testimony, the Department identified several projects that it believes are likely to be constructed. Based on this assertion, it continued to recommend 50 percent of the test year expense be capitalized. The Department's calculation of the amount to be capitalized, however, does not appear to be based on project-specific study costs, but rather appears to be based on 50 percent of the total costs for all project studies.[607]

527. The issue to be decided by the Commission is whether certain specific study costs should be capitalized. The Company, under its capitalization policy, cannot capitalize the costs of any of the specific studies absent a Commission order identifying the studies to be capitalized.[608] Because the Department's recommendation does not appear to be based on specific studies, the Company has appropriately sought recovery of these transmission study costs as an expense item.

---

[602] *See* Findings 344-345 in the 10-971 Report.
[603] Issue 33.
[604] Ex. 166 at 75-79 (Campbell Direct); Ex. 173 at 72-76 (Campbell Surrebuttal); Ex. 173 at 6 (Campbell Opening Statement).
[605] Ex. 173 at 76 (Campbell Surrebuttal).
[606] Ex. 52, at 36-38 (Perkett Rebuttal); Ex. 58 at 49-50 (Heuer Rebuttal). The Company stated that specific study costs could be capitalized if the Commission directed capital treatment. Ex. 52 at 38 (Perkett Rebuttal).
[607] Ex. 173 at 75, Schedule NAC-S-5 (Campbell Surrebuttal - Public); Ex. 174 at 75 (Campbell Surrebuttal – Non-Public).
[608] Ex. 52 at 37 (Perkett Rebuttal).

S. FERC 921 Fluctuations[609]

528. The Company requested recovery of approximately $47 million in expenses that are included in FERC Account 921 (Administrative and General Office Supplies and Expenses).[610] The Company stated that this expense has increased since the Company's 2010 rate case largely because of: 1) a correction in the allocation for phones and computers used by nuclear employees, which was identified in 2012; 2) moving costs from other FERC accounts; and 3) costs for software maintenance, data storage and communication technology. The total increase is an average annual increase of 3.44 percent since 2011.[611]

529. The Department initially recommended removing some amounts from this category and using a three-year average of the remaining amounts to establish the test year expense. The Department also recommended that as part of the Company's next initial rate case filing, the Company compare its General Ledger to the actual costs shown in its FERC Form 1 rate case income statement and balance sheet schedules. The Department made this recommendation because the comparison is necessary to review the FERC Account 921 costs and it is difficult to accomplish through information requests.[612]

530. In Surrebuttal Testimony, the Department accepted the Company's explanation as to what costs should be included, but continued to recommend use of a three-year historic average for these costs. This approach would result in a lowering of the test year revenue requirement by approximately $1.08 million. The Department also continued to recommend that the Commission require the Company to provide a General Ledger comparison as part of its next initial rate case filing, and to explain any large differences between actual expenses and the test year.[613]

531. The Company has demonstrated that the 2013 test year cost levels for its FERC Account 921 are just and reasonable. The record establishes that the expected increases above the 2011 test year are primarily due to accounting corrections and increased software maintenance, communication technology, and data storage costs.[614]

532. The FERC Account 921 costs are reasonable and prudent expenses to the provision of utility service and the costs are representative of what the Company would be expected to incur during the test year. The effective 2013 test year level, after accounting explanations ($40.3 million), is nearly the same as the level of costs incurred in 2010 ($40.1 million).[615] Using a three-year average to derive this number, as

---

[609] Issue 34.
[610] Ex. 162 at 49 (Byrne Direct).
[611] Ex. 29 at 13-16, and Schedules 3, 4 and 5 (Stitt Rebuttal).
[612] Ex. 162 at 53 (Byrne Direct).
[613] Ex. 164 at 21-25, 30 (Bryne Surrebuttal).
[614] Ex. 29 at 15-16 (Stitt Rebuttal).
[615] Ex. 164 at 24 (Byrne Surrebuttal).

proposed by the Department, would understate the Company's actual test year costs and would not result in a reasonable cost of service for this item.[616]

533. The Department's request that the Commission require the Company to provide additional information in its initial filing in its next rate case is reasonable.

T. Nuclear Fees[617]

534. The Company pays a number of nuclear-related fees including fees to government agencies, nuclear industry organizations, and nuclear equipment owner groups. The government agencies include the Nuclear Regulatory Commission (NRC), the U.S. Department of Homeland Security (DHS), the Federal Emergency Management Agency (FEMA) and Minnesota and Wisconsin state agencies. The government agency fees compromise approximately 80 percent of the total fees paid by the Company. The Company also pays fees to industry organizations such as the Nuclear Energy Institute and equipment owners groups such as the Boiling Water Reactor Owners Group.[618]

535. The Company requested recovery of approximately $34.8 million for nuclear related fees in its 2013 test year. The Company based this amount on fee estimates it received from the respective agencies for the current fiscal period, and then projected increases through the end of the test year. The Company has used a similar process for estimating its nuclear-related costs in the past.[619]

536. The Company provided a break-down of the estimated fees. The Company noted that the biggest increase in its nuclear fees has been in the area of emergency planning (EP). Over the last two years, the EP fees assessed by FEMA and state EP agencies have increased approximately $2.4 million, or an average of about 27 percent per year.[620]

537. In Rebuttal Testimony, the Company noted that, based on updated information from the government agencies, the Company expects that its actual nuclear-related fees will be higher than the amount included in the 2013 test year.[621]

538. Neither the Department nor any other party disputed the need to pay nuclear-related fees. The Department did, however, dispute the reasonableness of the amount included by the Company in its 2013 test year.

539. The Department questioned the reasonableness of the $34.8 million included by the Company because the Company has a history of over-estimating its

---

[616] Ex. 29 at 16 (Stitt Rebuttal).
[617] Issue 35.
[618] Ex. 48 at 41 (O'Connor Direct).
[619] *Id.* at 42 (O'Connor Direct); Ex. 49 at 50, 53 (O'Connor Surrebuttal) (explaining how nuclear fees are estimated for the test year, and noting that in 2011 the fee amount was less than anticipated based on agency guidance).
[620] Ex. 48 at 42 (O'Connor Direct); Ex. 49 at 51 (O'Connor Surrebuttal).
[621] Ex. 59 at 52 (O'Connor Surrebuttal).

nuclear-related fees. The $34.8 million requested represents a 9.8 percent increase over the $31.7 million actually paid in 2012 for nuclear-related fees. In addition, nuclear-related fees actually paid in 2011 and 2012 were less than the amount used in the 2011 test year in the last rate case. Fees paid in 2011 were $30.9 million and fees paid in 2012 were $31.7 million, whereas the 2011 test year included an amount of $32.6 million for nuclear-related fees. The Department noted that actual 2012 nuclear-related fees only resulted in a 3.65 percent annual increase for 2010 through 2012.[622]

540. Based on this past experience, the Department recommended the recovery of the 2013 nuclear-related fees be set at 3.65 percent over actual 2012 nuclear fees, or $32.86 million. This amount represents a $1.94 million reduction to the revenue requirement on a total company basis. Using the jurisdictional allocator, this results in a $1.45 million reduction to nuclear-related fees on a Minnesota jurisdictional basis.[623]

541. The Department maintained that historical averages are useful in determining the reasonableness of costs and in evaluating the direction that costs may be trending. The Department noted that the Company did not provide any underlying documentation from the government agencies to support the projected $34.8 million nuclear-related fee expense. The Department also asserted that the Company appears to highlight cost increases without giving equal consideration to likely cost decreases.[624]

542. The record in this case shows that the Company has overestimated its actual nuclear-related fees in recent years. The Company has not explained why its current test year estimate is any more reliable than its 2011 test year estimate, which proved to be too high. In addition, while the Company has provided testimony that its 2013 test year expense for nuclear-related fees is based on information from the pertinent government agencies and industry groups, it is difficult to assess how firm or reliable the Company's estimate is without the underlying information provided by those entities. For these reasons and given that any doubt as to reasonableness is to be resolved in favor of the consumer,[625] the Administrative Law Judge concludes that the Company has failed to demonstrate that the amount the Company included in its 2013 test year for nuclear-related fees is reasonable. Instead, the Administrative Law Judge concludes, based on the record of fees actually paid, that the alternative amount proposed by the Department is reasonable.

U. Property Tax Expense[626]

543. The Company requested recovery of $142.3 million in 2013 test year property taxes,[627] approximately $40 million more than the Company sought in its last

[622] Ex. 166 at 124-26 (Campbell Direct); Ex. 175 (Campbell Summary Opening Statement).
[623] Ex. 166 at 126 (Campbell Direct); Ex. 175 at 115.
[624] Ex. 173 at 114-16 (Campbell Surrebuttal).
[625] *See* Minn. Stat. § 216B.03.
[626] Issue 43.
[627] Ex. 58 at Schedule 20, Page 1 of 3 (Heuer Rebuttal); Ex. 88 at 3 (Heuer Opening Statement); Ex. 77 (Duevel Supplemental Examination).

rate case.[628] The increase in property taxes is primarily attributable to: 1) the Company's system investments; 2) changes in Minnesota Department of Revenue (DOR) valuation inputs; and 3) increases in local property tax rates.[629]

544. The Company also proposed that the Commission create a Property Tax Rider to address the inherent timing issues in the property tax system, which cause a difference between the amount of property taxes included in the test year and the actual property taxes paid by the Company. A Property Tax Rider was also proposed by the Company to address the recent substantial increases in property taxes.[630]

545. A number of parties disagreed with the Company's proposed Property Tax Rider. As a result, the Company agreed to withdraw its proposed Property Tax Rider.[631]

546. The Department, XLI, and the ICI Group also disagreed with some aspects of the Company's forecasted property tax expense.[632] MCC offered an alternative calculation of the test year property tax expense.[633] The remaining property tax issues before the Commission are the forecast and the amount of property tax expense to include in the 2013 test year.

i. The Company's 2013 Property Tax Forecast and Adjustments

547. The Company asserted that it forecasts its property taxes using a methodology that projects certain inputs and incorporates actual information as it becomes available.[634] Due to the length and timing of the property tax cycle, important information regarding the Company's 2013 property tax expense was not available when the Application was filed. The Company updated its forecast as new information became available.[635]

548. The Company's initial property tax forecast of $137.7 million was based on projected December 31, 2012 plant balances, projected 2013 Minnesota DOR capitalization rates and 2011 tax rates.[636]

549. Over the course of the proceeding, the Company adjusted its forecast in three ways. First, the Company updated 2012 local tax rates based on the 2012 Truth in Taxation Notices.[637] This eliminated one year of the two-year lag in tax rates (2013

[628] Ex. 58 at Schedule 20, Page 1 of 3 (Heuer Rebuttal); Ex. 88 at 3 (Heuer Opening Statement); Ex. 77 (Duevel Supplemental Examination); Ex. 31 at Schedule 6 (Duevel Rebuttal).
[629] Ex. 30 at 5-6 (Duevel Direct).
[630] *Id.* at 10-11 (Duevel Direct).
[631] Ex. 31 at 2 (Duevel Rebuttal).
[632] Ex. 183 at 33 (Lusti Surrebuttal); Tr. Vol. 5 at 225-226 (Lusti); Department Edits to Issues List – Red-Line at 31 (May 15, 2013); Ex. 119 at 25 (Pollock Direct); ICI Group Initial Brief at 4.
[633] Ex. 107 at 19 (Schedin Direct); MCC Edits to Issues List – Red-Line at 29 (May 15, 2013).
[634] Ex. 30 at 9 (Duevel Direct).
[635] Ex. 30 at 11-12 (Duevel Direct); Ex. 31 at 3 (Duevel Rebuttal).
[636] Ex. 56 at Schedule 23 (Heuer Direct); Ex. 30 at 9 (Duevel Direct); Ex. 31 at 6-8 (Duevel Rebuttal).
[637] Ex. 31 at 3-4 (Duevel Rebuttal).

property taxes are based on 2012 tax rates) and increased the expense by $3.996 million.[638] The Department accepted this update.[639]

550. Second, the Company made an update to reflect the DOR's 2013 capitalization rates.[640] The 2013 DOR capitalization rates are higher than the Company's projected capitalization rates.[641] Incorporating the new capitalization rates reduced the test year property tax expense by $2.845 million.[642] The Department accepted this update.[643]

551. XLI initially challenged the Company's projected DOR capitalization rates and recommended using actual, 2012 DOR capitalization rates.[644] By replacing the Company's projected capitalization rates with the DOR's 2013 capitalization rates, the Company effectively resolved XLI's concerns.

552. Third, in Rebuttal Testimony, the Company added a new component to its calculation of its 2013 property tax expense. This component is intended to reflect the Company's belief that there will be an increase in the 2013 local tax rates.[645] This new component is based on the average fourth quarter increase in Minnesota property tax forecasts from 2009 through 2012.[646] The adjustment for this component increased the property tax expense by $4.6 million on a total company basis ($3.444 million on a Minnesota jurisdictional basis).[647] The Company stated this adjustment was appropriate given its decision to withdraw a proposed Property Tax Rider in response to opposition by parties.[648] The Company also proposed a one-time refund to customers of the difference between the test year property tax expense and the property tax expense recorded as of December 31, 2013. The Company made its refund proposal contingent upon inclusion of this new component in its 2013 test year expense.[649]

553. The Department and the ICI Group objected to the inclusion of this new component in the calculation of the Company's 2013 property tax expense.[650] The Department opposed the proposed adjustment for this new element on the grounds that it adds a new component to the property tax calculation, and because it was not

---

[638] Ex. 31 at 3 (Duevel Rebuttal); Ex. 184 at 6 of 6 (Lusti Evidentiary Hearing Financial Schedules at DOC Operating Income Adjustments) (showing the amount of the adjustment).
[639] Ex. 184, DVL-HE-7 at Page 6 of 6 (Lusti Evidentiary Hearing Financial Schedules, DOC Operating Income Adjustments at note 47).
[640] Ex. 77 at 1, 3 (Duevel Supplemental Examination).
[641] *Id.* at 1.
[642] Ex. 88 at 3 (Heuer Opening Statement).
[643] Ex. 184, DVL-HE-7 at Page 6 of 6 (Lusti Evidentiary Hearing Financial Schedules, DOC Operating Income Adjustments at note 47).
[644] Ex. 119 at 23, 26 (Pollock Direct).
[645] Ex. 31 at 4-5 (Duevel Rebuttal).
[646] *Id.*
[647] *Id.* at 5; Final Issues List, Issue 43 at 34 of 55.
[648] Ex. 31 at 4-5 (Duevel Rebuttal).
[649] Ex. 31 at 5 (Duevel Rebuttal).
[650] Tr. Vol. 5 at 225-226 (Lusti); Department Edits to Issues List – Red-Line at 31 (May 15, 2013); ICI Group Initial Brief at 4.

discussed in Direct Testimony.[651] The ICI Group also opposed the addition of this new component in the 2013 property tax forecast because it was raised for the first time in Rebuttal Testimony.[652]

ii. Reasonableness of the Forecast

554. The purpose of the test year is to produce an accurate measure of the Company's revenues and expenses during the test year.[653] In order to arrive at an accurate measure, the Commission is "disinclined to exclude useful information absent a showing that its inclusion raises problems of fairness or accuracy."[654]

555. Applying this standard, the Administrative Law Judge concludes that the updates to reflect the 2012 Truth in Taxation Notices and the 2013 DOR capitalization rates should be incorporated into the calculation of the expense. They are accurate and their inclusion is fair.

556. The Company's proposal to add a new component to the calculation of the 2013 property tax expense, however, does not meet this standard. First, the adjustment proposed by the Company for an assumed increase in 2013 local tax rates has not been shown to be accurate. There is no evidence in the record to demonstrate that, in the current fiscal environment, any increase in local tax rates will result in a $3.44 million increase to the Company's 2013 property tax expense (on a Minnesota jurisdictional basis). The four year (2009-2012) average is based on past economic conditions, and fails to consider current conditions. While the Company's proposal to provide a refund of any over-collection would address this concern, the Company still has the burden to prove that the amount it has proposed is reasonable. The limited evidence provided by the Company to support the inclusion of this new component is not sufficient to meet that burden.

557. Also, the Company's proposal to add this new component raises fairness questions. The Company added this component to its calculation for the first time in its Rebuttal Testimony. Given that the parties only had 15 working days between the filing of Rebuttal Testimony and Surrebuttal Testimony and had an extremely large number of other issues to examine and address, the Company's addition of this new component at that late stage in the proceeding was not fair. There is no reason why the Company could not have included this component in its initial filing in November 2012.

---

[651] Department Edits to Issues List – Red-Line at 31 (May 15, 2013); Tr. Vol. 5 at 225-226 (Lusti).
[652] ICI Group Initial Brief at 4.
[653] *Northwestern Bell Tel. Co. v. State*, 253 N.W.2d 815, 822 (Minn. 1977).
[654] In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota, Docket No. E002/GR-91-1, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 7 (November 27, 1991).

iii. MCC's Proposal

558. MCC recommended setting the 2013 test year expense at the same level as the Company's 2012 property tax expense.[655] MCC's proposal does not result in an accurate expense for 2013 because it ignores current information.

559. MCC recommended delaying any property tax refund until after appeals are completed.[656] This proposal is unnecessary.[657]

iv. Conclusion

560. For these reasons, the Company has demonstrated that its initial 2013 test year expense as updated to reflect 2012 Truth in Taxation Notices and the DOR's 2013 capitalization rates is reasonable and should be adopted. The Company's proposed inclusion of a $3.44 million adjustment to account for an assumed increase in 2013 local tax rates is not reasonable and should not be adopted.

V. Prairie Island Steam Generator/Rate Base Adjustment[658]

561. The Steam Generator Project (SGR Project) at Prairie Island Unit 2 will replace the two steam generators that have been in use at the facility for more than 38 years.[659] The steam generators have now reached the end of their operating lives and need to be replaced to support an additional 20 years of operations at the plant.[660] The total in-service cost is $285 million.[661] The Company completed the SGR Project at Prairie Island Unit 1 in 2004, and has based its current cost and schedule projections upon that experience.[662] The Unit 2 SGR Project cost categories are consistent with the types of costs incurred for the Prairie Island Unit 1 SGR Project, and the budget for the Unit 2 SGR was informed by the knowledge and experience gained from the Unit 1 SGR Project.[663]

562. The Company requested NRC approval for the Prairie Island Unit 2 SGR Project last year and its request is expected to be approved by the NRC on August 31, 2013, in advance of the final Project implementation.[664] The NRC has indicated that the Company has met its compliance requirements and the agency is in the final approval process.[665] Industry-wide, these projects have not experienced the same types of

---

[655] Ex. 107 at 19 (Schedin Direct).
[656] MCC Brief – Issues List at 29 (May 15, 2013).
[657] Xcel Initial Brief at 128. *See also In the Matter of a Request by Northern States Power Company d/b/a/ Xcel Energy for Approval of Deferred Accounting for Various Tax Matters*, Docket No. E-002/M-04-1605, ORDER (January 18, 2005) (approving deferred accounting to refund to customers funds related to disputed income tax items).
[658] Issue 47.
[659] Ex. 48 at 27 (O'Connor Direct); Ex. 49 at 31 (O'Connor Rebuttal).
[660] *Id.*
[661] *Id.*
[662] Ex. 49 at 36 (O'Connor Rebuttal).
[663] *Id.*
[664] *Id.* at 37 (O'Connor Rebuttal); Tr. Vol. 2 at 130 (O'Connor).
[665] *Id.* at 37 (O'Connor Rebuttal).

licensing delays as seen by projects like the Monticello LCM/EPU Project.[666] Under the current schedule, the Unit 2 SGR will be returned to service in the middle of the fourth quarter of 2013, with the new steam generators fully in service, and producing the full output steam requirements for Unit 2.

563. Because the Unit 2 SGR Project is currently on schedule and on budget, the Company and the Department agreed on the test year revenue requirement related project.[667] MCC, however, asserted these costs should be kept in CWIP until the project is complete and NRC approval is obtained. Alternatively, MCC recommended that the project be left in rate base provided that it is removed from rate base (including the return, depreciation, and operating costs) if NRC approval is not received by the time of the compliance filing following the Commission Order in this case. The amount in dispute is $6.364 million.[668]

564. The Administrative Law Judge concludes that the Company has shown with reasonable certainty that the project will receive NRC approval and be operational during the current test year. Accordingly, the Administrative Law Judge concludes that the project will be "used and useful" during the test year and recommends inclusion of the costs of the Unit 2 SGR Project in rate base for the 2013 test year.

W. Depreciation Expenses and Reserves[669]

565. In its 2013 test year, the Company included depreciation expenses based on proposals in its pending depreciation and decommissioning proceedings before the PUC. It also included a change that the Company expects to propose in its 2013 Remaining Lives filing.[670] The test year expenses incorporate the Company's proposal in the depreciation proceeding to change depreciation for Transmission, Distribution and Generation (TD&G) assets from an average service life method to a remaining service life depreciation method, based on the Company's most recent five-year depreciation study.[671]

566. XLI objected to the Company's test year depreciation expenses for TD&G and nuclear assets. XLI claimed that the Company overstated its depreciation expenses because it "ignored" the surplus in its depreciation reserve.[672] XLI initially alleged that the Company has a $602 million surplus for the Minnesota jurisdiction.[673] XLI later revised its estimate to $484 million, which consists of an alleged $219 million nuclear plant depreciation surplus and an alleged $265 million TD&G depreciation surplus. XLI proposed that the Company amortize the alleged $484 million depreciation

---

[666] *Id.*
[667] *See Id.* at 38 (O'Connor Rebuttal); Ex. 173 at 14 (Campbell Surrebuttal).
[668] Ex. 107 at 17-18 (Schedin Direct); Ex.108 at 11-12 (Schedin Surrebuttal); Final Issues List, Issue 47.
[669] Issue 48.
[670] Ex. 52 at 25 (Perkett Direct).
[671] *Id.* at 2-3, 9-11.
[672] Ex. 119 at 9-10 (Pollock Direct).
[673] *Id.* at 10.

surplus over five years to help mitigate the rate increases in this case.[674] XLI noted that the rate increases proposed by the Company in this case are the largest in its history.[675]

567. MCC also recommended that the Company amortize the TD&G surplus over five years to help mitigate rate impacts. MCC did not address the issue of nuclear plant depreciation.[676] MCC asserted that ratepayers need relief now and are facing economic conditions that necessitate amortization of the surplus.[677]

568. For reasons explained in more detail below, the Company and the Department opposed the XLI and MCC proposals.

i. Depreciation Methods

569. Depreciation reflects the consumption or use of assets used to provide utility service.[678] "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 known to be in current operation and against which the utility is not protected by insurance."[679]

570. "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."[680]

571. The Commission:

> [p]rescribes the straight-line method for calculating depreciation, excluding depletion, accruals. Depletion costs should be allocated on the basis of the unit-of-production method. Any exceptions to these methods will require specific justification and certification by the [C]ommission. No specific methods are prescribed by the [C]ommission in estimating service lives and salvage values. The methods selected by each utility will be reviewed for appropriateness by the [D]epartment staff as part of the utility's certification filing.[681]

---

[674] *Id.* at 13 (Pollock Direct); Ex. 122 at 11 (Pollock Surrebuttal) (revising estimate of the surplus to $484 million).
[675] Post-Hearing Brief of the Xcel Large Industrials at 10.
[676] Ex. 108 (Schedin Direct) (recommending return of the TD&G surplus; Mr. Schedin refers to the total company TD&G surplus of $317 million, not the Minnesota jurisdiction portion).
[677] Initial Brief of the Minnesota Chamber of Commerce at 9; Ex. 110 (Willimanson Surrebuttal) at 2 (explaining that Cypress Semiconductor cannot pass on rate increases to its customers); Ex. 111 at 2 (Myhrman Surrebuttal) (stating that RockTenn, a manufacturer of recycled paperboard, cannot pass along electric rate increases).
[678] Ex. 119 at 11 (Pollock Direct).
[679] Minn. R. 7825.0500, subp. 6.
[680] Minn. R. 7825.0500, subp. 7.
[681] Minn. R. 7825.0800.

572. 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.[682]

573. Where a depreciation reserve surplus arises, the two most common methods of eliminating an imbalance are annual amortization over a short period of time and the setting of depreciation rates using the remaining life technique. [683]

574. Under Minn. R. 7825.0800, the Commission can deviate from straight line depreciation and authorize amortization of surplus depreciation over a defined period of time (i.e., five year period) if it finds there is a specific justification for doing so.[684]

ii. Nuclear Asset Reserve

575. XLI initially alleged that the Company has a nuclear reserve surplus of approximately $338 million for the Minnesota jurisdiction.[685] XLI later revised this estimate to approximately $219 million to account for interim retirements and interim net salvage costs of nuclear assets.[686] The alleged $219 million reserve depreciation surplus equals the amount by which the actual reserve exceeds the theoretical reserve for nuclear production plant.[687]

576. The actual reserve represents the actual accumulated depreciation balance. The theoretical reserve is a prospective view, and represents the amount calculated such that it and annual accruals over the estimated remaining life of the property will equal the original cost, adjusted for net salvage value, as the assets retire over the future life curve or through interim retirements.[688]

577. For nuclear assets, the approved remaining life is unit-specific and assumes final retirement at shutdown. To properly analyze whether a reserve exists for nuclear assets, interim retirements and associated interim net salvage values should be included.[689]

---

[682] Ex. 122 at 7 (Pollock Surrebuttal) (quoting *NARUC Public Utility Depreciation Practices*, August 1996 at 1 and 187).
[683] Ex. 119 at 20 (Pollock Direct) (quoting *NARUC Public Utility Depreciation Practices*, August 1996 at 189).
[684] Tr. Vol. 2 at 179-181 (Perkett); Minn. R. 7825.0800.
[685] Ex. 119 at 15 (Pollock Direct).
[686] Ex. 122 at 11, Schedule 30 (Pollock Surrebuttal).
[687] *Id.*
[688] Ex. 52 at 17 (Perkett Rebuttal).
[689] *Id.*

578. The Company maintained that XLI's $219 million nuclear reserve calculation fails to adequately account for interim retirements and interim salvage at its three nuclear plants.[690] The $219 million estimate calculated by XLI assumes that the interim retirements for each of these plants are the same as those experienced in the 2007-2011 timeframe.[691] According to the Company, the actual retirements that occurred during 2007-2011 are not representative of future interim retirements.[692]

579. The Company asserted that there is actually no excess depreciation for its nuclear plants as demonstrated in its annual remaining live filings with the Commission.[693] The Company stated that interim retirements and interim salvage will occur during the remaining lives of its three nuclear plants starting in 2013. The shorter interim lives require additional current reserves, and salvage costs will be deducted from accumulated depreciation reserves. The existing reserve is needed to account for these interim plant retirements and interim salvage.[694] The Company also anticipates investing more than $1 billion in its nuclear plants over the next four years, from 2014 to 2017. Those investments will result in additional depreciation expense compounded by the interim net salvage necessary to retire the assets being replaced. According to the Company, returning any of the current nuclear reserve would further increase future rates.[695]

580. For these reasons, the Company recommended that XLI's proposal be denied and that the current remaining life method be continued.[696]

581. The Department agreed with the Company's recommendation. The Department asserted that it is highly unlikely that there is a surplus reserve for nuclear assets given that nuclear costs are the largest driver in this rate case. The Department expressed concern that any surplus will be short-lived and that the nuclear depreciation expense in future rate cases will be significantly higher.[697]

582. The Administrative Law Judge concludes that the Company has established by a preponderance of the evidence that there is no surplus depreciation reserve for nuclear assets because the existing reserve is needed to account for interim plant retirements and interim salvage of nuclear assets. In addition, as noted by the Company and the Department, the Company will be making significant investments in its nuclear assets in the near future. These investments will require additional depreciation expense. Accordingly, the Administrative Law Judge recommends that the Commission reject XLI's proposal to amortize the claimed nuclear depreciation reserve over five years.

---

[690] *See* Ex. 122 at 11 (Pollock Surrebuttal); Ex. 52 at 19-20 (Perkett Rebuttal).
[691] Ex. 122 at 11.
[692] *See Id.*; Ex. 52 at 19-20 (Perkett Rebuttal).
[693] *See* Ex. 52 at 18-19; Xcel Initial Brief at 132.
[694] Ex. 52 at 19-20.
[695] *See Id.* at 21.
[696] *Id.*
[697] Ex. 172 at 5 (Campbell Rebuttal).

iii. TD&G Asset Reserve

583. The parties agree that there is a $317 million reserve surplus for TD&G assets ($265 million on a Minnesota jurisdictional basis). This surplus represents the amount that the actual reserve exceeds the theoretical reserve for TD&G Assets.[698]

584. This surplus has accrued as a result of the Company's use of the average service life methodology. The Company has proposed in its Five Year TD&G Depreciation Study docket, Docket E,G002/D-12-858, to change from the average service life methodology to the remaining life methodology for TD&G assets. The Company maintained that this change will amortize the $317 million ($265 million Minnesota jurisdiction) difference between the actual and theoretical reserves over the 33.47 average remaining life of the assets, resulting in a reduction of the annual TD&G depreciation expense of $9.5 million. The Company has incorporated this proposed change in methodology into its 2013 test year.[699]

585. As noted above, XLI and MCC both proposed that the Commission instead require that the $265 million reserve surplus be amortized over a five year period.

586. XLI recommended that the Commission require the Company to amortize the depreciation reserve over five years for several reasons. First, the annual TD&G depreciation reserve is over twice the annual expense.[700] Second, according to XLI, the TD&G depreciation surplus indicates that current customers are paying more depreciation than necessary, and amortization will restore generational equity.[701] Third, the rate relief provided by XLI's proposal would be significant.[702] XLI also noted that both the Georgia Public Service Commission and the Florida Public Service Commission have required the use of surplus depreciation to help mitigate rate increases.[703]

587. Like XLI, MCC recommended that the Commission require amortization of the TD&G reserve difference over the next five years because it would help mitigate the rate impact in the current rate case.[704]

588. The Company disagreed with the five year amortization proposal for several reasons. First, the difference between the actual and theoretical reserves represents costs recovered from prior customers based on the facts at the time, not

---

[698] Ex. 119 at 13 (Pollock Direct); Ex. 108 at 13 (Schedin Direct); Ex. 52 at 15 (Perkett Rebuttal).
[699] Ex. 51 at 21-23, 25 (Perkett Direct); Ex. 52 at 24 (Perkett Rebuttal at 24). (In her Direct Testimony, Witness Perkett states that the average remaining life of the TD&G assets is 33.47 years. In her Rebuttal Testimony, she states that the average remaining life is 28.47 years. *Compare*, Ex. 51 at 23 *with* Ex. 52 at 24.)
[700] Trans. Vol. 2 at 179 (Perkett).
[701] Ex. 119 at 10 (Pollock Direct); Trans. Vol. 4 at 132 (Pollock).
[702] *See* Ex. 122 at Schedule 30 (Pollock Surrebuttal).
[703] Ex. 119 at 20 (Pollock Direct).
[704] Ex. 108 at 13-15 (Schedin Direct).

current customers.[705] Second, because all of the accumulated reserves will be needed over the remaining lives of the TD&G assets, the proposal to use a five-year amortization period would require higher depreciation rates beginning in the sixth year, 2018.[706] Finally, the Company maintained that its approach is consistent with the Commission's rule requiring straight line depreciation because it spreads the reserve surplus over the remaining lives of the assets.[707]

589. The Company recognized, however, that the Commission has the authority to authorize the Company to deviate from straight line depreciation where good cause exists, and periods of high investment could constitute good cause. The Company stated that before adopting a plan to use depreciation reserves to mitigate rate increases, it would be necessary to fully understand both the short-term and long-term consequences of using reserves in this manner. The Company noted that it believes that the five-year depreciation proposal would result in undesirable rate increases starting in the sixth year, but the Company is open to discussing other proposals that better recognize the impacts to future ratepayers in its next rate case.[708]

590. The Department also objected to the five-year amortization proposal of XLI and MCC. The Department expressed concern that the short-term reduction in rates resulting from a five-year amortization period would lead to higher rates than necessary in future years.[709] The Department noted that significant transmission facilities will go into service during the 2014-2015 timeframe as a result of CapX transmission projects. These investments will likely deplete the TD&G depreciation surplus in the near future.[710] The Department also stated that it believes the calculation of the theoretical reserve used by XLI and MCC has flaws.[711]

591. The Administrative Law Judge concludes that the proposal of XLI and MCC to amortize the $265 million (Minnesota jurisdictional) difference between the theoretical reserve and the actual reserve for TD&G Assets over five years is not reasonable because the five-year amortization period is too short. The proposal would impose an undue burden on future ratepayers. The Company's proposed 2013 test year expense, which incorporates the Company's proposal to amortize the surplus over the remaining average life of the assets, is reasonable. The Administrative Law Judge notes, however, that the Company's proposed approach is not necessarily the only reasonable method of addressing the TD&G depreciation reserve.

592. Accordingly, the Administrative Law Judge recommends that the Commission adopt the Company's proposal in this rate case but also suggests that the Commission direct the Company to work with the parties to explore other reasonable approaches for use in the next rate case. Alternatively, if the Commission believes the

---

[705] Ex. 52 at 22 (Perkett Rebuttal).
[706] *Id.*
[707] *Id.*
[708] *Id.* at 23-24.
[709] Ex. 172 at 6 (Campbell Rebuttal); Ex. 173 at 120-121 (Campbell Surrebuttal).
[710] *Id.* at 5.
[711] *Id.* at 7.

2013 rate increases require mitigation, the Administrative Law Judge recommends that the Commission consider adopting a 15-year amortization period for the TD&G depreciation surplus in this case. This approach would help moderate the current rate increases, yet delay the resulting future impact for 15 years. In the next rate case, the Commission could re-evaluate the 15-year amortization period, and make changes if a better alternative is developed.

X. Corporate Aviation[712]

593. The Company has included $756,000 for corporate aviation costs in its 2013 test year. This amount represents half of the approximately $1.5 million that the Company has budgeted for corporate aviation in 2013.[713] According to the Company, there has not been significant variation in the Minnesota electric jurisdictional portion of its total corporate aviation expense in recent years.[714] The Company argued that its request to include 50 percent of the corporate aviation costs is reasonable and consistent with Commission precedent.[715]

594. 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.[716]

595. To support its claim of prudency, the Company commissioned a cost-benefit analysis of corporate aircraft use from 2011 to June 2012. Most of the corporate flights were between Minneapolis and Denver.[717] 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 approximately 69 percent of the Company's corporate aviation costs provide a benefit when compared to the costs of commercial air travel.[718]

596. The OAG initially recommended that no more than $45,000 be included in the test year cost of service for corporate aviation.[719] The OAG later revised its position and recommended that corporate aviation costs included in the test year be no more than $203,111.[720] This amount reflects the number of passenger round-trip flights in 2011 identified by the Company multiplied by the assumed price per commercial ticket ($300), and applying the test year 2013 budget allocator.[721] The OAG maintained that

---

[712] Issue 66.
[713] Ex. 33 at 28 (O'Hara Direct).
[714] Ex. 34 at 3 (O'Hara Rebuttal).
[715] Xcel Initial Brief at 137.
[716] Ex. 33 at 28 (O'Hara Direct).
[717] Ex. 33 GJO-1, Schedule 9.
[718] *Id.* at 29-30, GJO-1, Schedule 9.
[719] Ex. 124 at 34 (Lindell Direct).
[720] Initial OAG Brief at 24.
[721] *Id.*; Ex. 34 at 4-5 (O'Hara Rebuttal).

this adjustment would compensate the Company for aviation costs at a reasonable level rather allowing recovery for a costly and extravagant mode of corporate travel.[722]

597. The OAG's calculation of aviation expenses does not account for employee time savings or increased productivity.[723] The Company's aviation services study did factor in benefits associated with employee time savings and increased productivity.[724] According to the Company, increased productivity is the most important benefit of using corporate aviation. 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.[725]

598. The Company has demonstrated that it is reasonable to include $756,000, or 50 percent of the approximately $1.5 million that the Company has budgeted for corporate aviation costs in 2013. The Company's request is based on a detailed analysis of its costs, and properly considers increased productivity and employee time savings.[726] The Company's request is also consistent with Commission precedent.[727]

Y. FAS 106, 112 – Amoritization of Prepaid Asset[728]

599. The OAG proposed that the Company amortize and return to ratepayers amounts it has accumulated for FAS 106 (retiree medical benefits) and FAS 112 (long term disability benefits).[729] The OAG recommended that the Company amortize $70 million of the approximately $74 million prepaid FAS 106 and 112 included in rate base. The OAG proposed the amortization be over a period of four years.[730]

600. The OAG recognized that the Company must record expenses according to GAAP, and as required by FAS 106 and 112. Prepayments are recognized on the Company's books and included as a reduction to rate base.[731] According to the OAG, under the current accounting, the reductions to rate base have been increasing for the years 2009 through 2012 because the expense used for rate recovery has been greater than the cash payments made in those years. In the view of the OAG, this imbalance has the effect of forcing ratepayers to invest in the Company, which they should not be required to do.[732]

---

[722] Initial OAG Brief at 24.
[723] *See id.*; Ex. 34 at 5 (O'Hara Rebuttal).
[724] Ex. 34 at 5 (O'Hara Rebuttal).
[725] Ex. 33 at Schedule 9, Page 6 of 21; Ex. 34 at 4-6 (O'Hara Rebuttal).
[726] Ex. 33 at 28-30 (GJO-1, Schedule 9) (O'Hara Direct); Ex. 34 at 2-6 (O'Hara Rebuttal).
[727] *See* Docket E002-GR/10-971; Docket No. E015/GR-08-415 (Minnesota Power); Docket No. E015/GR-09-1151 (Minnesota Power).
[728] Issue 67.
[729] Ex. 124 at 38 (Lindell Direct); Ex. 39 at 25-26 (Moeller Direct) (identifying FAS 106 as consisting of retiree medical expenses and FAS 112 as consisting of long term disability expenses).
[730] Ex. 124 at 34-38 (Lindell Direct); Ex. 126 at 22 (Lindell Surrebuttal).
[731] *Id.* at 35-6.
[732] *Id.* at 37.

601. The OAG maintained that amortization does not result in a change to the accounting treatment that the Commission uses to set rates. Instead, it corrects the excessive accumulation of ratepayer supplied funds. The OAG noted that the Company recently modified its retiree medical benefits, which reduced its future obligations by $29.8 million. The OAG asserted that it is proper to make corrections in accounting and ratemaking to recognize that prior accounting treatment produced inaccurate results.[733]

602. The Company asserted that its accounting methods are consistent with sound accounting practices and Commission direction to utilities. With regard to FAS 106, the Company stated that its current approach follows the Commission's 1993 decision to use the accrual method. The Commission adopted this method to better match rate recovery with the period in which expenses are earned.[734] The Company maintained that the OAG's recommendation would, in effect, reverse the Commission's policy.[735] With regard to FAS 112, the Company stated that the balance is simply a cash flow timing difference between past obligations and the future period when the actual cash flows occur. The Company maintained that to refund these costs to ratepayers today would effectively transfer the cost of paying for these prior period disability costs to a future generation of ratepayers.[736] The Company also noted that in the last rate case, the Administrative Law Judge concluded that the OAG had failed to demonstrate that a similar proposal would benefit ratepayers.[737]

603. The Administrative Law Judge concludes that the Company has demonstrated that its accounting for FAS 106 and FAS 112 expenses is consistent with accepted accounting principles and the Commission's direction to handle FAS 106 expenses on an accrual basis. Just as in the last rate case, there is no evidence in this case to show that the OAG's recommendation would benefit ratepayers over the long run. If, however, the accumulated amounts for FAS 106 and/or FAS 112 rise significantly over time, the Commission may want to evaluate FAS 106 and 112 in a separate docket. This would allow the Commission an opportunity to examine in detail why the increase is occurring and whether amortization or some other change in the treatment of FAS 106 and FAS 112 expenses is appropriate.

Z. Nuclear Refueling Outage Costs[738]

604. The Company requested recovery of approximately $59.4 million for nuclear refueling outage expenses in the 2013 test year. The Company calculated its

---

[733] Ex. 126 at 22.
[734] In the Matter of the Accounting and Ratemaking Effects of the Statement of Financial Accounting Standards No. 106, U-999/CI-92-96, ORDER ADOPTING ACCOUNTING STANDARD AND ALLOWING DEFERRED ACCOUNTING at 4 (Sept 22, 1992) ("FAS 106 ORDER") ("SFAS 106 reporting of OPEBs is a reasonable means of matching the employee benefit costs with utility services from which those costs arose").
[735] Ex. 39 at 26-27 (Moeller Rebuttal).
[736] *Id.* at 27.
[737] ALJ Report, Docket 10-971 at Finding 225.
[738] Issues 68 and 69 (Nuclear Refueling Outage Costs - Accounting Methodology and Expense).

expense using the deferral and amortization method. Its actual 2013 Minnesota jurisdictional costs are expected to be $80.6 million.[739]

605. 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.[740]

606. Nuclear refueling outage costs include costs for both routine refueling activities as well as periodic and one-time activities. The 2013 test year amount of approximately $59.4 million includes the 2013 amortization of costs from the following nuclear refueling outages: 2011 and 2013 refueling outages at Monticello; 2012 refueling outage at Prairie Island Unit 1; and Spring 2012 and Fall 2013 outages for Prairie Island Unit 2. These costs are tracked and accounted for consistent with the Uniform Policy and FERC accounting guidelines. The test year amount also includes a "carrying charge," equal to the rate of return, of approximately $4.3 million. The carrying charge is included to reflect the cost of financing the expense.[741]

607. The Company's nuclear refueling outage expenses have increased from $59.7 million in 2011 to $80.6 million in 2013, on a Minnesota jurisdictional basis.[742]

608. The Company asserted that deferral and amortization of its outage costs is appropriate because: 1) deferral and amortization moderates costs that are increasing by spreading them over longer periods; 2) deferral and amortization smoothes the cost differences associated with the varied number of outages that can occur during a particular year; and 3) deferral and amortization matches outage expense levels with their benefits to ratepayers.[743]

609. The Company also asserted that the inclusion of a carrying charge is standard ratemaking practice. The Company stated that the utility is normally entitled to earn a return on the unamortized balance, net of accumulated deferred income tax. Similarly, if ratepayers have prepaid expenses, they are entitled to receive a carrying charge on the balance.[744]

610. The OAG opposed the Company's use of the deferral and amortization method to recover NSP's nuclear outage expenses, and instead recommended recovery of $51.4 million based on a five-year average (2009-2013) of NSP's outage costs on a Minnesota jurisdictional basis.[745]

---

[739] Ex. 124 at 25 (Lindell Direct); Ex. 18 at 3-4, Schedule 2 (Robinson Direct).
[740] Ex. 18 at 2-3, 21 (Robinson Direct); Ex. 48 at 45 (O'Connor Direct).
[741] Ex. 48 at 44-53 (O'Connor Direct); Ex. 40 at 38-47, Schedule 9 (O'Connor Rebuttal); Ex. 124 at 25 (Lindell Direct); Ex. 19 at 27 (Robinson Rebuttal).
[742] Ex. 18 at 4 (Robinson Direct).
[743] Ex. 19 at 22-25 (Robinson Reubuttal).
[744] *Id.* at 27 (Robinson Rebuttal).
[745] Ex. 124 at 25, 27 (Lindell Direct).

611. The OAG noted that the Company's proposed use of the deferral and amortization method in this rate case would capture the abnormally high outage costs incurred during 2012 and 2013. The OAG also asserted that the deferral and amortization method inflates these already high costs by applying an additional return on this expense. The OAG maintained that the increased outage costs during 2012 and 2013 are primarily the result of LCM and EPU projects, rather than a general increase as claimed by the Company. The OAG also asserted that use of the deferral and amortization method does not match these increased costs with the benefits of the LCM and EPU projects — projects intended to keep the facilities operating for 10 to 20 additional years. Finally, the OAG asserted 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.[746]

612. The Company explained that the increased costs are attributable to a variety of factors including routine work, period inspection work, and number of one-time costs including but not limited to the LCM and EPU work. The Company also noted that the Commission has authorized it to use the deferral and amortization method for ratemaking purposes since the Company's 2008 rate case. Switching to the OAG's proposed five-year average method now would cause the Company to under-recover its costs. In addition, the Company asserted that the five-year average method is more complex and difficult to apply because the costs vary significantly depending on the number of outages in the test year and for the period during which the rates will remain in effect.[747]

613. When the Commission approved the use of the deferral and amortization method for nuclear refueling outage costs in the 2008 rate case, the Commission found that:

> These costs are substantial, variable, and trending upward. They vary from reactor to reactor and over time. They occur at staggered intervals that can result in one, two, or three refueling shutdowns occurring in any given year.

[746] *See, e.g.,* OAG Initial Brief at 28-30; Ex. 124 at 21-23.
[747] Ex. 48 at 41-53 (O'Connor Direct); Ex. 18 at Schedule 3 (Robinson Direct); Ex. 19 at 26 (Robinson Rebuttal).

The Commission determined that the deferral and amortization method was a more accurate method of recovering these expenses than the historical averaging method used in the past.[748] In the 2010 rate case, the Commission again approved of the use of the deferral and amortization method for nuclear refueling outage costs.[749]

614. The Commission's analysis in the 2008 rate case applies equally to this case. As noted above, the nuclear outage costs in this case are substantial and unusual, and have been increasing over time. The deferral and amortization method helps to moderate and smooth these costs. For these reasons, the Administrative Law Judge concludes that the use of the amortization and deferral method remains reasonable.

615. In order to use the five-year average method suggested by the OAG, the Commission would need to make several adjustments so that the test year expense is representative of actual costs.[750] As the Administrative Law Judge in the 2008 rate case noted: "The point is to develop a representative test year number, not to simply perform a mathematical average."[751] Moreover, the Company has demonstrated that use of the OAG's five-year average method without adjustments would lead to an under-recovery of its nuclear outage costs.[752]

616. With respect to the carrying charge included in the expense, the Administrative Law Judge in the 2010 rate case addressed this very issue. In the 10-971 docket, 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.[753]

617. For these same reasons, it continues to be reasonable for the Company to include a carrying charge in this rate case. The Administrative Law Judge agrees with the OAG, however, that rather than using the rate-of-return for the carrying charge rate, a more appropriate rate would be the short-term cost of debt or the prime interest rate. A lower rate is reasonable because the expense is amortized over a relatively short

---

[748] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 30-32 (October 23, 2009).

[749] *See In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-10-971, Petition for Reconsideration of the Office of the Attorney General – AntiTrust and Utilities Division (June 4, 2012) and ORDER DENYING RECONSIDERATION (July 26, 2012).

[750] *Id.* at 32 (noting that to properly calculate the test year based on a historical average the Commission must consider multiple data sources and evaluate which past costs are most representative, which future costs are most reasonable, what sorts of repairs and maintenance are likely, and what the inflation rate is likely to be).

[751] Ex. 19 at 26 (Robinson Rebuttal) (citing Finding of Fact 110 in the 08-1065 docket, adopted by the Commission).

[752] Ex. 18 at 6 (Robinson Direct).

[753] 10-971 Findings at ¶ 286.

period of time.[754] Accordingly, the Administrative Law Judge recommends that the Company be allowed to impose a carrying charge but the carrying charge should reflect the short term use of the money.[755]

AA. CWIP/AFUDC[756]

618. 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.[757]

619. The Company included $732.405 million in rate base for its 2013 test year as CWIP.[758] The return on CWIP in rate base is usually offset by the amount of AFUDC. The offset is accomplished by adding the amount of AFUDC to net operating income for the revenue requirement. In this case, this adjustment increased the Company's operating income by $51.132 million in the test year (thus lowering the revenue requirement).[759] It is the combination of CWIP in rate base and the inclusion of AFUDC in net operating income that results in the deferral of construction period financing cost during the construction period.[760] Once the asset goes into service, CWIP and AFUDC are recovered over the life of the asset through the recording of book depreciation expense.[761]

620. The OAG and the Commercial Group both opposed the Company's treatment of CWIP and AFUDC in this case.

621. 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 capital nature.

---

[754] OAG Initial Brief at 25, note 85; Ex. 18 at 5 (Robinson Direct) (stating the costs are amortized over an 18 to 24 month period generally).
[755] If the Commission sets the interest rate on Interim Rate Refunds at the rate-of-return (grossed up for taxes), as requested by several parties including the OAG, then the Commission should not lower the carrying charge rate as recommended in this paragraph. There should be consistency in the approach to both issues.
[756] Issue 70.
[757] Ex. 52 at 39 (Perkett Rebuttal).
[758] Ex. 56, Schedule 16, at 2 (Heuer Direct).
[759] Ex. 7, Volume 3, tab 4. Operating Income Schedules, Schedule A-1, line 13.
[760] Ex. 52 at 41-42 (Perkett Rebuttal).
[761] *Id.* at 41.

Also, Minn. Stat. § 216B.16, subd. 6a (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.

i. The Objections of the OAG and the Commercial Group

622. The OAG contended that the Company has not provided any justification for short term projects to be included in CWIP. The OAG noted that in the MERC rate case, the Commission disallowed rate base inclusion of CWIP where the utility's "CWIP balance include[d] short-term projects with no project-by-project documentation."[762]

623. The OAG's reliance on the MERC decision is not well taken. In the MERC docket, the decision to exclude CWIP arose from the inclusion of CWIP late in the rate-setting process.[763] In this matter, there has been ample time for discovery and a full inquiry into the Company's CWIP projects.

624. The OAG also maintained that the Company has not complied with the FERC accounting rules regarding the inclusion of CWIP in rate base and the calculation of AFUDC.[764] The OAG recommended that only projects requiring financing of at least $25 million be included in CWIP and allowed to accrue AFUDC.[765]

625. The Commercial Group also objected to the Company's treatment of CWIP. The Commercial Group opposed the $90 million increase in CWIP since the Company's last rate case. The Commercial Group asserted that the inclusion of CWIP causes ratepayers to pay for assets during a period when they are not receiving benefits. The Commercial Group also maintained that the inclusion of CWIP shifts risks, that are normally borne by shareholders, to ratepayers. The Commercial Group

---

[762] OAG Initial Brief at 34 (citing *ITMO the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-007, 011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 34 (July 13, 2012) ("*MERC Order*")).
[763] *Id*.
[764] Ex. 124 at 40-43 (Lindell Direct); Ex. 126 at 14 (Lindell Surrebuttal); OAG Initial Brief at 34-36.
[765] Ex. 126 at 18 (Lindell Surrebuttal); OAG Initial Brief at 38.

recommended if the Commission does include the additional CWIP amount in rate base, then the return on equity should be reduced.[766]

626. The Company responded that its treatment of CWIP and AFUDC conform to the Commission's established policies. The Company also maintained that its treatment of these items is consistent with FERC's Uniform System of Accounts.[767] The Company noted that CWIP and AFUDC are authorized by statute, commonly included in rates, and audited by FERC. The Company asserts that the methods it uses for CWIP and AFUDC are fair to both the Company and its customers.[768]

ii. Conclusion

627. The Company has shown that its proposed inclusion of CWIP and AFUDC is consistent with FERC accounting requirements and past Commission practice. None of the other parties have demonstrated that any change to the Company's accounting for CWIP and AFUDC is necessary to meet applicable legal requirements. Including CWIP in the rate base and providing AFUDC in the manner proposed by the Company is an appropriate exercise of the Commission's discretion under Minn. Stat. § 216B.16, subds. 6 and 6a.

BB. Bad Debt – Credit and Collection Expense[769]

628. The OAG recommended that the Company's costs for administration of its collection activities be reduced because the Company receives government Energy Assistance funds to pay certain customer's bills.[770]

629. The Company opposed the OAG's recommendation, countering that its test year expense for credit and collection activities fully reflects any reduction in cost resulting from Energy Assistance programs. The Energy Assistance funds are reflected in reduced outstanding receivables. Also, to the extent the funds helped customers avoid credit and collection action, the amounts have served to reduce the Company's administration expense.[771] The impact of Energy Assistance funds is also reflected in the Company's bad debt ratio because the Company's bad debt ratio is based on historical information.[772]

630. The Company has demonstrated that its credit and collection expense is reasonable and fully reflects any reduction in cost resulting from Energy Assistance programs. The OAG failed to present any evidence to the contrary.

---

[766] Ex. 81 at 7-8 (Chriss Direct).
[767] Ex. 87 at 2 (Perkett Opening Statement); Tr. Vol. 2 at 191 (Perkett).
[768] *See* Xcel Initial Brief at 144-147.
[769] Issue 73.
[770] Ex. 124 at 52 (Lindell Direct).
[771] Ex. 54 at 12 (Gersack Rebuttal).
[772] Ex. 53 at 17 (Gersack Direct).

VII. Rate Design Issues

A. Rate Design Principles

631. Once the Commission has determined the utility's revenue requirement, it must determine which customer classes should pay for the costs reflected in the revenue deficiency, and how rates should be constructed to recover those costs from customers.

632. 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.[773]

633. 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.[774]

634. The Commission has relied on the following four principles in establishing reasonable rate design:

- Rates should be designed to allow the Company a reasonable opportunity to recover its revenue requirements, including the cost of capital;

- 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.

- 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 by being protected from rate shock associated with dramatic increases in rates, and utilities are afforded the opportunity to recover a steady revenue requirement; and

- Rates should be understandable and easy to administer. Maintaining ease in administration and understanding helps ensure that customers have a better understanding about their utility bills.[775]

635. 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.[776] Rate design should favor energy conservation and the

---

[773] *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 312 Minn. 250, 260, 251 N.W.2d 350, 357 (1977).
[774] 10-971 Order at 14, 25.
[775] Ex. 155 at 2-4 (Peirce Direct).
[776] Minn. Stat. §§ 216B.07 and 216B.03.

use of renewable energy.[777] Doubts about the reasonableness of the rates should be resolved in favor of the consumer.[778]

B. Class Cost of Service Study

636. Typically, the first step in determining the appropriate rate design is to conduct a "class cost of service study" (CCOSS). The purpose of the CCOSS is to identify, as accurately as possible, the responsibility of each customer class for costs incurred by the utility in providing service.[779]

637. To develop a CCOSS, utility costs are first functionalized, or grouped according to their purpose – typically production, transmission and distribution. Next, the functionalized costs are classified as customer, demand or energy costs according to how they are incurred. Customer costs, such as the costs of metering and billing, follow the number of customers served, not their energy consumption. Demand costs, such as the size of the distribution system, stem from the necessity of serving the peak demand on the system rather than the number of customers being served. Energy costs, such as fuel, track the quantity of energy produced. Once functionalized and classified, the utility's costs are normally allocated to customer classes, weighted according to each class's imposition of costs on the system. [780]

638. The Company allocated costs among four customer classes: Residential, Commercial and Industrial (C&I) Non-demand, C&I Demand, and Street Lighting (Lighting).[781]

639. The Company's filing contained a proposed embedded CCOSS which used nearly the same process as that approved by the Commission in its last rate case. In three changes from its prior CCOSS methodology, the Company:

a. Added a line to its CCOSS spreadsheet to directly assign a portion of its underground wiring capital costs to the Street and Outdoor Lighting class;

b. Changed its allocation methodology for Other O&M, thereby moving the percentage of costs treated as fixed and allocated on demand from seven percent to 25 percent; and

c. Modified the allocation of the capacity portion of purchase power agreements.[782]

640. The following parties raised objections or concerns regarding some aspect of the Company's CCOSS: the OAG, the Department, XLI, MCC, and SRA.

---

[777] Minn. Stat. §§ 216B.03 and 216C.05.
[778] Minn. Stat. § 216B.03.
[779] Ex. 140 at 13 (Ouanes Direct).
[780] *Id.* at 14-15.
[781] Ex. 60 at 7 (Peppin Direct).
[782] *Id*. at 3-5.

i. The OAG Objections to the CCOSS

641. The OAG asserted that a CCOSS produces only estimates of costs of service that at best serve as guidelines for assigning costs to customer groups. For this reason, the OAG argued, the Company should not depend upon the CCOSS as the sole foundation for reasonable rate design.[783] To illustrate what it viewed as CCOSS inaccuracy, the OAG stated that the Company's use of the E8760 energy allocator did not produce precise measurements of each customer's actual hourly load because the Company used estimates, not historic averages of hourly loads.[784]

642. The OAG also argued that because the Company filed seven different CCOSS models and these models had a range of resulting revenue deficiencies, the CCOSS does not provide a precise indication of the cost of service.[785]

643. The Company responded that the allocator used 2006 through 2010 historical load shapes, and adjusted this data for 2013 test year weather values. This methodology was approved in the Company's last three rate cases.[786]

644. In the Company's last rate case, the Commission addressed the same concerns regarding the use of the E8760 energy allocator and the overall accuracy of the CCOSS. In approving the E8760 energy allocator, the Commission stated that it had consistently done so in prior cases "because it appropriately incorporates and assigns energy-related costs to customer classes in accordance with the time and quantity of their usage."[787] The Commission concluded that, "[a]lthough a fully-embedded CCOSS may not be precise, it can be a useful tool for setting rates" and that "Xcel's fully embedded CCOSS contributes to the Commission's analysis."[788] The Company's current CCOSS is consistent with the Commission's finding in the last rate case.

ii. The Department's Objections to the CCOSS

645. The Department originally objected to two aspects of the Company's CCOSS. By the close of the evidentiary portion of the rate case, the Department's focus had narrowed to one contested issue. The Company acceded to the Department's view on allocation of capacity-related plant costs, but disputed an adjustment of Conservation Improvement Program (CIP) expenses.[789]

---

[783] Ex. 130 at 18 (Chavez Surrebuttal).
[784] Ex. 129 at 6-7 (Chavez Direct) at 6-7.
[785] Ex. 129 at 6-7 (Chavez Direct) at 4-5.
[786] Ex. 61 at 12 (Peppin Rebuttal).
[787] 10-971 Order at 22.
[788] *Id.* at 23.
[789] Ex. 143 at 7 (Ouanes Surrebuttal).

a. Use of Winter Peak in Allocation of Capacity-Related Production Plant Costs

646. The Department expressed concern regarding the Company's allocation of the capacity-related portion of generation plant costs. While the Company is clearly summer-peaking, it allocated generation plant costs based on weighting of both the summer system coincident peak and the winter system coincident peak.[790] The Company stated that, while its system did peak in the summer, the system was nevertheless used in other seasons for such things as plant maintenance and the operation of combustion turbine peaking plants.[791] The Department argued that proper cost allocation must be tied to cost-causation at the time of incurring the investment, not to how the resource may be used later. Since the production plant investment would have been undertaken to enable the Company to serve its summer peak, the capacity-related portion of generation plant costs must be allocated according to the summer system coincident peak.[792] The Department's recommendation was supported by XLI and MCC.[793] In Rebuttal Testimony, the Company agreed to the parties' recommendations. In what it termed its Rebuttal CCOSS, the Company changed its methodology to allocate the capacity-related portion of generation plant using the summer coincident peak.[794]

b. Allocation of CIP CCRC Costs

647. A utility's CIP expenses are eligible for recovery under two calculations. First, pursuant to Minn. Stat. § 216B.16, subd. 6b(a), the utility is able to include CIP expenses in its rate case test year expenses as the Conservation Cost Recovery Charge (CCRC). If approved, the expenses are set in base rates and then "tracked" for eventual recovery. Second, under Minn. Stat. § 216B.16, subd. 6b(c), the utility is eligible to recover its CIP expenses annually through its Conservation Recovery Adjustment (CCRA), outside of a rate case proceeding, if the expenses exceed the expense level recovered in base rates.[795]

648. The Company allocated the CCRC using the Percent-of-Benefits method. Under this method, the CIP costs are first separated into demand and energy components, based on the average avoided costs in the test year, and then allocated to the customer classes using the utility's demand and energy allocators. The Company allocated the CCRA (or, under Xcel's terminology, the CIP Adjustment Factor, or CAF) by the per-kWh energy-only method. Under this method, the Company divided the forecasted CIP tracker balance by the forecasted energy sales corresponding to the recovery period to arrive at the allocation. The Company stated that the Percent-of-Benefits method is consistent with the allocation of the supply-side investments which would take place but for the Company's pursuit of CIP programs. The accounting and

[790] Ex. 140 (Ouanes Direct) at 21.
[791] Ex. 60 at 13 (Peppin Direct).
[792] Ex. 140 at 21-22 (Ouanes Direct).
[793] Ex. 113 at 18-20 (Maini Direct); Ex. 119 at 33-36 (Pollock Direct).
[794] Ex. 61 at 3-4 (Peppin Rebuttal).
[795] Ex. 160 at 15-17 (Davis Direct).

billing required for the Percent-of-Benefits method, however, is more complex. In contrast, the per-kWh allocation is straightforward and easy to calculate and bill; but does it not parallel the allocation of non-CIP supply-side energy and capacity investments.[796]

649. The Department recommended that the Company be required to allocate both portions of its CIP costs under the per-kWh method. It asserted that applying two methods, with different theoretical bases, to the same type of expense, is illogical. The Department further noted the Commission had approved of utilities' continued use of the per-kWh allocation method for CCRA cost allocation in the Commission's recent round of Orders on annual CIP filings. The Department included a table in its testimony, showing the estimated impact on revenue apportionment if the Company were required to change its cost allocation for the CCRC from Percent-of-Benefits to per kWh in this rate case. The resulting changes ranged from plus $1,213 for the C&I Non-Demand class to minus $1,379 for the Residential Class. [797]

650. The Company stated that, particularly given the modest overall impact, it is appropriate to use different allocation methods. The much larger CCRC costs should be allocated using the Percent-of-Benefits method, which better links costs to the avoided investment, while the administratively less burdensome per-kWh is appropriate for the relatively small CCRA costs. Further, since the latter costs appear directly on customers' bills, it is more consumer-friendly to use the clear, simplified per-kWh system.[798]

651. The Company has sufficiently supported its reasonable method of CIP cost allocation.

iii. XLI and MCC Objections to the CCOSS

a. Other Operation and Maintenance Costs

652. 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.[799]

653. In its last rate case, the Company classified these Other Production O&M Costs into "demand-related" and "energy-related" according to the corresponding percentage of the underlying power plant investment. At that time, XLI argued that the costs should be divided into labor-related, which it labeled "fixed" (demand), and materials-and-maintenance-related, which it labeled "variable" (energy), with a resulting

[796] Ex. 60 at 31-32 (Peppin Direct).
[797] Ex. 160 at 17-20 (Davis Direct).
[798] Ex. 61 (Peppin Rebuttal) at 17-18.
[799] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E-002/GR-10-971, Findings of Fact, Conclusions, and Recommendation (February 22, 2012) at 87. (10-971 FINDINGS).

lower energy attribution.[800] The Administrative Law Judge accepted the Company's methodology but noted that the issue warranted additional consideration in the future.[801] The Commission did not agree with XLI's strict fixed/variable cost allocation and accepted the Company's allocation of Other Production O&M costs in the 10-971 rate case.[802]

654. In this rate case, the Company re-evaluated part of its process for determining the proportion of fixed versus variable Other Production O&M costs. While continuing to depend on underlying plant investment as its basis, the Company now determined the proportion of fixed versus variable costs by splitting total Other Production O&M costs by Baseload subfunction. The calculation uses the ratio of Original Plant Investment that has been stratified as Energy- or as Baseload-related (including nuclear fuel) as a percent of Total Production Plant Investment. This allocation method produced 25 percent of the O&M costs as fixed and 75 percent as variable.[803]

655. The Department did not object to the Company's proposed Other Production O&M allocation but recommended that the Company refine its method further in the next rate case as follows:

> 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.[804]

656. XLI continued to object to the Company's classification. XLI instead recommended a cost separation of 57 percent demand and 43 percent energy in this rate case, using the methodology it had previously advocated.[805] XLI also stated that the Company should be required to further refine its Other O&M allocation in its next rate case along the lines recommended by the Department.[806] The Company committed to provide a more detailed analysis of these costs and to incorporate the analysis into its next rate case filing.[807]

657. The Administrative Law Judge concludes that the Company's attempt to refine its method of allocating Other O&M Costs from the last rate case is sufficient to

---

[800] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E-002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS, AND RECOMMENDATION (May 14, 2012) at 17 (10-971 ORDER.).
[801] 10-971 FINDINGS at 88.
[802] 10-971 ORDER at 18.
[803] Ex. 60 (Peppin Direct) at 4-5.
[804] Ex. 140 at 20 (Ouanes Direct).
[805] Ex. 119 at 40-41 (Pollock Direct).
[806] Ex. 121 at 5-6 (Pollock Rebuttal).
[807] Ex. 61 at 16 (Peppin Rebuttal).

produce a reasonable result for this rate case. The Company should be required to provide a more refined analysis of its Other O&M allocation in its next rate case, as proposed by the Department and XLI and agreed to by the Company.

b. Allocation of Economic Development Discounts

658. The Company proposed two new economic development tariffed services. The Competitive Response Rider (CRR) addressed retaining and expanding large customers. The CRR merged and modified two existing economic development tariffs to increase the qualified load and allow interim rates to more quickly address a customer's changing circumstances. The Business Incentive and Sustainability Rider (BIS) offered business customers incentive discounts to expand operations. The discounts were offered over five years to customers with new loads of at least 350 kW if the customer committed to certain new capital investment in equipment that uses electricity as its primary energy source and entered into a six-year service agreement. [808]

659. XLI argued that there would be no reduction in the energy portion of the applicable economic development rate and thus costs should be allocated relative to base rate, excluding base fuel costs.[809] The Company countered that the allocation of these costs should reflect the fact that adding and retaining load will allow the Company to spread overhead costs more broadly, which benefits all customers by lowering their average cost of service. While noting that the Commission approved the current allocation of the CRR's seminal tariffs in the settlement in Xcel's last case, the Company stated that it was open to the possibility of a different cost allocation going forward.[810] XLI did not change its position regarding the Company's allocation methodology, but agreed with the idea of considering alternatives in the next rate case.[811]

660. The Administrative Law Judge concludes that the Company is reasonably adding the costs associated with these tariffs to the overall cost of service and that its allocation of economic development costs is sufficiently aligned with that of its prior approved competitive rider. The Company should incorporate further study of the proper class allocation of these costs in its next rate case.

c. Allocation of Fixed Production Plant

661. The Company classified fixed production plant into capacity- or energy-related using a process called "Plant Stratification." Under this method, plant capacity costs are based on the cost of a comparable 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

[808] Ex. 63 at 18-19, 22 (Krug Direct).
[809] Ex. 119 at 49-50 (Pollock Direct).
[810] Ex. 63 at 37-38 (Krug Direct).
[811] Post-Hearing Brief of the Xcel Large Industrials at 13.

intermediate and baseload generation facilities. These facilities are built to provide low-cost energy, not capacity.[812]

662. While noting that the Commission has accepted the Company's stratification approach in past rate cases, MCC recommended that the Company use a Peak Demand CCOSS method to allocate costs, using a single coincident peak.[813] Under the Peak Demand or Straight Fixed Variable method, the plant capacity is deemed built to serve demand and reserve margin requirements and is therefore all demand-related. Variable costs such as fuel are incurred to serve energy needs and are totally energy-related.[814] MCC argued that in a down economy, the Company's CCOSS method specially burdens its large, energy-intensive customer membership. MCC further justified its recommendation by pointing to upcoming Midwest Independent Transmission System Operator (MISO) resource adequacy rules, which MCC asserted are consistent with the single coincident peak Straight Fixed Variable approach it advocated.[815]

663. The Company showed the adjusted percent revenue deficiency by customer class using its earlier filed Stratification CCOSS and MCC's Peak Demand method, as well as several other fixed production plant allocation methods. The Company's method produced a Residential revenue deficit of 11.7 percent and a C&I Demand class deficit of 10.0 percent. By comparison, the proposed MCC method resulted in a Residential deficit of 12.5 percent and a C&I Demand deficiency percent of 9.4 percent.[816]

664. The Department supported the Company's Plant Stratification methodology over the Peak Demand CCOSS. The Department cited a recent electric rate case in which the Commission required the filing utility in its next rate case to return from the Peak Demand CCOSS it had filed to the Equivalent Peaker method it had previously used. The Commission stated that the Peak Demand method "…fails to recognize the dual nature of baseload plants in meeting both the peak demands and the annual energy requirements of customers." [817]

665. The Department also argued that MCC had failed to show that MISO's new rules would affect resource planning in a way that would render the Equivalent Peaker method unreasonable.[818]

666. MCC has given little basis for rejecting the Stratification CCOSS long approved by the Commission in favor of the Peak Demand method, other than its desire to reduce costs that are allocated to its large user membership. MCC has not

---

[812] Ex. 60 at 9; 20 (Peppin Direct).
[813] Ex. 113 at 17-18 (Maini Direct).
[814] Ex. 115 at 21-22 (Maini Surrebuttal).
[815] Ex. 113 at 16-18 (Maini Direct).
[816] Ex. 60 at 19 (Peppin Direct).
[817] Ex. 142 at 11-15 (Ouanes Rebuttal), (citing *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E-001/GR-10-276, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 50-51 (August 12, 2011)).
[818] Ex. 142 at 15 (Ouanes Rebuttal).

responded to the Commission's emphasis on the need to recognize the dual nature of baseload plants. Neither has MCC shown a nexus between MISO's resource planning rules and the relative merits of the Alternative Peaker and Fixed Variable CCOSS methods. The Administrative Law Judge concludes that the Company has shown that its Stratification method for the CCOSS is reasonable.

d. Average and Excess Demand (AED) CCOSS Method

667. While XLI did not challenge the Company's use of a stratification methodology in this rate case, it reran the Company's CCOSS to address what it claimed are CCOSS flaws. The adjustments to the Stratification CCOSS included XLI's recalculation of the Company's allocation of Other O&M costs, load management credits, and demand-related costs relative to excess demand.[819]

668. XLI presented an alternative AED CCOSS, which it termed a "less extreme method" than Stratification, to assess the relative reasonableness of the Company's CCOSS. XLI stated that the results of using the AED methodology with XLI's "corrections" were similar to those of its adjusted version of the Company's Stratification CCOSS. [820]

669. The AED method allocates production plant costs to rate classes using an excess demand factor, the difference between the sum of non-coincident peaks and system total average demand. The Department stated that the AED method's emphasis on non-coincident peaks is misplaced. It asserted that coincident peak or system peak load is the load that drives the need for additional generation capacity. The Department opined that the AED method failed to answer a basic question for proper allocation: What influences a utility's production plant investment decisions?[821]

670. The Company noted that XLI's rerun of the CCOSS resulted in a significant cost shift away from the C&I Class to all other classes, and primarily to the Residential class. While acknowledging that the AED method can be used as the basis of a CCOSS, the Company cited what it believed were the significant drawbacks of this approach, such as: imprecision in dividing fixed production costs into demand and energy and in allocating the resulting energy portion into classes based on simple MWH energy requirements; use of the sum of non-coincident peaks, which do not add up to the system's generation capacity requirements, for allocation; and failure to follow the Stratification method's second step of allocating the portion of fixed production costs that are energy-related to the energy charge rather than to the demand charge.[822]

671. It appears that XLI has offered its adjusted CCOSS because it leads to a hoped for shift away from the C&I class. Yet, the methods it proposes also leads to greater imprecision in allocating costs and undermines the purposes of the CCOSS

[819] Ex. 119 at 32; 62 (Pollock Direct).
[820] *Id.* at 62-63.
[821] Ex. 142 at 15-18 (Ouanes Rebuttal).
[822] Ex. 61 at 26-28 (Peppin Rebuttal).

analysis. XLI has failed to demonstrate that the AED method should be used to assess the reasonableness of the Company's filed CCOSS in this proceeding.

e. Counting Average Demand in Demand Allocator

672. XLI argued that the Company double-counts when calculating its capacity costs because it improperly uses average hourly demand in its calculation of baseload capital plant investment and coincident demand (which would also include a portion of the baseload costs) to arrive at peaking investment. XLI stated that it was necessary to remove average demand and use only load in excess of average when allocating peaking plant costs in order to avoid this problem.[823]

673. The Department stated that the Company's Equivalent Peaker method properly classifies the fixed production plant costs between energy and demand components. The demand-related costs are those costs "needed to meet system demands"; not "to meet system demands when they are in excess of the average year-round demand."[824] Thus, it is reasonable to allocate demand-related costs on the basis of each customer class's contribution to system peak, not on the basis of excess demand.[825] The Company argued that average demands are not used at all for allocating the energy-related portion of fixed production costs and thus do not result in double-counting.[826]

674. In the Company's last rate case, the Commission fully considered the same arguments from XLI regarding this topic and found them unconvincing. The Commission stated in relevant part:

> Xcel's demand allocation does not rely on the distinctions implicit in XLI's criticism and double-counting claim. Under Xcel's method, energy-related generation facility costs exclude demand-related costs, and energy-related costs are allocated using the E8760 allocator. The Commission is satisfied that Xcel's demand-allocation methodology does not double-count average demand.[827]

675. The Administrative Law Judge concludes that the Company is properly applying its demand allocation methodology and is not double-counting average demand.

f. Allocation of Transmission

676. The Company allocated capacity costs of transmission facilities according to each class's weighted contribution to summer and winter peak demand. The

---

[823] Ex. 119 at 37-38 (Pollock Direct).
[824] Ex. 142 at 19 (Ouanes Rebuttal).
[825] *Id.*
[826] Ex. 61 at 25-26 (Peppin Rebuttal).
[827] 10-971 at 20 ORDER.

Company did not change its proposal even after it agreed to allocate the capacity-related portion of generation plant using the summer coincident peak only.[828]

677. The OAG argued that the Company's demand-related transmission allocation unfairly benefits large customers and disfavors residential and other low load factor customers. For transmission that is built to allow for the interconnection of generation, the OAG recommended that Xcel allocate between demand and energy in the same proportion as the interconnected generators.[829] The Company responded that it properly allocates costs of bulk transmission to demand/capacity because the primary cost driver is peak system demand. The totality of its integrated transmission system, rather than the generation source served by various transmission sections, is required for peak demand. The Company stated further that the OAG's recommendation would be administratively complex and would result in little appreciable cost shift.[830]

678. In recommending allocation of transmission costs to summer peak only, XLI noted that the transmission system must meet the demand imposed by the summer peak, like the generation system.[831]

679. In briefing, the Company stated that it planned to review the transmission system allocation before its next rate case.[832]

680. The Company has provided a reasonable rationale for continuing to allocate transmission costs according to contribution to peak demand rather than according to the allocation of the connected generation. The Company has not, however, provided any valid reason for allocating bulk transmission costs according to both summer and winter peak when it has agreed to allocate generation costs according to summer peak only. The Company has failed to demonstrate a reasonable basis for distinguishing between the two allocations regarding this issue.

681. Accordingly, the Administrative Law Judge concludes that the Company should be required to reallocate transmission facility costs in this rate case in a manner consistent with its allocation of capacity costs, that is, according to contribution to summer peak demand.

g. Allocation of Interruptible Credits

682. The Company characterized interruptible service as firm service with a purchased-power option by which the Company can buy back all or part of the interruptible customer's erstwhile firm service to meet peak demand, when doing so is a cost-effective choice for the Company. The Company provides credits to its customers who undertake to manage their energy needs without the guarantee of firm service. In

[828] Ex. 61 at 19 (Peppin Rebuttal).
[829] Ex. 129 at 5 (Chavez Direct).
[830] Ex. 61 at 19-20 (Peppin Rebuttal).
[831] Ex. 122 at 19 (Pollock Surrebuttal).
[832] Xcel Initial Brief at 161.

its CCOSS process, the Company treats the credits provided to interruptible customers as a cost of peaking capacity and allocates the costs to classes based on firm load.[833]

683. As it had in the last rate case, XLI argued that the Company improperly mismatched its calculation of costs and revenues by including interruptible customers in costing of firm service but netting out the load management credits to determine revenues from the service. XLI stated that load management credits should not be allocated to interruptible customers because firm, not interruptible customers are contributing to peak demand costs.[834] MCC argued that interruptible customers should not be allocated costs of interruptible credits because interruptible load is deducted from peak load for resource planning purposes and interruptible customers can be assessed penalties if they do not allow service interruption when called upon by the Company.[835] The Department supported the Company's allocation of load management credits to all customers, both firm and interruptible, because both types benefit from interruptible service's contribution to lower capacity costs.[836]

684. In the Company's last rate case, the Administrative Law Judge found that differing treatment of load management credits for ratemaking purposes and for resource planning purposes, an argument here raised by MCC, was not relevant.[837]

685. The XLI arguments regarding load management credits in this rate case are the same as it offered in the prior Xcel rate case. There the Commission considered the arguments and found the Company's CCOSS treatment reasonable. The Commission's Order stated in relevant part:

> In this case, Xcel treats the cost of a demand-side resource, Interruptible service credits, just as it teats 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.[838]

686. The Administrative Law Judge concludes that the Company's treatment of interruptible service credits is reasonable.

iv. Street Lighting

687. Since 1980, the Company has directly assigned a portion of overhead wiring capital costs to the Street Lighting class.[839] Its CCOSS in this rate case also directly assigned a portion of underground wiring capital costs to the Street Lighting

[833] Ex. 61 at 20 (Peppin Rebuttal).
[834] Ex. 119 at 43-44 (Pollock Direct).
[835] Ex. 115 at 22 (Maini Surrebuttal).
[836] Ex. 142 at 10 (Ouanes Rebuttal).
[837] 10-971 FINDINGS at 90.
[838] 10-971 ORDER at 25.
[839] Tr. Vol. 3 at 82 (Peppin).

class.[840] This is the first time the Company has assigned underground wiring capital costs to the Street Lighting class. This new proposal resulted in the direct allocation of $22.21 million in underground wiring capital costs, which was in addition to the identical figure for overhead wiring costs.[841] The direct assignment of underground wiring costs to Street Lighting represented approximately two percent of total underground distribution costs.[842]

688. The Company reasoned that its historical assignment of a portion of its overhead wiring capital costs and the growing trend toward underground service justified a parallel assignment of underground distribution costs to the Street Lighting class.[843] The Company used its accounting staff, in consultation with distribution staff, to arrive at the total underground wiring costs to be assigned.[844] The Company did not use field representatives to develop the newly proposed costs.[845] The Company stated that its treatment of either overhead or underground distribution lines would capture only the portion of the line that is dedicated solely to serving the Street Lighting class. Overhead distribution wire assignment, the Company stated, reflects the portion of the overhead distribution system that passes through areas such as undeveloped land and through parks served entirely by the Company.[846] The Company characterized its previous failure to directly assign underground wiring costs to Street Lighting as an oversight.[847]

689. Although it did not make a recommendation regarding the issue, the Department stated that it did not object to the Company's proposed direct assignment of a portion of underground wiring capital costs to Street Lighting. The Department agreed with the concept of direct allocation of costs when such costs can be exclusively identified.[848] No party objected to Xcel's treatment of overhead wiring costs in the Company's last two rate cases. If there is a rationale for direct assignment of overhead distribution costs, the Department reasoned, there should be a similar rationale for direct assignment of underground wiring costs.[849]

690. The SRA objected to the Company's proposal to directly assign costs of underground wiring in its CCOSS. The SRA sponsored a witness, David J. Groman, who has worked for 26 years in the public works department of the City of Spring Park; a city that is located within the Company's service territory. For the last 11 of those years, Mr. Groman directly reviewed the Company's design and installation of street lights. During the past 26 years, Mr. Groman observed a consistent conversion from overhead street lighting distribution to underground distribution.[850] Mr. Groman is not

---

[840] Ex. 60 at 4 (Peppin Direct).
[841] Tr. Vol. 3 at 88-89 (Peppin).
[842] Ex. 61 (Peppin Rebuttal) at 24.
[843] *Id.* at 23-24.
[844] Tr. Vol. 3 at 82-84 (Peppin).
[845] *See* Tr. Vol. 3 at 81-82 (Peppin).
[846] Ex. 61 at 23-24 (Peppin Rebuttal).
[847] Tr. Vol. 3 at 84 (Peppin).
[848] Ex. 140 at 19 (Ouanes Direct).
[849] Tr. Vol. 4 at 217 (Ouanes).
[850] Ex. 98 at 3 (Groman Direct).

aware of any distribution lines in his city that are installed solely for purposes of servicing street lights in right-of-ways to the exclusion of other customers.[851]

691. Another SRA-sponsored witness, Ken Ashfield, has been Public Works Director for three years and City Engineer for the City of Maple Grove for 25 years. Maple Grove is also within the Company's service territory.[852] During that time, Mr. Ashfield has overseen permit approval and reviewed plans for Xcel street lighting proposals.[853] According to Mr. Ashfeld, there have been more underground than overhead distribution lines feeding street lights in his city for the past 25 years. In addition, he has not observed the Company installing distribution lines that were dedicated solely to street lights without also serving other customers.[854]

692. The Administrative Law Judge agrees with the Department that one can reasonably infer from the consistently approved direct assignment of overhead distribution costs to the Street Lighting class that some amount of underground distribution costs should be directly assignable. The Company's assignment of $22.210 million for underground distribution costs to the Street Lighting class, however, is not based on any actual field data or other analysis specific to underground street lighting costs. Rather, the Company simply assigned the Street Lighting class the same cost for underground distribution as it assigned to overhead distribution. In addition, the SRA has raised a serious question as to whether any underground distribution lines are used solely for Street Lighting as claimed by the Company. For these reasons, the Administrative Law Judge concludes that the Company has failed to demonstrate that the proposed new assignment of $22.210 million for underground wiring capital costs to the Street Lighting class is reasonable.

693. In addition, the Administrative Law Judge recommends that the Company provide a detailed analysis of its street lighting costs, both overhead and underground, as part of its next rate case filing. A much more detailed analysis is necessary to properly assign costs for underground wiring to the Street Lighting class for the first time.

C. Revenue Apportionment[855]

694. Responsibility to pay for the approved revenue requirement must be apportioned to 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.[856]

695. Revenue apportionment is important because it ultimately determines the price customers are charged for their electrical service.

---

[851] *Id.* at 4.
[852] Ex. 99 at 2 (Ashfeld Direct).
[853] *Id.* at 3.
[854] *Id.* at 3-4.
[855] Issue 58.
[856] *See* Minn. Stat. § 216.03 and ¶ _____ *supra*.

696. Ideally, revenue apportionment for the customer classes would match the cost allocations by class identified in the CCOSS.[857] Moving classes closer to cost is consistent with the second rate design principle. Cost-based rates promote 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.[858]

697. 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.[859]

698. The Company, Department, MCC, XLI, and OAG each provided recommendations regarding the allocation of the revenue requirement among customer classes.[860] The following table reflects their recommendations based on the Company's updated revenue requirement and CCOSS.

Table 18 Comparison of Recommended Revenue Apportionment[861]

Customer Class	Company	Department	OAG	MCC
Residential	36.1%	36.06%	36.1%	38.11%
C & I Non-Demand	3.86%	3.90%	3.9%	4.08%
C & I Demand	58.59%	59.0%	59.0%	56.90%
Street Lighting	1.00%	1.0%	1.0%	0.90%
Total	100%	100.00%	100.0%	100.00%

[857] Ex. 155 at 9 (Peirce Direct).
[858] *Id*.; Ex. 63 at 10-11 (Krug Direct).
[859] *Id*. at 9-10; Ex. 115 at 30 (Maini Surrebutal).
[860] Because XLI's expert Mr. Pollock used different customer classes, a direct comparison of the XLI's recommended apportionment and implied rate increase is not possible. *See* Ex. 122 at 33 (Pollock Surrebuttal).
[861] Ex. 64 at 4 (Krug Rebuttal); Ex. 157 at 2 (Peirce Surrebuttal); Ex. 131 at 24 (Chavez Surrebuttal); Ex. 115 at 29-32 (Maini Surrebuttal); Ex. 122 at 33 (Pollock Surrebuttal). *See*, Xcel's Proposed Findings of Fact at 140 (Table 8).

699. Applying each party's recommended apportionment to the Company's Rebuttal revenue requirement by the percentages set forth above results in different implied rate increases for the customer classes:

Table 19 Comparison of Implied Rate Increases[862]

Customer Class	Company	Department	OAG	MCC
Residential	10.10%	8.61%	8.22%	14.79%
C & I Non-Demand	10.78%	11.98%	8.22%	17.14%
C & I Demand	6.90%	7.71%	8.22%	3.82%
Street Lighting	9.48%	10.07%	8.22%	-0.78%
Total	8.22%	8.22%	8.22%	8.22%

700. The Company, Department, MCC, XLI, and Commercial Group all agreed that rates should be moved closer to cost of service.[863] They differ, however, as to the degree of the movement to cost, and for the MCC and XLI, the underlying cost of service.

701. The OAG did not agree that rates should be moved closer to cost of service.[864] The OAG urged the Commission to reject the Company's proposed revenue apportionment and to use instead the existing revenue apportionment for any increase in revenue.[865]

i. The Company's Proposed Revenue Apportionment

702. The Company's proposed revised revenue allocation is primarily based on its updated CCOSS. It moves the Residential and Street Lighting classes fully to cost, while moving C&I Non-Demand class moderately closer to the cost of service. The Company maintained that past movements toward cost make it possible to move these classes at or near cost without violating the principles of moderation or rate continuity.[866] The remaining revenues are recovered from the C&I Demand class.[867]

---

[862] Ex. 61 at 6 (Table 1, Row 4) (Peppin Rebuttal); Ex. 157 at 2 (Peirce Surrebuttal); Ex. 64 at 4 (Krug Rebuttal); *See*, Xcel's Proposed Findings of Fact at p. 141 (Table 9).
[863] Ex. 63 at 2 (Krug Direct); Ex. 155 at 6 (Peirce Direct); Ex. 113 at 17 (Maini Direct); Ex. 119 at 65 (Pollock Direct); Ex. 82 at 3-4 (Chriss Surrebuttal).
[864] Ex. 131 at 24 (Chavez Surrebuttal).
[865] OAG Initial Brief at 16.
[866] Ex. 64 at 5-7 (Krug Rebuttal).
[867] *Id.* at 5.

703. Specifically, the Company explained that because the updated cost study indicates that the Street Lighting class is relatively close to cost, the Company's revised apportionment takes that class to cost, amounting to an increase of 9.48 percent. The Company's revised CCOSS also shows that the C&I Non-Demand class is further below cost than was earlier indicated. In light of that change, the Company recommends a more moderate increase for this class rather than full movement to cost. The revised apportionment continues to assign a 10.78 percent increase to this class, but requires that the additional cost responsibility be assigned elsewhere to keep the rate increase to this level. The Company assigned the remainder of the cost responsibility for the C&I Non-Demand class to the C&I Demand class, amounting to a total recommended increase of 6.9 percent for that class.[868]

704. The Company's proposed revised revenue apportionment can be summarized as follows:

Table 20 Xcel's Proposed Rebuttal Apportionment of Revenue Responsibility[869]

Customer Class	Current Revenue	Cost	Xcel Proposed Revenue	% of Total	% Increase	Proposed As % of Cost
Residential	$958,311	$1,055,123	$1,055,123	36.6%	10.1%	100.00%
C & I Non-Demand	$100,645	$113,012	$111,496	3.9%	10.8%	98.7%
C & I Demand	$1,581,988	$1,689,590	$1,691,106	58.6%	6.9%	100.1%
Street Lighting	$26,276	$28,767	$28,767	1.0%	9.5%	100.0%
Total	**$2,667,220**	**$2,886,492**	**$2,886,492**	**100.0%**	**8.2%**	**100.00%**

705. The Company asserted that its recommended apportionment, which moves all classes except the C&I Non-Demand class fully to cost, is reasonable. The Company pointed to the economic challenges facing its business customers and the relatively small inter-class subsidies present in the existing rates as support for the Commission taking the full step toward cost in this proceeding[870] The Company maintained that setting the rates to cost will help ensure that its services are as competitive as possible, especially for the business class where sales erosion is most severe. The Company noted that lower sales to its business customers means each remaining customer is responsible for a larger share of the fixed cost of service. While the Company acknowledged that, in the short-term, this means increasing residential rates slightly more than the average rate for all classes, it contended that competitive

[868] *Id.* at 4-5.
[869] *Id.* at 4; Ex. 67 SVH-2 Schedule 2 (Huso Rebuttal); Ex.157 at 2 and Errata (Peirce Surrebuttal); Department's Initial Brief at 204 (Table 9).
[870] Ex. 63 at 12-16 (Krug Direct); Ex. 64 at 7 (Krug Rebuttal).

rates will broaden the overall sales base in the long-term, thus keeping rates lower for all customers.[871]

706. The Company argued that its proposed revenue apportionment does not pose an excessive increase on any one class and instead appropriately considers the cost of service while moderating the rate increase for the C&I Non-Demand class.[872] The Company maintained that its proposal is a moderate but reasonable move toward having all customers pay a more accurate share of customer-related fixed costs.[873]

ii. The Department's Proposed Revenue Apportionment

707. The Department recommended slight adjustments to the Company's proposed apportionment of revenue responsibility to moderate the move to cost for the Residential and Street Lighting classes.

708. In its proposed allocation, the Department first applied an across-the-board 10.7 percent increase to all classes and then moved the apportioned revenue requirement for all classes 50 percent closer to cost (as indicated in the Application CCOSS). This approach was designed to balance the goal of moving toward cost with the goal of moderating the overall revenue increase experienced by each class.[874]

709. This approach moderated the increases to the Residential and Non-Demand classes, but caused the Street Lighting class revenue responsibility to rise to 13.3 percent rather than the 12.6 percent initially proposed by the Company. Consequently, the Department held the Street Lighting class increase to 12.7 percent and allocated the remaining revenue deficiency among the three remaining classes equally. The results of the Department's initial proposed revenue apportionment are shown in the table below:[875]

Table 21 Department's Initial Proposed Apportionment of Revenue Responsibility

Customer Class	Current Revenue	Cost	Current as % of Cost	DOC Proposed Revenue	Percent of Total Revenue	Percent Increase	DOC Proposed as % of Cost
Residential	$957,201	$1,068,780	89.56%	$1,064,201	36.1%	11.2%	99.57%
C&I Non-Demand	$104,009	$115,221	90.27%	$115,179	3.9%	10.7%	99.96%
C&I Demand	$1,578,819	$1,736,853	90.90%	$1,742,303	59.0%	10.4%	100.31%
Lighting	$26,259	$30,427	86.30%	$29,598	1.0%	12.7%	97.27%
Total	$2,666,288	$2,951,281	90.34%	$2,951,281	10.7%	10.7%	100.00%

710. After the Company submitted its revised revenue requirement and CCOSS, the Department updated its apportionment of revenue responsibility to reflect the Company's most recent proposed revenue requirement as follows:

[871] Ex. 63 at 8-9, 13 (Krug Direct).
[872] *Id.*
[873] Ex. 67 at 6-7 (Huso Rebuttal).
[874] Ex. 155 at 8 (Peirce Direct).
[875] *Id.* at 6-8.

Table 22 Department's Updated Apportionment of Xcel's Proposed Rebuttal Revenue Requirement[876]

Customer Class	Current Revenue	Xcel's Proposed Rebuttal Revenue Responsibility	DOC % of Total from Direct	DOC Rebuttal Revenue Responsibility	Percent Increase
Residential	$958,311	$1,055,123	36.1%	$1,040,843	8.6%
C & I Non-Demand	$100,645	$111,496	3.9%	$112,703	12.0%
C & I Demand	$1,581,988	$1,691,06	59.0%	$1,704.025	7.7%
Street Lighting	$26,276	$28,767	1.0%	$28,921	10.1%
Total	**$2,667,220**	**$2,886,492**	**100.0%**	**$2,886,492**	**8.2%**

711. Recognizing that its updated results shown in Table 22 above deviate from the class structure that the Department initially recommended, as shown in Table 21, the Department in its Surrebuttal Testimony recommended that the Commission instead use the proportional adjustment methodology recommended by the Company to adjust the Department's initially recommended apportionment. The table below summarizes how this approach would affect the final revenue responsibility, assuming the 8.2 percent revenue increase proposed by the Company.[877]

Table 23 Department's Final Apportionment of Xcel's Proposed Rebuttal Revenue Requirement

Customer Class	DOC Proposed Direct	% of Total	% Increase	Revised Current Revenues	DOC Rebuttal % of Total	% Incr.	Prop. Adj. DOC	% Chg from Rev. Current
Residential	$1,064,206	36.1%	11.2%	$958,311	$1,040,843	8.6%	$1,040,707	8.6%
C&I Non-Demand	$115,233	3.9%	10.8%	$100,645	$112,703	12.0%	$108,998	8.3%
C&I Demand	$1,742,273	59.0%	10.4%	$1,581,988	$1,704,025	7.7%	$1,707,957	8.0%
Lighting	$29,570	1.0%	12.6%	$26,276	$28,921	10.1%	$28,824	9.7%
Total	$2,951,281	100.0%	10.7%	$2,667,220	$2,886,492	8.2%	$2,886,486	8.2%

712. The Department suggested that the Commission adopt its proposed revenue apportionment and adopt the Company's proposed proportional adjustment methodology to set the final revenue responsibilities by class. The Department noted that the Company is seeking the highest revenue increase it has ever proposed and, consequently, it is likely to result in rate shock to all customer classes. To lessen the impact to customer bills and limit rate shock, the Department recommended the

[876] Ex. 157 at 2 (Table 2) and Errata (Peirce Surrebuttal); Department Initial Brief at 205 (Table 10); Ex. 64 at 4 (Krug Rebuttal) and Ex. 67 SVH-2 Schedule 2 (Huso Rebuttal).
[877] Ex. 157 at 6-7 (Table 4) (Peirce Surrebuttal).

Commission adopt its revenue apportionment which moderates the increases to the Residential class.[878]

iii. OAG's Proposed Revenue Apportionment

713. The OAG argued that the Company's proposed revenue apportionment disproportionately shifts costs onto the Residential class without adequately incorporating non-cost factors.[879] The OAG noted that the record is replete with over 1,000 comments from residential customers concerned about their ability to bear the proposed rate increase. Citizens on fixed-incomes and those with limited incomes due to unemployment or underemployment were especially concerned that they would be unable to absorb such a rate hike. The OAG contended that residential customers have been and are currently paying their fair share, and that the Company's proposed rate increase for residential customers is unreasonable and will result in rate shock.[880]

714. The OAG noted that avoiding or minimizing rate shock is an important ratemaking goal because sudden, drastic increases in energy costs can be burdensome and difficult to absorb for residential and non-residential customers alike.[881] Avoiding rate shock is particularly important for residential ratepayers, however, because increases in the cost of basic needs can cause hardship for customers on low or fixed-incomes.[882] Moreover, unlike the commercial classes, residential ratepayers cannot pass along the cost of the rate increases to customers or take a tax deduction for their electricity costs.[883]

715. The OAG maintained that the revenue apportionment set in Xcel's last rate case should be used to apportion costs in this rate case and any increase should be applied equally to all classes (8.2 percent under the Company's Rebuttal revenue requirement).[884] The OAG contended that the best way to achieve the goal of moderating the overall revenue increase experienced by each class is to maintain the current revenue apportionment which has already been determined to be fair and reasonable by the Commission in Docket 10-971.[885]

iv. MCC and XLI Proposed Revenue Apportionments

716. MCC and XLI both recommended a full movement to cost as measured by their respective CCOSS methodologies.[886] Both MCC and XLI maintained that business ratepayers should not be subsidizing the other classes.

---

[878] Ex. 155 at 7-8 (Peirce Direct).
[879] Ex. 129 at 10 (Chavez Direct).
[880] OAG Initial Brief at 15-16; Ex. 130 at 15 (Chavez Rebuttal).
[881] Ex. 130 at 17 (Chavez Rebuttal) (citing Findings of Fact, Conclusions of Law, and Order, Docket No. G-010/GR-90-676 (July 12, 1991) at 35).
[882] *Id*.
[883] Ex. 129 at 15 (Chavez Direct).
[884] *Id*. at 10.
[885] Ex 130 at 15 (Chavez Rebuttal).
[886] Ex. 122 at 32 (Pollock Surrebuttal); Ex. 115 at 30 (Maini Surrebuttal).

717. MCC pointed out that electric bills for non-residential customers constitute a substantial component of total operating costs and have been outpacing other categories. According to MCC, many businesses cannot afford these increases and, contrary to the OAG's claim, businesses in competitive markets cannot simply pass on the increases to customers and expect to remain in business. MCC stressed that shifting a greater proportion of the costs onto businesses has a cascading effect - the more a manufacturer's bottom line is adversely impacted the greater the potential for job losses, which in turn has a detrimental impact on residential ratepayers.[887] MCC asserted that large business ratepayers should not be subsidizing other classes. Instead, it argues that non-cost factors such as rate shock should be weighed for all ratepayers, including business ratepayers.[888]

718. MCC advocated allocating cost to classes according to the final outcome of the CCOSS or, in the alternate, in the manner proposed by the Company.[889]

719. XLI objected to the Company's proposal to set the C&I Demand class rates above cost and subsidize the C&I Non-Demand class. XLI contended that there is no reason why all classes should not be moved to cost. XLI maintained that moving all rates to cost would not violate the principle of gradualism because no class would experience an increase in base rates higher than 1.5 times the system average.[890] In addition, given the loss of C&I Demand loads identified by Company, XLI asserted it is inappropriate to double the subsidy provided by the C&I Demand class.[891] According to XLI, adhering to cost of service principles when setting rates will have the additional benefits of equity, engineering efficiency, rate stability, and conservation.[892]

720. XLI also criticized the revenue allocation calculations performed by the Department's expert, Ms. Peirce. The XLI asserted that by using the cost ratios after applying an equal (10.7) percent increase across-the-board for all classes, Ms. Peirce initially moves rates away from cost before moving each class 50 percent closer to cost. XLI contended that by doing this and by including fuel revenues, Ms. Peirce does not move rates 50 percent closer to cost as claimed.[893]

721. XLI also asserted that the difference between the Company's proposal and the Department's proposal is so small ($0.35 per month according to XLI) that it would hardly be noticeable to the average residential customer. XLI contended that mitigating rate shock does not warrant moderating the Company's proposed movement to cost-based rates.[894]

---

[887] Ex. 110 at 1-3 (Williamson Surrebuttal); Ex. 111 at 2 (Myhrman Surrebuttal); Ex. 114 at 13 (Maini Direct); Ex. 115 at 28-29 (Maini Surrebuttal).
[888] MCC Initial Brief at 24; *See*, Tr. Vol. 4 at 178 (Chavez).
[889] MCC Initial Brief at 24.
[890] Ex. 122 at 32 (Pollock Surrebuttal).
[891] *Id*. at 32-33; Ex. 63 at 8 (Krug Direct).
[892] XLI Initial Brief at 20-21; XLI Reply Brief at 30-31; Ex. 119 at 66-69 (Pollock Direct).
[893] Ex.121 at 8-13 (Pollock Rebuttal).
[894] *Id.* at 11-12.

v. The Commercial Group's Proposed Revenue Apportionment

722. The Commercial Group found the Company's proposed revenue allocation to be substantially correct, but urged even more movement toward cost. The Commercial Group criticized what it sees as the Department's arbitrary and inadequate 50 percent movement toward cost. Given the financial pressures currently weighing on commercial and industrial customers, the Commercial Group argued that this class cannot bear an unfair subsidy load.[895]

723. The Commercial Group also maintained that the Department's expert, Ms. Peirce did not update her revenue apportionment calculations to reflect the Company's revised CCOSS. Instead, she used the Company's first CCOSS. By doing this, the Department's proposed 50 percent movement to "cost" is the cost determined by the Company in its initial CCOSS. The Commercial Group maintained that basing class revenue apportionment upon a flawed initial CCOSS is an arbitrary and unreasonable approach because it means the corrections to the CCOSS would have no impact on rates. Finally, the Commercial Group joined the XLI in criticizing Ms. Peirce for applying an across-the-board increase in the revenue requirement for all classes before proposing to move the classes 50 percent closer to cost.[896]

vi. Final Revenue Apportionment

724. If the final revenue requirement approved by the Commission is lower than the one proposed by the Company, it will be necessary to adjust the proposed revenue allocation to reflect the final revenue requirement. The Company has proposed adjusting the final revenue requirement proportionally among classes to incorporate changes in the revenue requirement and sales forecasts ordered in this case. The Commission adopted this methodology in apportioning revenue in the Company's previous rate case.[897]

725. As noted above, the Department agreed with the Company's recommendation. The Department stated that proportional adjustment of the final revenue requirement will help ensure that the relative structure of the classes to each other is maintained, and avoid distortions resulting from revisions to the class distribution as sales forecasts and revenue estimates are revised over the course of the proceeding.[898]

vii. Conclusion

726. The Administrative Law Judge concludes that the Department's proposed methodology of revenue apportionment, which seeks to move each class moderately closer to cost, is the most reasonable. The Department's proposal appropriately balances the goal of economic efficiency by moving rates toward cost with the goal of

---

[895] Commercial Group Initial Brief at 7-8.
[896] *Id*. at 7-9.
[897] Docket No. E002/GR-10-971. Ex. 157 at 3-8 (Peirce Surrebuttal).
[898] Ex. 157 at 3 (Peirce Surrebuttal).

tempering the overall revenue increase experienced by each class to avoid rate shock. The proposals of other parties that urge greater movement toward cost fail to give due weight to non-cost factors such as continuity of existing rates and rate shock. Given the exceptionally large number of customers who expressed concern about the Company's proposed rate increases, it is appropriate to give due weight to these non-cost factors. The OAG's proposal to use the rate design from the last rate case, on the other hand, fails to appropriately consider the current CCOSS.

727. For these reasons, the Administrative Law Judge recommends that the Commission adopt the Department's initial apportionment set forth in Ms. Peirce's Direct Testimony, and proportionally adjust that apportionment based on the final revenue determination.

728. If the Commission adopts any major changes to the Company's initial CCOSS, then the Commission should direct the Department and the Company to recalculate the apportionment using the Department's methodology as applied to the revised CCOSS. The recalculation would be necessary because the Department's apportionment is based on the CCOSS set forth in the Company's Application.

D. Residential Customer Charge[899]

729. The primary function of a customer charge is to recover the fixed cost of serving customers that is not related to energy usage. These fixed costs include the cost of meters, service lines, meter reading and billing.[900] The average customer-related cost, according to the Company's revised CCOSS, is $17.32 per month for a residential customer.[901]

730. The Company, Department, and SRA proposed to increase customer charges for Residential and Small General Service customers in order to move those charges closer to the cost of service. Their proposals are reflected in the table below.

[899] Issue 61.
[900] Ex. 66 at 7 (Huso Direct).
[901] Ex. 67 at 8 (Huso Rebuttal).

Table 24 Comparison of Customer Charge Proposals[902]

Service Category	Cost of Service[903]	Current Charge[904]	Company Proposed[905]	Department Proposed[906]	SRA Proposed[907]
Residential Overhead	$17.32	$7.11	$10.00	$8.50	$8.25
Residential Underground – Standard	$17.32	$9.11	$12.00	$10.50	$10.50
Residential Heating – Overhead	$17.41	$9.11	$12.00	*	*
Residential Heating – Underground	$17.41	$11.11	$14.00	*	*
Small General Service	$19.25	$8.61	$12.00	*	*

i. Company's Proposed Customer Charge

731. The Company proposed to increase its monthly customer charge from $7.11 to $10.00 per month for overhead residential customers, and from $9.11 to $12.00 per month for underground customers.[908] The proposed increase moves 0.5 cents per kWh in customer costs from the energy charge to the customer charge. While the Company contended that this amount is not large enough to impact conservation,[909] it results in an increase of as much as 40 percent for the Residential class over the existing charge.[910]

732. The Company pointed out that current overhead and underground customer charges are 59 percent and 47 percent below cost, respectively.[911] When the customer charge is kept below cost, fixed costs must be recovered in energy charges.[912] Because the subsidy inherent in a below-cost customer charge is determined by usage, not income, customers with above-average usage end up paying more than their proportionate share of customer costs.[913] The Company noted that approximately 40 percent of Low Income Home Energy Assistance Program (LIHEAP)

---

[902] *Id*.
[903] Ex. 66 at 8 (Huso Direct).
[904] *Id*.
[905] Ex. 67 at 8 (Huso Rebuttal).
[906] Ex. 155 at 11 (Peirce Direct).
[907] SRA Initial Brief at 19.
[908] *Id*.; Department Initial Brief at 208.
[909] Ex. 67 at 12 (Huso Rebuttal).
[910] OAG Initial Brief at 16; Ex. 129 at 13 (Chavez Direct).
[911] Xcel Initial Brief at 171.
[912] Ex. 67 at 8-9 (Huso Rebuttal).
[913] Ex. 66 at 8-9 (Huso Direct).

customers, for example, end up contributing to this subsidy. Thus, keeping the customer charge below cost benefits customers with below average usage at the expense of customers with above average usage, some of whom are low-income customers.[914]

733. The Company asserted that its proposed customer charge is a moderate move towards cost and should be adopted.

ii. The Department's Proposed Customer Charge

734. The Department agrees that an increase in the residential customer charge is reasonable. It maintained, however, that the size of the Company's proposed increase is unreasonable. The Department recommended increasing the monthly customer charge for overhead residential customers from $7.11 to $8.50 per month, and from $9.11 to $10.50 per month for underground residential customers.[915]

735. The Department asserted that a comparison of the Company's proposed customer charge to customer charges of other utilities demonstrates that the Department's proposal is reasonable and consistent with the customer charges approved for other Minnesota utilities in recent cases.[916]

Table 25 Summary of Residential Customer Charges for Minnesota Utilities

Company/Docket No.	Company Proposed Customer Charge	PUC Approved/DOC Proposed Customer Charge
Minnesota Power –E015/GR-09-1151	$9.75	$8.00
Otter Tail Power – E017/GR-10-239	$9.00	$8.50
Interstate Power & Light – E001/GR-10-276	$10.00	$8.50

736. The Department stated that its recommendation seeks to balance the impact that an increase in the residential customer charge has on customers or households with the impact of intra-class subsidies.[917] Customers who use larger amounts of energy (e.g., those who are unemployed and are home more than those who work outside the home, those who work at home instead of elsewhere, homes with many household members, homes with customers who are not able to invest in energy conservation to reduce their energy use) would pay lower bills if customer charges were set closer to such costs because these customers would not have to pay the subsidy in their energy charge for the fixed customer costs that low-use (but not necessarily low-income) households impose on the system for which they do not pay.[918]

[914] Ex. 66 at 9 (Huso Direct).
[915] Ex. 155 at 11 (Peirce Direct); Department's Initial Brief at 208.
[916] *Id*.
[917] *Id*. at 12.
[918] *Id*. at 13-14.

737. The Department noted that in the past, the Commission expressed concern that high customer charges may be burdensome to low-income households based on the assumption that low-income households use less energy than other residential customers. The Department cautioned, however, that this may not be true in all cases, including the examples noted above.[919]

738. The Department also analyzed 2012 monthly residential usage data provided by the Company. Based on its analysis, the Department concluded that low-income customers do, at times, subsidize other customers.[920]

739. The Department maintained that its recommended increase is a modest movement toward cost that lessens the intra-class subsidy in energy charge from high-use to low-use customers within the class.[921]

iii. SRA Proposed Customer Charge

740. The SRA opposed the Company's proposed customer charge as immoderate and states that an increase of the customer charge for overhead residential customers from $7.11 to $8.25 and for underground customers from $9.11 to $10.50 is reasonable.[922] The SRA noted that residential customers, including low-income, low-use customers, are most affected by this fixed charge. The SRA maintained that keeping the customer charge lower still promotes conservation by recovery of a portion of the Company's fixed charge through volumetric rates, not fixed charges.[923]

iv. The OAG's and ECC's Responses

741. The OAG opposed the Company's proposed increase in the customer cost charge and recommended that the Commission reject it and provide no increase in the monthly residential and small commercial customer charges.[924] The OAG noted that the Commission has never raised the residential customer charge by 40 percent and it maintained that such a request is unprecedented and would violate the non-cost factors of continuity with prior rates and ease of understanding.[925]

742. The OAG asserted that the Company's proposed increase would result in rate shock and cause hardship for customers on low or fixed-incomes.[926] Moreover, the OAG pointed out that it has been less than one year since the Company increased its residential customer charge by $1.00 or about 15 percent.[927]

---

[919] *Id.* at 14, 18.
[920] *Id.* at 15-18.
[921] *Id*. at 18.
[922] SRA Initial Brief at 19; SRA Reply Brief at 6.
[923] *Id*.
[924] OAG Initial Brief at 18.
[925] *Id*.
[926] *Id.* at 16-17.
[927] Ex. 129 at 14-15 (Chavez Direct).

743. The ECC also opposed any increase in the customer charges. The ECC contended that high customer service charges raise rates disproportionately and negatively impact lowest usage and low-income customers, who are the least able to absorb high customer charges.[928]

v. Conclusion

744. The Administrative Law Judge concludes that the Department's recommended increase is a modest movement toward cost that lessens the subsidy in the energy charge. Raising the residential customer charge to $8.50 per month for overhead customers and $10.50 per month for underground customers is a reasonable step toward cost-based rates that limits the impact of intra-class subsidization. A modest increase of this type, which is smaller than that proposed by the Company, would also help to minimize rate shock.

E. Inverted Block Rate[929]

745. ECC proposed that the Company be required to implement an Inverted Block Rate (IBR) structure for residential customer rates. An IBR structure is characterized by energy rates that increase as an individual customer's energy usage increases. It identifies two or more fixed kWh usage blocks and applies rates that increase successively with the amount of usage.[930] ECC asserted that an IBR structure is the most efficient way to insulate low and moderate-income customers from higher energy costs and encourage conservation.[931]

746. Currently, the Company charges its standard residential customers a flat per kWh energy charge that varies by season (winter and summer), but does not vary by usage level. In this proceeding, the Company is proposing to charge customers a flat $0.07872 per kWh for usage from October through May, and a rate of $0.09223 per kWh during June through September.[932]

i. ECC's Proposed IBR

747. The ECC maintained that flat energy rate increases disproportionately harm customers with the lowest levels of energy usage. ECC also asserted that the evidence in the record demonstrates that lower usage customers are most likely to be low-income customers.[933] ECC stated that data from the Energy Information Administration's Residential Energy Consumption Survey (RECS) establishes a correlation between lower household income and lower energy use.[934] In addition, on average, LIHEAP customers use less electricity than non-LIHEAP customers (637kWh

[928] ECC Brief at 9-11; Ex. 101 at 3, 22 (Marshall Direct).
[929] Issue 83.
[930] Ex. 67 at 12 (Huso Rebuttal).
[931] ECC Brief at 3.
[932] Ex. 156 at 1 (Peirce Rebuttal).
[933] Ex. 101, Attachments 1-4 (Marshall Direct).
[934] ECC Initial Brief at 3-5.

versus 713 kWh, respectively).[935] Moreover, the ECC maintained that lower-income LIHEAP households use less electricity than LIHEAP customers generally. According to the ECC, seniors who rent and receive LIHEAP have, on average, annual incomes of $13,877 and spend $678 for electric costs, while LIHEAP customers generally have annual incomes of $16,582, on average, and spend $909 for electric costs.[936]

748. ECC argued that under the Company's proposed flat rate increase, the lowest income, lowest usage customers pay the highest percentage increase.[937] At the same time, flat rates discourage higher usage customers from conserving electricity because their bills do not increase significantly with increased usage.[938]

749. ECC maintained that, in contrast to flat rates, an IBR structure rewards customers who use less energy, promotes affordable utility service for low- and fixed-income customers generally and provides price incentives to higher usage customers to conserve energy.[939] ECC asserted that customers with higher usage are more likely to be higher income customers. According to the ECC, higher usage customers are also more likely to have both elastic energy demand and the financial resources to install energy efficiency measures.[940]

750. ECC recommended that the Commission require the Company to adopt a five-tier inverted block rate based on the IBR structure used by Minnesota Power. Specifically, ECC proposed that the Commission require Xcel to use the following five blocks for setting its rates:

Block 1:	0-500 kWh
Block 2:	501-750 kWh
Block 3:	751-1,000 kWh
Block 4:	1,001 – 1,500 kWh
Block 5:	over 1,501 kWh[941]

751. ECC recommended that rates in the first two blocks be set lower than the current residential rate, and that the third usage block receive a minimal increase with increases in the successive blocks.[942] Under this proposal, ECC maintained that rate increases for the average residential customer, the majority of LIHEAP customers, and other low and fixed-income customers can be minimized.[943]

752. According to ECC, its proposed IBR is the most efficient way to insulate the greatest number of low-income customers from the Company's proposed rate

[935] Exhibit 101, Attachment 2 (Marshall Direct).
[936] Ex. 101, Attachment 4.
[937] ECC Initial Brief at 6.
[938] *Id.* at 13.
[939] *Id.* at 7.
[940] Ex. 101 at 21 (Marshall Direct).
[941] Ex. 101 at 20 (Marshall Direct); Ex. 156 at 2 (Peirce Rebuttal).
[942] Ex. 101 at 20 (Marshal Direct); Ex. 156 at 2 (Peirce Rebuttal).
[943] ECC Brief at 14.

increase.[944] ECC stated that the average LIHEAP monthly usage is 637 kWh and the maximum average usage level for all LIHEAP customers is 868 kWh.[945] According to the ECC, all residential customers below 900 kWh of monthly usage would pay less than under the Company's proposed flat rate increase.[946]

753. In addition, ECC maintained that programs such as the Company's POWER On program are available to mitigate the impact of an IBR structure on low-income, high-usage customers. ECC also recommended that Xcel specifically exempt customers with in-home medical equipment and with electric space heating because these customers are more likely to consume electricity in the higher proposed usage blocks.[947]

754. The Environmental Intervenors support ECC's proposal primarily on conservation grounds.[948] The Environmental Intervenors asserted that ECC's proposed IBR is the only proposal that meets the statutory mandate to encourage conservation.[949] The Environmental Intervenors maintain that it is indisputable that a price structure that costs more as use increases provides an incentive for consumers to use less energy.[950] They note that the inverse relationship between price and consumer usage is built into the very models used in rate cases to forecast energy consumption. The Environmental Intervenors agree with ECC that there are likely to be few high-usage low-income customers, and those who have high-use needs for medical or other reasons have cost subsidies and other targeted programs to assist with conservation.[951]

755. The Company, Department, and OAG opposed ECC's IBR proposal for the reasons discussed below.[952]

ii. Impact of Proposed IBR on Customers' Bills

756. To gauge the impact of an IBR structure on customer bills, the Department requested the Company calculate the energy charges required to recover its proposed residential revenue requirement using ECC's proposed usage blocks.[953] The Company used 2011 actual sales, excluding seasonal rates, space heating rates, the Saver's Switch Rider, and the Low Income Rate Energy Discount Rider. The Company calculated the inverted block rates based on the average monthly rate rather than its proposed seasonal rates.[954]

---

[944] Ex. 101 at 3 (Marshall Direct).
[945] ECC Brief at 17; Ex. 101, Attachment 2 (Marshall Direct); Ex. 155, SLP-4 (Peirce Direct).
[946] *Id.* at 18.
[947] *Id.* at 14, 19.
[948] Initial Brief of the Environmental Intervenors at 5.
[949] Minn. Stat. § 216B.03 (stating the Commission shall, to the maximum reasonable extent, set rates to encourage energy conservation).
[950] Initial Brief of the Environmental Intervenors at 5-6; Ex. 145 at 22-25 (Heinen Direct).
[951] Id. at 9; Ex. 103 at 10 (Marshall Surrebuttal).
[952] Ex. 67 at 12-15 (Huso Rebuttal); Ex. 156 at 11-12 (Peirce Rebuttal); Ex. 130 at 20 (Chavez Rebuttal).
[953] Ex. 156 at 3 and SLP-R-1 (Peirce Rebuttal).
[954] *Id.*

757. The table below provides a comparison of estimated customer bills under the current rates, the Company's proposed rates, and the IBR rate structure at various usage levels.

Table 26 Estimated Impacts of Inverted Block Rates on Customer Bills[955]

				% Change from current	
Usage	**Current Rates**	**Xcel Proposed**	**IBR**	**Xcel Proposed**	**IBR**
300 kWh					
Winter	$28.44	$33.62	$28.94	18.2%	1.8%
Summer	$32.13	$37.69	$28.94	17.2%	-9.9%
600 kWh					
Winter	$49.36	$57.23	$51.64	15.9%	4.6%
Summer	$56.75	$65.34	$51.64	15.1%	-9.0%
900 kWh					
Winter	$70.29	$80.85	$79.88	15.0%	13.7%
Summer	$81.36	$93.01	$79.88	14.3%	-1.8%
1,200 kWh					
Winter	$91.21	$104.46	$113.01	14.5%	23.9%
Summer	$105.98	$120.68	$113.01	13.9%	6.6%
1,700 kWh					
Winter	$126.09	$143.82	$171.93	14.1%	36.4%
Summer	$147.01	$166.79	$171.93	13.5%	16.9%

758. The rate calculation assumes a single rate for each rate block consistent with Minnesota Power's IBR rate structure and ECC's recommendation, rather than the seasonal rates currently charged by the Company. As a result, the bill impact of implementing IBR rates would vary depending on the season. For example, under ECC's proposal, customer bills at the lowest usage blocks would increase slightly compared with current winter bills while dropping significantly (9-10 percent) when compared to current summer bills. By contrast, for customers in the highest usage blocks, bills would increase between 24 and 36 percent during the winter months compared with 14 percent under the Company's proposal.[956]

759. ECC asserted that "the vast majority of low income customers will not incur usage and charges in the highest IBR blocks."[957] LIHEAP customers use less electricity than residential customers generally, and the ECC maintains that there is no reason to assume the usage patterns of low-income customers not receiving LIHEAP assistance differs from LIHEAP customers.[958]

iii. The Company's Opposition to ECC's Proposed IBR

760. The Company argued that ECC's IBR should be evaluated on the basis of energy charges and not the "total bill" (i.e. energy charge and customer charge) as

[955] *Id.* at 4 (Peirce Rebuttal).
[956] *Id*.
[957] Ex. 101 at 27 (Marshall Direct).
[958] *Id*. at 14.

suggested by ECC's witness, Ms. Marshall.[959] The tables below compare the proposed energy charges put forth by the Company and ECC.[960]

Table 27 Comparison of Proposed Energy Charges (% Difference from Current Rates)

	Summer Months		Winter Months		Average Month	
Usage Level	Company	ECC	Company	ECC	Company	ECC
300	12%	-13%	13%	2%	13%	-2%
600	12%	-10%	13%	5%	13%	0%
900	12%	-2%	13%	14%	13%	8%
1200	12%	7%	13%	24%	13%	18%
1700	12%	18%	13%	36%	13%	29%

Table 28 Comparison of IBR Energy Charges (Difference from Company's Proposal, $ Per Month)

Usage Level	Summer Months	Winter Months	Average Month
300	($6.24)	($2.19)	($3.54)
600	($11.21)	($3.10)	($5.80)
900	($10.64)	$1.52	($2.53)
1200	($5.18)	$11.04	$5.63
1700	$7.63	$30.60	$22.94

761. The Company's proposal increases energy charges equally across all usage levels. Whereas, under the ECC proposal, high-usage customers would see significant bill increases, especially in winter months.[961]

762. The Company contended that an IBR design is an inefficient way to deliver benefits to low-income customers. Because an IBR design specifically benefits lower energy usage and penalizes higher energy usage, it is only effective at helping low-income customers *if* all low-income customers had below average usage and *only* low-income customers had below average use. According to the Company, this is not the case. While the IBR may help certain low-income customers, it would clearly harm other low-income customers with higher usage. It would also benefit customers with middle and high incomes that have below average energy use. According to the

[959] Xcel Reply Brief at 77; ECC Brief at 6.
[960] Tables recalculated from Ex. 156 at Schedule 2 (Peirce Rebuttal).
[961] Xcel Reply Brief at 76-78; Tables recalculated from Ex. 156 at Schedule 2 (Peirce Rebuttal).

Company, the end result dilutes the overall low-income benefits associated with the program and magnifies the total cost of delivered benefits.[962]

763. The Company asserted that nearly 40 percent of low-income customers have monthly usage that exceeds 600 kWh per month.[963] Regardless of the level of the energy charge, an average low-income customer would have usage that falls into the third rate block every month of the year. These same customers would have usage in the fourth block eight months a year.[964] Rates in these blocks would be higher than those proposed by the Company. The Company maintained that the fact that the proposed IBR would ultimately raise prices for almost half of the low-income population it is designed to help, and low-income customers would only be a small fraction of all the customers that benefit from the lower prices, demonstrates that the proposal is unreasonable.[965] The Company also argued that ECC's proposed IBR gives price signals that could encourage usage during the highest cost summer months.[966]

764. In addition, the Company raised concerns that its lack of history with IBR would lead to unintended consequences and customer confusion.[967] Minnesota Power had a three-tier inverted block rate structure in place for a number of years before implementing a five-tier structure in its last rate case, thereby limiting customer confusion.[968] The Company, however, has no such history. As a result, an abrupt and drastic change in residential rate design could lead to customer confusion and dissatisfaction – aspects that also plagued the CenterPoint Energy's IBR program.[969]

765. Finally, the Company asserted that the conservation benefits of IBR designs have not been borne out. The Company notes that Minnesota Power has not been able to conclude their IBR resulted in conservation, which limits the weight that can be placed upon a conservation-based argument.[970]

iv. The Department's Opposition to ECC's Proposed IBR

766. The Department identified several concerns with respect to implementing the ECC's proposed IBR. The Department pointed out that because the IBR lacks a seasonal component, low-usage customers would see significant bill reductions in the summer relative to the current rate structure. According to the Department, this would send the wrong price signal to customers to use more energy.[971] The Department also

---

[962] Ex. 67 at 8-10, 13-14 (Huso Rebuttal).
[963] Ex. 155 at Schedule 4 page 2 of 2 (Peirce Direct).
[964] *Id*.
[965] Xcel Reply Brief at 76; Ex. 67 at 13-14 (Huso Rebuttal).
[966] Xcel Reply Brief at 76-78.
[967] Xcel Initial Brief at 171-172.
[968] Ex. 156 at 7-8 (Peirce Rebuttal).
[969] Xcel Initial Brief at 172.
[970] *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015/GR-09-1151, COMPLIANCE FILING at 1 (January 11, 2013) ("As a result, no meaningful conclusions can be drawn about whether or not the five-block rate design resulted in conservation.").
[971] Ex. 156 at 6-7 (Peirce Rebuttal).

stated that implementing a seasonal block rate structure would further increase the complexity of the IBR structure, cause customer confusion, and would not give customers price signals in a timely manner.[972]

767. Further, the Department challenged ECC's assertion that the IBR would necessarily promote conservation. The Department argues that the IBR structure does not provide customers with appropriate price signals in advance of their energy use, and it does not provide customers appropriate price signals as to the appropriate timing of energy conservation.[973] The Department explained that customers whose energy use is near the cutoff point for a particular block rate will see their bills only after they have used the energy. Additionally, usage may vary depending on factors that the customer cannot control, such as the weather. Moreover, the Department noted that customers who work from home (such as home daycare facilities) and households with more people pay higher bills under the proposed IBR.[974]

768. The Department also disagreed with ECC's claim that "the vast majority of low-income customers will not incur usage and charges in the highest IBR blocks."[975] While it is true that LIHEAP customers use less on average per month than non-LIHEAP participants, the Department stressed that a sizeable number of LIHEAP customers (41 percent of all LIHEAP customers or about 25,000 customers) have monthly usage that would result in economic harm to them under an IBR structure. In addition, the Department pointed out that approximately 461,000 customers not participating in LIHEAP, some of whom are low-income, had average usage of 1,100 kWh per month, and would see their electric bills rise significantly with an IBR structure.[976] While it is true that LIHEAP customers meet certain low-income eligibility requirements, the converse is not true; that is, not participating in LIHEAP does not indicate that the household has a particular income.[977] The Department echoed the Company's concern that customers with higher usage levels, some of whom are households with low-incomes, would be subsidizing the customer costs of lower usage households that may have average or high incomes.[978]

769. Finally, in response to ECC's contention that programs are available to mitigate the impact of an IBR on low-income/high-usage customers, the Department notes that both the Low Income Discount (LID) and POWER On program require the receipt of LIHEAP as a criterion for eligibility.[979] Thus, if the customer is not able to receive LIHEAP funding, the POWER On program would not provide any benefit. Moreover, programs such as the POWER On program are only able to assist low-income, high-usage customers if funding is available. According to ECC's witness, over

---

[972] *Id*. at 4-5.
[973] *Id.* at 6 (Peirce Rebuttal); Department Initial Brief at 217.
[974] *Id.* at 5 (Peirce Rebuttal).
[975] Ex. 101 at 27 (Marshall Direct).
[976] Ex. 156 at 6 (Peirce Rebuttal).
[977] Ex. 157 at 10 (Peirce Surrebuttal).
[978] Ex. 155 at 15-16 (Peirce Direct).
[979] Ex. 101 at 32 (Marshall Direct).

3,500 households have been denied assistance from POWER On because no funding is available.[980]

770. The Department maintained that there are other more efficient ways to encourage conservation, such as through the Company's numerous conservation improvement programs, which do not risk the potential undesired effects of an IBR design.[981]

v. The OAG's Opposition to ECC's Proposed IBR

771. The OAG likewise recommended that the Commission not approve the proposed IBR based on the experience of CenterPoint Energy's now terminated IBR.[982] The OAG noted that in terminating CenterPoint's IBR, the Commission found that low-income customers in poorly insulated homes, renters in multi-unit buildings with only one gas meter, and customers billed using extended billing periods had all been adversely affected by CenterPoint's IBR.[983] The Commission further found that the unintended and undesirable consequences of the IBR could not be sufficiently addressed by any program modifications.[984] The OAG asserted that there is no reason to assume that ECC's proposed IBR in this case will not produce the same undesirable results.[985] In addition, the OAG pointed to the recent changes made by the Minnesota Legislature in response to the unfavorable consequences of CenterPoint's IBR program, including removing all references to IBR rate structures in Chapter 216B.[986]

772. The Environmental Intervenors argued in response that the reliance on CenterPoint's failed IBR is misplaced. They contend that a much more relevant recent decision is the Minnesota Power rate case, which was decided more recently and concerns electricity instead of gas.[987]

773. Minnesota Power, however, already had a three-tier inverted block structure in place for a number of years when the Commission ordered expanding it as proposed by the ECC. In contrast, Xcel's customers have no current experience with block rates and have not had the opportunity to review such a rate structure.[988]

---

[980] *Id.* at 16 (Marshall Direct).
[981] *Id.*; Department Initial Brief at 217.
[982] OAG Reply Brief at 8.
[983] *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-08-1075, ORDER TERMINATING INVERTED BLOCK RATE STRUCTURE, ACCEPTING EVALUATION AND WORKGROUP REPORTS, AND REQUIRING COMPLIANCE FILINGS (August 10, 2012) at 3-4 (CENTERPOINT IBR ORDER].
[984] *Id.*
[985] OAG Reply Brief at 8; Ex. 130 at 20-23 (Chavez Rebuttal).
[986] OAG Initial Brief at 20.
[987] Initial Brief of the Environmental Intervenors at 10; Ex. 103 at 11 (Marshall Surrebuttal).
[988] Ex. 156 at 8 (Peirce Rebuttal).

vi. Conclusion

774. The Company, the Department and the OAG have shown that the proposed IBR would have undesired effects on low-income customers with above average energy use. The added complexity associated with an IBR and the unsuccessful experience of the CenterPoint IBR are also troublesome. In addition, the Administrative Law Judge is persuaded that the proposed IBR is an ineffective way to address energy affordability and conservation. Together these factors render the implementation of the proposed IBR unreasonable. Programs that target benefits to low-income customers based on income would be more effective at meeting the needs of low-income customers. Similarly, conservation improvement programs are a more effective means of encouraging conservation. For these reasons, the Administrative Law Judge concludes that the proposed IBR is not reasonable and recommends that it not be implemented at this time.

F. Competitive Response Rider

775. The Company's current tariff includes a set of special riders which permit the Company to offer discounted energy prices to certain larger customers, so as to spur load growth. These special provisions are the Competitive Service Rider (CS Rider), Competitive Market Rider (CM Rider) and the Area Development Rider.[989]

776. The CS Rider has a minimum load requirement of 5 megawatts.[990]

777. The CM Rider has a minimum load requirement of 500 kilowatts.[991]

778. Currently, there are only two customers receiving service under these tariffs.[992]

779. As part of an effort to expand participation in these programs, and to utilize excess capacity within its system, the Company proposed to combine its existing Competitive Service Rider (CS Rider) and the Competitive Market Rider (CM Rider) into the newly proposed Competitive Response Rider (CR Rider).[993]

780. Under the Company's proposal, a customer on commercial and industrial demand-metered service would be eligible to apply for discounted demand and energy charges under the CR Rider if the customer had a minimum load requirement of 5 megawatts and is subject to either "effective competition" or "operate[s] under competitive market conditions."[994]

---

[989] Ex. 64 at 8, 13 (Krug Rebuttal).
[990] *Id.* at 9.
[991] Ex. 136 at 3 (Amit Direct).
[992] Ex. 64 at 8 (Krug Rebuttal).
[993] Ex. 63 at 32 (Krug Direct).
[994] *Id.* at 21, 35, 36 (Krug Direct); Ex. 136 at 3 (Amit Direct).

781. As proposed by the Company, the terms "subject to effective competition" would mean that the customer met the eligibility requirements of Minn. Stat. § 216B.162, subd. 1(b).[995]

782. As proposed by the Company, the phrase "operate[s] under competitive market conditions" would mean "a direct competitor in the customer's own product or service market can obtain electric energy from another utility at a lower cost than the Company's comparable electric service," or "the customer can obtain service from a directly substitutable energy source."[996]

i. Support for and Opposition to the Proposed Rider

783. The Department supported the new Competitive Response Rider in principle. The Department noted that as long as the incremental revenues resulting from the CR Rider exceeds its incremental costs, the CR Rider will benefit all ratepayers. The Department, however, proposed the following modifications to the CR Rider: (1) the "competitive market conditions" language be removed; (2) the minimum load be reduced from 5MW to 2MW; (3) the trade secret language be amended; and (4) the proposal to track discounts provided between rate cases for recovery in subsequent rate cases be removed.[997]

784. In its Rebuttal Testimony, the Company agreed to reduce the minimum load requirement from 5 MW to 2 MW and to amend rider language on the handling of trade secret information, thus resolving two of the four concerns raised by the Department.[998]

785. MCC and XLI also supported the proposed rider in principle.[999]

786. The OAG opposed the proposed rider on the grounds that residential customers would not benefit from the proposed rider and would bear a portion of the costs.[1000]

787. The SRA suggested that if the rider is approved, the Commission should require the Company to identify, in a compliance filing, how all classes of customers have benefited.[1001]

ii. "Competitive Market Conditions" Language

788. As noted above, the Company proposed to make the CR Rider available to a C&I customer on demand-metered service with a minimum load of 2MW if the

[995] Ex. 136 at 3 (Amit Direct).
[996] *Id.* at 10.
[997] Ex. 139 at 1 (Amit Opening Statement); Ex. 136 at 9-22 (Amit Direct).
[998] Ex. 65 at 16 (Krug Surrebuttal).
[999] Ex. 115 at 39 (Maini Surrebuttal); Ex. 123 at 5 (Pollock Opening Statement).
[1000] Ex. 133 at 1-2 (Chavez Opening Statement).
[1001] SRA Initial Brief at 2.

customer is subject to either "effective competition" or "operate[s] under competitive market conditions."[1002]

789. The Department recommended the elimination of the "operate[s] under competitive market conditions" language in the eligibility provision because the language is unclear, overly broad, and inconsistent with the definition of "effective competition" in Minn. Stat. § 216B.162.

790. Because the CR Rider could be read to permit discounted rates for a large customer that competed with companies in other states, at a time when those other companies paid less for electricity than is charged by Xcel, the rider language is overly broad. Such a provision assumes, incorrectly, that the key determinant in market position or national market share for firms within the Company's service area is the amount that those firms pay for electricity. The record does not support such a broad claim. It is much more likely that a combination of different factors, beyond energy prices, determines the market position of the Minnesota firms that compete nationwide for sales.[1003]

791. To the extent that the CR Rider provisions are meant to discourage companies from moving to locations outside of the service area because of differentials in electricity rates, the terms "subject to effective competition" in the proposed language (and the protections of Minn. Stat. § 216B.162, subd. 1 (b)) are sufficient to meet these concerns. The Company could offer discounted rates to these customers under the "subject to effective competition" provisions.[1004]

792. Similarly, in those cases in which local, self-generation of energy might prompt large customers to suspend purchases, in favor of using alternative energy sources, the "subject to effective competition" terms of the rider and Minn. Stat. § 216B.162, subd. 1 (b), are sufficient to meet these concerns. The Company could offer discounted rates to these customers under the "subject to effective competition" provisions.[1005]

793. Because the Company's "competitive market conditions" provision is overly broad and unnecessary, the Administrative Law Judge concludes the language should be eliminated as recommended by the Department. The Company's smaller, non-participating customers should not be asked to pay higher rates in order to "subsidize" the rates of Xcel's large customers unless there is a demonstrated need that is firmly grounded in the record.[1006]

[1002] Ex. 63 at 21, 35, 36 (Krug Direct); Ex. 136 at 3 (Amit Direct).
[1003] Ex. 136 at 10-12 (Amit Direct); Ex. 138 at 16-17 (Amit Surrebuttal).
[1004] *Compare,* Ex. 138 at 16 (Amit Surrebuttal) *with* Ex. 64 at 12 (Krug Rebuttal).
[1005] *Compare,* Ex. 138 at 17 (Amit Surrebuttal) *with* Ex. 64 at 12 (Krug Rebuttal).
[1006] *See* Ex. 136 at 12 (Amit Direct).

iii. Deferred Accounting of the Revenue Deficiency Provision

794. The Company proposed to track all of the discounts provided under the CR Rider through a deferred account and to recover these sums in the next general rate case. Under the terms of its proposal, from the date that customers covered by the CR Rider receive service until the Company's next rate case filing, the Company would accumulate revenue deficiencies. These deficiencies would accumulate because, all other factors being equal, customers covered by the CR Rider would pay less than their cost of service.[1007]

795. The Department objected to the Company's deferred accounting proposal because such treatment is contrary to well accepted regulatory principles and to Commission precedents.[1008]

796. The Company's deferred accounting proposal is not reasonable because it is at odds with the ordinary procedures for cost and revenue treatment between rate cases. For instance, Minn. Stat. § 216B.162, subd. 4(3), authorizes recovery of the competitive service discounts on a prospective basis only. The statute does not contemplate recovery of historical competitive rate discounts.[1009]

797. The Company's deferred accounting proposal also is not reasonable because it eliminates important incentives to minimize costs. As proposed, the Company would be permitted to recover all of the historical discounts associated with the CR Rider. Therefore, the incentives for the Company to sparingly grant rate discounts or to critically assess applications for such discounts would be sharply reduced. Likewise, customers within the large commercial and industrial class, knowing that the Company will be held harmless as to discounts extended under the CR Rider, would be encouraged to seek discounts under the CR Rider – even when they do not have a credible alternative supplier or source. Extending discounts in inappropriate circumstances is contrary to the interests of other ratepayers and the system as a whole.[1010]

798. Finally, the Company's deferred accounting proposal is not reasonable because it reduces the utility's operational risks. Acceptance of the proposal would move the ratemaking process from one that allows the utility a fair opportunity to recover its costs to a process that grants the utility a guaranteed rate of return.[1011]

iv. Conclusion

799. The Administrative Law Judge concludes the Company's proposed CR Rider should be approved with the modifications suggested by the Department, namely: (1) the "competitive market conditions" language be removed; (2) the minimum load be

---

[1007] Ex. 63 at 36 (Krug Direct); Ex. 136 at 17 (Amit Direct).
[1008] Ex. 136 at 17-22 (Amit Direct); Ex. 139 at 2 (Amit Opening Statement).
[1009] Ex. 136 at 15 and 18 (Amit Direct).
[1010] *Id.* at 20.
[1011] *Id.* at 15 and 18.

reduced from 5MW to 2MW; (3) the trade secret language be amended; and (4) the proposal to track discounts provided between rate cases for recovery in subsequent rate cases be removed. If the Commission approves the CR Rider, the Commission should consider requiring the Company to make a compliance filing on an annual basis that analyzes the costs and benefits to ratepayers of the CR Rider.[1012]

G. Business Incentive and Sustainability Rider[1013]

800. The Company proposed adoption of a new Business and Incentive Sustainability Rider (BIS Rider) to encourage existing customers to increase their loads, and to attract new commercial and industrial customers. The BIS Rider would provide fixed discounts over a five-year period to large qualifying customers. The Company proposed demand charge discounts of 40 percent for years one to three, 20 percent for year four, and 10 percent for year five. The Company would end the discount after year five.[1014]

801. As proposed by the Company, in order to qualify for the discounts a customer must:

(a) Add at least 350 kW of new load; and

(b) Undergo an energy audit to identify possible energy savings.[1015]

802. The cost of a typical energy audit ranges between $400 and $700, depending on the size of the customer.[1016]

803. The Company proposed to retain the right to refuse the BIS Rider to a customer if the Company needs to make a significant capital investment to accommodate the increased load. However, any such customer may make a non-refundable contribution necessary to facilitate receipt of service.[1017]

804. The Company proposed that any new revenues from increased load would be retained by Xcel's shareholders between rate cases. The Company also proposed deferred accounting and recovery of the BIS Rider discounts in a subsequent rate case.[1018]

[1012] *Id.* at 26; Ex. 138 at 15 (Amit Surrebuttal).
[1013] Issue 60.
[1014] Ex. 136 at 23 (Amit Direct).
[1015] Ex. 63 at 22 (Krug Direct); *see* Ex. 136 at 5, 23-24 (Amit Direct). Originally, the Company proposed that prospective customers covered by the BIS Rider "make an investment of at least $500 per kW in new equipment that uses electricity as its primary energy source." In rebuttal testimony, Xcel agreed to eliminate the $500 per kW investment requirement. Ex. 64 at 20-21 (Krug Rebuttal); Ex. 138 at 20 (Amit Surrebuttal).
[1016] Ex. 64 at 19 (Krug Rebuttal).
[1017] Ex. 136 at 24 (Amit Direct).
[1018] Ex. 63 at 19-20 (Krug Direct); Ex. 136 at 6 (Amit Direct).

805. So as to assure prompt execution and completion of service contracts, and to avoid delays by the Company's competitors, it was agreed by the Department that submission by the Company of an annual filing as to each contract was sufficient to permit Commission oversight of administration of the BIS Rider.[1019]

806. The Department, MCC and XLI all supported the proposed BIS Rider.

807. The OAG and the Environmental Intervenors opposed the BIS Rider. The OAG opposed the BIS Rider for the same reasons that it opposed the CR Rider. The Environmental Intervenors claimed the BIS Rider is contrary to the state goal of decreasing energy consumption and the Commission's duty to set rates to encourage energy conservation to the maximum extent reasonable.

808. The Administrative Law Judge recommends that the Commission approve the BIS Rider as modified by the agreement of the Company and the Department, but disapprove the Company's proposal for deferred accounting and recovery of the BIS Rider discounts. Additionally, the proposed tariff should be modified with respect to "existing customers" and "new customers" of the Company, as recommended in Mr. Amit's Surrebuttal testimony.[1020]

809. The Administrative Law Judge concludes that the sale of incremental load, from the Company's excess generation capacity, at discounted prices, is better for ratepayers than foregoing both the proposed discounts and the incremental large load sales. In addition, the BIS Rider encourages conservation by requiring customers to undergo an energy audit to qualify for the discounts.[1021]

H. Standby Service Tariff[1022]

810. MCC recommended changing how standby hours are measured under the Company's Standby Service Tariff. Under the Company's current tariff, standby service is taken whenever the generator meter shows the unit to be producing at less than its standby capacity rating. MCC maintains that when customer generation is operating at less than rated capacity and when plant demand is less than peak demand, then no standby capacity should be determined to be taken. This is not the case under the existing tariff. MCC proposed to exempt hours from the annual limit by the degree that the total load of a facility, at any hour during the month, is less than the month peak load of the facility.[1023]

811. The Company opposed the MCC proposal. The Company maintained that the current measurement recognizes all hours that standby service is used by the customer. The Company also asserted that MCC's proposal would result in a substantial change to the fundamental design of standby service. According to the

[1019] Ex. 138 at 21 (Amit Surrebuttal); Ex. 64 at 18 (Krug Rebuttal).
[1020] Ex. 136 at 27 (Amit Direct) and Ex. 138 at 25 (Amit Surrebuttal).
[1021] Ex. 138 at 23 (Amit Surrebuttal).
[1022] Issue 78.
[1023] Ex. 107 at 26 (Schedin Direct); Ex. 108 at 17 (Schedin Surrebuttal).

Company, the standby service tariff is designed to move customer billing from lower standby reservation rates to higher firm service rates in relation to the degree the Company provides backup capacity for customer generation. The Company claimed that MCC's proposal would diminish important price incentives for the operation of customer owned generation.[1024]

812. The Administrative Law Judge agrees that MCC has raised a serious question regarding the fairness of the existing standby service tariff, but concludes that the issue would be better addressed in a separate docket where the parties and Commission can analyze the issue in more detail. Accordingly, the Administrative Law Judge does not recommend a change to the Standby Service Tariff at this time.

I. Coincident Peak Billing[1025]

813. Under the Company's existing service rules, a C&I demand-billed customer who has two or more meters at a single business site is billed by determining the maximum demand from each meter.[1026] If the maximum demand for each meter occurs at different times during the month, the total of all billed demands for the month will exceed the billing demand from serving the entire site through a single meter and account.[1027]

814. Coincident peak billing is a concept that allows synchronized interval-by-interval aggregated demand billing for all meters rather than billing based on separate peak demands.[1028]

815. MCC recommended that the Commission require Xcel to modify its tariffs to allow coincident peak billing. MCC maintained that coincident peak billing is fair and reasonable because it allows a customer to capture the diversity benefits that the customer provides to the system.[1029]

816. Coincident peak billing would be a change from the Company's established rate design.[1030]

817. In order to offer coincident peak billing, the Company would need to install expensive interval recording meters at each electric service location on a customer site and aggregate all demand interval readings to determine and bill peak demand.[1031]

818. The Company opposed MCC's proposal for coincident peak billing because of the cost to the Company of putting in new metering and billing systems. The Company also opposed the proposal because it would require separating the

---

[1024] Ex. 67 at 20 (Huso Rebuttal).
[1025] Issue 79.
[1026] Ex. 107 at 27 (Schedin Direct).
[1027] Ex. 67 at 21 (Huso Rebuttal).
[1028] Ex. 107 at 27 (Schedin Direct).
[1029] *Id.* at 27-30.
[1030] *Id.* at 29-30; Ex. 67 at 22 (Huso Rebuttal).
[1031] Ex. 67 at 21 (Huso Rebuttal).

generation and distribution capacity costs, which are currently recovered by a single demand charge, into two separate demand charges for these customers.[1032]

819. The Company noted that it had an experimental demand aggregation rider that was cancelled at the end of 2001 because interest in the program was not as great as expected.[1033]

820. The Company suggested that a C&I customer can change the wiring configuration at the business site to accommodate a single meter. If the customer believes the bill for the site would be lower with a single meter, the customer could weigh the cost of re-wiring against the potential bill savings to determine if the investment is worthwhile.[1034]

821. MCC responded that re-wiring is seldom feasible because of voltage and other differences between the multiple services. MCC also stated that Xcel could require the customer to pay for the metering equipment necessary for coincident peak billing.[1035]

822. The Administrative Law Judge concludes that MCC's current proposal for coincident peak billing is not sufficiently developed to show that it will result in reasonable rates. MCC has not provided any evidence to demonstrate that it would be cost-effective for C&I customers to use coincident peak billing if they were responsible for the cost of the additional metering equipment. MCC also has not addressed who would pay for the additional billing expenses incurred by the Company. Similarly, MCC has not explained how its proposal would affect demand billing quantities. Finally, MCC has not explained how its current proposal differs from the experimental program that Xcel cancelled in 2001.

J. Interruptible Service Rates[1036]

823. Customers who take interruptible service agree to have their service interrupted when called upon by the Company, or face high penalties. Customers with interruptible service are paid a credit for being available to shed their load when needed.[1037]

824. Interruptible loads provide a number of benefits to the Company and its ratepayers from an operational and system planning perspective. Interruptible loads allow for flexible load management on days with the highest system loads. Interruptible loads also reduce the planning reserve margin required under MISO rules.[1038]

[1032] *Id.* at 21-22.
[1033] *Id.* at 22.
[1034] *Id.* at 21.
[1035] Ex. 108 at 18 (Schedin Surrebuttal).
[1036] Issue 81.
[1037] Ex. 113 at 24 (Maini Direct); Ex. 115 at 33 (Maini Surrebuttal).
[1038] Ex. 113 at 24-25 (Maini Direct); Ex. 67 at 15-16 (Huso Rebuttal).

825. The Company currently uses a market-based approach to set its interruptible rate discounts (credits). The Company seeks to set the rates at a level that use the lowest discount necessary to attract an optimal supply of interruptible load for the short-term and maintain such load for longer-term capacity planning purposes. To minimize the costs to the system and ratepayers, the cost of interruptible load credits should be lower than the cost of purchasing or building new peaking capacity.[1039]

826. With interruptible load credits at the current rates, the Company has been able to maintain the necessary level of interruptible load. The current credit levels were set in the Company's last rate case.[1040]

827. MCC noted that there are a number of factors, including the need to comply with EPA's Reciprocating Internal Combustion Engines rules, that could result in a loss of interruptible customers at current credit levels.[1041]

828. MCC recommended that the current interruptible credit rates be increased because, on an annual basis, they are lower than the avoided cost of building a new peaking plant. According to MCC's calculations, the avoided cost of a new peaking facility is $122.16/KW-year, whereas the current credits range from $37.20-$51.60/KW-year.[1042]

829. MCC also recommended that the cost of interruptible credits be allocated only to firm customers because requiring interruptible customers to share in the cost further reduces the value of the credit.[1043]

830. The Company opposed MCC's proposal to set interruptible credit levels based on avoided costs because interruptible load is not directly analogous to a peaking plant. Interruptible load is a more limited resource. The Company also disagreed with the method used by MCC to calculate the avoided cost of a peaking plant. In addition, the Company maintained that its current rates are fair and reasonable because it has been able to attract and retain the level of interruptible load needed for its operations.

831. The Company acknowledges that changes in the overall market place for capacity will have an impact on the appropriate pricing for interruptible service, but suggested that rates be re-evaluated in the future rather than changed now.[1044]

832. The Administrative Law Judge concludes that the Company has demonstrated its current interruptible load rates are reasonable because they are set at a level that attracts and maintains interruptible customers while minimizing the cost to the system as a whole. As a result, all ratepayers benefit from the current levels. In addition, MCC's suggestion that fewer customers are likely to take interruptible service

---

[1039] Ex. 67 at 16 (Huso Rebuttal).
[1040] *Id.* at 16-17.
[1041] Ex. 115 at 32-34 (Maini Surrebuttal).
[1042] Ex. 113 at 27 (Maini Direct).
[1043] *Id.* at 2728 (Maini Direct).
[1044] Ex. 67 at 17-18 (Huso Rebuttal).

at these rates due to changes in regulation and other factors is purely speculative. If MCC's speculation comes to fruition, the rates for interruptible service can be re-evaluated in the next rate case. For these reasons, the Administrative Law Judge recommends that the Commission reject MCC's proposal regarding interruptible service rates.

K. Distributed Generation (DG) Tariff Change[1045]

833. As part of the settlement in the last rate case, the Company agreed to work with MCC to modify its DG tariff language to provide firm estimates to perform interconnection studies. The Company provided a proposal to MCC on November 1, 2012. MCC responded to the Company's proposal on January 16, 2012, with a counter proposal. The Company has stated that it will continue to work with MCC to reach a resolution. MCC has stated that if a resolution is not reached, it will bring the matter to the Commission. The Company has not proposed any DG tariff changes in this rate case. [1046]

834. The Administrative Law Judge concludes that the parties are working to resolve the issue, and recommends that the Commission take no action in this rate case on the issue.

VIII. Other Disputed Issues

A. Interest Rate on Interim Rate Refund[1047]

835. Minn. R. 7825.3300 establishes the interest rate that a public utility is required pay on an interim rate refund. The rule states in part:

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

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

836. Pursuant to Minn. R. 7829.3200, the Commission can vary its rules when its determines that the following requirements are met:

A. enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;

[1045] Issues 81a.
[1046] Ex. 107 at 35-36 (Schedin Direct); Ex. 67 at 23-24 (Huso Rebuttal); Ex. 108 at 24 (Schedin Rebuttal).
[1047] Issue 49.

B. granting the variance would not adversely affect the public interest; and

C. granting the variance would not conflict with standards imposed by law.

837. MCC recommended that the Commission vary Minn. R. 7825.3300 and require the Company to pay an 11.83 percent interest rate (the Company's rate-of-return, grossed up for taxes, as calculated by the MCC) on any interim rate refunds ordered in this case. MCC asserted that the 3.25 percent prime interest rate provided for by the rule is too low and is not fair or reasonable. MCC argued that the Company should be required to pay 11.83 percent interest on interim rate refunds because this is the same rate that the Company seeks to impose on its customers as a carrying charge for its nuclear outage expenses.[1048]

838. The MCC maintained that the interest rate on interim rate refunds should be increased because: (1) the prime interest rate is at historic lows; (2) there has been an increased frequency of rate cases; (3) there have been more significant over estimates of interim rates for Xcel; (4) the Company will have had ratepayer over-collections for 30 of 34 months by the conclusion of this case (and will immediately be incurring the costs again for 18 months of the 2014 Xcel rate case); (5) the low prime interest rate as compared to the carrying charge that the Company imposes on ratepayers creates an inequity.[1049]

839. The Department supported MCC's recommendation. The Department asserted that the low prime rate gives the utility an incentive to overstate its rate request. According to the Department, when the utility charges high interim rates to its customers, even when the charges are eventually disallowed, the utility still receives the difference between its rate-of-return and the prime rate applied to the disallowed charges. The Department also stated that the Company has a history of requesting much greater revenue increases than those that are ultimately approved by the Commission.[1050] The Department argued that, under these facts, it is reasonable for the Commission to vary its rule and require interest at the authorized overall rate-of-return, grossed up for taxes.[1051]

840. The OAG also supported MCC's recommendation. The OAG agreed that the Company has an incentive to overstate its revenue request. The OAG also noted that from 2008 to 2010, Xcel has refunded far more in interim rates than any other utility. Finally, the OAG stated that the Company has recognized that the Commission

[1048] Ex. 107 at 31, Attachment 19 (Schedin Direct); Ex. 108 at 19 (Schedin Surrebuttal); MCC Initial Brief at 27-29.
[1049] Tr. Vol. 1 at 154 (Robinson); Ex. 108 at 19-21 (Schedin Surrebuttal).
[1050] Ex. 182 at 3 (Lusti Rebuttal).
[1051] *Id.* at 2-3, 7.

has the authority to vary its rule and require the Company to pay a higher interest rate on the interim rate refund.[1052]

841. The Company disagreed that it has an incentive to overstate its revenue request. According to the Company, it does not earn its rate-of-return on the amount refunded to customers because it returns the full difference between interim rates and final rates. Any rate-of-return included in interim rates is returned to the customers. The refund also includes an additional payment of the prime interest rate. The Company also noted that it treats interim rate revenues as a short-term resource because those revenues are typically available for a year or less.[1053]

842. 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.[1054]

843. The Administrative Law Judge will address the three prongs in reverse order.

844. 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*.[1055]

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.

845. The second prong of Minn. R. 7829.3200 requires a finding that "granting the variance would not adversely affect the public interest."[1056] The OAG maintained that this prong is met because the higher interest rate is fair to both ratepayers and the Company, and the higher interest rate also provides the Company with an incentive not to overstate its interim rate request. Similarly, the Department and MCC agreed the public interest would be served.[1057]

846. 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

---

[1052] Ex. 131 at 4-6, 10 (Chavez Rebuttal).
[1053] Ex. 20 at 1-10 (Robinson Rebuttal); Ex. 44 at 1-3 (Tyson Surrebuttal).
[1054] Minn. R. 7829.3200.
[1055] Minn. Stat. § 216B.16, subd. 3 (emphasis added).
[1056] Minn. R. 7829.3200, subp. 1(B).
[1057] OAG Initial Brief at 23; Department Initial Brief at 234; MCC Brief at 27-28.

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 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.[1058]

847. 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."[1059]

848. None of the parties have shown that the first prong is met. The Department re-characterized the first prong when arguing that the standard has been met. The Department asserted that "enforcement of the rule *would not impose* an excessive burden on ratepayers or the Company (because the Company is repaying to customers what the Company already charged to customers)."[1060] Similarly, the OAG asserted that "it is *not* an excessive burden to require NSP to refund money to ratepayers that was over collected at the same rate it charges ratepayers on behalf of its shareholders."[1061] The MCC simply listed a number of facts that it maintains support a variance without addressing the prongs individually.[1062]

849. Because the parties have not shown that the first prong is met, the Administrative Law Judge recommends that the Commission not grant the variance unless it determines, on its own, that "enforcement of the [average prime interest rate] rule would impose an excessive burden" on the Company or others affected by the rule.

850. Finally, the Administrative Law Judge notes that even if the Commission does not grant the variance, the Commission still has the ability to address the apparent inequity caused by the Company imposing a carrying charge equal to its rate-of-return but providing only 3.25 percent interest to customers on the interim rate refund. The Commission could limit the carrying charge to the Company's short term cost of debt or the prime interest rate, as recommended above.

B. Interim Rates in the Next Rate Case[1063]

851. The Company has publically stated that it plans to file another rate case later this year. As a result, current interim rates would be followed immediately by 2014 interim rates, and the rates set in this case would never go into effect.[1064]

[1058] *See* Ex. 75. This conclusion assumes the Commission allows the Company to charge its rate-of-return as a "carrying charge" on its nuclear refueling outage costs, as requested by the Company, and not the lower carrying charge recommended by the Administrative Law Judge above. Regardless, the Company has not explained the inconsistency in its positions.
[1059] Minn. R. 7829.3200, subp. 1(A) (emphasis added).
[1060] Department Initial Brief at 234 (emphasis added).
[1061] OAG Initial Brief at 53 (emphasis added).
[1062] MCC Initial Brief at 27-28.
[1063] Issue 49a.
[1064] *See* Ex. 12 at 7 (Poferl Direct).

852. The OAG asserted that this unusual situation would constitute "exigent circumstances" within the meaning of Minn. Stat. § 216B.16, subd. 3(b) (the Interim Rate Statute).[1065] The Interim Rate Statute provides a formula by which interim rates are set using the utility's proposed test year, unless the Commission finds that "exigent circumstances exist."[1066]

853. To address this situation, the OAG proposed that the Commission put the Company on notice that the Commission will find "exigent circumstances" if the Company files another rate case later this year, as promised, and also put the Company on notice that the Commission will set interim rates at the levels established in this rate case. The OAG claims that Commission precedent supports its position.[1067]

854. The Company opposed the OAG's proposal on several grounds. First, the Company asserted that the fact that the next rate case will be filed a year after this rate case does not by itself constitute "exigent circumstances." The Company maintains that there is precedent for interim rates being set according to the statutory formula in two consecutive years. The Company also noted that the OAG's proposal is unnecessary because the Commission can make a decision on interim rates when the next rate case is filed.[1068]

855. The Administrative Law Judge concludes that the OAG's proposal is premature. The Interim Rate Statute provides that a decision on interim rates will be made after the initial filing by the utility.[1069] The statute, by its plain language, contemplates that the Commission will consider the circumstances at the time of the filing.[1070] In addition, it would be premature for the Commission to make a decision regarding interim rates at this time because there is a case currently pending before the Minnesota Supreme Court involving the Interim Rate Statute and the meaning of "exigent circumstances" as used in the statute.[1071] The case has been fully briefed and argued. A decision by the Court is likely by October of this year. The Commission's decision on interim rates in the next rate case would benefit from the Court's guidance.

856. For these reasons, the Administrative Law Judge recommends that the Commission deny the OAG's request.

[1065] Ex. 131 at 15 (Chavez Rebuttal).
[1066] Minn. Stat. § 216B.16, subd. 3(b).
[1067] Ex. 131 at 14 (Chavez Rebuttal).
[1068] Ex. 74 at 4 (Robinson Supplemental Examination).
[1069] *See* Minn. Stat. § 216B.16, subd. 3(a) (providing that the Commission "shall order an interim rate schedule into effect not later than 60 days after the initial filing date").
[1070] *Id.*
[1071] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, 807 N.W.2d 484 (Minn. Ct. App. 2011), *review granted* (Feb. 2012) (currently pending as Minnesota Supreme Court No. A11-0352).

C. Fuel Clause Adjustment Incentive[1072]

857. Currently, the Company's costs of fuel and purchased power are automatically passed through to customers, subject to annual review conducted after the end of the year.[1073]

858. The OAG recommended that the Commission adopt a fuel clause incentive mechanism as part of this rate case. Specifically, the OAG recommended that the Commission establish a three percent cap on the automatic adjustment for fuel and purchased power, which would limit the Company's recovery of these costs to three percent above the base cost per MWh established in this proceeding. If the Company is under the cap, no adjustment would be made. If the Company is over the cap, then the excess of the cap would be refunded to customers through the Fuel Clause Adjustment (FCA).[1074]

859. The OAG recommended adoption of the cap because the Company currently has no incentive to control these costs other than the after-the-fact prudence review. The OAG noted that there is no internal incentive for the Company to control these costs.[1075]

860. The OAG noted that in its last two rate cases the Company committed to provide a proposal to address the issue. According to the OAG, the Company has failed to do so in any meaningful manner.[1076]

861. In Surrebuttal Testimony, the OAG suggested that if the Commission does not adopt the cap as part of this rate case, then it should adopt a strict time frame for the Company to provide an incentive mechanism proposal. If an incentive mechanism is not adopted by December 31, 2013, then the OAG recommended that the Commission suspend the Company's automatic Fuel Clause Adjustment.[1077]

862. The Department agreed that the OAG had raised an important issue that warrants Commission attention. The Department suggested, however, that the issue would be better addressed in the current Annual Automatic Adjustment (AAA) proceeding, Docket No. E999/AA-12-757. The AAA proceeding covers fuel clause adjustment issues and involves all electric public utilities. The Department noted that the issue is not unique to Xcel and the AAA proceeding would provide an opportunity for other utilities to comment on the issue.[1078]

863. The Company objected to the OAG's incentive proposal. The Company agreed with the Department that the AAA docket is the appropriate proceeding in which to address the issue. The Company also asserted that the OAG's proposed cap should

---

[1072] Issue 55.
[1073] Ex. 124 at 12 (Lindell Direct).
[1074] *Id.* at 15-16.
[1075] *Id.* at 12.
[1076] *Id.* at 13-14.
[1077] Ex. 126 at 24 (Lindell Surrebuttal).
[1078] Ex. 142 at 3-4 (Ounes Direct).

not be adopted because it requires the Company to bear all of the risk and none of the reward.[1079]

864. While the OAG raises an important issue, the Administrative Law Judge agrees with the Department and the Company that a better approach would be to address the issue in current AAA proceeding, Docket No. E9999/AA-12-757. As the Department correctly noted, the issue applies to all electric utilities, not just Xcel. Therefore, the current AAA proceeding provides the best forum for addressing the issue.

865. If, however, the Commission believes that the issue should be addressed in this rate case, then the Administrative Law Judge recommends that the Commission adopt a more balanced approach than that proposed by the OAG. For example, Wisconsin has adopted an approach that uses a symmetrical bandwidth around a fuel cost within which the utility either absorbs the cost or retains the savings.[1080]

D. Historical Test Year[1081]

866. The Company used a 2013 forward-looking test year in this rate case, which it filed on November 2, 2012. In its Application, the Company also included actual financial information for 2011 and projected 2012 financial results.[1082]

867. The actual results for 2011 were included as the Company's "most recent fiscal year." For projected fiscal year 2012, the Company included actual financial results through March 2012 as rate base data and actual financial results through June 2012 as operating expenses and revenues. Forecast projections were provided for the remainder of 2012.[1083]

868. The Company has followed this same test year, actual fiscal year and projected year process in six rate cases, starting with E002/GR-05-1428.[1084]

869. The OAG maintained that the Company should have used 2012 as its most recent fiscal year because the rate case was filed in November 2012. To avoid this type of situation in the next rate case, the OAG recommended that the Company be required to use a historical test year, adjusted for known and measurable changes, in its next rate case. Alternatively, the OAG recommended that Xcel be required to file 2013 financial information as its most recent fiscal year for comparison purposes if it proposes 2014 as its test year and files in November, 2013.[1085]

[1079] Ex. 65 at 9 (Krug Surrebuttal); Ex. 64 at 21-22 (Krug Rebuttal).
[1080] *See* Ex. 64 at 21-22 (Krug Direct).
[1081] Issue 71.
[1082] Ex. 56 at 16 (Heuer Direct).
[1083] *Id.* at 16-17.
[1084] Xcel Initial Brief at 147.
[1085] Ex. 126 at 26-27 (Lindell Surrebuttal).

870. The Commission requires that certain financial information be provided with the rate case application. Minn. R. 7825.3100, subp. 10, defines the "most recent fiscal year" as follows:

> the utility's prior fiscal year unless notice of a change in rates is filed with the commission within the last three months of the current fiscal year and at least nine months of historical data is available for presentation of current fiscal year financial information, in which case the most recent fiscal year is deemed to be the current fiscal year.

871. The Company has demonstrated that the use of its 2013 forward-looking test year is reasonable and consistent with Minn. R. 7825.3100, subp. 10. When the Company filed this case on November 2, 2012, the Company did not have nine months of actual 2012 data available. Because one of the requirements for using 2012 as the "most recent fiscal year" was not met, the rule required the Company to use 2011 as the most recent fiscal year.

872. The Commission recently found that the historical test year is not necessarily superior to the projected test year.[1086]

873. Based on this record, the Administrative Law Judge concludes that the use of the 2013 test year is reasonable. The Administrative Law Judge makes no recommendation as to the type of test year the Company should use in its next rate case.

E. Bad Debt Expense Study[1087]

874. As part of the settlement of the Company's last rate case, the Company was required to assess the effect of low-income programs on bad debt expense.[1088] The Company filed the results of its study with its Application in this rate case, and has requested that the Commission find that the study fulfills the commitment made in the last proceeding.[1089]

875. The study is based on a review of more than 91 million billing records for the period April 2009 through December 2011, which assessed approximately 152,000 low-income customers. Customers were considered to be low-income if they received Energy Assistance at some point during the study period.[1090]

876. The study concluded that Energy Assistance had a significant effect on the provision of bad debt, with customers who received Energy Assistance having a 58 to 62 percent lower amount of bad debt than low-income customers who did not receive Energy Assistance. The study also found that Energy Assistance programs reduced the

---

[1086] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota,* Docket E015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 10.
[1087] Issue 72.
[1088] Ex. 53 at 26, Schedule 6 (Gersack Direct).
[1089] Xcel Initial Brief at 149.
[1090] Ex. 53 at Schedule 6 (Gersack Direct); Ex. 54 at 10.

Company's bad debt expense between $0.021 and $0.095 for every $1.00 of Energy Assistance.[1091]

877. Based on its review of the study, the OAG recommended that the Commission reject the study for two main reasons. First, the OAG claimed that Xcel improperly assumed that customers who had been recipients of Energy Assistance but were not presently receiving Energy Assistance were still low-income. Second, the OAG asserted that Xcel's results were inconsistent with the findings of other utilities.[1092]

878. The Company countered that it used reasonable assumptions and the best available information regarding low-income customers. The Company also stated that its results were consistent with a similar May 1997 Department of Commerce study. The Company also noted that its study differs from those of other utilities identified by the OAG.[1093]

879. The Company's study provides a detailed and thorough analysis of the impact of Energy Assistance programs on bad debt for low-income customers. The OAG, however, has raised a valid question regarding whether the low-income customer group used in the study is actually comprised of only low-income customers. Before accepting the report, the Administrative Law Judge recommends that the Commission require the Company to supplement its report with a filing addressing why the Company chose the specific parameters used in the study to identify low-income customers, whether there are any alternative means of identifying low-income customers, and comparing the parameters used by the Company to the parameters used by other utilities and the Department of Commerce in their studies.

F. Momentary Average Interruption Frequency Index[1094]

880. Both MCC and the Company asked that the Commission address the issue of Momentary Average Interruption Frequency Index (MAIFI) monitoring and reporting.

881. MAIFI is a reliability standard that addresses outage durations of less than five minutes. Other reliability standards address outages lasting longer than five minutes, including: the System Average Interruption Duration Index (SAIDI); the System Average Interruption Frequency Index (SAIFI); and the Customer Average Interruption Frequency Index (CAIDI).[1095]

882. Minnesota law requires the Commission to establish reliability standards based on SAIDI, SAIFI and CAIDI.[1096] Minn. R. 7826.0500 specifically requires each public utility to annually report the utility's SAIDI, SAIFI and CAIDI for the calendar

---

[1091] Ex. 53 at Schedule 6 (Gersack Direct).
[1092] Ex. 124 at 49-51(Lindell Direct).
[1093] Ex. 54 at 9-12 (Gersack Surrebuttal).
[1094] Issue 76.
[1095] Ex. 107 at 33 (Schedin Direct).
[1096] Minn. Stat. § 216B.029.

year.[1097] Currently, there is no specific statute or rule that requires a reliability standard based on MAIFI or reporting of MAIFI.[1098]

883. Momentary outages lasting only a few seconds can have a significant impact on C&I customers. For example, a brief outage can stop an entire manufacturing operation and result in a restart period lasting several days.[1099]

884. The Company currently reports available MAIFI data in its annual service quality filing. This MAIFI reporting includes momentary outages experienced at the feeder level for customers served by substations enabled with Supervisory Control and Data Acquisition (SCADA). This reporting covers approximately 92 percent of retail customers.[1100]

885. It would cost the Company approximately $130 million for the meter upgrades to track MAIFI for all Minnesota customers. This estimate does not include any costs associated with the information system changes needed to use and process the data.[1101]

886. MCC has requested that the Commission require the Company to give additional importance to MAIFI, treating it the same as it treats SAIDI, SAIFI, and CAIDI. MCC asked that the Company be required to have goals and management incentives for MAIFI; that it do additional MAIFI reporting, including trend lines; and that it make the MAIFI data available to its customers via a website. MCC agreed that the Company could phase-in the equipment needed to report MAIFI data for the remaining eight percent of the customers.[1102]

887. The Company has requested that the Commission find that its current reporting and treatment of MAIFI complies with existing statutes and rules.[1103]

888. Because existing statutes and rules do not require tracking or reporting of MAIFI data, the Administrative Law Judge concludes the Company's current monitoring and reporting complies with existing law.

889. Monitoring and reporting of MAIFI data, however, helps to ensure that C&I customers are provided with adequate service as required by Minn. Stat. § 216B.04. As such, the Commission could require the reporting of additional MAIFI data.[1104] For this reason, the Administrative Law Judge recommends that the Commission consider requiring the Company to provide additional reporting of its *currently available* MAIFI data, such as trend lines. This recommendation is not intended to require monitoring or reporting of MAIFI data for the remaining eight percent

---

[1097] Minn. R. 7826.0500.
[1098] *See id.*; Minn. Stat. § 216B.029.
[1099] Ex. 107 at 33 (Schedin Direct).
[1100] Ex. 15 at 47 (Larson Direct); Ex. 15 at 47 (Larson Rebuttal).
[1101] Ex. 15 at 48 (Larson Rebuttal).
[1102] Ex. 107 at 35; Ex. 108 at 23 (Schedin Rebuttal).
[1103] Xcel Initial Brief at 151.
[1104] *See* Minn. Stat. §§ 216B.13, 216B.14.

of customers, beyond the reach of SCADA because collection of that data has not been shown to be cost-effective at this time. The Company, however, should be encouraged to add substations enabled with SCADA or other similar technology for those remaining customers when it is cost-effective to do so.

G. End-of-Month Billing[1105]

890. The Company currently renders monthly bills but the bills do not typically reflect usage during the prior calendar month.[1106]

891. The Company recently completed an analysis of the effectiveness of a calendar-month based billing cycle. The analysis showed that a limited number of customers could be accommodated with existing staff and equipment without increased costs.[1107]

892. Between October 2011 and February 2012, the Company moved a small number of customers who had requested end-of-month billing to that billing cycle.[1108]

893. MCC noted that C&I customers are increasingly auditing their electric bills for business purposes, and that it is more challenging and time consuming to do so without end-of-month billing. For that reason, MCC recommended that the Company be required to change its billing system to provide end-of-month billing.[1109]

894. The Company countered that there are "operational, financial, and workforce considerations associated with clustering customer billing at a single point of the month." The Company maintained that it is willing to work with customers to develop special billing arrangements upon request.[1110]

895. In response to concerns raised by the Company, MCC presented a more limited proposal. In its Surrebuttal Testimony, MCC recommended that the Company include the following language in its tariff: "Upon request by a C&I customer with total peak demand in excess of 1000 KW, Xcel will convert all of the specified accounts to end-of-month billing."[1111]

896. MCC has demonstrated that it is fair and reasonable to require the Company to include language in its tariff to allow a C&I customer with total peak demand in excess of 1000 KW to be switched to end-of-month billing upon request. MCC's proposal is consistent with the Company's position that it is willing to work with customers who request alternative billing cycles. In addition, the proposal is limited in scope. Furthermore, the Company has failed to provide any specific evidence regarding the alleged "operational, financial and workforce considerations" that cause

---

[1105] Issue 77.
[1106] Ex. 107 at 31 (Schedin Direct).
[1107] *Id.*, Attachment 20 (Xcel Response to MCC IR 900).
[1108] *Id.*
[1109] Ex. 107 at 31-32 (Schedin Direct).
[1110] Ex. 54 at 13 (Gersack Rebuttal).
[1111] Ex. 108 at 22 (Schedin Surrebuttal).

the Company to oppose the MCC's proposal. For these reasons, the Administrative Law Judge recommends that the Commission adopt the MCC's latest proposal regarding end-of-month billing.

H. Wind Integration Study[1112]

897. The Company proposed to study the costs of integrating wind resources as part of its 2014 Resource Plan.[1113] XLI requested that the study be performed and incorporated in the Company's next rate case.[1114]

898. The Company agreed it would be appropriate to study the potential operational impacts of additional wind generation and indicated a willingness to work with XLI on a study's scope.[1115] The Company stated, however, that its 2014 Resource Plan is the appropriate context in which to consider the size, type and timing of future renewable energy additions necessary to comply with the Renewable Energy Standard.[1116]

899. XLI acknowledged the Company's desire to conduct a wind integration study as part of its next resource filing. XLI noted, however, that its overarching concern with respect to wind integration is that a number of recent changes to the Company's system demonstrate that not all of the Company's variable costs are energy related. XLI requested that the Company address the issue of non-fuel variable costs in its next rate case. The Company agreed to do so.[1117]

900. The Company's proposal to incorporate the Wind Integration Study into its next resource plan filing is reasonable. Similarly, the Company's commitment to address the issue on non-variable fuel costs in the next rate case is reasonable. This approach addresses the concerns raised by XLI.

I. In General

901. Citations to the transcripts or hearing exhibits in these Findings of Fact are not inclusive of all applicable evidentiary support in the record.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

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 and 216B.08.

[1112] Issue 82.
[1113] Ex. 15 at 44-47 (Larson Rebuttal).
[1114] Ex. 119 at 61 (Pollock Direct).
[1115] Xcel Initial Brief at 153.
[1116] Ex. 15 at 44-47 (Larson Rebuttal).
[1117] XLI Initial Brief at 4; Tr. Vol. 3 at 107 (Peppin).

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, 216B.241 and 216C.05.

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.

5. The record supports the resolution of the settled, resolved, and uncontested matters set forth in 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 December 26, 2012, and a refund ordered to the extent that the interim rate exceeds the final rate, subject to any true-up that is ordered.

8. Any Findings of Fact more properly designated as Conclusions are hereby adopted as such.

Based upon these Conclusions, 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 July 15, 2013, the Company file with the Commission for its review and approval, and serve on all parties in this proceeding, a revised rate base, income statement, and revenue requirement summary, a schedule of the class revenue allocations and all billing determinants, and bridge schedules, that reflect the test year revenue requirement 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: July 3, 2013

s/Jeanne M. Cochran
JEANNE M. COCHRAN
Administrative Law Judge

Reported: Transcript Prepared
Shaddix & Associates

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 and 7829.3100, 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.

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 revenue requirement of $215.442 million, with the exception of the adjustments for Issue 23 (NSP-Minnesota Wholesale Customers) and Issue 24 (NSP-Wisconsin Wholesale Customers). The agreed-upon adjustments for Issues 23 and 24, which were resolved during the post-hearing briefing period, are noted in the Final Issue List filed by the Company on June 5, 2013:

1. Capital Additions Greater Than $1 Million (Issue 2)[1118]
2. Cancelled Project – Chisago 2nd Transformer (Issue 3)
3. Cancelled Project – St. Could Loop Transformer (Issue 4)
4. Black Dog Remediation (Issue 6)
5. Transmission Cost Recovery – Internal Labor (Issue 9)
6. Nuclear Employee Retention Program – Restricted Stock Units (Issue 10)
7. Nuclear Employee Retention Program – Long Term Incentive (Issue 11)
8. NSP- Minnesota Wholesale Customers (Issue 23)
9. NSP- Wisconsin Wholesale Customers (Issue 24)
10. Emissions Control Chemical Costs (other than Sherco 3) (Issue 28)
11. Xcel Energy Foundation Administration Costs (Issue 29)

[1118] The issue number refers to number in the Final Issues List filed by the Company on June 5, 2013, Edocket No. 20136-87866-01. 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.

12. Bad Debt Expense (Issue 30)

13. Charitable Contributions (Issue 31)

14. AFUDC Correction (Excluding Prairie Island EPU) (Issue 36)

15. FAS 106 Correction (Issue 37)

16. Asset Based Margin Correction (Issue 38)

17. Windsource Avoided Capacity Correction (Issue 39)

18. Incentive Compensation Correction (Issue 40)

19. Association Dues Correction (Issue 41)

20. Non-Asset Based Margin Correction (Issue 42)

21. Cost of Capital Impact (Issue 44)

22. Net Operating Loss Impact (Issue 45)

23. Cash Working Capital Impact (Issue 46)

24. Capital Structure, Long Term Debt Refinancing and Effects of Adding Hypothetical Long Term Debt (Issue 50)

25. Paid Leave (Issue 51)

26. Labor Hours versus Employee Count (Issue 52)

27. Sales Pre-filing Compliance Requirement (Issue 53)

28. Property Tax Rider (Issue 54)

29. Transmission Revenue and Expense Tracker (Issue 56)

30. Time-of-Day Energy Charges/Energy Charge Credit (Issue 62)

31. Standby Service Tariff – Tariff Modifications (Issue 63)

32. Voltage Discount (Issue 64)

33. General Rules and Regulations (Issue 65)

34. Solar Standby Capacity Credit (Issue 80)

OAH 68-2500-30266
PUC E-002/GR-12-961

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:

March 4, 2013, at 1:00 p.m. at the Earle Brown Heritage Center, Minneapolis, Minnesota;

March 4, 2013, at 7:00 p.m. at the Sabathani Community Center, Minneapolis, Minnesota;

March 7, 2013, at 7:00 p.m. at Woodbury Central Park, Woodbury, Minnesota;

March 8, 2013, at 1:00 p.m. at the West Minnehaha Recreation Center, St. Paul;

March 18, 2013, at 7:00 p.m. at the Civic Center, Mankato, Minnesota;

March 19, 2013, at 7:00 p.m. at the Eden Prairie Community Center, Eden Prairie, Minnesota; and

March 22, 2013, at 1:00 p.m. at the Lake George Municipal Complex, St. Cloud, Minnesota.

Appearances:

Laura McCarten, Regional Vice President and Kari L. Valley, Assistant General Counsel, on behalf of Northern States Power (NSP, Xcel Energy or Applicant);

Susan Peirce, Samir Ouanes, Adam Heinen, Rates Analysts; Angela Byrne and Dale Lusti, Financial Analysts; Kate O'Connell, Manager, on behalf of the Department of Commerce, Division of Energy Resources;

Ron Giteck and Ian Dobson, Assistant Attorneys General; John Lindell, Vince Chavez, Financial Analysts, on behalf of the Office of the Attorney General;

James Strommen, Attorney at Law, Kennedy & Graven, appeared on behalf of the Suburban Rate Authority.

Tracy Smetana, Robert Harding, Dorothy Morrissey, Clark Kaml, Susan Mackenzie, Brain Swanson, Public Utilities Commission staff members.

The public comment period closed on April 1, 2013, as provided in the Notice of Public Hearings approved by the Commission on January 30, 2013. Written comments were filed in the electronic docket system.[1119]

SUMMARY OF PUBLIC COMMENT

1. Over 1000 written public comments were received by the April 1, 2013, deadline set by the Public Utilities Commission. In addition, over 40 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 referenced description below summarizes the topics raised, although not all persons raising the topic are cited.

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.[1120] Others suggested that any rate increase should be much smaller than that requested by the Company.[1121]

4. Many individuals noted that a rate increase of the size requested by the Company would impose a hardship.[1122] For example, Carol Kleven, a ratepayer from Brooklyn Center, stated that she thought the 10 percent rate increase sought by Xcel is too burdensome for seniors on fixed-incomes and others who are struggling to pay their mortgages and make ends meet in this tough economy.[1123] Eleanor Leonard stated that the increase would "take money from [her] food budget. [Her] only other option is to

---

[1119] Notice of Approval of Public Hearing-Newspaper Advertisement and Public Hearing-Revised Customer Notice (January 30, 2013) (Edocket No. 20131-83348-01).

[1120] *See, e.g.*, Janet Murray (February 13, 2013 email); Coletta Lundeen (February 18, 2013 email); Jay Gasner (February 19, 2013 email); Jesse Jaeger (March 25, 2013 email).

[1121] *See*, e.g. Mike Thissen (January 19, 2013 email); Mike Boeve (February 14, 2013 email); Dale and Vivian Jack (February 19, 2013 letter); William LaLonde (March 1, 2013 letter).

[1122] *See*, *e.g.*, Vernon Anderson (January 16, 2013 letter); Joseph Hlavka (February 15, 2013 email); Cheryl Pieper (February 20, 2013 email); Gail Cronquist (February 22, 2013 email); Floyd Paurus (March 18, 2013 email); Douglas Pederson (March 26, 2013 email)

[1123] Tr. Minneapolis Hrg. at 35-36 (Carol Kleven). *See also*, Tr. Minneapolis Hrg. at 19-22 (Mike Grabow); Tr. St. Cloud Hrg. at 33-35 (Howard Rowland); Tr. St. Cloud Hrg. at 41-43 (Bert Bosshart).

turn out all [her] lights, lower [her] heat to about 58 degrees and not listen to music or watch television."[1124] Similarly, Joseph Hlavka stated that his wife has serious medical problems and, as a result, their budget is "stretched to the limit now…." He explained that "[they] desperately need electric power, so increasing the rate would really be a hardship for us."[1125]

5. Many residential customers also expressed concern that the Company is seeking an increase of over 10 percent, yet most residential customers have had only very small raises in the last few years, if any.[1126] 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.[1127] Edith Quam, a 100-year-old ratepayer living on Social Security, stated that she cannot afford an increase in her electric bills because she has not received comparable cost-of-living increases.[1128] Many other retirees also stated that they cannot afford to pay the increase in electric rates proposed by the Company.[1129] Likewise, customers who have limited incomes due to unemployment, underemployment, or other financial difficulties expressed concerns about being able to afford the proposed increases.[1130] Several residential customers described Xcel's 10.7 percent rate increase request as "unfair," "immoral," "outrageous," "excessive," "unreasonable," and "out of line" in these difficult economic times.[1131]

6. A number of customers noted that Xcel has had several rate increases since 2005. They stated that customers cannot afford the continued rate increases.[1132] Individuals outlined in detail their efforts to save money and energy, and stated that they do not know how they will be able to pay for an additional increase.[1133]

[1124] Eleanor Leonard (March 26, 2013 email).
[1125] Joseph Hlavka (February 15, 2013 email).
[1126] *See, e.g.*, Mark Hess (February 10, 2013 email); Beverly Stark (February 13, 2013 letter); Scott E. Smith (February 17, 2013 email); Ron Weinzierl (February 20, 2013 letter); Sandra Gundy (February 28, 2013 email); Leah Haugen (March 14, 2013 email).
[1127] *See*, *e.g.*, Georganne Krause (February 13, 2013 email); Robert Barnes Jr. (February 20, 2013 letter); Lawrence Smith (February 21, 2013 letter); Don and Linda Crawford (February 28, 2013 email).
[1128] Edith Grace Quam (March 25, 2013 email).
[1129] *See, e.g.*, Georganne Krause (February 13, 2013 email); Dale and Vivian Jack (February 19, 2013 letter); Kathleen A. Deming (February 19, 2013 letter); Don and Linda Crawford (February 28, 2013 email); Comments of AARP Minnesota (March 27, 2013 email attachment); Tr. St. Cloud Hrg. at 33-35 (Ray Rowland).
[1130] *See*, *e.g.*, Jamie Geir (February 20, 2013 email); Caroline Mannheimer (February 20, 2013 email); Karyn Apitz (February 25, 2013 letter); Wendy Raschke (February 26, 2013 letter); Erin Mortenson (March 20, 2013 email); Joan Riederer (March 25, 2013 email).
[1131] See, e.g., Comments of AARP Minnesota (March 26-28, 2013 emails).
[1132] *See*, *e.g.*, Greg and Julie Paul (February 16, 2013 email with attached letter); Joan Riederer (March 25, 2013 letter); John Cyphers (March 26, 2013 email); Comments of AARP Minnesota (March 26-28, 2013 email attachments).
[1133] *See, e.g.,* Rita Oliver (February 14, 2013 email); Kathy Denino (February 19, 2013 letter); Zhenya Stone (February 27, 2013 email); Leo and Terri Goblirsch (March 4, 2013 email).

Conservation Efforts Resulting in Higher Rates

7. A number of Xcel customers expressed their frustration that increased conservation efforts have led the Company to propose increased rates.[1134] Several of these customers noted that they have spent a considerable amount of money investing in energy efficiency measures only to see their rates increase.[1135]

8. For example, the Goblirsch family keeps its lights turned off, does not use the dryer very often, uses energy efficient light bulbs, and has "done everything within [their] power to keep [] costs down …, and yet, [their] electric bill continues to increase."[1136]

9. Similarly, Tom and Sandy Ahlstrom have taken a number of steps to conserve energy. They have replaced all lighting with energy efficient bulbs, have purchased an energy efficient air conditioner and furnace, have replaced their insulation, and have replaced their old windows with energy-efficient models. Despite making these substantial investments in energy conservation, their electric bill is expected to increase if Xcel's proposal is approved. The Alhstroms are both 72 years old and live on a fixed-income.[1137]

10. Dennis Laliberte, a ratepayer from Crystal, stated that he has spent more than $17,000 to insulate his home and install energy efficient windows and lighting to reduce his energy costs. Mr. Laliberte said he "almost fell over" when he saw Xcel's 10 percent rate increase request. Mr. Laliberte expressed frustration that despite his best efforts to conserve energy, the rates keep going up. Mr. Laliberte does not believe a 10 percent rate increase is justified and he urged Xcel to cut costs instead.[1138]

11. Still other Xcel ratepayers expressed frustration that Xcel justifies its proposed rate increase in part on reduced sales caused by customers' conservation efforts. Bernard and Arlene Menge, for example, noted that they have taken measures to conserve energy and make their home more energy efficient only to have Xcel raise their rates. According to the Menges, Xcel should cut costs and reduce its own wasteful practices before seeking another rate increase.[1139] Similarly, Jerome Beissel, a Dakota County ratepayer, stated that he feels as if ratepayers are being "penalized" for their energy conservation efforts when Xcel seeks a rate increase based in part on decreased energy consumption.[1140] Mr. Beissel, a senior citizen on a fixed-income,

---

[1134] *See, e.g.,* Douglas Verdier (February 10, 2013 letter); Dorothy Balen (February 14, 2013 email); Cheryl Elijah (February 17, 2013 email).
[1135] *See, e.g.,* Joe Gockowski (February 18, 2013 email); Kent Karnick (March 4, 2013 email); Tom and Sandy Ahlstrom (March 15, 2013 letter); Tr. Minneapolis Hrg. at 38-39 (Ryan Laniel).
[1136] Leo and Terri Goblirsch (March 4, 2013 email).
[1137] Tom and Sandy Ahlstrom (March 15, 2013 letter).
[1138] Tr. Minneapolis Hrg. at 39-40 and 45 (Dennis Laliberte).
[1139] Bernard and Arlene Menge (March 21, 2013 letter).
[1140] Jerome Beissel (March 27, 2013 letter).

stated that ultimately he is left with the feeling that there is no point in trying to conserve energy when Xcel will increase its rates regardless.[1141]

12. Justin Eibenholzl expressed similar frustration that the cost savings he expected to see as a result of his energy conservation efforts have been wiped out by Xcel's last four rate increases. Mr. Eibenholzl recommends that rate increases be tied to usage, with the largest users paying more. Otherwise, he believes the additional rate increase will punish those who have invested in energy efficiency measures to reduce usage.[1142]

Comments by Business Customers

13. While the vast majority of the public comments were received from residential customers, some business customers also provided public comments.[1143] Business customers expressed concern that the proposed rate increases would adversely affect their ability to compete, to remain profitable, and to provide raises and benefits to their employees.

14. Russell Graham with Gold'n Plump Poultry Company, which is headquartered in St. Cloud, estimated that Xcel's proposed rate increase will raise Gold'n Plump's energy costs by almost $2 million a year. Mr. Graham stated that such a significant increase in its operating costs will affect the cost of Gold'n Plump's products and may impact company decisions relating to employee wages and facility improvements or expansions.[1144]

15. Similarly, St. Cloud Cold Storage stated that it will not be able to pass its increased electric costs along to its customers because its customers will not pay higher storage fees. As a result, Xcel's rate increase will limit the ability of St. Cloud Cold Storage to give raises and health care benefits to its employees.[1145]

16. Farmers also expressed concerns about the proposed rate increase. Rick Meisch, a dairy farmer, stated that he uses electricity to milk his cows and cannot afford to pay higher rates. He noted that he is already "about doing work in the dark to save money." [1146]

17. Representatives of the local Chambers of Commerce in Mankato and Eden Prairie, on the other hand, praised Xcel's community involvement and corporate citizenry. Tom Riley with Greater Mankato Growth, a local chamber development group, stated that Xcel has been a great collaborative partner in helping new Mankato businesses find affordable solutions to their energy needs. Mr. Riley also noted Xcel's sponsorship of Mankato's "Songs on the Lawn" lunchtime concerts and "Business

---

[1141] *Id*.
[1142] Justin Eibenholzl (March 26, 2013 letter).
[1143] *See, e.g.,* David Hoefs (February 14, 2013 email); Rick Meisch (February 8, 2013 email); Tr. St. Cloud Hrg. at 29-31 (Russell Graham).
[1144] Tr. St. Cloud Hrg. at 29-31 (Russell Graham).
[1145] DiAnn Anderson, Controller, St. Cloud Cold Storage (email dated 1/8/2013).
[1146] Rick Meisch (February 8, 2013 email).

Showcase" events where local businesses promote their services and network with other businesses.[1147] Similarly, Glenn Schwartz, a past chair of the Eden Prairie Chamber of Commerce, credited Xcel for being a good corporate citizen and sponsoring various community events in Eden Prairie.[1148]

Xcel Should Control Costs Rather Than Raise Rates

18. Many members of the public suggested that, rather than raising rates, Xcel should do a better job of managing its expenses. 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.[1149]

19. Janet Scherbart commented that Xcel's rates are much higher than the rates of Noble Electric Cooperative (Noble). She suggested that Xcel learn how to reduce its costs from Noble.[1150]

20. The level of executive compensation was especially troubling to members of the public.[1151] Several members of the public suggested that CEO and other executive pay be reduced.[1152] Charles Hellie, a ratepayer from Northfield, suggested that Xcel's rate request be denied until it can show that it has cut upper management's "excessive compensation." According to Mr. Hellie, no Xcel employee should be making more than $900,000 a year.[1153] Others suggested that corporate jet expenses and executive travel costs be managed better.[1154]

21. 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. They noted that Xcel's customers have no ability to change to another provider if they

---

[1147] Tr. St. Cloud Hrg. at 17-19 (Tom Riley).
[1148] Tr. Eden Prairie Hrg. at 22-23 (Glenn Schwartz).
[1149] *See, e.g.,* Josh Downing (February 13, 2013 email); David Hoefs (February 14, 2013 email); Carl Altenbernd (February 14, 2013 email); Ben Humphrey (February 16, 2013); Peter O'Donnell (February 18, 2013 email); Margaret Krause (February 22, 2013 letter); Charly Urang (March 1, 2013 email).
[1150] Janet Scherbart (February 12, 2012 email).
[1151] *See*, *e.g.,* Bobbi Johnson (February 14, 2013 email); Charlie Hellie (February 27, 2013 email attachment); Bonnie L. Anderson (March 15, 2013 email); Phyllis Prissel (March 31, 2013 email); Tr. Hrg. St. Paul at 25-27 (Steven Cunningham).
[1152] *See, e.g.*, Jerry and Dianne Rood (February 14, 2013 letter); Kathy Selbitschka (February 14, 2013); Bonnie Anderson (March 15, 2013 mail); Kris McDonald (March 15, 2013 email); Patricia Piringer (March 25, 2013 letter); Tr. St. Cloud Hrg. at 53 (Rick Studer).
[1153] Charles Hellie (February 27, 2013 letter).
[1154] *See*, *e.g.*, Karen Leverentz (March 5, 2013 email); Barbara Warren (March 26, 2013 email); Tr. St. Cloud Hrg. at 35-36 (Elvin Schmidt).

feel the rates are too high.[1155] One residential customer likened the situation to being held hostage by Xcel.[1156]

22. A few customers also commented that Xcel should be subject to competition to help control its costs.[1157]

23. A number of members of the public also questioned the Company's need for any rate increase, noting that the Applicant's parent company has been performing well recently.[1158] One commenter suggested that Xcel reduce its dividend rather than increase its rates.[1159]

Residential Customer Charge Increases: Overhead vs. Underground Lines

24. The Company has proposed to increase the residential customer charge for both overhead line service and underground line service. Under the Company's proposal, the total customer charge for overhead line service would remain less than the total customer charge for underground line service, but the percentage increase to the overhead line charge would be greater than the percentage increase for underground line service.

25. A few customers expressed concern regarding the Company's proposal to impose a larger percentage increase on the overhead line service customer charge than on the customer charge for underground line service.[1160]

26. Others felt that the customer charge for underground line service should be less than the customer charge for overhead line service.[1161]

Other Customer Class Issues

27. There was some opposition to the Company's proposal to impose a greater percentage increase on the residential class than on the business and industrial classes.[1162]

[1155] *See, e.g.*, Matthew Rothchild (January 5, 2013 email); Ben Humphrey (February 16, 2013 email); Phil Darg (February 18, 2013 email); Beth Althouse (February 19, 2013 email); Jason Robinson (February 22, 2013 letter); Karen Brooks (March 25, 2013 email); Tr. Minneapolis Hrg. at 25-27 (Chris Hiatt).
[1156] Nancy Holt (March 25, 2013 email).
[1157] *See, e.g.,* Janet Frisch (March 28, 2013 email).
[1158] *See, e.g.*, Mary Samoszuk (January 30, 2012 email); Douglas Verdier (February 10, 2013 letter); Josh Patrick (February 14, 2013 letter); Tr. St. Cloud Hrg. at 18-22 (Judith Logue).
[1159] Douglas Verdier (February 10, 2013 letter)
[1160] *See*, *e.g.*, Glen Meintz (January 20, 2013 email); Paul Trovecke (February 16, 2013 email);
[1161] *See, e.g.*, Gid Cook (March 1, 2013 email); Scott Rausch (March 30, 2013 email).
[1162] *See, e.g.*, Robert Palmero (January 19, 2013 email); Comments of AARP (March 27, 2013 email attachment).

Rate of Return/Return on Equity

28. Several members of the public felt that the rate of return and/or the return on equity requested by the Company is too high.[1163] For example, Gary Hays stated that Xcel's request "assumes a return on equity that is high for a quasi-monopolistic enterprise." He noted that "National Oilwell Varco, …, an oil service company engaged in exploration, a highly risky venture, budgets ROE in the 10% range."[1164]

29. Retirees and shareholders of the Company, on the other hand, stated they believe that it is important that the Company be allowed to recover its costs and have a healthy rate of return.[1165] Eugene Danneman, for example, stressed the importance of assuring Xcel has sufficient funds "to promote effective asset management through preventative maintenance and timely capitalization upgrades of the power plants, transmission system and distribution system." According to Mr. Danneman, Minnesota needs a strong power company "that provides good service and is a solid investment for shareholders today and in the future."[1166]

Service Quality Issues

30. Several customers expressed concern with the level of service they are receiving at their homes.[1167] For example, David May stated that the power at his house is unreliable and goes out frequently.[1168] Peter Farrell stated that the service at his house in South Minneapolis has gotten worse over the last seven years, and yet there have been five rate increases during that time.[1169] Rita Oliver was frustrated that it took the Company over a year from the date she called to trim the trees by her house.[1170]

31. Dick Ottoman, on the other hand, has been very pleased with the service to his house. He has had less than five power outages of any significance in the last 33 years.[1171]

Comments Regarding Electric Generation Sources

32. A number of members of the public expressed their views about sources of electric generation. Some felt that customers should not be forced to pay for "high

---

[1163] *See, e.g.,* Jim Uttley (February 23, 2013 email); Gary Hays (March 26, 2013 email).
[1164] Gary Hays (March 26, 2013 email).
[1165] *See*, *e.g.*, Russell and June Hanson (March 14, 2013 email); Raymond Lundquist (March 18, 2013 letter); Don Henderson (March 19, 203 letter); Deloris Ringstead (March 20, 2013 letter); John and Betty Seelhammer (March 20, 2013 letter); Lyle and Elaine Salmela (March 26, 2013); Barbara Ihme (March 27, 2013 email).
[1166] Eugene Danneman (March 17, 2013 letter).
[1167] *See, e.g.*, Dave May (February 14, 2013 email); Jay Gasner (February 19, 2013 email); Lisa Manske (March 4, 2013 email): Tr. Minneapolis Hrg. at 47 (Timothy Denherder-Thomas).
[1168] Dave May (February 14, 2013 email).
[1169] Peter Farrell (February 12, 2013 email).
[1170] Rita Oliver (February 14, 2013 email).
[1171] Dick Ottman (February 13, 2013 email).

cost" wind energy and other "alternative energies."[1172] Others questioned whether the increased transmission infrastructure costs were due to increased wind energy on the system.[1173] One member of the public suggested that the funds from the rate increase be used to phase out Sherco 3.[1174] Another member of the public suggested that Xcel decommission its nuclear plants.[1175]

33. Several 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.[1176]

34. Another ratepayer criticized Xcel for not leading the way on the transition from carbon-based energy sources to renewable energies, such as solar and wind. This customer recommended that the state divest from Xcel and move to "green-power based energy independence."[1177]

35. Similarly, Deborah Kitzmann urged more reliance on wind energy as a cleaner and safer alternative to energy derived from coal, nuclear or transmission lines.[1178]

36. Peter Simmons, a ratepayer from Minneapolis, objected to having to pay increased rates relating to costs associated with maintaining Xcel's nuclear power plants. Mr. Simmons is a subscriber to Xcel's Windsource renewable energy program. As a Windsource subscriber, Mr. Simmons pays an additional monthly fee to purchase renewable energy from wind farms and increase renewable energy production in the state. Mr. Simmons stated that Windsource subscribers should be exempt from the portion of the rate increase relating to nuclear power plant maintenance and improvement as they have opted out of non-renewable energy sources.[1179]

Support for Xcel's Proposed Rate Increases

37. A small number of individuals provided comments supporting Xcel's proposed rate increases,[1180] but these comments were far outweighed by those opposed to Xcel's proposed rate increases.

[1172] *See*, *e.g.,* Dean Plank (February 13, 2013 email); Eugene Davidson (February 16, 2013 letter); Thomas Willenbring (March 25, 2013 email); James Adkins (March 26, 2013).
[1173] *See, e.g.,* Bill Bienemann (February 13, 2013 email).
[1174] Dick Ottman (February 13, 2013 email).
[1175] Ken Pentel (March 4, 2013 email).
[1176] *See, e.g.,* Tim Kerian (March 3, 2013 letter); Nancy Reynolds (March 25, 2013 email); John Schwen (March 25, 2013 email); Chris Oxenreider (March 27, 2013 email): Tr. Woodbury Hrg. at 26-26 (Cynthia Benson).
[1177] Matthew Schaut (March 25, 2013 email).
[1178] Deborah Kitzmann (March 28, 2013 email).
[1179] Tr. Minneapolis Hrg. at 20-3 (Peter Simmons).
[1180] *See, e.g.,* Dick Ottman (February 13, 2013 email); Orion Benson (March 14, 2013 email); Raymond Lundquist (March 18, 2013 letter).

Xcel's Public Notice

38. 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.[1181]

Interim Rates

39. Several customers questioned why Xcel is allowed to increase its rates before the Commission has made a final decision. These customers believe such a practice is unfair and unusual.[1182]

Other Issues

40. Allen J. Shetka suggested that customers who heat with electricity be given a lower rate. He stated that when he built his house 42 years ago, NSP persuaded him to heat with electricity through its "Electricity is Penny Cheap" campaign. For that reason, he believes that his rates should be lower.[1183] Rick Studer also suggested that Xcel offer lower rates for customers in older homes who put in electric heat at the urging of the Company.[1184]

41. John Alessio opposed any cost recovery for the transmission lines built recently in the St. Cloud area. He lives near the lines and believes that the lines are unattractive, unnecessary, harmful to human health, and environmentally devastating.[1185]

42. Elisabeth Grimley urged the Commission to review whether Xcel's employees will be better off if the rate increases are approved, and states that all Xcel employees should be compensated above the poverty line or above minimum wage.[1186]

43. Brett Post recommended that the Commission oppose any decoupling request.[1187]

[1181] Charles Wendle (February 12, 2013); Jean Olson (February 20, 2013).
[1182] *See*, e.g., Dorothy Balen (February 14, 2013 email); Douglas and Beverly Klompenhower (February 17, 2013 email); Tr. Minneapolis Hrg. at 29 (Roger Kloster); Tr. Minneapolis Hrg. at 61 (Kyle Sack); Tr. Eden Prairie Hrg. at 20 (Steve Friedrichs); Tr. St. Cloud Hrg. at 26-28 (Kay O'Neill). (At the public hearings, the Administrative Law Judge referred members of the public to the statutory authority for imposing interim rates.)
[1183] Allen Shetka (February 6, 2013 letter); *see also*, Judy Ronnie (February 2, 2013 email).
[1184] Tr. St. Cloud Hrg. at 22-26 (Rick Studer).
[1185] John Alessio (February 22, 2013 email)
[1186] Elisabeth Grimley (February 13, 2013 letter).
[1187] Brett Post (February 17, 2013 email).

44. 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.[1188]

45. Thomas Ambrose, a senior citizen living on a fixed-income, suggested that Xcel improve its collection methods. He stated that he had his power turned off twice and managed to pay his bill, but Xcel's collection methods were "nightmarish."[1189]

46. Jim Schraeder stated that he has heard that Xcel spends a very large amount of money on lobbying, and suggested that Xcel reduce its lobbying expenses.[1190]

47. Delores Fero suggested that Xcel switch to monthly calendar billing because it is easier to account for and budget for within billing cycles.[1191]

48. The AARP filed comments opposing the pass-through of various costs through riders and the fuel clause. The AARP also supported the normalization of nuclear refueling expenses, and opposed the inclusion of Construction Work in Progress (CWIP) in rate base.[1192]

[1188] *See, e.g.,* Phil Darg (February 18, 2013); Jason Robinson (February 22, 2013 letter); Joel Jackson (April 1, 2013 email).
[1189] Thomas Ambrose (February 16, 2013 letter).
[1190] Jim Schraeder (February 7, 2013 email)
[1191] Delores Fero (February 19, 2013 letter)
[1192] Comments of AARP (March 27, 2013 email attachment). (The other issues raised by the AARP are discussed in the general topics set forth above).

MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS

600 North Robert Street
Saint Paul, Minnesota 55101

Mailing Address:
P.O. Box 64620
St. Paul, Minnesota 55164-0620

Voice: (651) 361-7900
TTY: (651) 361-7878
Fax: (651) 361-7936

July 3, 2013

See Attached Service List

Re: ***In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota***
OAH 68-2500-30266
MPUC PUC E-002/GR-12-961

To All Persons on the Attached Service List:

Enclosed herewith and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATIONS** in the above-entitled matter

Sincerely,

s/Jeanne M. Cochran

JEANNE M. COCHRAN
Administrative Law Judge

Telephone: (651) 361-7838

JMC:dsc
Enclosure

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
ADMINISTRATIVE LAW SECTION
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota	OAH Docket No.: 68-2500-30266 PUC E-002/GR-12-961

Denise Collins, certifies that on July 3, 2013 she served a true and correct copy of the attached **FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATIONS** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

Assigned Service List Members - Windows Internet Explorer

https://www.edockets.state.mn.us/EFiling/filing/filing.do?method=viewPrintUniqueServiceListMembers

State of Minnesota [US]

File Edit View Favorites Tools Help

Snagit

Google Search More » Sign In Convert Select

Service List Member Information

Electronic Service Member(s)

Last Name	First Name	Email	Company Name	Delivery Method	View Trade Secret
Anderson	Julia	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	Electronic Service	Yes
Archer	Alison C	alison.c.archer@xcelenergy.com	Xcel Energy	Electronic Service	Yes
Bradley	Michael	bradleym@moss-barnett.com	Moss & Barnett	Electronic Service	Yes
Canaday	James	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Electronic Service	Yes
Cochran	Jeanne	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	Electronic Service	Yes
Dasinger	Jerry	jerry.dasinger@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Denniston	James	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	Electronic Service	Yes
Dobson	Ian	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Electronic Service	Yes
Ferguson	Sharon	sharon.ferguson@state.mn.us	Department of Commerce	Electronic Service	Yes
Gerber	Benjamin	bgerber@mnchamber.com	Minnesota Chamber of Commerce	Electronic Service	Yes
Giteck	Ronald	ron.giteck@ag.state.mn.us	Office of the Attorney General-RUD	Electronic Service	Yes
Haar	Burl W.	burl.haar@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Harding	Robert	robert.harding@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Jensen	Linda	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	Electronic Service	Yes
Johnson	Richard	johnsonr@moss-barnett.com	Moss & Barnett	Electronic Service	Yes
Kaml	Clark	clark.kaml@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Lindell	John	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	Electronic Service	Yes
Mackenzie	Susan	susan.mackenzie@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Marshall	Pam	pam@energycents.org	Energy CENTS Coalition	Electronic Service	No
Martinka	Mary	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	Electronic Service	Yes
Meloy	Brian	brian.meloy@leonard.com	Leonard, Street & Deinard	Electronic Service	Yes
Moratzka	Andrew	apmoratzka@stoel.com	Stoel Rives LLP	Electronic Service	Yes
Morrissey	Dorothy	dorothy.morrissey@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Reuther	Kevin	kreuther@mncenter.org	MN Center for Environmental Advocacy	Electronic Service	Yes
Savelkoul	Richard	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	Electronic Service	Yes
Shaddix Elling	Janet	jshaddix@janetshaddix.com	Shaddix And Associates	Electronic Service	Yes
Shaw	Christopher	christopher.shaw@ag.state.mn.us	Office of the Attorney General-RUD	Electronic Service	Yes
Strommen	James M.	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	Electronic Service	No
Thompson	SaGonna	Regulatory.Records@xcelenergy.com	Xcel Energy	Electronic Service	Yes
Valley	Kari L	kari.l.valley@xcelenergy.com	Xcel Energy Service Inc.	Electronic Service	Yes

Paper Service Member(s)

Last Name	First Name	Company Name	Address	Delivery Method	View Trade Secret
Chandarana	Aakash	Xcel Energy Services Inc.	414 Nicollet Maill, 5th Floor, Minneapolis, MN-55401	Paper Service	Yes
Jenkins	Alan	Jenkins at Law	2265 Roswell Road, Suite 100, Marietta, GA-30062	Paper Service	No

Done Internet | Protected Mode: On 100%