BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John A. Tuma	Commissioner
Betsy Wergin	Commissioner

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

ISSUE DATE: May 8, 2015

DOCKET NO. E-002/GR-13-868

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

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PROCEDURAL HISTORY

I. Initial Filings and Orders

On November 4, 2013, Northern States Power Company d/b/a Xcel Energy (Xcel or the Company) filed this general rate case. The Company asked to increase Minnesota retail electric rates in 2014 by some $192,708,000, or 6.9%, and by an additional $98,535,000, or 3.5%, in 2015; combined, these proposals would increase Xcel's Minnesota revenues by a total of $291,243,000 per year, or approximately 10.4%. The filing included a proposed interim rate schedule.

On the same date, the Company filed a petition to establish a new base cost of energy for the period during which interim rates would be in effect; that petition was granted by order dated January 2, 2014.[1]

Also on January 2, 2014, the Commission issued three orders in this case:

- an order finding the rate-case filing substantially complete and suspending the proposed final rates;
- a notice and order for hearing referring the case to the Office of Administrative Hearings for contested-case proceedings; and
- an order setting interim rates for the period during which the rate case was being resolved.

[1] *In the Matter of the Petition of Northern States Power Company for Approval of a New Base Cost of Energy*, E-002/MR-13-869.

II. The Parties and Their Representatives

The following parties appeared in this case:

- Northern States Power Company d/b/a Xcel Energy (Xcel or the Company), represented by Aakash H. Chandarana, Kari L. Valley, James R. Denniston, and Stephen E. Fogel, all of Xcel Energy Services Inc.; and Richard J. Johnson and Patrick T. Zomer, Moss & Barnett, P.A.

- Minnesota Department of Commerce (Department) represented by Linda S. Jensen, Peter E. Madsen, and Julia E. Anderson, Assistant Attorneys General.

- Office of the Minnesota Attorney General–Residential Utilities and Antitrust Division (OAG), represented by Ian Dobson and Ryan Barlow, Assistant Attorneys General.

- Suburban Rate Authority, represented by James M. Strommen, Kennedy & Graven, Chartered.

- Flint Hills Resources, LP; Gerdau Ameristeel US Inc.; Unimin Corporation; and USG Interiors, Inc. (collectively, the "Xcel Large Industrials"), represented by Andrew P. Moratzka and Sarah Johnson Phillips, Stoel Rives LLP.

- Minnesota Chamber of Commerce (Chamber), represented by Richard J. Savelkoul, Martin & Squires, P.A.

- U.S. Energy, Inc. on its own behalf and on behalf of an ad hoc group of its industrial, commercial, and institutional customers (collectively, "the ICI Group"), represented by Peder A. Larson and Connor T. McNellis, Larkin, Hoffman, Daly & Lindgren, Ltd.

- The "Commercial Group," an ad hoc association of large commercial customers, including JC Penney Corporation, Inc.; Macy's, Inc.; Sam's West, Inc.; and Wal-Mart Stores, Inc., represented by Alan R. Jenkins, Jenkins at Law, LLC.

- Energy CENTS Coalition (ECC), represented by Pam Marshall, Executive Director.

- Fresh Energy, Izaak Walton League–Midwest Office, Sierra Club, and Minnesota Center for Environmental Advocacy, represented by Kevin Reuther, Legal Director, Minnesota Center for Environmental Advocacy; and Natural Resources Defense Council, represented by Samantha Williams, Attorney at Law, Natural Resources Defense Council (collectively, "Clean Energy Intervenors").

- AARP, represented by John B. Coffman, John B. Coffman, LLC.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Jeanne M. Cochran to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held evidentiary hearings in Saint Paul on August 11–15, 2014. After the hearings the parties filed initial briefs, reply briefs, and proposed findings of fact.

The ALJ also held seven public hearings in the case, on the dates and at the locations set forth below:

- Earle Brown Heritage Center, Minneapolis—June 23
- Sabathani Community Center, Minneapolis—June 23
- West Minnehaha Recreation Center, Saint Paul—June 24
- Woodbury Central Park, Woodbury—June 24
- Civic Center, Mankato—June 25
- Eden Prairie City Center, Eden Prairie—June 26
- Lake George Municipal Complex, St. Cloud—June 27

IV. Public Comments

The Administrative Law Judge held seven public hearings. Representatives of the Company, the Department, the Office of the Attorney General, the Commission, AARP, the Clean Energy Intervenors, and the Suburban Rate Authority attended.

Some 90 members of the public spoke at the public hearings, and over 900 members of the public filed written comments; the vast majority were residential customers. The Administrative Law Judge categorized and summarized the public comments in a 14-page attachment to her report.

Nearly all commenting members of the public either opposed the rate increase entirely or argued that it was too high. The objections raised most frequently were that the increase would cause hardship for low-income households, that the amount of the increase should not exceed the inflation rate or the latest Social Security cost-of-living adjustment, that customers' conservation efforts were not being rewarded and might therefore be discouraged, and that the Company was not controlling costs sufficiently, especially in the area of executive compensation.

Several commenting parties specifically objected to the proposed increase in the residential customer charge, arguing that it reduced conservation incentives and disproportionately affected low-income households. There was widespread opposition to the Company's proposal to increase residential rates by a higher percentage than commercial and industrial rates, with commenters arguing that business customers were better able to absorb rate increases.

Several members of the public supported the Company's revenue decoupling proposal, believing that removing the link between Company revenues and energy sales would increase its openness to conservation, energy efficiency, and rooftop solar installations by customers. Public opinion was divided on the Clean Energy Intervenors' proposal to establish inclining-block rates, under which per-unit rates would increase with a customer's total usage. Opinion was similarly divided on which generation resources—e.g., fossil fuel, nuclear, renewable—should be favored and under what time frames.

Several members of the public raised service-quality concerns, while others praised the service quality in their neighborhoods. Several commenters opposed allocating to ratepayers any portion of cost overruns incurred in recent nuclear upgrade projects undertaken by the Company. Several commenters proposed institutionalizing rate discounts for low-income senior citizens, low-income households generally, and customers making substantial contributions to state energy-policy and environmental objectives.

All public comments are filed in the case record. Written comments are labeled "Public Comment," and oral comments appear in the public-hearing transcripts filed by the court reporter.

V. Proceedings Before the Commission

On December 26, 2014, the Administrative Law Judge filed her Findings of Fact, Conclusions of Law and Recommendations (the ALJ's Report). The following parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700: the Company, the Department, the OAG, the Xcel Large Industrials, the Minnesota Chamber of Commerce, the ICI Group, the Clean Energy Intervenors, and AARP.

On March 19 and 26, 2015, the Commission heard oral argument from and asked questions of the parties. On March 26, 2015, the record closed under Minn. Stat. § 14.61, subd. 2.

Having examined the entire record in this case, and having heard the arguments of the parties, the Commission makes the following findings, conclusions, and order.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[2] The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers," citing Minn. Stat. § 216B.16, subd. 6.[3] That statute is set forth in pertinent part below:

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.

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[2] Minn. Stat. § 216B.16, subds. 4, 5, and 6.

[3] *In re Interstate Power Co.*, 574 N.W.2d 408, 411 (Minn. 1998).

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate recoverability, leaving to the Commission the tasks of determining (a) the accuracy and validity of claimed costs; (b) the prudence and reasonableness of claimed costs; and (c) the compatibility of claimed costs with the public interest.

In ratemaking, therefore, the Commission must decide a wide range of issues, ranging from the accuracy of the financial information provided by the utility, to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking the Commission acts in both its quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained,

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[4]

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.[5] Any doubt as to reasonableness is to be resolved in favor of the consumer.[6]

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court, requiring that facts be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.

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[4] *In re N. States Power Co.*, 416 N.W.2d 719, 722–23 (Minn. 1987) (citation omitted).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

Utilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable, under the "just and reasonable" standard set by statute. As the Court of Appeals explained, quoting the Supreme Court,

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4 (1986). "Preponderance of the evidence" is defined for ratemaking proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[7]

II. Rate Case Overview

A. Capital Expenses

Xcel states that its request for a rate increase is motivated by being "in the peak years of an investment cycle that began several years ago." The Company plans significant capital investment in 2014 and 2015 that it believes necessary to provide safe, reliable electric service to its Minnesota customers. It initially identified 733 projects for 2014 representing approximately $954,000,000 of capital additions, and another 116 projects for 2015 representing just over $932,000,000 of capital additions.

B. Multiyear Rate Plan Proposal

The Company proposed a multiyear rate plan, the first of its kind in Minnesota since they were authorized by the Legislature in 2011. The Company explained that its goal was to provide more gradual rate increases and predictable bill impacts.

Minn. Stat. § 216B.16, subd. 19, authorizes the Commission to approve multiyear rate plans. A multiyear rate plan establishes the rates a utility may charge for each year of a specified period of years (not to exceed three years), based only on the utility's reasonable and prudent costs of service over the term of the plan.

The statute also authorizes the Commission to establish the terms, conditions, and procedures for such plans, which it did by order on June 17, 2013.[8] The Commission established that utilities may propose a multiyear rate plan to improve the regulatory process for recovery of (a) costs related to specific, clearly identified capital projects, and (b) appropriate non-capital costs.[9]

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[7] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. App. 1989) (citation omitted).

[8] *In the Matter of the Minnesota Office of the Attorney General–Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans Under Minn. Stat. § 216B.16, subd. 19*, Docket No. E,G-999/M-12-587, Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans (June 17, 2013) (the Multiyear Rate Plan Order).

[9] Multiyear Rate Plan Order at 12.

The Company requests that the Commission establish rates based on a 2014 test-year revenue requirement, and adjust them for a 2015-Step increase to incorporate specified 2015 capital projects and related non-capital costs.

Because this is the first opportunity for the Commission to consider a multiyear rate plan proposal, several issues are presented for Commission consideration for the first time. These issues are identified and discussed in greater detail, below.

C. Multiyear Rate Plan Refund Mechanism

During the evidentiary hearing, Xcel proposed a refund mechanism as part of the multiyear rate plan. The Company agreed to a process for refunding differences between 2014 and 2015 Commission-approved revenue requirements and actual revenue requirements associated with capital additions that are postponed or canceled.[10]

This proposal was resolved as agreed between the Company and the Department and was not presented as a disputed issue for resolution by the ALJ or the Commission.[11] The ALJ incorporated this refund mechanism into her recommendations.[12] The Commission finds the refund mechanism, generally, to be in the interest of ratepayers, has incorporated it into its decisions, and refers to it throughout this order.

III. Summary of the Issues

In its Notice and Order for Hearing the Commission directed the Company to address three issues unique to this case:

1) How to incorporate the results of a separate Commission investigation into the prudence of Xcel's expenditures for life-cycle management and an extended power uprate at its Monticello nuclear plant;

2) How to account for any insurance proceeds and litigation recoveries stemming from an accident at the Company's Sherburne County Generating Station Unit 3; and

3) How to determine the short-term and long-term consequences of rate-moderation mechanisms proposed in the Company's initial filing.

The first and last issues—pertaining to cost overruns at the Monticello nuclear plant and to the Company's proposals for moderating the rate impacts of this case—were contested and are discussed with the other contested issues listed below. The remaining issue—how to account for insurance proceeds and litigation recoveries resulting from an accident at the Company's Sherburne County Generating Station Unit 3 (Sherco 3)—is not yet ripe, since the Company's insurance claims and related litigation are not yet concluded.[13]

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[10] Subject to certain exclusions. *See* ALJ's Report at 17 n.81 and October 7, 2014 Issues List at 34–35.

[11] ALJ's Report, Attachment A at A-2.

[12] *See, e.g., id.* ¶ 90.

[13] *Id.*, Attachment A at A-3.

Many initially contested issues were resolved in the course of evidentiary proceedings. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; she recommended accepting them.[14] The Commission concurs.

Other issues remained contested. The following issues were either contested or otherwise require discussion.

Financial Issues

- ***Ratemaking Treatment of Extended Power Uprate at Monticello Nuclear Plant***— Has the Company demonstrated that the Extended Power Uprate project, designed to increase generating capacity at its Monticello nuclear plant, meets the "used and useful" ratemaking standard for inclusion in the 2014 test year or the 2015 multiyear rate plan Step?

- ***Discount Rate and Treatment of 2008 Market Losses for Qualified Pension and Retiree Medical Expenses***—What is the appropriate discount rate, the interest rate used to adjust anticipated future benefits to present dollars, for the Company's qualified pension plan? Are cost increases attributable to the Company's 2008 market losses recoverable in rates?

- ***Total Labor Costs***—Has the Company demonstrated that the total labor costs built into test-year expenses are reasonable and prudent?

- ***Impact of Passage of Time on 2015-Step Revenue Requirement***—Should the Company's proposed 2015-Step increase reflect cost decreases attributable to the passage of time, especially reductions in depreciation expense?

- ***Delays in In-Service Dates for Capital Projects Included in 2015 Step***—Should the Company be permitted to substitute different capital projects for specific capital projects included in the test year or 2015 Step when delayed in-service dates make them ineligible for inclusion?

- ***Treatment of Nuclear-Refueling-Outage Costs in the 2015 Step***—Should the 2015-Step revenue requirement be adjusted to reflect a one-year decrease in nuclear-refueling-outage costs?

- ***Carrying Charge on Nuclear-Refueling-Outage Costs***—Should the Company continue to recover a carrying charge on unamortized nuclear-refueling-outage costs?

- ***Costs of Cancelled Extended Power Uprate at Prairie Island Nuclear Plant***—To what extent, if any, should the Company be permitted to recover the costs of its cancelled project to expand the generating capacity of its Prairie Island nuclear plant?

- ***Method of Recovering Pleasant Valley and Border Winds Wind-Farm Costs***—Should the capital costs of these wind farms be recovered through base rates or the Renewable Energy Standard rider?

[14] *Id.*, Conclusion of Law 5.

- ***Nuclear-Depreciation-Reserve Surplus*—**What is the magnitude of the Company's nuclear-depreciation-reserve surplus and should amortization of any portion of it be required?

- ***Corporate Aviation*—**Has the Company demonstrated that the corporate-aviation costs included in test-year expense are reasonable and prudent?

- ***Key Performance Indicator Relating to Transmission Operation and Maintenance Costs*—**Should the Company be required to add a new key performance indicator to its incentive-compensation program relating to transmission operation and maintenance (O&M) costs, supported by a comparison study of the transmission O&M costs of peer utilities?

- ***CWIP and AFUDC*—**Should the Company be permitted to continue placing Construction Work in Progress in rate base and offsetting Allowance for Funds Used During Construction from the income statement?

- ***Fuel-Clause Concerns*—**Should the Commission require the Company to propose a new cost-of-fuel recovery mechanism on a timeline set in this order?

- ***Replacement-Power Costs Caused by Sherco 3 Outage*—**Should the ratemaking treatment of purchased-power costs incurred to replace the power lost in the Sherco 3 outage be addressed in this rate case or in the annual fuel-clause-adjustment case?

- ***Costs of December 2012–March 2013 Outage at Black Dog Units 2 and 5*—**Should the Commission address the costs of this three-month outage in this rate case?

- ***Babcock & Wilcox Litigation*—**How should the Commission address the Company's inclusion in test-year costs of some $46,000,000 in unpaid capital costs that are being litigated and potentially subject to substantial interest charges?

- ***Rate-Moderation Proposals*—**Should either of the Company's two rate-moderation proposals be adopted? (These proposals are to apply portions of the nuclear-waste settlement reached with the U.S. Department of Energy to rate relief and to accelerate the amortization ordered in the last rate case of the surplus in the Company's transmission, distribution, and general depreciation reserve.)

Cost of Capital Issues

- ***Return on Equity*—**What is a fair and reasonable return on equity for this company, on this record, at this time?

Class Cost of Service Study (CCOSS) Issues

- ***Classifying Fixed Production Plant*—**Does the Company's use of the plant-stratification method in its CCOSS properly allocate the costs of its fixed production plant between capacity and energy?

- ***Classifying Fixed Production Plant in Wind Facilities—***Does the Company's classification of two wind facilities as 100% capacity-related properly allocate the fixed production plant of these facilities?

- ***D10S Capacity Allocator—***Does the Company's D10S allocator properly allocate capacity-related fixed production plant costs among the customer classes?

- ***Classifying Other Production Operation and Maintenance Costs—***Does the Company's CCOSS properly allocate production-plant O&M costs other than fuel and purchased power between capacity and energy?

- ***Minimum System Study—***Does the Company's minimum-distribution-system study properly classify distribution costs as customer-related or capacity-related?

Rate Design Issues

- ***Decoupling—***Should the Company be permitted to implement a decoupling rate design and, if so, under what terms and conditions?

- ***Class Revenue Apportionment—***What percentage of the revenue requirement should be allocated to each customer class?

- ***Method of Recovering CIP Costs—***Should the Company stop recovering its Conservation Improvement Program costs through base rates, subject to true-up through a rate rider, and start recovering them entirely through a rate rider?

- ***Residential and Small-General-Service Customer Charges***—At what level should the Commission set the fixed monthly charge for residential and small-general-service customers?

- ***Interruptible-Service Discounts***—What are the appropriate discounts for customers who agree to accept risks of disconnection that vary in terms of maximum hours disconnected, minimum notice of disconnection, length of contract term, and other factors?

- ***Inclining-Block Rates***—Should the Commission open a new docket to explore the conservation potential and public-interest implications of an inclining-block rate design for the Company's residential class?

- ***Coincident-Peak Billing***—Should the Company be required to permit synchronized interval-by-interval aggregated demand billing for all metered locations on a single business site, including meters on contiguous properties?

- ***Defining "Contiguous"—***Should the Company be required to incorporate a statutory definition of "contiguous property" into its tariff?

- ***Renewable-Energy-Purchase Tariff***—Should the Company be required to work with stakeholders and present in its next rate case a proposal for pairing large high-load-factor customers operating 24 hours per day with renewable energy resources available primarily during off-peak hours?

These issues are examined individually below, with issues on which the Commission declines to accept the ALJ's recommendation discussed in greater detail.

IV. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held five days of formal evidentiary hearings and seven public hearings. She reviewed the testimony of 54 expert witnesses and related hearing exhibits. She heard testimony from 90 members of the public and read some 900 written comments submitted by members of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law. She made 1,032 findings of fact and conclusions of law and made recommendations on all stipulated, settled, and contested issues based on those findings and conclusions.

The Commission has itself examined the record, considered the report of the Administrative Law Judge, considered the exceptions to that report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in most of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission reaches different conclusions, as delineated and explained below. And on a few issues it provides technical corrections and clarifications.

On all other issues, the Commission accepts, adopts, and incorporates the ALJ's findings, conclusions, and recommendations.

FINANCIAL ISSUES

V. Ratemaking Treatment of Extended Power Uprate at Monticello Nuclear Plant

A. Introduction

1. The Monticello LCM/EPU Project

The Monticello Nuclear Power Generating Plant (Monticello or the plant) has been operating since 1971 and was initially licensed to operate until 2010.

In 2006, Xcel obtained a license extension from the federal Nuclear Regulatory Commission (NRC) to continue operating the plant until 2030. In 2008, the Company requested a license amendment from the NRC to increase, or "uprate," the plant's generating capacity from 600 to 671 megawatts (MW) and applied to this Commission for a certificate of need for the uprate. Xcel stated that it would achieve the additional 71 MW by increasing the amount of steam produced in the reactor and by improving plant equipment that converts steam into electricity.

In January 2009, this Commission granted the certificate of need for the additional generating capacity at Monticello.[15] Xcel began a project to (a) extend the useful life of the plant (the Life-Cycle Management, or LCM, portion) and (b) increase its generating capacity (the Extended Power Uprate, or EPU, portion). In its certificate-of-need application, the Company estimated that $133 million of the anticipated $320 million project cost, or 41.6%, could be attributed to the EPU.

Xcel planned to implement the LCM/EPU project in phases timed to correspond to scheduled refueling outages in 2009 and 2011. During implementation, however, the Company discovered the need for a series of modifications that forced it to delay some of the installation work until the 2013 outage and caused significant cost overruns.

2. Xcel's 2012 Rate Case

Xcel first sought to recover Monticello LCM/EPU project costs of $587 million in its 2012 rate case. At that time, the NRC had not yet granted a license amendment authorizing the Company to operate the plant at the higher EPU power level. As a result, the plant was running at its licensed 600 MW capacity using the improved equipment intended to accomplish both the LCM and the EPU aspects of the plant upgrade.

Because Monticello was not yet operating at the uprate level, the Commission found that only the LCM portion of the project was used and useful and required Xcel to remove 41.6% of the project costs from rate base, based on the Company's estimated EPU allocation in the 2008 certificate-of-need application.[16] The Commission stated that Xcel could seek recovery of those costs in future rate cases once the EPU was in service.

3. Xcel's 2013 Rate Case

Two months after the Commission decided its 2012 rate case, Xcel filed this rate case. The Company requested recovery of $665 million in Monticello LCM/EPU costs, stating that it expected to receive the NRC license amendment for the EPU during the 2014 test year.

In early 2014, Xcel obtained the necessary NRC license approvals and began a "power ascension process" at the plant under the NRC's supervision. Under the power-ascension process, a plant's capacity is gradually increased, and data is sent to the NRC for review at predefined power levels. The plant cannot ascend to the next predefined power level without NRC approval.

On March 11, 2014, Monticello reached the first NRC data-collection level, which was approximately 640 MW. After reviewing the data, Xcel discovered an anomaly with the steam-dryer data. As a result, and to comply with its license, on March 27, 2014, the Company returned the plant to its pre-EPU level of 600 MW.

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[15] *In the Matter of the Application of Northern States Power Company for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate*, Docket No. E-002/CN-08-185, Order Granting Certificate of Need and Accepting Environmental Assessment (January 8, 2009).

[16] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 19 (September 3, 2013).

The plant remained at pre-EPU levels throughout the spring and summer of 2014 while Xcel reviewed the data and responded to follow-up questions from the NRC. As of the August 11, 2014 evidentiary hearing in this case, the NRC had not yet completed its review of data from the first ascension level. The Company did not know when it would receive the NRC's approval to restart the ascension process but stated that it believed that it would be able to complete the process before the end of 2014.[17]

4. Monticello Prudence Investigation

Because of the significant cost overruns experienced at Monticello, in December 2013 the Commission opened a new docket to investigate whether Xcel's handling of the LCM/EPU project was prudent, whether the Company's request for recovery of cost overruns was reasonable, and which cost increases were due to (1) solely the EPU, (2) solely the LCM, and (3) both projects.[18] The Commission referred the investigation to an administrative law judge (ALJ) and requested that the ALJ complete the investigation in time to incorporate the results into this rate case.

The Commission issued its order concluding the prudence investigation concurrently with this order.[19] The Commission found that Xcel's management of the LCM/EPU was not prudent and denied the Company any return on the overrun, a disallowance that significantly impacts Xcel's revenue requirement in this rate case. The Commission also determined that 50% of the project costs were attributable to the LCM and that 50% were attributable to the EPU.

B. Positions of the Parties

The Department argued that the EPU was not "used and useful" because Xcel had never operated the EPU at its intended level of 71 MW, nor had the Company shown that the EPU was likely to become fully operational by the end of the 2014 test year. It argued that the EPU should not be considered used and useful until the NRC allows Xcel to operate Monticello at 671 MW. The Department recommended that the Commission exclude the EPU from rate base for 2014 and allow the project in rate base in the 2015 Step, subject to refund if the plant does not operate successfully at the uprate level by January 2015.

XLI agreed with the Department that Xcel had failed to meet its burden to show that the EPU was used and useful. XLI argued that there was no meaningful difference between the EPU's current status and its status at the time of the last rate case, since the Company was unable to operate Monticello at the full 671 MW uprate level on an ongoing basis. XLI therefore recommended that any EPU costs be excluded from rate base.

The Chamber agreed with the Department and XLI that the Monticello EPU was not currently used and useful. However, rather than excluding EPU costs from rate base, the Chamber proposed that the Commission leave the EPU in rate base but require Xcel to remove the 2014

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[17] In March 2015, during oral arguments before the Commission, Xcel stated that Monticello had ascended to 656 MW by the end of 2014, although the plant was not operating continuously at that level.

[18] *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/ Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Docket No. E-002/CI-13-754, Order Approving Investigation and Notice and Order for Hearing (December 18, 2013).

[19] Docket No. E-002/CI-13-754, Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes.

depreciation expense and recover it over Monticello's remaining life. The Chamber also recommended that the increased fuel costs resulting from the delay in power ascension be returned to current ratepayers and instead be collected over the life of the plant.

Xcel argued that the EPU was used and useful based on several circumstances that had changed since the last rate case. First, the Company has received all necessary NRC license amendments to operate at EPU levels. Second, the LCM/EPU equipment is currently being used to produce power, resulting in higher safety margins and more efficient operation. And third, the plant achieved a partial uprate, ascending to 640 MW for approximately 20 days.

Xcel nonetheless accepted the Chamber's proposal to defer 2014 depreciation expense and fuel costs and to amortize them over Monticello's remaining life. The Company argued that the Chamber's proposal reasonably reflects the plant's current status while also recognizing the benefits that the upgraded plant provides to ratepayers.

C. The Recommendation of the Administrative Law Judge

Applying Minn. Stat. § 216B.16, subd. 6, the ALJ concluded that Xcel had failed to demonstrate that the EPU was in service and used and useful, or that it was likely to be so during the 2014 test year. The ALJ reasoned that, until the Company completes the EPU ascension process, ratepayers will not be able to receive the benefit of the additional 71 MW of power that the EPU was intended to provide, and the EPU will not be in service or used and useful.

Having found that the EPU was not used and useful during the test year, the ALJ recommended that the Commission adopt the Department's proposal to remove the EPU portion of the LCM/EPU project from 2014 rate base, and the associated depreciation expense from the 2014 test year. The ALJ recommended that Xcel be allowed to include the EPU costs in the 2015 Step subject to refund as part of the multiyear-rate-plan refund process.

Finally, the ALJ recommended rejecting the Chamber's proposed remedy. The ALJ reasoned that allowing Xcel a current return on the EPU and deferred recovery of 2014 depreciation expense would be inconsistent with the conclusion that the EPU was not used and useful during 2014. And she concluded that the increased fuel costs should be addressed in Xcel's Annual Automatic Adjustment (AAA) proceeding.

D. Commission Action

The Commission concurs in and adopts the Administrative Law Judge's findings, conclusions, and recommendations on this issue.

The Commission must consider the factors in Minn. Stat. § 216B.16, subd. 6, when determining what utility property should be included in Xcel's rate base. Specifically, the statute requires the Commission to consider a utility's need for revenue sufficient to enable it to meet the cost of furnishing service, "including adequate provision for depreciation of its utility property used and useful in rendering service to the public."

The Commission finds that the Monticello EPU was not used and useful in 2014. The circumstances of the EPU have not materially changed since the 2012 rate case. While Xcel did briefly bring the plant up to 640 MW in March 2014, as of the end of 2014 the Company still did not have the NRC's permission to operate Monticello at the full 671 MW uprate level. Thus, ratepayers are still not receiving the benefit for which Xcel is asking to be paid.

Because the Monticello EPU was not used and useful in 2014, the Commission will order that the 2014 depreciation expense and return on the EPU be excluded from the 2014 test year, based on the 50% LCM, 50% EPU allocation determined in the prudence-investigation docket. As recommended by the Department and the ALJ, the Commission will allow Xcel to recover EPU costs in the 2015 Step. However, if the EPU is not in service by January 1, 2015, the Company should refund any excess amounts collected in rates through the refund mechanism for the multiyear rate plan.

The disallowance of the 2014 depreciation expense for the Monticello EPU will be a permanent disallowance. Xcel should reduce Construction Work in Progress (CWIP) by this amount, or if the plant is shown as being included in Plant in Service, the disallowed depreciation expense should remain in the depreciation reserve, whichever is applicable. The Commission will direct the Company to make a compliance filing providing the accounting entries and explaining how this permanent disallowance is reflected in its accounting records.

Finally, there exists an increased cost of fuel due to Monticello's inability to produce power at 671 MW as planned. The Chamber argued that this increased cost should be accumulated and recovered from the ratepayers that benefit from the plant over its useful life. The Commission concurs with the ALJ that the issues raised by the Chamber—i.e., the amount of the increased cost, return to current ratepayers, and recovery from ratepayers benefitting from the EPU output—should be addressed in Xcel's Annual Automatic Adjustment proceeding.

VI. Qualified Pension Discount Rate

A. Introduction

Xcel described its employee retirement-income plan as a combination of defined-benefit pension and defined-contribution 401(k) plans. In its initial filing, the Company identified $19,933,516 in 2014 test-year qualified pension expenses, comprising $14,555,504 for its Northern States Power Company – Minnesota (NSPM) Plan and $5,378,012 for its Xcel Energy Services (XES) Plan. The Company arrived at the figures using different accounting methods for each plan. The Company uses the Aggregate Cost Method (ACM) for the NSPM Plan, and Financial Accounting Standard number 87 (FAS 87) methodology for the XES Plan.

Xcel and the Department disagree about the appropriate discount rate for the XES Plan. The lower the discount rate used in the calculation, the higher the calculated pension expense; the higher the discount rate, the lower the calculated pension expense. The ALJ recommended a discount rate for the XES Plan higher than the rate the Company initially recommended, and lower than the Department recommended.

B. Positions of the Parties

1. The Company

Xcel initially proposed to apply a discount rate of 4.74% for its XES Plan, the rate the Company calculated using the FAS 87 accounting standard. But following the contested case, Xcel accepted the ALJ's recommendation of 5.05%.

The Company argued that the ALJ's rationale and discount-rate recommendation were supported by the record and that the Commission should adopt the ALJ's proposed discount rate of 5.05% for the XES Plan. Xcel opposed the Department's proposal to set the XES Plan's discount rate equal to the rate of expected return on assets, arguing that doing so would result in under-recovery of pension costs.

2. The Department

The Department recommended setting the XES Plan's discount rate at 7.25% to match the plan's expected return on assets, and to match the discount rate applied over the same time period for the NSPM Plan. The Department argued that the pension-expense calculation for ratemaking purposes did not need to be governed by accounting practices implemented for another purpose, and that the discount rate applied to the two defined-benefit plans for the same time period should be the same. The Department also expressed concern that the figures used for financial accounting are "point-in-time" figures that generally change more frequently than rates, and challenged the reliability of the Company's supporting analysis.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended using a five-year average discount rate for the XES Plan, which results in a discount rate of 5.05%. The ALJ concluded that using a five-year average "is reasonable and strikes an appropriate balance" between the parties' positions.

The ALJ noted that, in the Company's 2012 rate case, the ALJ and the Commission adopted the Department's position. The ALJ recognized that the Company more thoroughly explained in this case the basis of its proposed discount rate. However, the ALJ still recommended a rate equal to the five-year average to mitigate the effect of a proposed discount rate "that is on the lower end of rates for the last five years."

D. Commission Action

The Commission will adopt the ALJ's recommendation for a 5.05% discount rate for the XES Plan. The calculation of pension expenses requires actuarial assumptions appropriate to the factual circumstances in each case. In this case, the Company has adequately explained the rationale for using different accounting methods, and different discount rates, for its XES and NSPM Plans. The Commission concludes that it is reasonable for ratemaking purposes to use the plans' different accounting methodologies as a basis for each plan's discount rate.

The Commission agrees with the Department that neither financial accounting standards nor pension funding requirements necessarily govern pension-expense calculations for ratemaking purposes. When the facts and circumstances support adopting a discount rate that differs from the rate dictated by accounting standards applied for other purposes, it is appropriate to adopt a rate that differs.

The appropriate discount rate varies, but changes are only reflected in utility rates periodically—when a rate case is decided. As the ALJ recognized, the Company's proposed discount rate is low relative to rates over the previous five years. For rate-setting purposes, in this case, it is appropriate to use a historical average to buffer the effect that the recently-below-average discount rate would have on the overall test-year pension expense. Under these conditions, a discount rate based on the five-year average is more reasonable than a discount rate determined at a single point in time.

The Commission also declines to adopt the following sentence from ALJ Finding 126: "For that reason, use of the FAS 87 bond-matching discount rate will help ensure that the XES Plan, which is subject to FAS 87, is fully funded." While it is reasonable in this case to use the XES Plan's FAS 87 accounting method to establish a reasonable discount rate, doing so does not ensure full funding of the Plan; absent Commission directives, pension funding is governed by federal law and company policy. Because the sentence overstates the effect of the discount-rate decision, it is not adopted by the Commission.

Certain XES Plan costs identified in the Company's previous rate case have been deferred for recovery over time.[20] The Commission will require the Company to apply a rolling five-year average FAS 87 discount rate when determining XES Plan costs subject to deferral (or reversal) in subsequent years (i.e., non–rate-case test years) as the mitigation continues.

VII. Qualified Pension Market Loss

A. Introduction

In 2008, Xcel's pension funds experienced a loss in value. Because of the accounting methods used by the Company, the losses did not begin to significantly affect its pension expense until its 2012 rate case. In that rate case, the Commission authorized Xcel to recover the amortized pension-fund losses identified in that case, but required that future recovery would be based on "[f]urther evaluation and evidence of the Company's policy and practice pertaining to past and future pension policies, including surplus" to be provided in its next rate case.[21]

In this case, Xcel attributed most of the increase in its pension expense to amortized and phased-in 2008 market losses. The Company also introduced testimony describing its policy and practices related to accounting for pension market gains and losses. The Department disputed the continued presence and magnitude of 2008 market losses in the Company's pension-expense-recovery proposal.

B. Positions of the Parties

1. The Company

Xcel argued that recovery of the 2008 market losses is reasonable. It stated that its practice of amortizing and phasing in market losses is both longstanding and consistent with pension accounting standards. It also clarified that the amount sought for recovery had been offset by market gains in the years since 2008, but that the magnitude of the losses means some losses have not yet been offset or recovered.

Xcel asserted that its accounting method for losses and gains is symmetrical, and that in previous years market gains resulted in pension expenses at or below zero between 2000 and 2011. It

[20] XES Plan costs were capped at 2011 levels in the Company's previous rate case. See the discussion of qualified-pension-expense mitigation, below.

[21] Docket E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 42 (September 2, 2013).

argued that denying amortized and phased-in recovery for market losses now would be asymmetrical. The Company also disputed the Department's suggestion that pension fund market gains since 2008 were unreasonably small.

2. The Department

The Department objected to full recovery of amounts attributable to the 2008 market loss. It argued that because the market has recovered substantially since 2008, the proposed recovery for 2008 market losses was extreme, should have been offset by market gains, and should not be passed along in its entirety to ratepayers. The Department recommended that the Commission reduce the approved recovery for 2008 market losses by 50%.

The Department also expressed concern about the performance of the pension funds, asserting that underperformance was at least partly responsible for the failure of market gains to substantially offset the 2008 losses.

C. The Recommendation of the Administrative Law Judge

The ALJ found that "the Company's treatment of the 2008 market loss is consistent with the Company's long standing practice of including both market gains and losses in its calculation of the pension expense." The ALJ recognized that the approach "results in a significant pension expense in the 2014 test year" but that in previous years ratepayers had received substantial benefits from the approach.

The ALJ concluded that excluding the losses now, when ratepayers had benefited from pension-expense relief during periods of market gains, would be unreasonable. The ALJ concluded that the Company's accounting method is reasonable, and that the proposed phase-in and amortization amount for the 2014 test year should be included.

Finally, the ALJ found no record support for the idea that the pension funds were imprudently invested, resulting in unreasonably low performance. She did not recommend reducing the pension expense on that basis.

D. Commission Action

The Commission agrees with the ALJ, and will not reduce the 2008-market-loss amount included in the test-year pension cost. The Commission determined in the Company's previous rate case that future recovery of amortized and phased-in losses as a component of pension expense would be subject to Commission review of the Company's policies and practices with regard to pension accounting. The Commission is satisfied with the Company's explanation.

As the Company explained, what has been characterized in this case as recovery for a 2008 market loss is actually the 2014 test-year portion of that substantial loss—an amount that is being phased in and amortized over a period of years consistent with ordinary and longstanding accounting practice—and is offset by gains in intervening years. The Commission agrees with the ALJ that treating losses and gains symmetrically in this way is reasonable.

The Commission also agrees that the Department's concern about pension-fund performance lacks record support and does not serve as a basis in this case to reduce the amount authorized for recovery. Higher market performance often comes with higher risk, and the record here is inadequate to conclude that the investment decisions made by the Company were unreasonable.

The effect of market volatility and investment risk on ratepayers, raised by the Department in this case, potentially affects all utilities. A generic Commission inquiry concerning pension discount rates is already under way.[22] To facilitate discussion of the issues raised by the Department, the Commission will expand that inquiry to include discussion on pension investment risk and rewards and ratepayer impacts.

Finally, because a well-performing pension fund provides some benefit to shareholders by reducing cash-flow needs, the Commission will revise ALJ Finding 157, as follows:

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

VIII. Qualified Pension Expense, Mitigation, and Future Filing Requirements

A. Introduction

The Company proposed two methods to decrease the effect of pension expense on rates in this case by postponing recovery. The proposals would not reduce the amount of revenue required to recover the pension-expense amounts, but defer a portion of the recovery to future years.

B. Positions of the Parties

1. The Company

Xcel suggested two ways to "normalize" pension-expense amounts to provide more certainty in the amount of an expense that can be affected by market swings and other factors. Both methods involved authorizing an expense amount based on an average of a five-year forecast, annual tracking of the difference between the authorized amount and actual (or forecast) expense amounts, and a Commission determination in the future about how to handle the difference between the two.

The Company offered these proposals in addition to agreeing that the normalization approach adopted in its last rate case is acceptable. In the Company's 2012 rate case, it proposed extending the amortization of pension expenses for the NSPM Plan from 10 to 20 years, and capping expenses of the XES Plan at 2011 levels.

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[22] A docket number has not yet been assigned. *See In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-011/GR-13-617, Findings of Fact, Conclusions, and Order at 59 (October 28, 2014).

2. The Department

The Department did not recommend adopting either of the Company's pension-expense-mitigation proposals. It argued that these proposals would result in inappropriate incentives for the Company. The Department recommended that the Commission continue the mitigation measure adopted in the Company's 2012 rate case.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the normalization mechanism adopted in the last case be continued. In the Company's 2012 rate case, the Commission adopted the ALJ's recommendation 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.

D. Commission Action

For rate-base purposes, the Commission will require that the pension asset reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost determined under the ACM/FAS 87 methods since plan inception, not to exceed the Company's filed request. The Commission will require the Company to provide a detailed compliance filing within ten days of the Commission's decision that explains the calculated amount of qualified pension asset.

The Commission will adopt the ALJ's recommendation to require continuation of the qualified pension mitigation approved in the Company's 2012 rate case. As the ALJ recognized, this mitigation method has previously been found to be consistent with the public and ratepayer interests, and this record supports the same conclusion. The Commission will therefore again require the Company to extend the NSPM Plan amortization period for unrecognized pension costs from 10 to 20 years; and cap the XES pension expense at the 2011 level of $6.1 million and defer any excess of this amount to future years. Deferred amounts will not be included in rate base.

The Commission will further direct that, if approved recovery exceeds future years' pension expense, the Company will apply that amount to recovery of the deferred XES expense amount. The Commission will specify in the ordering paragraphs how that accounting is to be accomplished. The Commission will require the Company to file annual compliance reports that, among other things, provide the pension plans' cost-calculation reports, the XES Plan accumulated deferred balance, and the excess rate level recovery applied toward satisfying the deferral.

Finally, the Commission will direct the company to include information in its next initial rate-case filing addressing several of the issues raised in this case, so that they may be examined more closely. Those issues include details about the Company's target asset allocations, investment strategies, actuarial reports, and other supporting information related to the Company's calculation of its qualified pension expense. A full description of the information required is in the ordering paragraphs.

IX. Retiree Medical Expenses

A. Introduction

Xcel requested recovery of $5,258,504 in costs related to postretirement medical benefits for certain employees who retired prior to 2000. These postretirement medical benefits are paid for retired employees' health care costs such as medical, dental, vision, and life-insurance expenses.

Because the methods of accounting are similar, many issues affecting the calculation of qualified pension expenses similarly affect postretirement medical expenses. Accordingly, just as for pensions, both the discount rate and the 2008 market loss were raised as issues with respect to the retiree medical expenses.[23]

B. Positions of the Parties

1. The Company

Xcel applies FAS 106 accounting methods for retiree medical expenses, which it described as identical to FAS 87 (the method it uses for the XES Pension Plan), with one exception. According to the Company, under FAS 106, asset gains or losses are not phased in but are amortized over the average number of years to retirement for active employees.

The Company applied a discount rate of 4.08%, which it asserted was calculated based on FAS 106 accounting standards, and proposed including the amortized portion of the 2008 market loss in the 2014 test year.

2. The Department

The Department offered arguments that paralleled its arguments about the qualified pension expenses, recommended excluding 50% of the proposed 2008 market-loss amount, and recommended applying a discount rate equal to the weighted average of the expected return on assets.

C. The Recommendation of the Administrative Law Judge

The ALJ found that the proposed inclusion of the 2008 market loss is reasonable and consistent with the Company's long-standing practice of including both market gains and losses in its calculation of this expense. She concluded that including the entire 2008 market-loss amount was appropriate.

The ALJ also found that it is not appropriate to increase the FAS 106 discount rate to match the expected return on assets. However, absent evidence of the prior years' discount rates to calculate a five-year average (as recommended for the pension expense), the ALJ recommended applying an updated FAS 106 discount rate of 4.82%.

[23] These issues are discussed in greater detail in this order in the sections titled Qualified Pension Discount Rate and Qualified Pension Market Loss

D. Commission Action

There is no basis in this case to reach different conclusions on the similar issues raised with respect to both pension expenses and retiree medical expenses. As the Commission concluded was appropriate for pension expenses, the requested 2008 market-loss amortized amount may be included in the calculated retiree medical benefit cost. And it is appropriate to set the discount rate used to calculate retiree medical benefit costs for ratemaking purposes at the five-year average of the FAS 106-based discount rates.

The historical FAS 106 discount rates were not entered into the record in this proceeding, but the Commission recognizes the FAS 106 discount rates disclosed by the Company in its annual 10-K reports to the Securities and Exchange Commission. The five-year average of the amounts reported by the Company between 2010 and 2014 is 5.08%. Therefore the Commission will require the discount rate for retiree medical expenses to be set to 5.08%.

The Commission will also require that the Company levelize the retiree medical-expense amount by calculating the average of the annual projected benefit cost over two years (the expected length of time before the Company's next rate case). This will more evenly distribute the rate effect of this expense. Each year's projected cost amount subject to averaging must be calculated using the Commission-approved assumptions and the most proximate measurement date applicable to each year.

In its next rate case, the Company will be required to provide additional details on its postretirement benefits, including actuarial projections and assumptions, so that they can be more closely scrutinized.

X. Total Labor Costs

A. Introduction

The Company's 2014 projected test year included $419 million in total labor costs. This figure was 3.9% below actual 2013 labor costs, but it still represented a substantial increase over historical cost levels. (In 2013, labor costs jumped 12.2% because of two unexpectedly long nuclear-plant outages and higher-than-average storm activity.)

The Department claimed that the $419 million figure was inflated and recommended disallowing rate recovery of $5.6 million in total test-year labor expense.

B. Positions of the Parties

1. The Department

The Department argued on the basis of expert testimony that, under normal circumstances, the range of reasonable labor-cost increases was 2% to 3% per year. The agency emphasized that the Company's 2013 labor costs were abnormally high and should not be used as a baseline. The Department recommended using 2012 costs as a baseline, adding 3% per year thereafter, and disallowing the $5.6 million in test-year costs exceeding the resulting total.

The Department pointed out that labor costs did in fact rise by 3% between 2011 and 2012, confirming, in its view, that the 2011–2012 period was a representative baseline.

2. The Company

Xcel agreed that 2013 labor costs were not representative of costs going forward, noting that its test-year costs were 3.9% below that figure. But the Company argued that labor costs necessarily fluctuate with business and operational conditions and do not necessarily conform to expectations of set percentage increases.

The Company argued that its test-year labor costs were reasonable and pointed out that all increases above 2012 cost levels were due to increased staffing in two departments—nuclear operations and business systems. The Company pointed to its undisputed testimony outlining the need for higher staffing levels in these departments. And the Company noted that, while this increased staffing represented an ongoing increase in labor costs, it did not signify the continuing escalation of labor costs—Xcel projected annual cost increases of only 2–3% for 2014 through 2018.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended permitting rate recovery of all proposed 2014 test-year labor costs.

She pointed out that all increases over 2012 labor costs were attributable to increased staffing in the Company's nuclear and business-systems units and that the Company had provided detailed testimony from core employees explaining the need for increased staffing in these areas. She found that the 3% cap the Department recommended for annual labor-cost increases did not take into account the facts driving the 2014 test-year expense.

D. Commission Action

The Commission concurs with the Administrative Law Judge and will permit rate recovery of the Company's proposed 2014 test-year labor costs.

All test-year increases above 2012 cost levels—the most recent non-aberrant cost data available—are due to staffing increases in Xcel's nuclear-operations and business-systems units. The Company provided detailed testimony explaining the need for higher staffing levels in these units. In the nuclear-operations unit, Xcel needed more staff to meet regulatory and safety requirements and to ensure ongoing in-house expertise; in the business-systems unit, the Company needed more staff to support new cyber-security initiatives and to address issues stemming from aging infrastructure.[24]

No one challenged this testimony, and no one disputed the accuracy, prudence, or reasonableness of the costs it delineated. The Company has demonstrated the reasonableness of its 2014 test-year labor costs and the Commission will permit their recovery in rates.

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[24] Ex. 51 (O'Connor Direct) at 83–86; Ex. 62 (Harkness Direct) at 60–62.

XI. Depreciation and Plant Retirements in the 2015 Step — Passage of Time

A. Introduction

Because this is the Commission's first chance to consider a multiyear rate-case proposal, novel issues unique to multiyear rate-setting are presented for the Commission's consideration. One of these issues is how the Company should account for changes in rate base, depreciation expense, and accumulated depreciation reserve over the course of a multiyear plan.

The Department and the Company did not agree on how the Company's rate base should be adjusted from the 2014 test year to the 2015 Step. In a traditional rate case, the Commission would approve a test-year rate base that would remain in effect until the next rate case. All other things being equal, a lower rate base value would mean lower rates. At issue is whether the Company's proposal improperly excluded rate-base reductions attributable to depreciation and expected retirements.

B. Positions of the Parties

1. The Department

The Department recommended that the Commission make two downward adjustments to the Company's proposed 2015-Step rate base: a $17,528,919 reduction for accumulated-depreciation-reserve changes not accounted for by the Company, and a $535,552 reduction to reflect asset retirements planned in 2015. The Department contended that not applying a reduction for known and measurable changes in depreciation reserve would result in unreasonable rates.

The Department limited its exceptions to the ALJ's Report to the ALJ's conclusion (and related findings) that depreciation adjustments for the passage of time would not reduce the Company's 2015 revenue requirement. The Department argued that Xcel had not properly supported the figures that the ALJ used to reach her conclusion. In particular, the Department objected to the ALJ's reliance on an exhibit prepared by Xcel and submitted with the rebuttal testimony of one of its expert witnesses.

2. The Company

Xcel disagreed with the Department's recommended reductions. The Company argued that no passage-of-time reductions were appropriate because the Company's proposal focused on 36 capital projects and associated expenses and not the Company's entire revenue deficiency in the 2015 Step. Xcel objected to what it perceived as asymmetry in the Department's proposal. According to the Company, the Department's recommendation reflects asset values and expenses that decrease from 2014 to 2015, without recognizing expenses that increase over that period.

Xcel argued that even if a passage-of-time adjustment was appropriate, the Department's proposed reduction omitted a depreciation-expense increase that should be included in any passage-of-time calculation. According to the Company's rebuttal testimony, a symmetrically-calculated passage-of-time adjustment would result in a small increase to its rate base, rather than a decrease.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that no downward adjustment to the Company's 2015-Step revenue requirement for the passage of time was necessary. She found that the Department's proposed passage-of-time adjustments did not fully, symmetrically account for capital-related effects of the passage of time. The ALJ found that Xcel had satisfactorily established that no decrease was appropriate because, correctly calculated, a depreciation passage-of-time adjustment would slightly increase Xcel's 2015 rate base.

D. Commission Action

The Commission agrees with and adopts the ALJ's findings and conclusions concerning the Department's proposed $17,528,919 reduction for depreciation expense and accumulated depreciation due to the passage of time. The Commission concludes that Xcel's rebuttal testimony and exhibits adequately support the ALJ's conclusion that no downward adjustment is appropriate in this proceeding.

This is not to say that depreciation adjustments for the passage of time in future multiyear rate plans will never be appropriate, only that there is an adequate basis to conclude that no such reduction is appropriate here.

But the Commission agrees with the Department that a downward adjustment of $535,552 is required to reflect 2015 capital retirements of transmission and distribution facilities. As the Department testified, there is a 2015 impact for these retirements, and it is appropriate to incorporate the impact in the calculation of the Company's 2015-Step revenue requirement.

XII. Delays in In-Service Dates for Capital Projects Included in 2015 Step

A. Introduction

Xcel's initially proposed revenue requirements include costs associated with 733 capital projects for the 2014 test year and costs associated with 116 projects in the 2015 Step. But in an update during the course of this proceeding, the Company acknowledged that 49 of the projects scheduled for 2014 would not be in service until 2015, and that two projects scheduled for 2015 would not be in service until after 2015.

At issue is whether an adjustment to the Company's revenue requirement is appropriate in light of the updated information, and whether the Company's revenue requirement should be calculated using substitute projects identified by the Company.

B. Positions of the Parties

1. The Company

Xcel argued that its proposed 2014 and 2015 revenue requirements are representative of its actual costs. It asserted that, while projects may shift to earlier or later completion as an ordinary matter of implementing projects of this nature, rate-setting involves determining a revenue requirement based on information available at a particular point in time. The Company argued that when in-service dates change, it maintains the flexibility to fund like-kind projects, or projects that are unexpected but necessary.

Opposing the Department's recommendation to reduce its proposed 2014 and 2015 revenue requirements, the Company asserted that it should be allowed to substitute projects in 2014, and argued that because the Company had agreed to a refund mechanism for postponed or canceled 2015 projects, no adjustment is necessary.

2. The Department

The Department opposed allowing Xcel to recover costs of capital projects that have been determined not to fall within the relevant test (or step) year, and asserted that to allow recovery would "constitute a significant and unwarranted departure from traditional ratemaking." It argued that the most up-to-date anticipated in-service dates should be used to calculate the Company's revenue requirements. The Department recommended adjusting the Company's revenue requirement downward based on the updated information, excluding recovery for identified capital projects that will not be in service in the relevant year.

The Department also opposed allowing the Company to substitute projects that had not been vetted by the parties. It disagreed with the ALJ's conclusion that it had had adequate time to review the substitute projects proposed by the Company.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed with the Department's assertion that Xcel's revenue requirements should be based on the most up-to-date in-service information available. The ALJ also concluded that Xcel should only be permitted to substitute replacement projects

> when (1) the Company has shown that the replacement projects are necessary, the costs are prudent, and the projects will be in-service during the test year; and (2) the other parties have had sufficient time to review the proposed replacement projects.[25]

Having found that the Department had sufficient time to review a list of substitute projects proposed by the Company, she concluded that the Company's revenue requirement should be determined with those projects as substitutes.

The ALJ therefore recommended that the Commission reduce the Company's proposed 2014 and 2015 revenue requirements to reflect updated in-service dates for projects, and allow substitution of projects identified by the Company. The ALJ's recommendation would reduce the Company's 2014 revenue requirement by $1.8 million.

D. Commission Action

The Commission will adopt the ALJ's findings and conclusions, and require that the 2014 and 2015 revenue requirements be calculated with updated in-service-date information, but allow inclusion of replacement projects specified by the Company in Ms. Perkett's Rebuttal Testimony, Schedule 11.

[25] ALJ's Report ¶ 499.

The Commission recognizes that changes to in-service dates often arise in the course of managing capital projects like those identified by the Company. If the Commission is to consider updated in-service-date information provided during the course of the rate case, it is reasonable also to consider the Company's list of projects that are candidates to substitute for delayed or canceled projects as well. The Commission agrees with the ALJ that this outcome is a reasonable balance of the interests expressed by the Department's and the Company's positions that will result in just and reasonable rates.

XIII. Nuclear-Refueling-Outage Costs — 2015 Step

A. Introduction

Xcel seeks to include $89.3 million in amortized nuclear-refueling-outage costs in the 2014 test year. According to the Company, this amount does not include capital costs or regular O&M expenses, which are accounted for elsewhere. Because these costs can vary significantly, the Company defers and amortizes them. At issue is whether a change in the amortized cost should be reflected in the Company's 2015-Step revenue requirement.

B. Positions of the Parties

Xcel's information reflected a $5.5 million decrease from 2014 to 2015 in the amortized expense that was not reflected as a downward adjustment in its proposed 2015 Step. The OAG and the Department (initially) recommended that the 2015-Step revenue requirement be reduced by $5.5 million to reflect the lower 2015 amortized expense.

The Company responded that the nuclear-refueling-outage costs are neither capital costs nor non-capital costs associated with a step-year capital project. It argued that the adjustment proposed by the Department and the OAG was inconsistent with the Commission's Multiyear Rate Plan Order, which indicated that step-year adjustments were limited to costs related to specific, clearly identified capital projects, and related non-capital costs. According to the Company, there are corresponding step-year cost increases that should also be considered if the 2015 revenue requirement is to be adjusted for non-capital cost variations such as this.

The Department withdrew its recommendation upon the Company's explanation that nuclear-refueling-outage costs are not capital costs. The OAG, however, still argued for the adjustment in 2015. The OAG argued that these costs are similar to capital costs and so should be treated like capital costs.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that the Commission's Multiyear Rate Plan Order precluded adjusting the 2015-Step revenue requirement for the change in the amortized nuclear-refueling-outage costs. The ALJ further concluded that if an adjustment were made for these costs, only through symmetrical consideration of other similar upward and downward variations could the Commission establish just and reasonable rates. Accordingly, the ALJ recommended not making the adjustment recommended by the OAG.

D. Commission Action

The Commission agrees with Xcel, the Department, and the ALJ. No adjustment is required in the 2015 Step for the $5.5 million reduction in nuclear-refueling-outage cost in 2015.

Consideration of the full spectrum of increasing and decreasing non-capital costs in a step year would undermine the efficiency purpose of multiyear rate-setting—to do so would effectively require a full rate case for each year of the plan. The Commission concludes that the amortized nuclear-refueling-outage costs are among the costs for which step-year adjustments should only be accomplished in conjunction with a fuller consideration of all rising and falling non-capital costs. Neither the deferral-and-amortization method of accounting for these costs—nor the Commission-approved carrying charge—transform them into capital costs for the purpose of implementing a multiyear rate plan.

XIV. Nuclear-Refueling-Outage Costs — Carrying Charge

A. Introduction

Since the conclusion of its 2008 rate case, Xcel has been deferring and amortizing its nuclear-refueling-outage costs. The Commission approved this cost treatment to ensure greater accuracy in cost recovery by reasonably matching the time these costs are incurred with the time they are recovered while avoiding substantial fluctuations in these costs between rate cases. The Commission has in the past approved a carrying charge to compensate the Company for the time value of money forgone as part of this deferred recovery.

B. Positions of the Parties

1. The Company

Xcel proposed that it be permitted to impose a carrying charge equal to its overall rate of return, as has been approved in prior rate cases. The Company argued that a carrying charge is appropriate where, as here, the Company uses operating funds to cover costs before receiving those funds from customers.

2. The OAG

The OAG opposed allowing the Company to earn a carrying charge for the deferred nuclear-refueling-outage expenses. It argued that authorizing a carrying charge on these expenses deprives the Company of incentive to keep its refueling costs low.

C. The Recommendation of the Administrative Law Judge

The ALJ, after reviewing previous Commission decisions authorizing a carrying charge for these expenses, found no reason to reach a different conclusion and recommended that a carrying charge again be permitted.

D. Commission Action

As the ALJ recognized, the Commission has in Xcel's last two rate cases authorized a carrying charge for the amortized nuclear-refueling-outage expenses. The Commission again concludes that a carrying charge at the Company's overall rate of return is reasonable.

The underlying reasoning is unchanged: the Company's approved rate of return is the appropriate time cost of money for this expense, which is generally amortized over 18–24 months—longer than the Company's time frame for short-term debt. And the Company credits ratepayers at the rate of return when amortized amounts exceed actual costs, ensuring equitable treatment. The requirement that the Company demonstrate that its nuclear-refueling-outage costs are reasonable and accurate is also unchanged.

The Commission will therefore allow Xcel to include the unamortized nuclear-refueling-outage costs in rate base and earn the overall allowed rate of return on that balance.

XV. Costs of Cancelled Prairie Island Extended Power Uprate Project

A. Introduction

The Company seeks rate recovery of $78.9 million in costs incurred for a cancelled project to increase the generating capacity of its Prairie Island nuclear plant. The $78.9 million figure includes $66.1 million in total expenditures and $12.8 million in accrued AFUDC (Allowance for Funds Used During Construction), the net cost of money used for construction.

On December 18, 2009, the Commission issued a certificate of need for the project, called an "extended power uprate." The Commission found that there was a need for the additional 164 MW of electricity the project would generate and that the extended power uprate the Company proposed was the most reasonable means developed in the record for meeting that need.[26] The project was one of more than 100 similar projects proposed throughout the country at that time; the order stated that as of the date of issue the federal Nuclear Regulatory Commission (NRC) had completed its review of some 118 power-uprate projects.[27]

As the project progressed, problems developed. In January 2011, the Company determined, in conjunction with Westinghouse, the manufacturer of the Prairie Island nuclear reactors and the firm conducting the engineering analyses for the project, that an uprate of 164 MW could not be achieved cost-effectively; the Company lowered its uprate goal to 132 MW.[28]

In March 2011, there was a disaster at the Fukushima Daiichi nuclear power plant in Japan. This disaster prompted changes to the NRC review process, which became lengthier, more detailed, increasingly backlogged, and more expensive. In August 2011, the Company had a meeting with NRC staff that led it to conclude that heightened review requirements would substantially

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[26] *In the Matter of the Application of Northern States Power Company for a Certificate of Need for an Extended Power Uprate at the Prairie Island Nuclear Generating Plant*, Docket No. E-002/CN-08-509, Order Accepting Environmental Impact Statement and Granting Certificates of Need and Site Permit with Conditions (December 18, 2009).

[27] *Id*. at 8.

[28] ALJ's Report ¶ 438.

increase the cost of preparing its application for an NRC license and would delay project implementation by about two years.

At about the same time, a nationwide pattern of significant cost overruns for uprate projects similar to the one planned for Prairie Island emerged. Meanwhile, Company sales forecasts indicated a persistent softening of demand for electricity within its service area. And the price of natural-gas generation, a potential competitor of increased Prairie Island generation, continued to decline, due to structural changes in the natural-gas sector.

On October 7, 2011, the Company filed a letter in its pending resource-plan case apprising the Commission that it saw a need for a comprehensive update of its 2011–2025 resource plan in light of obstacles to completing the Prairie Island extended power uprate on schedule. On December 1, 2011, it filed the update, stating, among other things, that the extended power uprate might no longer be in the public interest and that it planned to file a Notice of Changed Circumstances in the certificate-of-need docket requesting Commission review of that issue.

Meanwhile, the Company reduced spending on the uprate in the third quarter of 2011 and ended all spending by the end of that year, with the exception of the Westinghouse contract, whose early-termination penalty provisions would have been nearly equal to the cost of performance.

On April 2, 2012, the Company filed the Notice of Changed Circumstances in the certificate-of-need docket. The Commission initiated an all-stakeholder comment-and-review process. On February 27, 2013, the Commission issued an order terminating the certificate of need prospectively, explicitly deferring the issue of cost recovery for later treatment. Cost recovery issues will be addressed below.

B. Positions of the Parties

1. The Company, the Department, and the Chamber of Commerce

These three parties initially took different positions from one another. They agreed that the costs had been prudently incurred and should be recovered but disagreed on amortization periods and on whether the Company should earn any return on unamortized costs.

The Company initially proposed recovery over 12 years while earning its full rate of return on unamortized balances or, in the alternative, recovery over six years with no return. The Department initially recommended recovery over 20.3 years, the remaining life of the plant, with no return. The Minnesota Chamber of Commerce initially recommended recovery over 20 years with no return.

During evidentiary hearings these three parties agreed that the public interest supported recovery over 20.3 years with a return at the Company's cost of debt, 2.24%, and recommended that ratemaking treatment.

2. The OAG

The OAG argued that, at a minimum, the Commission should reject rate recovery of the following:

1) A $10.1 million pre-tax charge on uprate-related expenses the Company recorded at the end of 2012, on grounds that costs that have been written off are no longer recoverable.

2) $9.2 million in AFUDC costs incurred after the Company's August 2011 meeting with NRC staff, which, the OAG contended, should have apprised the Company that the project was no longer viable. At that point, the OAG argued, AFUDC was no longer appropriate under Federal Energy Regulatory Commission (FERC) accounting rules limiting AFUDC accruals to projects that are "viable and ongoing."

3) Payments made to Westinghouse, the project's engineering consultant, after the August 2011 meeting with the NRC staff. Although the contract with Westinghouse subjected the Company to termination payments nearly equal to the payments made after August 2011, the OAG claimed that the Company had been imprudent in agreeing to those terms, and that the costs were therefore unrecoverable.

4) Any return on any extended uprate costs for which rate recovery might be permitted.

3. The ICI Group

The ICI Group recommended denying recovery of all costs associated with the cancelled project, on grounds that the project did not meet the traditional cost-recovery standard of being used and useful. The Group also contended that permitting recovery of the costs of cancelled projects would encourage utilities to incur costs for marginal or imprudent projects.

The Group opposed any return on unamortized costs for which rate recovery might be permitted, or, in the alternative, recommended a very low return—perhaps the rate paid on U.S. Treasury bills or bonds—to reflect the nearly risk-free nature of the investment.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended adopting the course of action recommended by the Department, the Company, and the Chamber of Commerce—permitting cost recovery over 20.3 years, the remaining life of the plant, with a return on unamortized balances at the Company's cost of debt, 2.24%.

The ALJ found that the Company had acted prudently and in good faith both in developing the project and in cancelling it. She rejected the ICI Group's claim that the project's failure to attain "used and useful" status precluded rate recovery, noting that the Commission has permitted recovery of the costs of cancelled projects in the past, based on the unique circumstances and specific facts of each case.

She rejected the OAG's claims that the $10.1 million in costs represented by the 2012 pre-tax charge and the AFUDC accrued after the 2011 meeting with NRC staff were unrecoverable, finding that accounting rules—which required the first action and allegedly barred financial reporting of the second—did not dictate ratemaking treatment. She rejected the OAG and ICI Group claims that the Company's execution of the Westinghouse contract, with its substantial early-termination penalties, had been imprudent, finding that those claims were based solely on hindsight and speculation.

The ALJ rejected the OAG's claim that costs and AFUDC incurred after the Company's August 2011 meeting with NRC staff should be disallowed as imprudent, noting that both the Company and the Department conducted independent cost-benefit analyses in 2012 that found the project still viable.

She rejected the ICI Group's claim that permitting recovery of the costs of cancelled projects would encourage utility spending on marginal or imprudent projects, noting that the Commission had reached the opposite conclusion in at least two recent cases.[29]

The ALJ found that a 20.3-year recovery period with a return at the 2.24% cost of debt was a reasonable outcome for both ratepayers and shareholders. She found the 20.3-year recovery period reasonable because it was the remaining life of the plant—the same time period during which the completed project would have served ratepayers and had its costs recovered in rates. And she found a return on unamortized costs at the Company's cost of debt reasonable, given the long recovery period and the time value of money.

D. Commission Action

The Commission concurs in the Administrative Law Judge's findings, conclusions, and recommendations, and will permit recovery of the cancelled project's costs over 20.3 years, with a return on unamortized balances at the Company's 2.24% cost of debt.

The Commission concurs with the ALJ that the record demonstrates that Xcel acted prudently and in good faith both in developing the project and in cancelling it. The Company did not embark on the project hastily or unilaterally—the need for and reasonableness of the project were scrutinized by stakeholders and regulators during an exhaustive certificate-of-need proceeding, which resulted in the Commission issuing a certificate of need.

Nor did the Company fail to recognize, react to, and disclose signs of trouble as they developed. Less than two months after the NRC meeting clarifying the new licensure standards and processes, the Company filed a notice of its intent to update its resource plan in light of these and other new realities. Less than two months later, it filed the update, which laid out the challenges the project faced and attempted to compare its costs and benefits with those of alternative resources.

Four months later, it filed a request for Commission review of the continued reasonableness of the project, given the changed circumstances. That request led to an expedited—but necessarily time-consuming—proceeding, which resulted in prospective termination of the certificate of need. These actions, and the time frames in which they were taken, demonstrate a diligent and responsible approach to securing regulatory review of the difficult technical and policy issues posed by the possible need to cancel the project.

[29] *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 (August 12, 2011); *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Findings of Fact, Conclusions, and Order (April 25, 2011).

The Commission concurs with the ALJ that the 2012 pre-tax charge taken by the Company to comply with financial-reporting requirements and the post-NRC-meeting AFUDC accruals the OAG claims are barred by FERC accounting rules are rate-recoverable. Accounting rules can provide valuable information about the nature of costs, but they do not dictate their ratemaking treatment.

Nor does the Commission concur with the OAG and the ICI Group that the costs of the Westinghouse contract were imprudently incurred and should be disallowed. As the ALJ found, these claims appear to be based entirely on hindsight and speculation, whereas the Company provided detailed testimony about its selection of Westinghouse as its engineering consultant. Among other considerations, as the manufacturer of the Prairie Island reactors and the designer of the Prairie Island plant, Westinghouse had unique knowledge of the facility and control of proprietary information necessary to complete the project.[30]

The Commission does not concur with the ICI Group that permitting recovery of cancelled-project costs encourages utilities to invest in marginal or imprudent facilities. While cancelled-project costs require careful scrutiny, the Commission continues to believe that a blanket prohibition on their recovery could be inequitable to utilities acting in good faith to meet their responsibilities to ratepayers and could encourage utilities to complete projects rendered marginal or imprudent by changing circumstances. As the Commission explained in the Interstate Power rate case in 2011:

> The Commission concludes that there is no public interest or regulatory benefit to be gained by disallowing costs prudently incurred in good faith to meet future need. And there is much to be lost by potentially chilling a utility's diligence in developing resources and in promptly withdrawing from projects when experience shows that they will no longer serve ratepayers' best interests.[31]

For all these reasons, the Commission will permit rate recovery of these cancelled-project costs under the terms set forth above.

XVI. Recovering Pleasant Valley and Border Winds Project Costs

A. Introduction

The Company proposed to include in the 2015-Step base rates the capital costs for two new wind farms it expects to place into service by the end of 2015, Pleasant Valley and Border Winds.

New capital projects go into rate base at the average of their first-of-year and end-of-year project balances. If these projects go into service late in the year, as expected, base-rate recovery would for a time exceed the dollar-for-dollar recovery the Company would receive if it recovered project costs through the Renewable Energy Standard (RES) rider, an automatic-rate-adjustment

[30] Ex. 49 (McCall Direct) at 12, 16–17.

[31] Docket No. E-001/GR-10-276, Findings of Fact, Conclusions, and Order at 33 (August 12, 2011).

mechanism used to ensure recovery between rate cases of costs incurred to comply with the Minnesota Renewable Energy Standard.[32]

The Company did, however, propose to use the RES rider to true up discrepancies between the amount of federal production tax credits (PTCs) it projected receiving from the wind farms over the course of the year and the amount of PTCs it actually received.

B. Positions of the Parties

The Minnesota Chamber of Commerce recommended recovering the costs of these projects through the RES rider, both because rider recovery would ensure that ratepayers did not begin to pay for the projects until they were actually in service and because rider recovery would reduce the 2015-Step revenue requirement by some $5.538 million. The Chamber pointed out that the Commission has sometimes permitted costs to remain in riders despite an intervening rate case, and that some project costs—the PTCs—would continue to be trued up through the rider in any case.

The Company stated that it placed the wind farms in the 2015-Step rate base instead of the RES rider mainly because, in its Multiyear Rate Plan Order, the Commission directed filing utilities to scrutinize and streamline rider recovery as much as possible.[33] The Company stated that it did not have a strong preference for either rate-recovery method. It did not, however, view project delay as a major risk, since all parties to the construction contracts understood that achieving operational status by the end of 2015 was critical to receiving the favorable tax treatment on which the projects' economic projections were based.

The Department stated that it considered base-rate recovery superior to rider recovery as a matter of regulatory practice and consistency with the generic order, but did not oppose rider recovery. It, too, did not consider project delay a major risk.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that both rate-recovery methods were reasonable and that the Commission should decide which method was more appropriate, based in part on the relative value it placed on reducing rider use and moderating the rate impact of the 2015 Step.

D. Commission Action

The Commission will require rate recovery through base rates with a PTC true-up through the RES rider.

While the Chamber is correct that rider recovery would provide some protection against the recovery of costs not incurred because of delays in project completion, the Commission concurs with the Company and the Department that delays are unlikely, given the contracts' emphasis on timely completion and the financial consequences delays would entail. Further, the Company has committed to refund to ratepayers any difference between total capital costs included in the 2015 Step and total capital costs incurred, in large part alleviating this concern.

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[32] Minn. Stat. §§ 216B.1691, subd. 2a, .1645, subd. 2a.

[33] Docket No. E,G-999/M-12-587, Multiyear Rate Plan Order at 7–8, 12, 14.

The main rationale for rider recovery, therefore, would be to moderate the 2015-Step increase. This rationale, however, is not only outcome-driven, but will not necessarily achieve the outcome desired, since the actual costs flowing through the RES rider could exceed the projects' 2015 rate-base component, depending on factors such as the dates the projects actually go into service, the timing of the next rate case, and the magnitude of costs that would be posted to the rider in the intervening period.

Further, as the Commission made clear in the Multiyear Rate Plan Order, the Commission sees value in seizing the opportunity to examine, rationalize, and simplify existing riders when utilities file multiyear rate plans. Riders exist to address regulatory lag, as do multiyear rate plans, but both ratemaking devices introduce additional complexity to the ratemaking process that can present ratepayer risks.

The statute acknowledges this by permitting the recovery of costs expected to occur in future years "provided that the costs are not being recovered elsewhere in rates."[34] For the same reason, the Multiyear Rate Plan Order requires detailed disclosure and analysis of existing riders when utilities file multiyear rate plans:

> 10. Where a utility is recovering continuing, predictable costs through riders, a utility seeking approval of its multiyear rate plan shall propose to recover those costs via base rates at the beginning of the rate case.
>
> 11. Regarding other riders and cost recovery mechanism, the utility shall design its multiyear rate plan to consolidate as many of them as practical, in the most reasonable manner available. . . .
>
> 22. Regarding an applicant's existing rate riders, an application for a multiyear rate plan must include or be accompanied by the following:
>
> A. A proposal to restructure its riders as follows:
>
> 1) a proposal to recover through base rates the cost of existing riders that are likely to continue and are sufficiently predictable to support recovery through base rates,
>
> 2) a proposal to consolidate as many other riders and cost recovery mechanisms as is practical, and
>
> 3) a demonstration that the utility's proposals to restructure its rate riders are the most reasonable alternatives available to the utility.

[34] Minn. Stat. § 216B.16, subd. 19 (b).

B. Clear evidence that double recovery will not occur as a result of the way the utility proposes to handle its multiyear rate plan and existing riders, including evidence that the periods during which the utility is recovering a cost via a rider does not overlap with the period during which it is recovering the cost via base rates or the multiyear rate plan mechanism.[35]

The Commission continues to view reduced dependence on rate riders and their continuing simplification as important regulatory goals and will not authorize rate recovery of the capital costs of these wind facilities through the RES rider.

As a housekeeping matter the Commission will direct the Company to include estimated PTCs in rate base, as agreed by all parties, for ultimate true-up in the RES rider. The Commission will also require the Company to report to the Commission and potentially pass through to ratepayers any contract cost reductions or performance penalties or other cost changes that develop in the course of contract completion.

Finally, the Commission will direct the Company to report in its next RES-rider filing on the results of its ongoing discussions with the Chamber and other stakeholders on alternative cost-recovery formulas designed to allocate risks and create cost-savings incentives for these and other wind resource acquisitions undertaken by the Company. These discussions were required as part of Commission action in the Company's last wind-acquisition docket,[36] and the parties report they are continuing.

XVII. Nuclear-Depreciation-Reserve Surplus

A. Introduction

The Xcel Large Industrials (XLI) contended that there was a $208 million surplus in Xcel's nuclear-production-plant depreciation reserve; the surplus consisted of the difference between the Company's theoretical reserve—what it would have collected in depreciation if all facts currently known had been known when depreciation rates were first set—and its actual reserve—amounts actually collected. This difference existed mainly because the operating licenses—and therefore the useful lives—of Xcel's two nuclear plants had been extended beyond their original licensure periods.

XLI proposed amortizing this surplus over five years, reducing annual revenue requirements by some $41.6 million per year.

The Company stated that its calculations showed a $72.5 million difference between its actual and theoretical nuclear depreciation reserves. But it cautioned that depreciation surpluses are just estimates, not guarantees, and that the amount of the actual reserve might ultimately be required

[35] Multiyear Rate Plan Order at 13–14.

[36] *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of 600 MW of Wind Generation*, Docket No. E-002/M-13-603, Order Approving Acquisitions with Conditions at 15 (December 13, 2013).

to meet contingencies such as changes in service lives or retirement costs. The Company recommended permitting any surplus to self-correct over the lives of the nuclear plants.

The Department and the OAG also opposed amortization, arguing that its rate benefits would be short-term and its adverse rate consequences long-term.

XLI had raised this issue in the Company's last rate case as well, where the Commission determined that the preponderance of the evidence did not demonstrate that a surplus existed; the Commission did, however, direct the Company to address the issue in more detail in its next rate case.[37]

B. Positions of the Parties

1. XLI

XLI maintained that its $208 million figure was correct and that Xcel's $72.5 million figure was flawed by failing to use "vintage" accounting—giving each asset its potential useful life regardless of the life of the plant in which it is situated—and by including future interim capital additions. Vintage accounting was reasonable, they contended, because it was plausible that the Company would again extend the operating licenses, and therefore the service lives, of its nuclear plants.

XLI emphasized that depreciation is not intended to help cushion the impact of future capital investments but to recover current expenses; it argued that the rate consequences of substantial capital improvements in the foreseeable future should play no role in the decision to amortize or not amortize any existing depreciation surplus. They contended that ratemaking principles of intergenerational equity required returning the surplus to ratepayers as soon as reasonably possible.

They argued that amortizing this depreciation surplus would be consistent with the Commission's decision in the last rate case to amortize the surplus in the Company's transmission, distribution, and general-plant depreciation reserve.[38]

2. The Company

Xcel emphasized the uncertainties surrounding setting depreciation rates for nuclear facilities and that depreciation rates reflected estimates of costs and service lives, not hard facts. The Company argued that there was no realistic comparison between the transmission, distribution, and general-plant depreciation account and this account—the much smaller number of assets in this account and the high cost of retiring nuclear plants made the surplus less certain and the impact of miscalculation more serious.

The Company argued that vintage accounting was inappropriate because the useful lives of nuclear assets are inextricably tied to the lives of the facilities in which they are situated—the useful life of a pump in a nuclear plant with a 15-year remaining life is 15 years, even if the pump could conceivably be used for 40 years if the plant remained in service for that long. The Company stated that it would be unreasonable to assume in setting depreciation rates that the operating licenses and service lives of both its nuclear plants would again be extended.

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[37] Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 29 (September 3, 2013).

[38] *Id*. at 25–29.

The Company denied that it factored future capital additions into its depreciation rates.[39] It stated that it noted its recent and continuing substantial investments in nuclear facilities only for purposes of helping parties gauge the consequences that amortizing the surplus would have on total depreciation expense and future rates. It stated that recent large additions to its nuclear facilities would substantially increase depreciation expense and that amortizing the surplus would exacerbate the rate impact of those additions.

3. The Department

The Department emphasized that the $72.5 million surplus currently reflected in the Company's nuclear depreciation account is only an estimate, not a guarantee.

The agency argued that amortizing the surplus in the depreciation reserve would be short-sighted, exchanging a short-term benefit for higher rates over the long term. It stated that it was difficult to conclude, given the Company's recent and ongoing substantial nuclear capital investment, that ratepayers had overpaid nuclear depreciation expense.

4. The OAG

The OAG opposed amortizing the surplus, stating that amortization would lead to ratepayers paying depreciation twice and a higher return on a larger rate base.

The OAG concluded that the short-term benefits of amortization would be outweighed by its long-term burden on ratepayers.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that a nuclear depreciation surplus exists, but that its amount is unclear.

She found that XLI was likely overestimating the surplus by using vintage accounting. She rejected vintage accounting on grounds that the life of a nuclear plant determines the lives of the assets within it and that the reasonable measure of the lives of Xcel's nuclear plants was the length of its operating licenses. She found that it was not reasonable at this point to assume that those operating licenses—and the plants' service lives—would be extended. She also found that Xcel was likely underestimating the surplus by including interim plant additions in initial-depreciation accounts.

She found that the purpose of depreciation is to recover current costs and that to the extent that the current depreciation reserve exceeds straight-line annual allocation of those costs, amortization of the surplus could reasonably be required.

She found that whether the Commission should require amortization of some amount below XLI's estimated surplus, such as the Company's estimate, would depend on the size of the final revenue deficiencies, the need to ensure adequate funding for future plant retirements, and a careful analysis of policy factors such as rate-shock mitigation, rate stability, and

[39] Xcel Initial Brief at 102; Xcel Reply Brief at 82.

intergenerational equity. She found that the Commission might also consider the impact of the Company's rate-moderation proposals, if adopted.

D. Commission Action

The Commission will not require amortization of the apparent surplus in the Company's nuclear-plant depreciation reserve but will permit that surplus to self-correct over the lives of the two nuclear plants.

The nuclear surplus is not reasonably comparable to the transmission, distribution, and general-plant (TDG) surplus that the Commission ordered amortized in the last rate case. The TDG surplus applied to a huge pool of transmission, distribution, and general-plant assets. Given the large number of assets in the pool, miscalculations of individual service lives or individual retirement or salvage costs were unlikely to have a substantial financial impact on the Company and its ratepayers.

This surplus, on the other hand, applies to two nuclear plants and their associated assets. Given the small number of assets in the pool, miscalculations of individual service lives or individual retirement costs or salvage values could have a substantial financial impact on the Company and its ratepayers, especially given the extremely high cost of decommissioning nuclear power plants. Similarly, unforeseen contingencies affecting the timing or cost of plant retirements carry more serious financial consequences for this smaller, less diversified group of assets than for the group of assets in the TDG account.

The Commission concurs with the Administrative Law Judge that XLI's calculation of the surplus is significantly overstated. The Commission also concurs that, while it might be reasonable to amortize whatever significantly smaller surplus might exist, amortization is not required and should only be done if necessary for rate relief, after careful consideration of the need to ensure adequate funding for nuclear-plant retirements and the impact of any other rate-moderation measures ordered in this case.

On the basis of that analysis, the Commission finds that the uncertainties and risks that would accompany reducing the nuclear depreciation reserve exceed the benefits of amortizing whatever surplus might exist. Permitting the surplus to self-correct over the remaining lives of the nuclear plants will help ensure adequate funding for plant retirements and help protect ratepayers from the financial consequences of unforeseen contingencies. And the rate-moderation measures adopted in this case will help smooth the transition to 2014-test-year and 2015-Step rates without compromising these goals.

For all these reasons, the Commission will not adopt XLI's proposal to amortize the difference between the actual and theoretical nuclear depreciation reserves but will permit that difference to self-correct over the remaining lives of the plants.

XVIII. Corporate Aviation

A. Introduction

The Company has proposed to recover $954,000 for corporate-aviation costs in the 2014 test year, which is 50% of what it actually has budgeted to spend in 2014, on a Minnesota-jurisdictional basis. The Commission has, in prior rate cases and in the absence of a record that would support more precision, allowed recovery of 50% of corporate aircraft expenses as a reasonable proxy for value to the utility.

Under Minn. Stat. § 216B.16, subd. 17, the Commission may not allow recovery for travel expenses that the Commission determines are unreasonable and unnecessary for the provision of utility service. The statute requires utilities seeking recovery for such expenses to itemize the expenses as specified by the Commission, and "include the date of the expense, the amount of the expense, the vendor name, and the business purpose of the expense."[40]

In Xcel's last rate case, the Commission required that the Company include in its next initial rate-case filing "more detailed flight data reports" including "the charged employee, each employee passenger and his/her assigned operating company, the other passengers on flight and reason for use, and primary purpose for scheduling the flight."[41] The Commission also determined in Xcel's 2010 rate case that the Company must provide more detailed recordkeeping and reporting for corporate aviation.[42]

B. Positions of the Parties

1. The Company

Xcel asserted that it complied with the Commission's reporting requirements set in the last rate case to the best of its ability. Relying on Commission decisions in previous rate cases, for Xcel and for other utilities, the Company proposed to recover 50% of its corporate-aviation expenses. It argued that it had offered information sufficient to support the 50% allowance, and disagreed with the OAG that any further downward adjustments were appropriate.

2. The OAG

The OAG argued that the corporate-aviation expense, even reduced by 50%, should be further reduced. It suggested that the Company should be limited to recovery of the cost of comparable commercial air travel—$300 per one-way trip.

The OAG also recommended reductions for flights identified that it argued did not benefit ratepayers, including reporting categories "personal travel," "investor relations," and "aviation use." The OAG further argued that other reporting categories were not detailed enough to support recovery. It asserted that the Company's air travel reporting did not comply with the Commission's order in the previous rate case and demonstrated that the Company did not have an adequate system to ensure that corporate flights were for a valid business purpose.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that the Company had substantially complied with the Commission's previous orders requiring additional information from its corporate-aviation recordkeeping. She

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[40] Minn. Stat. § 216B.16, subd. 17(a), (b).

[41] Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 53 (September 3, 2013).

[42] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-10-971, Findings of Fact, Conclusions, and Order at 36 (May 14, 2012).

found it reasonable to include 50% of the approximately $1.9 million budgeted for Minnesota-jurisdictional 2014 corporate-aviation costs, or $954,425.

The ALJ did not recommend further reductions such as those proposed by the OAG. The ALJ relied in part on the Commission's previous willingness to approve corporate-aviation expenses with the level of support provided by the Company. She also determined that the recommended 50% reduction of the expense adequately excluded travel expense that did not benefit ratepayers. The ALJ recommended that the Commission consider whether it wanted more detail in the aviation records, and if so, that the Commission specify the level of detail desired.

D. Commission Action

The Commission disagrees with the ALJ's aviation-related recommendations and will instead adopt revised conclusions as set forth below and in the ordering paragraphs.

The Commission concludes that the Company's proposed 50% exclusion to its jurisdictional corporate-aviation costs does not adequately remove flight costs that were incurred for reasons other than for the provision of utility service. The Commission will therefore not adopt ALJ Finding 559. The Commission will require that corporate-aviation costs be further reduced by the cost of flights categorized as personal travel (34 total company flights) and investor relations (45 total company flights). These flights were not required for the provision of utility service and should not be recovered.

The Commission will also disallow recovery for reported expenses with insufficient detail to allow the Commission to make an informed determination about their necessity and reasonableness. Minnesota law requires Xcel to provide information about the "business purpose" of each flight before recovery is permissible. Xcel did not meet this requirement because the "business purpose" descriptions in Xcel's flight log do not provide any information to determine the true business purpose of the flights.

Because Xcel has not demonstrated that the flights coded as Executive Business Travel, Director Travel, Manager Travel, and Business Area Travel have a business purpose necessary for the provision of utility service, they must be disallowed. Accordingly, the Commission will require the Company to reduce corporate-aviation costs further by the cost of each flight with the following descriptions:

- Business Area Travel (1,668 total company flights);
- Director Travel (615 total company flights);
- Manager Travel (55 total company flights);
- Xcel Executive Business Travel (831 total company flights).[43]

Finally, the Commission will require that the Company provide, in future rate cases seeking recovery of corporate aviation, more detailed, accurate records of the actual business purpose for flights that are scheduled, rather than reducing all flights to a generic "code." This will permit the

[43] The OAG also sought to exclude recovery for flights categorized as "Shareholders Meeting," but the Commission will allow recovery for those flights because annual shareholder meetings are required by statute, and the travel occurred close in time to the Company's annual meeting.

Commission to evaluate the reasonableness and necessity of the expenses for the provision of utility service, as required by statute.

XIX. Proposed FERC Comparison Study KPI Benchmarks

A. Introduction

Xcel annually conducts a study comparing its cost structure to peer companies. According to the Company, the study assesses performance in the following expense categories: nonfuel operation and maintenance (O&M), administrative and general, customer care, distribution, transmission O&M, and production O&M. In the 2013 study, the Company's performance was among the bottom half of its peers in two categories: nonfuel O&M and transmission O&M. Parties questioned whether the Company should implement benchmarks to improve performance in those categories.

B. Positions of the Parties

The Department and the Chamber recommended that the Commission require the Company to add nonfuel O&M and transmission O&M benchmarks as additional Key Performance Indicators (KPIs). KPIs are used as part of the Company's annual incentive program to measure and reward performance toward business goals.

Xcel opposed adding these additional benchmarks, arguing that their addition was unnecessary. It argued that it already has implemented a nonfuel O&M growth KPI. The Company also contended that using the transmission O&M benchmark from its 2013 study would result in inapt comparisons. But the Company has offered to work with the Chamber to develop a reasonable KPI metric for transmission costs.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that an additional KPI for transmission O&M was warranted, but concluded that because the Company already implements a nonfuel O&M growth KPI, adding a KPI for nonfuel O&M was not necessary.

D. Commission Action

The Commission agrees with the ALJ that the concerns about transmission O&M costs raised by the Chamber and agreed to by the Department justify closer examination. To ensure that an appropriate benchmark can be established, careful attention to the selection of peer companies will be necessary. The Commission will therefore require the Company, in its next rate case, to (1) present a new KPI for transmission O&M costs, and (2) provide a comparison study of its transmission O&M costs by using appropriate peer companies, along with justification for why certain utilities were included or excluded.

At this time, the Commission will not make a determination as to whether the Company's KPI target to restrict increases in its recoverable nonfuel O&M costs sufficiently addresses concerns raised by the parties. But the Commission agrees with and adopts the ALJ's determination that no additional nonfuel O&M KPI benchmark is necessary at this time.

XX. CWIP and AFUDC

A. Introduction

Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC) are accounting devices used to permit utilities to recover the financing costs of capital projects while they are under construction. Capital costs incurred during construction are placed in rate base as CWIP; the associated financing costs are added to net operating income as AFUDC, normally offsetting any return on CWIP until the plant under construction goes into service. At that time, CWIP and AFUDC are recovered over the life of the asset through the recording of book depreciation expense.

The Commission has been following this approach in Xcel rate cases since 1977. The Commission is authorized to consider CWIP and AFUDC in ratemaking under Minn. Stat. § 216B.16, subds. 6 and 6a.

In the Company's last rate case, some parties claimed that the Company was misusing CWIP/AFUDC by including short-term and low-cost projects. They also claimed that CWIP was inappropriate in principle because it shifted shareholders' risks to ratepayers and forced ratepayers to bear costs for which they receive no current benefit.

The Commission permitted the inclusion of CWIP and AFUDC in that case, but required that the Company provide a more detailed explanation of its CWIP and AFUDC practices in its next rate case:

> In the initial filing in its next rate case, Xcel shall provide evidence of FERC's accounting requirements for CWIP/AFUDC and demonstrate that it has met the FERC requirements. It shall also address whether a minimum dollar level should be set for projects placed in CWIP.[44]

The Company included detailed testimony on its CWIP and AFUDC practices in its initial filing in this case. No party disputed that the Company had demonstrated its compliance with FERC accounting requirements.

The OAG and the Commercial Group challenged the reasonableness of CWIP and AFUDC in principle, however. And the OAG also recommended that if the use of CWIP and AFUDC continued to be permitted, the AFUDC rate should be lowered and the application of CWIP and AFUDC should be limited to projects whose costs exceeded $25 million.

B. Positions of the Parties

The Commercial Group argued that the use of CWIP/AFUDC shifts the risk of investment from shareholders to ratepayers, especially in regard to construction delays or stoppages, and that CWIP/AFUDC violates principles of intergenerational equity by forcing ratepayers to bear the cost of projects from which they are receiving no benefit.

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[44] Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 9, 54 (September 3, 2013).

The OAG argued that current CWIP/AFUDC practices violate FERC ratemaking principles, despite compliance with its accounting principles; that they violate the "used and useful" ratemaking standard set forth in Minn. Stat. § 216B.16, subd. 6; that the Company can and should finance projects costing under $25 million from internal funds recovered through rates; and that the AFUDC rate for eligible projects should be set at 2.62% instead of the 6.79% used by the Company.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company's proposed ratemaking treatment of construction work in progress was consistent with Minnesota law, FERC regulations, and longstanding Minnesota practice. She also found that the Company's use of these accounting devices was appropriate and resulted in just and reasonable rates.

She noted that the Commission is required by statute to "give due consideration" to construction work in progress when determining the rate base upon which a utility is permitted to earn a fair rate of return.[45] She noted that all parties concurred that the Company had demonstrated compliance with FERC accounting requirements, as required by the last rate-case order. She noted that the FERC ratemaking principles that the OAG claimed barred the use of Minnesota's established approach to CWIP/AFUDC applied only to wholesale rates set at the federal level, not to retail rates set at the state level.

She found that following the logic of the OAG's proposal to use FERC ratemaking principles would not result in more reasonable rates and would in fact increase the Company's 2014 revenue requirement by $8.5 million and its 2015 revenue requirement by $12.4 million. She found that the record contained no evidence of any other jurisdiction using the CWIP/AFUDC approach the OAG recommended.

The ALJ found that it would not be reasonable to limit the Company's use of CWIP/AFUDC to projects costing more than $25 million, excluding 62% of its capital projects in the 2014 test year. (The Company currently uses CWIP/AFUDC for projects costing more than $25,000 that take longer than 30 days to complete.) She found that the record did not demonstrate that the Company had excess revenues sufficient to fund these projects without external financing.

She found that it would not be reasonable to reduce the Company's AFUDC rate from the 6.79% used by the Company to the 2.62% recommended by the OAG. The 6.79% figure is calculated in accordance with the FERC formula, which first recognizes the cost of short-term debt and then the weighted average of the cost of long-term debt and equity. The 2.26% figure is the average of the Company's short-term and long-term debt rates and relies in part on the assumption that interim-rate over-collections are available to help finance capital projects.

The Administrative Law Judge found that the Company clearly uses equity to help fund capital projects and that interim-rate overcollections are of limited usefulness, since they are refunded with interest under Minn. Stat. § 216B.16, subd. 3(c).

[45] Minn. Stat. § 216B.16, subd. 6.

D. Commission Action

The Commission concurs in the Administrative Law Judge's detailed and reasoned analysis of this issue and will continue to permit the use of CWIP and AFUDC in accordance with current practice.

The Commission concurs that the claim that the application of CWIP and AFUDC violates the "used and useful" provisions of Minn. Stat. § 216B.16, subd. 6, is effectively offset by that subdivision's requirement that the Commission give "due consideration" to construction work in progress when determining rate base:

> *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. For purposes of determining rate base, the commission shall consider the original cost of utility property included in the base and shall make no allowance for its estimated current replacement value.[46]

The Commission also concurs that the record does not demonstrate any public-policy or practical advantage to be gained by changing its existing approach to CWIP/AFUDC. The intergenerational impact of current ratepayers' contributions to financing pending projects is effectively counterbalanced by previous ratepayers' contributions to financing pending—and now completed—projects.

Similarly, the Commission concurs with the ALJ's analysis and rejection of the proposals to reduce the 6.79% AFUDC rate, to limit the use of CWIP/AFUDC to projects costing at least $25 million, and to apply FERC wholesale ratemaking principles—or some variation of those principles—to Minnesota CWIP/AFUDC practices. The Commission likewise rejects the claim that the Company has excess revenues with which it can and should finance capital projects costing less than $25 million; it concurs with the ALJ that interim rates are not set to include costs of this nature and magnitude.

For all these reasons, explained in greater detail by the Administrative Law Judge, the Commission concludes that the existing treatment of Xcel's construction work in progress properly reflects the due consideration required by statute.

XXI. Fuel-Clause Revision

A. Introduction

The Company recovers some 30% of its annual gross revenues through the "fuel clause," the automatic rate adjustment authorized under Minn. Stat. § 216B.16, subd. 7, and Minn. R.

[46] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

7825.2390 to .2920 to permit utilities to recover the amount by which their fuel and purchased-power costs exceed the amount built into base rates.

Under Minn. R. 7825.2900, the Company makes a filing before each automatic rate change. Under Minn. R. 7825.2820, the Company makes an annual filing on September 1 explaining and supporting all rate adjustments made through the fuel clause between July 1 and June 30 of the preceding year. Under Minn. R. 7825.2390, the Department files an annual evaluation of Xcel's and every other utility's use of the fuel clause.

The Commission examines the prudence and reasonableness of fuel-clause rate adjustments based on these annual filings.

B. Positions of the Parties

The Chamber and XLI argued that the structure and operation of the fuel-clause adjustments need revision to provide more accountability, greater ease of review, and more effective incentives to minimize fuel and purchased-power costs. They argued that the complexity of fuel and purchased-power costs and the time lag between when they are incurred and when they are reviewed makes effective review difficult.

The Department contended that the fuel clause, as currently designed, weakens utilities' incentive to minimize energy costs and that after-the-fact investigation of these costs is inefficient and difficult.

The Chamber recommended requiring Xcel to file a proposal for a revised fuel clause with its next rate-case filing, unless the Commission has taken action on fuel-clause revision before that time. XLI recommended requiring Xcel to file a new fuel-clause proposal as part of its next rate-case filing or 90 days from the date of the final order in this case, whichever occurs earlier.

The Department concurred on the need for revised fuel-clause procedures but recommended examining the issue in the pending fuel-clause docket where it is under consideration.[47]

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Chamber and XLI raised valid concerns, but found that the issue should be examined in the fuel-clause docket, because the issue involves all utilities operating in the State of Minnesota.

D. Commission Action

The Commission concurs with the Administrative Law Judge.

The issues raised by the Chamber and XLI are policy issues of great importance that affect all Minnesota utilities; they can be most effectively examined in the industry-wide fuel-clause proceeding. While company-to-company facts and issues may vary, industry-wide trends are important, and individual companies' experiences will help inform the analysis of how best to use this statewide regulatory tool.

[47] *In the Matter of the Review of the 2011–2012 Annual Automatic Adjustment Reports for All Electric Utilities*, Docket No. E-999/AA-12-757.

The Commission finds that this issue is best addressed in the pending fuel-clause proceeding.

XXII. Cost of Replacement Power During Sherco 3 Outage

A. The Issue

In November 2011, an accident at the Company's largest power plant, the Sherburne County Generating Station, or "Sherco," forced the shutdown of one of its three units, Sherco 3. Sherco 3 is a 900 MW coal-fired generator first put into service in November 1987; it is the largest generator in Xcel's system. Damage to the generator was massive, and it remained shut down from November 2011 to October 2013.

To replace Sherco 3's output, Xcel bought both replacement power and additional fuel for Company-owned generators capable of increasing their output to help meet the deficit; these costs were passed on to ratepayers through the "fuel clause," the Company's automatic rate adjustment for changes in energy costs.[48] The Chamber recommended requiring the Company to capitalize the amount by which these costs exceeded what would have been the costs of uninterrupted Sherco 3 generation and to recover these excess costs over the remaining life of the unit.

The Company and the Department said that all issues regarding the recoverability and ratemaking treatment of these costs were being addressed in two proceedings examining utilities' 2011–2013 fuel-clause rate adjustments and should be decided there.[49] The Administrative Law Judge concurred.

B. Commission Action

The Commission agrees that the ongoing annual fuel-clause-adjustment dockets are the best places to examine these issues and will not address them here.

Under Minn. R. 7825.2390 to .2920, utilities file detailed monthly and annual reports on all automatic rate adjustments made through the fuel clause. These filings receive careful review by interested stakeholders and by the Department, which files a report analyzing the year's fuel-clause activity and highlighting any concerns with accuracy, prudence, or related issues. The Commission holds an annual meeting to examine and act on the utilities' annual reports.

The causes of the Sherco 3 accident and the adequacy and prudence of the Company's response are being examined in the pending fuel-clause dockets for the nearly two-year period of the Sherco 3 outage. Those two proceedings focus on the issues raised by the Chamber of Commerce, and those two proceedings are a more efficient means for comprehensively examining them. The Commission concurs with the Administrative Law Judge that those issues should be addressed there, not here.

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[48] Minn. Stat. § 216B.16, subd. 7.

[49] *In the Matter of the Review of the 2011–2012 Annual Automatic Adjustment Reports for All Electric Utilities*, Docket No. E-999/AA-12-757 and *In the Matter of the Review of the 2012–2013 Annual Automatic Adjustment Reports for All Electric Utilities*, Docket No. E-999/AA-13-599.

XXIII. Cost of Replacement Fuel During Black Dog Outage

A. The Issue

From December 23, 2012, to March 10, 2013, two generating units at the Company's Black Dog power plant were out of service because of an accident caused by human error. During that time the Company incurred additional capital costs of some $24,104, additional operation and maintenance costs of about $1.838 million, and additional fuel-replacement costs in an amount that has been designated trade secret. The additional fuel-replacement costs were passed on to ratepayers through the Company's automatic rate adjustment for changes in the cost of fuel, the "fuel clause."

XLI recommended that test-year operations and maintenance costs be reduced by $1.838 million, that the $24,104 capital investment be removed from rate base, and that the replacement-fuel costs receive close scrutiny in the pending proceeding examining the Company's automatic rate adjustments through the fuel clause.[50] The Company agreed that replacement-fuel costs should be examined in the 2012–2013 fuel-clause adjustment docket, but pointed out that the other costs were incurred outside the test year and were not reflected in test-year costs.

The Administrative Law Judge concurred with the Company. She found that there was no basis for disallowing costs that were not in the test year and that such a disallowance would constitute retroactive ratemaking. She found that XLI had an opportunity to raise this issue in the Company's last rate case and had not done so. She concurred with both parties that the recoverability of the additional fuel-replacement costs was properly before the Commission in the annual fuel-clause adjustment docket.

B. Commission Action

The Commission concurs with the Administrative Law Judge and accepts and adopts her findings, conclusions, and recommendation. The costs associated with the Black Dog outage were incurred outside the test year and are not included in the test-year revenue requirement sought by the Company. The issue of the recoverability of the additional replacement-fuel costs is properly before the Commission in the 2012–2013 annual fuel-clause adjustment docket and will be examined there.

XXIV. Babcock & Wilcox Litigation

A. Introduction

In a January 20, 2015 letter, the OAG brought to the Commission's attention a pending lawsuit with the Company as a named defendant, filed after the evidentiary hearing in this case had concluded. The plaintiff, Babcock & Wilcox Nuclear Energy, Inc., is a subcontractor involved in the replacement-steam-generator project at the Prairie Island generating plant. At issue is a dispute over $45.3 million that Babcock & Wilcox asserts it is owed for its work, along with interest on the disputed amount if Babcock & Wilcox prevails.

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[50] Docket No. E-999/AA-13-599.

B. Positions of the Parties

1. The OAG

The OAG expressed concern that the disputed amount was included in the Company's rate base despite having been withheld from payments to Babcock & Wilcox. The OAG argued that the Company should be required to disclose the contracts at the center of the dispute to the OAG, and provide additional discussion, analysis, and information supporting all costs and interest paid to Babcock & Wilcox when the lawsuit is resolved. As an alternative to requiring the disputed $45.3 million to be excluded from rate base, the OAG supported refunding any costs included in rate base but not paid.

2. The Department

The Department generally supported the OAG's position and recommendations. The Department stated that it was concerned about how a refund would work, especially if the litigation was not resolved by the time 2014 and 2015 refunds agreed to by the Company or required by the Commission were to be calculated.

3. The Company

Xcel acknowledged the litigation and the underlying dispute with Babcock & Wilcox. It asserted that the contracts sought by the OAG were subject to confidentiality provisions limiting their disclosure. The Company argued that a favorable litigation outcome would benefit ratepayers, and agreed to address the disputed amount as part of the 2014 Plant Related Revenue Requirement True-Up process.

The Plant Related Revenue Requirement True-Up process was listed as an issue resolved between the Company and the Department, and was not presented as a disputed issue for resolution by the ALJ or the Commission. The Company has agreed to refund the difference between the Commission-approved revenue requirements and actual revenue requirements associated with capital additions in 2014 and 2015.[51]

C. The Recommendation of the Administrative Law Judge

Because this issue arose after the close of the evidentiary proceeding, the ALJ did not consider it.

D. Commission Action

The Commission will require that the Company refund disputed costs included in rate base but not used to pay for the Prairie Island replacement-steam-generator project. But the Commission will allow the litigation to run its course before requiring any true-up. To address the OAG's and the Department's concerns about how the true-up process will work, the Commission will impose additional procedural and filing requirements.

Once the lawsuit is resolved, the Company must make a compliance filing providing all relevant information as to costs and interest paid to Babcock & Wilcox and discuss what costs were included

[51] October 7, 2014 Issues List at 34–35.

as Plant in Service in the current rate case. Any costs included in rate base but not paid will be refunded to ratepayers as part of either the 2014 or 2015 refund, and if the lawsuit is not resolved at either of those times, then the refund will be made within 60 days after the lawsuit is resolved.

Within 30 days of completing the refund, the Company will be required to make a compliance filing with information detailing the refund and the resolution of the lawsuit. In the filing, the Company will describe the amount not paid to Babcock & Wilcox that remains in rate base and the revenue-requirement effect of that amount so the Commission can consider whether to require Xcel to track that amount for return to ratepayers in Xcel's first rate case after the resolution of the lawsuit.

XXV. Rate-Moderation Proposals

The Company proposed two measures to moderate the rate impact of its 2014 and 2015 revenue deficiencies:

- It proposed to accelerate the eight-year amortization ordered in its last rate case of the surplus in its transmission, distribution, and general-plant depreciation reserve by amortizing 50% of the remaining surplus in 2014, 30% in 2015, and 20% in 2016; and
- It proposed to reduce the 2015-Step increase by the approximately $25.7 million by which its 2013 and 2014 nuclear-waste-storage settlement payments from the U.S. Department of Energy exceeded the amounts required for 2013 and 2014 nuclear-decommissioning-fund accruals.

The Commission will adopt both measures, as discussed individually below.

A. Accelerating the Amortization of Transmission, Distribution, and General-Plant Depreciation Surplus

1. Introduction

In Xcel's last rate case, the Commission directed the Company to amortize over eight years a surplus of some $265 million in its transmission, distribution, and general-plant depreciation accounts.[52] In this case, the Company proposes to accelerate that amortization to moderate the rate increases sought here; it proposes to amortize 50% of the remaining surplus in 2014, 30% in 2015, and 20% in 2016.

2. Positions of the Parties

The Department did not oppose the Company's proposal but preferred slightly different amortization percentages in years two and three. The Department recommended a 50/40/10 split instead of the 50/30/20 split recommended by the Company, largely because the 50/40/10 split would mean smaller rate increases in the 2015 Step. In the alternative, the Department supported the Company's proposed split of 50/30/20.

The Company cautioned against reducing the 2016 depreciation-amortization surplus, when it could potentially play a significant role in moderating increases sought in future rate cases.

[52] Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order at 25–29 (September 3, 2013).

The Xcel Large Industrials supported the Company's proposal.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the determination of whether to adopt either or both of the Company's two rate-moderation proposals would depend on the size of the 2014 and 2015-Step revenue deficiencies found by the Commission. She found that accelerating the amortization of the depreciation surplus would reduce rates in the short term but result in higher rates in later years.

She found that there may be circumstances in which acceleration would be warranted to avoid rate shock or to address intergenerational equity. She noted that the Company's accelerated-amortization proposal had been factored into interim rates, which she found might make some form of continued acceleration reasonable.

4. Commission Action

The Commission finds that the revenue deficiencies and resulting rate increases for the 2014 test year and the 2015 Step, while necessary and reasonable, are large enough and close enough in time to the last rate increase to merit the accelerated-amortization moderation measure recommended by the Company. The Commission will therefore require accelerated amortization of the transmission, distribution, and general-plant depreciation surplus, using the amortization schedule recommended by the Company.

This approach will provide a measure of rate relief as to both the 2014 and 2015-Step rate increases. It will appropriately direct greater relief to the first and higher increase, especially in light of the application of the Department of Energy settlement funds to the 2015-Step increase, as discussed below. It will smooth the transitions from current rates to 2014 rates to 2015-Step rates. And it will accomplish these goals without exhausting the amortization surplus, potentially contributing to future rate stability.

Further, this approach will serve the ratemaking goal of intergenerational equity by ensuring a closer match between the subset of ratepayers whose rates reflected inflated depreciation costs and the subset of ratepayers whose rates will reflect the return of those overpayments.

For all these reasons, the Commission concludes that the amortization of the depreciation surplus should be accelerated and should follow the 50/30/20 split recommended by the Company.

B. Applying 2013 and 2014 Settlement Payments from the Department of Energy to the 2015-Step Increase

1. Introduction

Xcel proposed to reduce the 2015-Step increase by applying to the 2015-Step revenue deficiency the approximately $25.7 million by which its 2013 and 2014 nuclear-waste-storage settlement payments from the U.S. Department of Energy (DOE) exceeded the amounts required for 2013 and 2014 nuclear-decommissioning-fund accruals. [53]

2. Positions of the Parties

The Department did not oppose applying the DOE settlement payments to the 2015-Step revenue deficiency to offset the resulting rate increase.

The Commercial Group recommended using the DOE funds to offset both the 2014 and the 2015-Step rate increases, applying the 2013 settlement payment toward the 2014 increase and the 2014 payment toward 2015-Step increase. The Group argued that this approach appropriately balanced the goals of rate moderation and timely return of ratepayer funds.

The Company recommended applying both DOE payments to the 2015-Step increase to moderate the impact of amortizing a lower percentage of the depreciation surplus in 2015 than in 2014, as discussed above.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the determination of whether to adopt either or both of the Company's two rate-moderation proposals would depend on the size of the 2014 and 2015-Step revenue deficiencies found by the Commission.

She recommended applying the DOE funds to rate relief if the Commission found a need for rate moderation and declined to make a recommendation on whether the funds should be distributed between the 2014 and 2015-Step revenue deficiencies or applied to only one.

4. Commission Action

The Commission finds that the revenue deficiencies and resulting rate increases for the 2014 test year and the 2015 Step, while necessary and reasonable, are large enough and close enough in time to the last rate increase to merit the DOE-payments moderation measure recommended by the Company. The Commission will therefore require the application of the DOE 2013 and 2014 settlement payments to the 2015-Step revenue deficiency, in addition to the 30% portion of the unamortized depreciation surplus discussed above.

While applying just one of the two DOE payments to the 2015 Step would also bring some rate relief in 2015, applying both payments will obviously deliver more, and will cushion the impact of applying a smaller portion of the unamortized depreciation surplus to the 2015 Step than the 2014 test year. It will better serve the ratemaking goals of maintaining rate stability and avoiding rate shock. Where, as here, a utility is near the peak of a demanding investment cycle, with rate increases recurring at shorter-than-average intervals, it is reasonable to smooth the rate impact of that peak with the tools at hand, disrupting customers' settled rate expectations as little as possible.

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[53] These payments reflect the outcome of litigation against the Department of Energy for increasing the Company's nuclear-waste storage costs by failing to assume responsibility on schedule for the storage of nuclear waste.

For all these reasons, the Commission concludes that the DOE settlement payments for 2013 and 2014 should be applied to the 2015-Step revenue deficiency, in addition to the 30% of the unamortized depreciation surplus discussed above.

COST OF CAPITAL ISSUES

XXVI. Cost of Equity

A. Introduction

In 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 service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, *and to earn a fair and reasonable return upon the investment in such property.*[54]

One of the critical components of that fair and reasonable return upon investment is the return on common equity, which—together with debt—finances the utility infrastructure. The Commission must set rates at a level that permits stockholders an opportunity to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment.

In short, the Commission must determine a reasonable cost of equity and factor that cost into rates. It would normally begin by examining the price of the utility's stock, but Xcel is a subsidiary of Xcel Energy, Inc. and has no publicly traded common stock. Its cost of common equity—essential to determining overall rate of return and the final revenue requirement—must therefore be inferred from market data for companies that present similar investment risks.

B. The Analytical Tools

Xcel, the Department, and the ICI Group conducted cost-of-equity studies and based their analysis on comparison groups of utilities they considered similar enough to Xcel to serve as proxies in determining the Company's cost of equity. All three used the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance.

The Company and the Department also used the Capital Asset Pricing Model (CAPM) as a secondary, corroborating resource, consistent with the Commission's historical treatment of this model. The Company also conducted a third analysis using the Bond Yield Plus Risk Premium Model, which the Commission has historically relied on less heavily, considering the model prone to producing volatile and unreliable outcomes.

The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is high enough to induce investment. The model is derived from a

[54] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

formula used by investors to assess the attractiveness of investment opportunities using three inputs—dividends, market equity prices, and growth rates.

The CAPM model estimates the required return on an investment by determining the rate of return on a risk-free, interest-bearing investment; adding a historical risk premium determined by subtracting that risk-free rate of return from the total return on all market equities; and multiplying the remainder by beta, a measure of the investment's volatility compared with the volatility of the market as a whole.

The Bond Yield Plus Risk Premium Model determines the cost of equity by adding to current corporate bond yields a premium reflecting the greater returns realized by equity holders over various historical periods.

C. Positions of the Parties

1. The Company and the Department

Xcel recommended a return on equity of 10.25%, and the Department recommended a return on equity of 9.64%

The Company and the Department both conducted full-scale DCF analyses, each using two comparison groups of utilities screened for comparability with Xcel in terms of operating profiles and investment risks. One comparison group was made up of electric utilities and the other of utilities with both gas and electric operations.[55] The Company's electric group and combined group each consisted of 14 companies; the Department's electric group consisted of ten companies and its combined group of 14 companies. The parties' comparison groups contained many of the same companies.

Both parties conducted DCF analyses on all companies in both groups, using information from three nationally recognized investment-research firms—Value Line, Zack's, and First Call—for growth-rate estimates. Both added flotation costs (the fees and expenses incurred in issuing securities) of 2.926% to their results. Both filed updated DCF analyses at the end of the evidentiary hearings based on the most recent information available.

Both parties' updated DCF results were lower than their initial results, and the Department lowered its initial recommended return of 9.8% to 9.64%. This number was the midpoint of its updated DCF results for all companies in both its comparison groups, which it weighted 60/40 between the electric-utility and combined-utility groups. The update was based on the 30-day period between June 7 and July 7, 2014.

The Company continued to recommend 10.25%. This number was higher than the midpoint of its updated DCF results for all companies in both its comparison groups, which it weighted 80/20 between the electric-utility and combined-utility groups. The Company's update, like its initial analysis, was based on averaging stock closing prices over 30-day, 90-day, and 180-day periods, instead of the single 30-day period used by the Department.

[55] Xcel is a combined utility, with 91.67% of its net income derived from electric operations and 8.33% from gas operations. Ex. 28 (Hevert Rebuttal) at 19.

The Company argued that, given its need for major capital expansion in the near term—especially in transmission and renewable generation—it was important for the Commission to set the cost of equity at a level demonstrating strong regulatory support for the Company, to ensure continued access to capital at favorable rates. It argued that setting the return on equity below the 9.83% set in the last rate case would send the opposite signal to investors, especially since this would be the second consecutive rate case in which its cost of equity declined. The Company also argued that the multiyear rate plan would reduce its ability to react to changing market conditions, which it argued was especially concerning given what it perceived to be current volatility in the financial markets.

Finally, the Company pointed to rates of return on equity above the 9.64% recommended by the Department awarded in other jurisdictions and in earlier cases in this state.

2. The ICI Group

The ICI Group recommended a return on equity of 9%.

The ICI Group conducted four variants of the DCF analysis using one comparison group of 27 utilities. This group consisted of all companies classified as electric utilities by Value Line, minus those with no expected growth in earnings or dividends during the study period, those that had not consistently paid dividends over the past three calendar years, those known to be currently involved in mergers, and those whose principal business was transmission of electricity, not retail sales.

The Group's analysis relied on investment data from Value Line and was not subjected to check by any alternative analytical model. The Group questioned the value of using the CAPM or Bond Yield Plus Risk Premium models as checks as the Company and Department did, arguing that the Federal Reserve's intervention in current debt markets undermined the accuracy of current interest rates as indicators of true market conditions.

The Group pointed to returns on equity recently granted in other jurisdictions as evidence of the broad range of reasonable returns. The Group opposed recovery of a flotation adjustment on the grounds that the Company would not be issuing securities during the period the new rates would be in effect.

3. The Commercial Group

The Commercial Group did not recommend a specific return on equity but said the return should not exceed the 9.64% recommended by the Department.

The Commercial Group did not conduct a cost-of-equity study but pointed to factors that it argued reduced investment risk, thereby reducing the reasonable return on equity: the use of a future test year, the use of interim rates, the inclusion of CWIP in rate base, the second-year rate increase built into the multiyear rate plan, and the proposed revenue decoupling mechanism.

The Commercial Group also emphasized the broad range of returns granted in other jurisdictions and argued that the return in this case should not exceed the 9.64% recommended by the Department.

4. AARP

AARP argued that the cost of equity should be adjusted downward, to reflect reduced risk, if the Commission authorized revenue decoupling.

D. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that both Xcel and the Department had conducted fundamentally sound DCF studies meriting careful consideration. These studies formed the foundation for her analysis, which resulted in a recommended return on equity of 9.77%.

She derived this number by averaging the results in the Department's direct testimony, the Company's rebuttal testimony,[56] and the Department's surrebuttal testimony. These results represented three separate periods: October 1–31, 2013; May 1–30, 2014; and June 7–July 7, 2014, and each was based on the most recent information then available. The Department had followed its standard practice of recommending adoption of its final (surrebuttal) DCF outcome, in reliance on the economic principle that the most recent information is normally the best indication of future market performance.

The ALJ disagreed. She found that using a single 30-day period could lead to anomalous results and that the June 7–July 7, 2014 data on which the Department based its final recommendation might represent a short-term anomaly. She found that stock prices were unusually high during that 30-day period and that the Department's surrebuttal data might not be representative of the period during which the new rates would be in effect.

She found that the multiyear impact of this two-year rate plan compounded the need to ensure that market idiosyncrasies did not affect outcomes. She also found that 9.77% was the average return on equity in four 2014 rate cases in other states and that a return higher than the one recommended by the Department would help the Company attract the investment it needed for upcoming capital outlays.

She weighted the electric-utility and combined-utility comparison groups at the 60/40 ratio recommended by the Department, not the 80/20 ratio recommended by the Company. She found that the 60/40 ratio was consistent with past practice and that the critical element to ensure a valid comparison group was similar investment risk, not similar operations. She also noted that Xcel's parent company had subsidiaries with both gas and electric operations.

The ALJ recommended permitting the recovery of flotation costs as consistent with longstanding practice and necessary to ensure that the Company was not denied the opportunity to earn its authorized rate of return.

She recommended granting no weight to the ICI Group's cost-of-equity study, finding that the companies in the comparison group were not sufficiently comparable to Xcel and that the use of a single source of market and investment data was insufficiently rigorous. She also rejected one of the study's DCF variants—the sustainable-growth analysis—as not widely accepted, biased downward, and based on questionable assumptions.

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[56] She used the Company's 30-day DCF results.

The ALJ rejected claims that the return on equity should be reduced to reflect risk reductions attributable to the availability of interim rates, the inclusion of CWIP in rate base, or the use of a future test year, finding that these were routine Minnesota regulatory practices and had therefore already been taken into account by investors. Further, she found that these ratemaking tools were available to many of the utilities in the comparison groups, making investment risks similar.

She rejected the claim that revenue decoupling would necessitate a reduction in the cost of equity, for three reasons. First, many of the companies in the comparison group had decoupling rate designs, demonstrating the similarity in investment risk required for a reliable DCF analysis.

Second, the record contained a study by a national research and consulting group showing "no significant evidence of a decrease in the cost of capital following adoption of decoupling."[57] And finally, the Company's cost-of-equity expert witness provided a detailed analysis of a representative company's extensive and long-term experience with decoupling, which demonstrated that decoupling had no measurable impact on its cost of capital.[58]

E. Commission Action

1. Introduction

As explained below, the Commission will set the cost of equity at 9.72%, the midpoint of the Department's updated DCF results for its electric-utility comparison group.

The Commission concurs with the Administrative Law Judge that the Company's and the Department's cost-of-equity studies are methodologically transparent, analytically sound, and ably executed. Together they represent the best evidence in the record on the cost of equity and provide a workable framework for determining where to set the cost of equity in this case.

As the ALJ pointed out, the main differences between the two parties' DCF analyses were the time period used to determine the dividend-yield input and the relative weight given the DCF results of the electric-utility and combined-utility comparison groups. On the first issue, the ALJ accepted the Company's proposal to average data from more than one 30-day period over the Department's proposal to average data from the most recent 30-day trading period; on the second issue she accepted the Department's 60/40 ratio over the Company's 80/20 ratio.

The Commission does not concur with the ALJ on these two issues and will not accept all her findings, conclusions, and recommendations on them. The Commission will instead base the cost of equity on investment data from the most recent 30-day period in the record and will use data from the electric-utility comparison group only. These determinations yield a return on equity of 9.72%.

On all other issues the Commission accepts and adopts the findings, conclusions, and recommendations of the Administrative Law Judge. These determinations are further explained below.

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[57] ALJ's Report ¶ 389.

[58] *Id.*

2. Time Period for Averaging Data to Update DCF Analysis

The Department made the final update to its DCF analysis using averaged data from the most recent 30-day trading period for which investment data was available. The Company made its final update using averaged data from the most recent 30-day, 90-day, and 180-day trading periods for which investment data was available. The Administrative Law Judge concurred in the Company's multi-period averaging approach.

She found that, although the most recent 30-day trading period was normally the best reflection of the current market expectations used to set the cost of equity,[59] in this case abnormally high stock prices during that period made longer-period averaging a better choice:

> In this case, however, the Administrative Law Judge concludes that the record shows that the 30-day period used in the Department's Surrebuttal testimony may not be representative of the time period in which the ROE will remain in effect. More specifically, the record shows that the dividend yields used in the Department's Surrebuttal Testimony were significantly lower than the dividend yields used in its Direct Testimony, falling by 54 and 26 basis points, respectively, from the Department's initial analysis. These decreased dividend yields were the result of unusually high stock prices during the June-July 2014 time period used in the Department's Surrebuttal Testimony. Since that time, utility stock prices have declined relative to the overall stock market and moved more in line with historic expectations. As a result, the Department's updated 30-day dividend yields included in its Surrebuttal Testimony may reflect a short-term anomaly.[60]

She therefore averaged the DCF results in the Department's direct testimony, the Company's rebuttal testimony, and the Department's surrebuttal testimony—each representing a different 30-day trading period—yielding a cost of equity of 9.77%. She concluded that this number not only corrected for the abnormally high stock prices that had skewed the Department's updated DCF results, but (a) was more reasonable in light of the extended time period the rates would be in effect under the multiyear rate plan, and (b) would facilitate the Company's access to capital on favorable terms by avoiding the potentially negative signal the lower cost of equity proposed by the Department could send to investors.

The Commission disagrees on all three counts.

a. Multiple-Period Averaging Rejected

First and most important, there is no support in the record for the finding that stock prices were unusually high during the June 7–July 7 trading period, nor for the finding that utility stock prices declined relative to the overall stock market between that period and the December 26 filing of the Administrative Law Judge's Report.

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[59] *Id.* ¶ 380.

[60] *Id.* ¶ 382 (citations omitted).

These are factual claims for which the Administrative Law Judge cites only the Opening Statement made at the evidentiary hearing by the Company's cost-of-equity witness. That Statement neither contains nor points to any hard data or technical analysis purporting to prove these claims; it simply states them as if they were common knowledge.

As the Department pointed out in its briefs and exceptions, however, neither claim is common knowledge, and neither claim can be proved by expert testimony without supporting facts and analysis. Further, the Department contested both claims on the merits, with as much record support as the Company. Since there is no reliable evidence that the trading period used in the Department's updated DCF analysis is aberrant and no reliable evidence of a need to average data from multiple trading periods, the Commission rejects finding 382 as unsupported in the record.[61]

That leaves in place the ALJ's finding that the most recent information is normally the most reliable indicator of the current market expectations on which the cost of equity is based.[62] This finding is a restatement of the basic financial principle, followed by the Department, that financial markets are efficient such that the current stock prices fully reflect all publicly available information and are therefore the most reliable source of information on investor expectations. This finding is also consistent with longstanding Minnesota practice.

The Commission concurs and will base its cost of equity on the most recent information in the record, the Department's final DCF analysis.[63]

b. Secondary Rationales Rejected

The Commission also rejects the secondary rationales that the ALJ found supported the higher return resulting from multiple-period averaging—the 9.77% average return granted in other rate cases in other states, the need to demonstrate strong regulatory support for Xcel to facilitate access to capital on favorable terms, and the need to hedge against the possibility of the cost of equity being too low as the term of the multiyear rate plan wears on.

As to the first issue, the Commission sees little probative value in the four 2014 cost-of-equity decisions in other states cited by the ALJ, since these decisions were by definition specific to the circumstances of individual utilities, their service areas, and then-prevailing economic conditions.

As to the second issue, the Commission remains persuaded that utility investors are prudent and sophisticated investors who value regulatory stability, predictability, and integrity above specific

[61] In its reply brief and exceptions the Department also pointed to hard data from publicly available sources that it argued demonstrated that both claims were factually wrong. The Company did not object to these submissions, but they are not in the evidentiary record and have not been subject to analysis and cross-examination by other parties. *See* Reply Brief of the Department at 6–8; Exceptions at 8–14.

[62] ALJ's Report ¶ 380.

[63] The Company and the ALJ note that the Commission has on rare occasions averaged more than one trading period to smooth final DCF outcomes, most notably in the last MERC rate case. *In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-011/GR-13-617, Findings of Fact, Conclusions, and Order (October 28, 2014). They are correct, but that decision, like all rate-case decisions, was fact-specific and based on that gas utility's unique operational and financial situation, as well as the state of the economy at the time of the determination.

outcomes. The 9.72% return on equity reflects the assiduous application of sound economic models and accepted regulatory and legal principles to a solid evidentiary record; this is a signal of strong regulatory support for Xcel and other Minnesota utilities.

As to the third issue, the Commission concurs with the Department that the Company chose to file a multiyear rate plan and can therefore be presumed to have found it in its best interests. Further, there is no good evidence, analytical or factual, on the impact of multiyear rate plans on rates of return. The Commercial Group argued that the multiyear rate plan, with its guaranteed second-year rate increase, reduced Xcel's investment risk and should therefore reduce its return on equity.[64] The Department argued that rates of return were equally likely to go up or down during the term of the rate plan.[65]

Finally, in its Multiyear Rate Plan Order, the Commission found that the rate of return would be set on the basis of test-year data and applied throughout the term of the multiyear plan; no other approach had evidentiary support or even appeared to be practicable.[66] For all these reasons, the Commission concludes that it is not reasonable to treat the multiyear rate plan as a factor requiring a higher return on equity.

3. Weighting the Electric-Utility and Combined-Utility Comparison Groups

Both Xcel and the Department used two comparison groups, one of electric utilities and one of combined gas-and-electric utilities. The Department weighted the DCF results of the two groups 60/40 electric group/combined group; the Company weighted them 80/20 electric group/combined group.

The Administrative Law Judge accepted the 60/40 weighting recommended by the Department, for three reasons: (1) it was consistent with past practice, (2) the critical element to ensure a valid comparison group is similar investment risk—which the record demonstrated—not similar operations, and (3) Xcel's parent company has subsidiaries with both gas and electric operations.

The Commission will base its return on equity on the Department's DCF results for its electric comparison group, finding that that comparison group most closely matches the Company's situation. As stated earlier, the Company derives 91.67% of its net income from electric operations and 8.33% from gas operations;[67] The Department's electric comparison group on average derived 90% of its net income from electric operations, while the comparable number for its combined group was only 78.39%.

Since the electric group, like the combined group, was carefully screened for investment risk similar to Xcel's—comparing factors such as volatility of rates of return, common-equity ratios, long-term debt ratios, and bond ratings—it is clearly a valid comparison group. And since it more closely resembles Xcel in the significant category of operational profile, it is a better match for analytical purposes.

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[64] Initial Brief of Commercial Group at 9.

[65] Reply Brief of Department at 8; Exceptions at 13.

[66] Docket No. E,G-999/M-12-587.

[67] Ex. 28 (Hevert Rebuttal) at 19.

The fact that Xcel's parent company holds other subsidiaries with combined gas and electric operations does not affect this determination, since there is no evidence in the record that the operational profiles of these other subsidiaries have any effect on Xcel's investment risk. And past practice is not determinative; not only is the issue of Xcel's past investment risk vis-à-vis other combined utilities not developed in this record, but past practice must and should yield to current realities.

The Commission will therefore use the Department's electric comparison group in setting the Company's cost of equity in this case.

4. Conclusion

For all these reasons, the Commission will set the cost of equity at 9.72%, the midpoint of the Department's updated DCF results for its electric-utility comparison group.

XXVII. Capital Structure and Overall Cost of Capital

The Company and the Department agreed on the Company's capital structure for both the 2014 test year and the 2015 Step. The ICI Group initially argued that the equity component of the Company's capital structure should be the same as the equity component of its parent company, Xcel Energy, Inc., but it did not ultimately include that claim among the modifications it recommended to the ALJ's recommendations.[68]

The Company and the Department agreed on the cost of long- and short-term debt for both the 2014 test year and the 2015 Step; no other party commented. The Administrative Law Judge concurred in the Department and the Company's joint recommendation on both capital structure and the cost of debt, as does the Commission.

The Company, the Department, the ICI Group, the Commercial Group, and AARP disagreed on the cost of common equity. As explained above, the Commission has set the cost of equity at 9.72%.

The resulting overall capital structure and cost of capital are set forth below, rounded to the second decimal place:

2014 Test Year

Component	Component Ratio	Cost	Weighted Cost
Long-term Debt	45.6%	4.90%	2.23%
Short-term Debt	1.9%	0.62%	0.01%
Common Equity	52.5%	9.72%	5.10%
Total	100%		7.35%

[68] ICI Exceptions at 41–42.

2015 Step

Component	Component Ratio	Cost	Weighted Cost
Long-term Debt	45.61%	4.94%	2.25%
Short-term Debt	1.89%	1.12%	0.02%
Common Equity	52.5%	9.72%	5.10%
Total	100%		7.38%

CLASS COST OF SERVICE STUDY ISSUES

XXVIII. Class-Cost-of-Service Study

A. Background

As required by rule, the Company's rate-case filing included class-cost-of-service studies for the 2014 test year and the 2015 Step.[69] The 2015 study reflects an additional $98.4 million in revenue requirements for the 2015-Step increase.

The purpose of a class-cost-of-service study is to determine, as accurately as possible, the costs of serving each customer class. While these costs cannot be determined with precision, it is critical that the study make both its underlying assumptions and the cost figures they yield as accurate and transparent as possible, because the Commission puts substantial weight on cost causation in determining what portion of the total revenue requirement each customer class should pay.

Parties challenged various aspects of Xcel's studies: (1) the classification of the fixed costs of the Company's production plant, (2) the classification of the fixed costs of certain Company-owned wind farms, (3) the allocation of capacity costs among customer classes, (4) the classification of certain nonfuel O&M costs, and (5) the allocation of distribution costs.

Each challenge is addressed below.

B. Classifying Fixed Production Plant

1. Introduction

Xcel divided its fixed production-plant costs into capacity-related and energy-related subfunctions using a process called the "plant stratification method." The Company has used this method to classify fixed production-plant costs since the 1970s.

Under the plant-stratification method, Xcel compares the per-kilowatt (kW) cost of each plant type to the per-kW cost of a peaking plant to calculate a capacity and energy percentage for each plant type:

[69] *See* Minn. R. 7825.4300(C).

Stratification Allocation by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	$770	$770 / $770	100.0%	0.0%
Nuclear	$3,689	$770 / $3,689	20.9%	79.1%
Fossil	$1,976	$770 / $1,976	39.0%	61.0%
Combined Cycle	$1,020	$770 / $1,020	75.4%	24.6%
Hydro	$4,519	$770 / $4,519	17.0%	83.0%

Peaking plants have the lowest capital cost to build but also the highest operating costs. They are therefore used only to meet customer demand at peak times, and their capital cost is assumed to be entirely capacity-related. Per-kW costs that exceed that of a peaking plant are assumed to be energy-related.

After classifying its fixed production-plant costs as capacity- or energy-related, Xcel allocates the costs of the two subfunctions among its customer classes based on the percentage of capacity or energy costs caused by each class.

2. Positions of the Parties

The Chamber recommended that the Company classify fixed production plant using the "straight fixed–variable method." Under the straight fixed–variable method, all fixed production-plant costs are classified as demand-related on the theory that plant capacity is required to meet peak demand. Only variable costs such as fuel are classified as energy-related. The Chamber argued that the straight fixed–variable method should be used based on its view that high-volume energy users are allocated more than their fair share of costs under the plant-stratification method.

The Department disagreed with the Chamber's recommendation, arguing that the plant-stratification method properly reflects the dual value of baseload plants, which provide both capacity and low-cost energy. The Department noted that the Commission chose not to approve this same proposal by the Chamber in Xcel's last rate case.

XLI did not oppose the plant-stratification method but recommended two modifications. Under the plant-stratification method, Xcel compares the current-dollar replacement value of a peaking plant with the current-dollar replacement cost of the other plant types to calculate capacity and energy allocations for each type. XLI argued that Xcel's approach understates the capacity portion of the Company's fixed plant. To correct this, XLI recommended that Xcel use (1) the estimated cost of a new peaking plant instead of its current-dollar replacement value and (2) depreciated replacement values for the other plant types instead of current-dollar replacement values.

Xcel, the Department, and the OAG opposed XLI's modifications to the plant-stratification method. Xcel argued that XLI's approach would result in an apples-to-oranges comparison by mixing the undepreciated costs of a new peaking plant with the depreciated replacement values for the other plant types. The Company maintained that the replacement cost of a peaking plant, not the cost of a new peaking plant, is the relevant cost for study purposes.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge noted that the Commission has consistently approved the plant-stratification method and concluded that the Chamber had offered no new convincing argument for the straight fixed–variable method or addressed the need to recognize the dual nature of baseload plants. The ALJ concluded that Xcel's use of the plant-stratification method was reasonable.

As to XLI's proposal, the ALJ agreed with the other parties that comparing the cost of a new peaking plant to the depreciated value of other types of generating plants is not analytically sound.

4. Commission Action

The Commission concurs with the ALJ and adopts her conclusion that Xcel's continued use of the plant-stratification method is reasonable.

The Company's method, unlike the straight fixed–variable method advanced by the Chamber, appropriately reflects the fact that Xcel builds baseload plants to meet both demand and energy needs. If Xcel acquired production plants only to meet peak demand at the lowest cost, the Company would be building only peaking plants with the lowest cost per unit of capacity. Instead, Xcel selects a mix of generation facilities with varying capital costs to achieve the dual goals of sufficient capacity and viable energy costs.

Moreover, the Company's method makes appropriate comparisons between the current-dollar replacement cost for a peaking plant and current-dollar replacement costs for other plant types. For this reason, the Commission declines to adopt XLI's recommendation to use (1) the undepreciated cost of a new peaking plant and (2) depreciated replacement costs for other plant types.

C. Classifying the Fixed Costs of Company-Owned Wind Farms

1. Introduction

Xcel included in its class-cost-of-service studies four wind farms that it owns: (1) Grand Meadow, (2) Nobles, (3) Pleasant Valley, and (4) Border Winds.

Grand Meadow and Nobles are older projects that were included in Xcel's last rate case; Pleasant Valley and Border Winds are new projects that are expected to be online by the end of 2015. Accordingly, Grand Meadow and Nobles are included in both class-cost-of-service studies, while Pleasant Valley and Border Winds are only included in the study for the 2015 Step.

In its last rate case, Xcel classified Grand Meadow and Nobles costs on the same basis as its other fixed production-plant costs, using the plant-stratification method. As a result, the two plants were classified as roughly 4–5% capacity-related and 95–96% energy-related. In this case, however, the Company changed its analysis for Grand Meadow and Nobles, classifying the two facilities as 100% capacity-related.

Xcel applied the usual plant-stratification method to Pleasant Valley and Border Winds.

2. Positions of the Parties

Xcel argued that the change in classification methodology for Grand Meadow and Nobles is appropriate because these plants do not fit the resource-selection model that the plant-stratification method is designed to reflect. Specifically, Xcel stated that it added Grand Meadow and Nobles to comply with the Renewable Energy Standard,[70] not to cost-effectively meet energy or capacity needs. By contrast, Pleasant Valley and Border Winds were acquired to minimize system costs, consistent with how other fixed production plant is added to the system.

XLI and the Chamber supported Xcel's approach to classifying Grand Meadow and Nobles. Alternatively, the Chamber advocated that the Nobles and Grand Meadow costs be classified using the "percent of base revenue" method.

The Department opposed Xcel's change in treatment of Nobles and Grand Meadow costs and recommended that the Company continue to classify all its proprietary wind generation using the plant-stratification method. The Department argued that it was inappropriate to classify wind facilities as 100% capacity-related, since such facilities can only generate electricity when the wind blows and thus cannot be counted upon to provide capacity at times of peak demand.

The OAG also disagreed with Xcel's proposed classification of Grand Meadow and Nobles as 100% capacity-related. It recommended that the Company instead classify the costs of those facilities as 100% energy-related. In support of its position, the OAG noted that the Renewable Energy Standard measures compliance in terms of "total retail electric sales" (i.e., energy) and not in terms of installed capacity. The OAG, however, stated that it would also support continued use of the plant-stratification method for these wind facilities.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Xcel had not demonstrated that the Grand Meadow and Nobles facilities should be classified as 100% capacity-related. She reasoned that the fact that these facilities were built to satisfy a legislative mandate does not change their operational characteristics and therefore does not provide a basis for classifying them as 100% capacity-related. For similar reasons, the ALJ rejected the OAG's recommendation to classify Grand Meadow and Nobles as 100% energy-related.

The ALJ recommended that the Commission require Xcel to modify its 2014 and 2015 class-cost-of-service studies to classify the costs of Grand Meadow and Nobles on the same basis as its other fixed production-plant costs.

4. Commission Action

The Commission concurs with the Administrative Law Judge and adopts her findings and recommendation.

The Commission finds that the plant-stratification method is appropriate for classifying and allocating Xcel's production plant, including the costs of wind facilities acquired to satisfy the Renewable Energy Standard. State policy undoubtedly encourages the development of renewable

[70] Minn. Stat. § 216B.1691.

resources as part of electric utilities' generation portfolios. However, it does not necessarily follow that those resources are not least-cost. Nor does that appear to be the case here, since Xcel has acknowledged that Nobles and Grand Meadow were economical when acquired.

Moreover, regardless of why a wind farm is added to the Company's system, the fact remains that such a resource produces little capacity. The plant-stratification method results in a cost allocation that closely matches this reality. Thus, that method continues to be the most reasonable alternative for classifying the fixed costs of wind generation. The Commission will therefore require Xcel to modify its 2014 and 2015 class-cost-of-service studies to classify the costs of the Grand Meadow and Nobles wind farms using the plant-stratification method.

D. D10S Capacity Allocator

1. Introduction

Once fixed production-plant costs are split into capacity and energy subfunctions, those costs must then be allocated to the different customer classes. In its class-cost-of-service studies, Xcel allocated capacity-related costs to the various customer classes based on each class's contribution to the Company's summer peak demand. Xcel's summer-peak-based allocator is called the D10S Capacity Allocator.

To ensure reliability when one or more plants fail, Xcel must have extra generation available to provide a capacity cushion above the level needed to meet peak demand. This cushion is known as a "planning reserve margin" and is set by the Midcontinent Independent System Operator, Inc. (MISO), which operates the Midwestern transmission system. MISO requires that a utility's planning reserve margin be set based on the utility's load at the time of MISO's system peak, which is in the summer.

Xcel believes its D10S summer-peak-based allocator is consistent with cost causation because it reflects the fact that the Company must plan for MISO's summer peak.

2. Positions of the Parties

The OAG argued that Xcel's method of demand allocation does not align with cost causation because the Company's system peaks on a different day and at a different time of day than MISO's system. In other words, the D10S allocator does not reflect each customer class's contribution to Xcel's system load at the time of the peak for which the Company must plan—MISO's. The OAG recommended that Xcel be required to calculate its D10S allocator using each class's demand that coincides with MISO's peak, rather than the Company's peak.

Xcel agreed that aligning the D10S allocator with MISO's peak would accurately reflect cost causation. However, the Company stated that it cannot calculate its capacity allocator using MISO's peak because MISO does not produce a forecast of its hourly loads for a test year.

The OAG recommended that the Commission require Xcel to collect the data necessary to perform the allocation. However, the OAG's witness acknowledged that he was "unaware of the data that is currently available or could be acquired in the future" to support the calculation.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that, while the OAG had raised a noteworthy issue, it had not developed a sufficient record in this case to support its recommendation.

4. Commission Action

The Commission concurs with the ALJ that the record in this case does not contain the data needed to calculate a capacity allocator based on MISO's system peak, and it adopts her conclusion to that effect.

However, the Commission also agrees that the OAG has raised an important issue. Calculating a capacity allocator based on each customer class's contribution to Xcel's system load coincident with MISO's system peak would better reflect each class's share of the costs of meeting MISO's planning reserve margin. For the Company's next rate case, the Commission encourages Xcel to work with MISO and other parties to recalculate the D10S Capacity Allocator on the basis of MISO's peak for purposes of comparison with Xcel's peak.

E. Classifying Other Production Operation and Maintenance (O&M) Costs

1. Introduction

An electric utility incurs certain costs in operating a power plant for items other than fuel, such as labor, chemicals, information technology, maintenance, and licensing. These costs are referred to as "other production O&M costs." In this case, as in past rate cases, parties disagreed about the best method for classifying these costs as capacity- or energy-related.

Three different classification methods are relevant to this issue: (1) the overall-investment method, (2) the location method, and (3) the predominant-nature method.

Under the overall-investment method, other production O&M costs are classified as capacity- or energy-related in the same proportions as the plant where they were incurred.

Xcel used the overall-investment method in its last rate case. In that case, the Commission approved Xcel's use of the overall-investment method but required the Company to refine the method in its next rate case. Xcel calls this refined analysis the "location method."

Under the location method, other O&M costs are first reviewed to identify any costs that vary directly with the amount of energy produced. These costs are classified as energy-related and are allocated to the various customer classes using appropriate energy allocators. The remainder of the other production O&M costs are classified as capacity- or energy-related in the same proportion as the plant where they were incurred.

Xcel did not use the location method in its class-cost-of-service studies in this case. Instead, the Company used a method it called the "predominant nature method."

The predominant-nature method is similar to the first step of the location method. However, the predominant-nature method extends the analysis by classifying *all* nonfuel production O&M costs according to their "predominant" nature. If a particular item is determined to be predominantly a fixed expense, its cost is allocated to capacity; if an item is predominantly a variable expense, it is allocated to energy.

The table below shows the allocations that result when each method is applied to Xcel's other production O&M costs:

Method	Capacity Related	Energy Related
Overall investment	25.0%	75.0%
Location	35.0%	65.0%
Predominant nature	78.4%	21.6%

2. Positions of the Parties

The Chamber and XLI supported the Company's use of the predominant-nature method. These parties characterized the predominant-nature method as both more refined and more commonly used than the other methods.

The Department and the OAG, however, recommended that Xcel use the location method instead of the predominant-nature method in its class-cost-of-service studies. These parties argued that Xcel's use of the predominant-nature method was inconsistent with the Commission's order in the last rate case, which required the Company to use the location method. They also cited the Commission's and the Company's past preference for the overall-investment method rather than using a strict fixed/variable distinction to assign costs to demand and energy.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that Xcel did not show that classifying other production O&M costs based on their predominant nature moves the resulting allocation closer to cost. She found that the location method was the most reasonable method in the record of classifying other production O&M costs and recommended that the Commission require the Company to modify its class-cost-of-service studies to use this method.

4. Commission Action

The Commission concurs with the ALJ and adopts her findings and recommendation.

Classifying as energy-related any costs that vary directly with the amount of energy produced at a plant, as the Commission has ordered Xcel to do, clearly moves the resulting allocation closer to cost. However, it is not evident that classifying each O&M category as energy- or capacity-related based on whether the category is predominantly variable or fixed results in an accurate energy/capacity allocation.

A number of O&M expenses do not fit neatly into this binary distinction between fixed and variable costs. For example, Xcel classified both employee and contract labor as fixed costs and allocated them to capacity. However, labor costs are likely to increase somewhat as a plant's energy production increases and decrease somewhat when production decreases.

Moreover, the predominant-nature method fails to account for the fact that Xcel builds baseload plants to meet both demand and energy needs. The location method appropriately accounts for this fact by allocating nonfuel O&M costs, other than those that vary directly with the amount of energy produced, to the capacity and energy subfunctions based on the underlying allocation of fixed plant costs.

For the foregoing reasons, the Commission will require Xcel to modify its 2014 and 2015 class-cost-of-service studies to use the location method to allocate other production O&M costs. Further, in its next rate case, the Company should continue using the location method to allocate these costs. It should also explain each allocation method used in its class-cost-of-service study, as more fully detailed in the ordering paragraphs.

F. Allocating Distribution Costs

1. Introduction

Xcel used the "minimum size" method, a type of minimum-system study, to separate the costs of its primary lines, secondary lines, secondary transformers, and service drops into customer-related and capacity-related components.

Under the minimum-size method, a utility compares the cost of the minimum size of each type of component used in its distribution system to the actual cost of the facilities installed. The cost of the minimum-size facilities is the customer-related component, and the capacity-related component is the difference between the total installed cost and the minimum-size cost.

The theory of minimum-system analysis is that any distribution system larger than the minimum required to allow a customer to receive service (the customer cost) has been installed to allow the utility to meet demand.

2. Positions of the Parties

The OAG argued that Xcel's minimum-size analysis likely overstates the customer-related costs of its distribution system. The OAG pointed out several methodological flaws in Xcel's study, including a lack of clear criteria for what constitutes "minimum sized" equipment and outdated cost data for the Company's distribution components. Moreover, the OAG argued that a zero-intercept study, which uses regression analysis to estimate the cost of a hypothetical no-load distribution system, would yield a more accurate allocation of customer- and capacity-related distribution costs.

The OAG recommended that Xcel be required to conduct a zero-intercept analysis in its next rate case and to provide sufficient data for a minimum-size analysis. Also, based on its view that the Company's study overstated customer costs, the OAG recommended that Xcel be required to allocate 10% more distribution costs as capacity costs and 10% less as customer costs in this case.

Xcel defended the accuracy of its minimum-size study and argued that the OAG's proposed 10% adjustment is based on one minimum-size component whose cost was overstated but ignores other components whose cost was understated. Xcel stated that it did not object to the OAG's recommendation to conduct a zero-intercept analysis in the next rate case, provided that the Company is able to compile the detailed property records necessary for the analysis.

3. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission require Xcel to file a zero-intercept analysis of distribution costs in its next rate case, as well as a minimum-size analysis. The ALJ concluded that requiring the Company to improve its minimum-system analysis in the next rate case was preferable to adjusting distribution costs by 10% in this case.

4. Commission Action

The Commission concurs with the Administrative Law Judge and adopts her findings and recommendation.

The OAG has raised valid concerns regarding the value of the data Xcel used to support its minimum-system study. The Company last estimated the average cost of its minimum distribution equipment in 1991 and has since simply adjusted this cost yearly for inflation. Moreover, the minimum-size method may produce a larger customer-cost allocation than the more rigorous zero-intercept analysis. A zero-intercept analysis will serve as a valuable cross-check of Xcel's minimum-size analysis.

For the foregoing reasons, the Commission will require Xcel, in its next rate case, to provide the parties with data sufficient to verify and reproduce its minimum-system study and to file a zero-intercept analysis of distribution costs, or explain why it was not able to collect the data necessary to do so.

RATE DESIGN ISSUES

XXIX. Implementation of a Decoupling Mechanism: Introduction

A. Xcel's proposal

Xcel asked the Commission to authorize a three-year pilot program implementing a revenue decoupling mechanism (RDM) for three customer groups: residential customers with electric space heating,[71] residential customers without electric space heating,[72] and small business customers who do not pay a demand charge.[73] This would make Xcel the first electric utility in Minnesota to adopt a revenue decoupling mechanism.

Under Xcel's proposal, the Company would calculate each customer group's revenue requirement excluding fuel-related revenues and fixed customer charges, divided by the number of customers in the group. At the end of each calendar year, Xcel would compare this per-customer revenue requirement to the average revenues it derived per customer within each group (adjusted to reflect normal weather patterns), and adjust rates in the following year to true-up the difference.

[71] This would include customers served on rate codes A00, A01, A02, A03, A04, A05, and A06.

[72] This would include customers served on rate codes A01, A02, A03, A04, A05, and A06.

[73] This would include customers served on rate codes A05, A06 1S, A06 3S, A06 P, A09, A10, A11, A12, A16, A18, and A22.

Xcel proposed two limitations on any upward rate adjustment. First, in any year in which Xcel failed to achieve 1.2% in energy savings, the Company would forgo the opportunity to increase rates in the following year. Second, Xcel would adopt a 5% "soft cap" on any rate increase; any sums excluded from recovery by the cap would be deferred for recovery in the following year's adjustment. If the Commission were to modify Xcel's proposal to eliminate the weather adjustments, Xcel would propose increasing the soft cap to 10%.

B. Summary of Commission Action

In summary, the Commission will approve Xcel's proposal with modifications. In reaching this conclusion, the Commission makes the following findings.

First, Xcel has justified implementing a revenue decoupling mechanism for the customer groups in question, at least on a trial basis, with the following additions.

- *Customer education*: Xcel must file a plan to implement an education and outreach program for its customers explaining the goals and operations of its RDM program.
- *Start of energy-consumption measurement*: Xcel may begin calculating its over- or under-recovery of costs after the final compliance order authorizing implementation of final rates in this proceeding, but not before new rates take effect, and no sooner than January 1, 2016.
- *Annual report*: In the annual report Xcel proposes to file regarding its experience with the RDM, Xcel must include descriptions of factors other than the RDM that might have contributed to any change in conservation levels.

Second, the Commission will direct Xcel to implement a full decoupling mechanism (omitting weather normalization) rather than a partial decoupling (adjusting data to compensate for abnormal weather).

Third, the Commission will direct Xcel to cap any upward rate adjustment to 3% of the customer group's revenues, excluding revenues from the fuel clause or other riders. Where the cap prevents Xcel from fully recovering its deferred costs, the Commission will permit the Company to petition to recover these costs via the following year's adjustment. However, Xcel must first demonstrate that its demand-side-management programs and other company initiatives were a substantial contributing factor to the declining energy sales triggering the rate adjustment, and that other nonconservation factors were not the primary factors for the declining sales.

Fourth, the Commission will decline ECC's proposal to calculate adjustments based on average customer revenues including customer charges. Rather, the Commission will approve Xcel's proposal to exclude customer charges from the adjustment calculation.

These decisions will be discussed more fully below.

XXX. Implementation of a Decoupling Mechanism: General Objections

A. Introduction

Before addressing concerns about specific provisions in Xcel's revenue decoupling proposal, some parties stated an opposition to revenue decoupling in general.

B. Positions of the Parties

Decoupling was opposed on principle by AARP, the ICI Group, and the OAG. In contrast, decoupling was defended in principle by the Clean Energy Intervenors (CEI), the Department, ECC, and Xcel.

For example, AARP argued that decoupling would reduce a customer's incentive to conserve because reductions in sales today would trigger upward rate adjustments in the future. Xcel argued that these concerns were overstated: A customer who conserves a kilowatt-hour (kWh) reduces his bill by the price of one kWh immediately. The rate adjustment triggered by the customer's actions would be spread throughout the customer's class, and over 12 months. As an incentive to conserve, the magnitude and immediacy of reducing a bill would overwhelm the small, attenuated rate adjustment arising roughly a year later.

AARP and the OAG challenged Xcel's choice to propose its RDM only for its smallest customers, not for Xcel's large industrial customers that consume most of the Company's energy. Xcel explained that each kWh charged to a residential or small business customer contains a higher percentage of fixed (nonfuel) costs than a kWh charged to a large commercial and industrial customer, and the rate adjustments are designed to recover these costs. Xcel argued that it makes sense to initiate a pilot RDM program where the program could have the largest effect per kWh.

On the other hand, the ICI Group objected that Xcel's proposal fails to give enough emphasis to the distinctions among customer groups. The ICI Group asks the Commission to remedy this oversight by ruling that Xcel must never seek to apply a revenue decoupling mechanism to large commercial and industrial customers.

AARP and the OAG argued that revenue decoupling would impose disproportionate burdens on customers who consume the least energy. But Xcel analyzed how its RDM would affect customers in a variety of circumstances, and demonstrated that even customers with relatively low usage could be held harmless, or even benefit, from this rate design.[74]

AARP, the ICI Group, and the OAG argued that decoupling would not increase Xcel's implementation of conservation programs because the Company already has sufficient mandates and incentives to implement conservation programs. They objected that Xcel never proposed to track whether any additional savings would in fact result from its RDM. In response, Xcel argued that the Legislature has not treated conservation/efficiency programs and revenue decoupling as substitutes, but as complements.

Finally, AARP and the OAG argued that decoupling is complicated and will confuse customers. They claimed that Xcel has not developed a strategy for educating customers about this new rate design, or for managing the resulting confusion.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that it is reasonable for the Commission to implement revenue decoupling in this rate case. The ALJ found that revenue decoupling can remove a utility's disincentives to

[74] Ex. 111 (Hansen Surrebuttal) at 7–11.

promote energy efficiency and conservation without adversely affecting ratepayers. Moreover, while Xcel has been meeting its energy efficiency goals, the ALJ found that the Company had persuasively argued that meeting these goals would become more difficult in the future. Finally, the ALJ concluded that the record did not support a conclusion that decoupling would inevitably cause customer confusion.

Xcel expressly supported the ALJ's decoupling recommendation. CEI and the Department supported the ALJ's Report generally. In contrast, AARP, the ICI Group, and the OAG each opposed the ALJ's recommendation for the reasons previously stated.

D. Commission Action

1. Support for Revenue Decoupling

The Commission concurs with the ALJ that revenue decoupling has substantial potential to align the Company's interests with the public's interest in conservation and energy efficiency.

Based on the evidence in the record, the Commission finds insufficient support for the proposition that revenue decoupling would create systemic disadvantages for any customer group, or any specific type of customer. Ultimately Xcel's proposed mechanism is well designed to enable Xcel to recover its revenue requirement—no more and no less. Xcel will benefit from this type of assurance, and so will ratepayers.

Additionally, the Commission concludes that Xcel has articulated a reasoned basis to initially limit its proposed revenue decoupling mechanism to its residential and small business customers. That said, the Commission will decline the ICI Group's request to declare that Xcel may never implement revenue decoupling for its large energy group; as a general practice the Commission refrains from offering advisory opinions on proposals not yet submitted.

While the objecting parties have not persuaded the Commission to reject revenue decoupling, they have identified room for improvement in Xcel's proposal.

2. Reporting

Xcel stated that it proposed its RDM to remove disincentives for the promotion of conservation and energy efficiency, but AARP and the OAG objected to Xcel's failure to propose measuring the additional conservation that would result from the RDM.

The change in the amount of the electricity consumed can be measured directly; in contrast, whether revenue decoupling *caused* the change can only be inferred. This inference requires consideration of all other potential causes and an examination of the relevant data.

In establishing criteria for revenue decoupling proposals, the Commission directed each utility implementing an RDM to report data on its experiences annually.[75] Consistent with this requirement, Xcel has agreed to make an annual report including the following information:

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[75] *In the Matter of a Commission Investigation into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues*, Docket No. E,G-999/CI-08-132, Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling at 8–9 (June 19, 2009).

1) Total over- or under-collection of allowed revenues by customer class or group.

2) Total collection of prior deferred revenue.

3) Calculations of the RDM deferral amounts.

4) The number of customer complaints.

5) The amount of revenues stabilized and how the stabilization impacted Xcel's overall risk profile.

6) A comparison of how revenues under traditional regulation would have differed from those collected under partial and full decoupling.[76]

The Commission finds this reporting proposal reasonable and will accept it.

But in addition, an analysis of the effectiveness of Xcel's RDM would be aided by information about other circumstances that might have caused sales to the relevant customer groups to differ from forecasted sales. To this end, the Commission will direct Xcel to include the following supplementary information in its annual report:

7) A description of all new and existing demand-side-management programs and other conservation initiatives Xcel had in effect for the year covered by the report.

8) A description of the effectiveness of all new and existing demand-side-management programs and other conservation initiatives Xcel had in effect for the year covered by the report.

9) Other factors that may have contributed to a decline in energy consumption, including weather and the economy.

Under the RDM, Xcel will gather data on customer sales through the end of the calendar year, then calculate rate adjustments to take effect by April 1 of the following year. The Commission will direct Xcel to file its annual report by February 1, two months before the new rate adjustments take effect.

3. Customer Confusion

The Commission has considered the arguments that Xcel has not developed an adequate strategy for educating customers about this new rate design or for managing potential customer confusion. While the ALJ observes that there is little record evidence of revenue decoupling triggering customer confusion, the Commission finds that parties have raised reasonable concerns. Decoupling is a less familiar method of designing utility rates, and can be easily misunderstood.

To better address this issue, the Commission will direct Xcel to file a plan for implementing an education and outreach program for its customers. Xcel should design this program to convey to members of the relevant customer groups the goals and operations of its revenue decoupling

[76] Ex. 109 (Hansen Direct) at 18–19; Ex. 417 (Davis Direct) at 21.

program. With an appropriate education program, Xcel will be able to address customer questions as they arise, and help customers understand the new rate design's advantages.

Finally, the Commission will add clarity to Xcel's proposal by establishing a start date.

One of Xcel's first steps in implementing revenue decoupling is measuring a baseline customer consumption level to determine how much actual sales differ from forecasted sales. Consumption can vary for many reasons, including price. Xcel will set new rates through the current proceeding, but those rates have not taken effect yet. It would make sense to delay the collection of sales data until the new rates are implemented.

For purposes of calculating the first RDM adjustment, therefore, the Commission will authorize Xcel to begin collecting data on sales that occur after the Commission issues its final compliance order in this docket and the new rates take effect, but in no event sooner than January 1, 2016.

XXXI. Design of Revenue Decoupling Mechanism: Weather-Related Risk

A. Introduction

The weather influences the amount of energy an electric utility sells: all else being equal, hotter temperatures tend to increase energy sales while cooler temperatures tend to reduce them.

Under traditional rate design, utilities and customers bear this weather-related financial risk. But a revenue decoupling mechanism can be designed to permit all parties to mitigate this risk. That is, it can enable a utility to recover a customer group's nonfuel costs, and limit customer payment of nonfuel costs, to the levels found to be just and reasonable in a rate case regardless of the weather (so-called "full decoupling"). Or the mechanism can be designed to leave the weather-related financial risks with the parties ("partial decoupling").

Parties disagree about whether the Commission should authorize Xcel to pursue full or partial decoupling.

B. Positions of the Parties

1. Partial Decoupling

Xcel proposed a partial decoupling mechanism. The Company justified its proposed decoupling mechanism as a means of removing its disincentives to pursue conservation; avoiding weather-related risks was not part of Xcel's rationale. Also, having limited experience with decoupling, Xcel favors incremental steps—and incrementalism favors leaving weather-related risk with the utility, as occurs with traditional rate design.

2. Full Decoupling

The Department favored full decoupling on the theory that it could lead to cost reductions under some scenarios and that, when combined with Xcel's other incentives to promote conservation and efficiency, decoupling would improve the regulatory environment for promoting conservation. The Department argued that Xcel's proposed pilot program would provide an appropriate opportunity to explore a full-decoupling rate design.

The Department analyzed how full and partial decoupling would have influenced the size of customer bills for the residential and small business customer groups for a ten-year period relative to Xcel's actual rates. The Department's analysis showed that full decoupling would have increased customer bills less than partial decoupling. But the Department acknowledged that these results were influenced by the fact that Xcel experienced warmer-than-average weather during 2009-2013, and potentially by the economic recession.

While the OAG opposed decoupling overall, it favored full decoupling over partial decoupling. In an environment in which current weather may tend to be hotter than the 20-year historical average, the OAG argued that efforts to adjust electric rates for "normal weather" may contain a systematic bias for higher rates.

3. Either Full or Partial Decoupling

CEI stated that it could support either full or partial decoupling.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve a full decoupling mechanism, adjusting Xcel's rates to provide recovery of nonfuel costs from the relevant customer groups regardless of weather. The ALJ noted that either rate design would reduce Xcel's disincentive to promote conservation and efficiency. But the ALJ cited the Department's analysis for the proposition that customers could expect lower rates under a full decoupling regime than under a partial regime, and that partial decoupling could result in customers being overcharged.

Xcel disputed the statement that rate adjustments under partial decoupling could result in customers being overcharged. Xcel acknowledged that during periods of abnormally hot weather, partial decoupling would result in higher customer bills than full decoupling and potentially higher than traditional rates. But Xcel argued that this result would be driven by the unusual weather, not by any error in the rate design. Xcel reanalyzed the Department's study while making adjustments to reflect different weather patterns, and concluded that partial decoupling might produce bills that are higher or lower than bills under full decoupling depending on whether temperatures prove to be higher or lower than normal.

D. Commission Action

The Commission concurs in the Administrative Law Judge's recommendation to authorize the use of a full decoupling mechanism.

Xcel offered two arguments in support of partial decoupling. First, the Company argued that partial revenue decoupling tracks more closely the risk allocation of traditional rate design. But it is unclear that this risk allocation was ever a goal of traditional rate design, rather than simply an incidental result.

Second, Xcel argued that mitigating weather risk was simply irrelevant to the goal of removing disincentives for conservation and efficiency. Yet full revenue decoupling can accomplish both results, and the pursuit of either goal does not compromise the other. CEI's witness, while supporting Xcel's partial-decoupling proposal in this proceeding, acknowledged testifying in support of full decoupling in other proceedings.[77] Indeed, full revenue decoupling is simpler and more transparent than partial decoupling because the annual rate adjustments can be calculated without the need for complicated weather-normalization adjustments.

The OAG argued for one additional benefit of full decoupling: According to the OAG, the average weather conditions over the past 20 years no longer provide a reliable estimate of future weather due to long-term warming trends. If so, then a rate design that depends heavily on estimates of normal weather—including traditional and partially decoupled rate designs—would tend to underestimate the amount of electric energy consumers will demand, resulting in inappropriately high rates. Full decoupling would compensate for any such bias by adjusting future rates to reflect sales that differ from the forecast.

On the other hand, if the OAG's concerns prove to be unwarranted and sales forecasts prove to be accurate or high, revenue decoupling would appropriately adapt to that scenario as well. In other words, full revenue decoupling would provide a means of compensating for inaccuracies in the sales forecast—regardless of the source of the inaccuracies—without adding financial burdens to ratepayers if the sales forecast proves to be accurate.

Because full revenue decoupling is simpler, more transparent, and potentially more beneficial than partial decoupling, the Commission will authorize Xcel to implement a full revenue decoupling rate design for its residential and small business customers.

XXXII. Design of Revenue Decoupling Mechanism: Cap on Potential Rate Increase

A. Introduction

As previously discussed, a decoupling mechanism works by calculating the amount of nonfuel costs a utility has recovered through rates, comparing that sum to the amount the Commission authorized the utility to recover, and adjusting future rates to offset any over- or under-recovery over time.

To guard against the possibility that unforeseen circumstances might cause the adjustment formula to authorize inordinately large rate increases, all parties propose capping the size of the potential increase in any given year. But questions remain about the details of a cap. In particular, when a cap would exclude Xcel from recovering its full amount of nonfuel costs in a given year, should the Company have the opportunity to recover the excess via the following year's adjustment (a "soft cap") or not (a "hard cap")?

B. Positions of the Parties

1. Soft Cap

CEI and Xcel favored a soft cap. That is, whenever the amount of costs to be recovered in any year would cause the adjustment to exceed the capped level, Xcel would increase rates up to the level of the cap and would defer recovery of the remainder to the following year. Xcel argued that a cap provides ratepayers with assurance that the revenue decoupling mechanism could not produce rate swings large enough to provoke rate shock.

[77] Ex. 294 (Cavanagh Rebuttal) at 6.

But a hard cap, CEI and Xcel argued, would undermine the goals of decoupling: It would leave a utility at risk of being unable to fully recover its nonfuel costs if it sells less energy than forecast, thus discouraging the utility from promoting conservation and efficiency. In its review of 25 electric decoupling mechanisms adopted in other states, Xcel found only two that used a hard cap—and most had no cap at all.

If the Commission were to authorize full revenue decoupling, Xcel would propose limiting the size of any upward rate adjustment to no more than 10% of the customer group's revenues, excluding revenues for energy and other riders. If the Commission were to authorize partial revenue decoupling, Xcel would propose a 5% cap. Xcel argues that full decoupling—designed to address fluctuations in the weather as well as other variables—would warrant a larger cap than partial decoupling.

ECI also favored setting a cap as a percentage of a customer group's revenues excluding revenues from riders, but did not advocate a specific cap size.

2. Hard Cap

AARP, the Department, and the OAG favored a hard cap whereby Xcel would forgo recovery of any sums excluded from recovery by the adjustment cap. They noted that the Commission had approved hard caps for other utilities' revenue decoupling mechanism.[78] In contrast, they opposed Xcel's soft-cap proposal. They argued that a soft cap would fail to protect ratepayers from unforeseen circumstances triggering an inordinately large rate adjustment; it would merely spread the cost recovery over a longer period.

AARP, the Department, and the OAG opposed any proposal to set a cap greater than 3% of a customer group's revenues. In particular, they disputed Xcel's claim that full revenue decoupling would warrant a 10% cap. The Department's analysis showed that, if Xcel's standard residential group had operated with full revenue decoupling over the past ten years, the highest adjustment would have been less than 3%.

That said, each of these commenters offered its own rate-cap recommendation.

The Department recommended that the Commission limit any rate increase arising from the RDM to no more than 3% of the customer group's revenues, although the Department recommended that these revenues incorporate adjustments from the fuel clause and other riders. The Department estimated that this cap would limit the size of any decoupling-related rate adjustment to $27 per year for residential customers, and $35 per year for residential customers with electric space heating.

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[78] *See In the Matter of 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 (September 12, 2012); *In the Matter of an Application by CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-13-316, Findings of Fact, Conclusions, and Order (June 9, 2014).

The Department stated that a cap below 3% might provide more protection to ratepayers, but at the utility's expense. The Department argued that a 3% cap reflects a reasonable compromise among competing considerations.

AARP favored setting the hard cap at 2% of customer group revenues, excluding revenues from riders such as the fuel clause.

Finally, the OAG supported capping Xcel's decoupling adjustments at 1% of a customer group's revenues.

C. The Recommendation of the Administrative Law Judge

The ALJ found that the record did not demonstrate that Xcel's soft-cap proposal would appropriately shield ratepayers from unanticipated rate increases that might arise from an unfamiliar rate design. In addition, the ALJ found that the record did not demonstrate the need for a cap of more than 3%. Consequently the ALJ recommended that the Commission modify Xcel's proposed revenue decoupling mechanism as proposed by the Department—that is, to include a 3% hard cap on all revenues, including fuel and applicable riders.

AARP, the OAG, and Xcel each took exception to the ALJ's recommendations, generally reasserting their earlier positions.

D. Commission Action

The Commission concurs with the ALJ and all parties that it would be beneficial to establish a cap on rate increases triggered by the RDM, especially given the Commission's lack of familiarity with applying decoupling to electric utilities. But the parties disagree about whether to select a hard or soft cap, and the appropriate magnitude of the cap.

1. Hard Cap vs. Soft Cap

Both a hard cap and a soft cap could achieve the goal of limiting the RDM's capacity to adjust rates upward in any given year.

Relative to a soft cap, a hard cap would be simpler to explain and administer, and would be expected to result in somewhat lower rates over time.

But because a hard cap would function as a limit on an RDM, it would also limit Xcel's ability to achieve the advantages that a RDM has over traditional rate design. That is, a hard cap would again give Xcel some incentive to promote energy sales, conflicting with state policy and incentives promoting conservation and efficiency. And a hard cap would again put Xcel at risk of losing the opportunity to recover Commission-approved costs for reasons beyond the Company's control, such as unusually cold weather.

Given these competing considerations, the Commission will pursue a middle path. Consistent with a soft cap, the Commission will provide Xcel with the opportunity to recoup costs that the Company was unable to recover during the previous year due to the cap on RDM rate increases. Yet this cost recovery will not be automatic; rather, Xcel will have to petition the Commission for authority to recover these costs. In the petition, Xcel would have to demonstrate that its demand-side-management programs and initiatives were a substantial contributing factor to the declining energy sales that triggered the rate adjustment, and that its declining sales were not driven primarily by factors unrelated to conservation and efficiency.

This modified cap will mitigate some of the adverse consequences of a hard cap while providing assurance that large rate adjustments are in fact tied to the purposes for which the RDM was proposed: the promotion of conservation and efficiency.

2. Magnitude of Cap

The Commission must now establish the magnitude of the cap. Parties have proposed levels ranging from 1% to 10%. Additionally, parties have disagreed about whether the percentage should be applied to all of a customer group's revenues, or should exclude revenues coming from riders such as the fuel clause.

Here, the Commission concurs with the ALJ and the Department that the record does not demonstrate a need for a cap exceeding 3%. The Department's analysis shows that setting the cap above 3% would virtually eliminate the cap for the standard residential customer because RDM rate increases would rarely exceed that level.

But the Commission disagrees with the ALJ and the Department about the merits of calculating the cap on the basis of all of a customer group's revenues, including revenues from riders. Part of the value of a cap is the assurance it provides ratepayers about the potential consequences of this new rate design. Because the magnitude of revenues from the fuel clause and other riders is prone to large fluctuations, the magnitude of a cap calculated on this basis becomes more speculative—that is, it would no longer provide ratepayers with reassurance. The Commission prefers a cap formula that provides a greater degree of clarity.

In summary, the Commission will cap the amount by which the RDM may increase a customer group's rates at 3% of the group's revenues, excluding revenues from the fuel clause and other riders. If the cap precludes Xcel from fully recovering its nonfuel costs through the RDM adjustment, the Commission may authorize Xcel to recoup the unrecovered balance through the following year's RDM adjustment. But Xcel must first demonstrate that its conservation efforts were a primary factor in reducing its energy sales, and hence its under-recovery of nonfuel costs.

XXXIII. Design of Revenue Decoupling Mechanism: Measurement of Adjustment

A. Introduction

As previously discussed, a decoupling mechanism works by calculating the amount of nonfuel costs a utility has recovered through rates, comparing that sum to the amount the Commission authorized the utility to recover, and adjusting future rates to offset any over- or under-recovery over time.

But even when parties agreed about the amount of over- or under-recovery to be recouped, and about the sales forecast, parties disagree about how to calculate the appropriate adjustment.

B. Positions of the Parties

Xcel proposed calculating the RDM adjustment by dividing the amount to be recovered or refunded within a given customer group by the forecast of kWh sales for that group. Xcel's formula takes no account of the fixed monthly customer charge paid by residential and small business customers. Xcel reasoned that this charge does not vary with the number of kWh a customer consumes, so it is already "decoupled" and should not influence the adjustment calculation.

The ECC advocated calculating the adjustment by dividing the amount to be recovered or refunded by the customer group's total revenues—that is, per-kWh charges plus customer charges. The ECC argued that calculating adjustments in this matter would avoid adding needless burdens to households with relatively low rates of energy consumption.

While AARP did not take a specific position on this matter, it advocated calculating the adjustment in whatever manner would provide the greatest relief to customers who consume the least amount of energy.

C. The Recommendation of the Administrative Law Judge

The ALJ found that ECC's proposal was not well supported in the record—and that among the advantages of Xcel's adjustment formula, it would allocate less of the adjustment to low-usage customers than ECC's proposal. Consequently the ALJ did not recommend altering Xcel's adjustment formula in the manner proposed by ECC.

D. Commission Action

The Commission concurs in the ALJ's findings, conclusions, and recommendations, and will adopt them.

If a party wanted to allocate the RDM rate adjustments in a manner that would minimize the consequences for customers with low energy usage, the simplest strategy would be to allocate the adjustment based on energy usage—just as Xcel proposed. Indeed, a hypothetical customer who used no electricity in a given month would be completely unaffected by the RDM rate adjustment for that month.

But even a customer who used no energy would pay a monthly customer charge. Thus, if Xcel were to calculate the RDM adjustment based on total group revenues—including revenues from customer charges—then even a customer with no energy usage would bear a share of the RDM adjustment.

Because the record does not demonstrate that ECC's proposal would achieve ECC's objectives, the Commission will decline to adopt it.

XXXIV. Class Revenue Apportionment

A. Introduction

In every rate case the new revenue requirement must be apportioned among the customer classes. This raises the issue of interclass revenue responsibility built into the rate structure—what portion of the revenue requirement should be recovered from each class? In this case, eight parties (the Company, the Department, the Chamber, XLI, the Commercial Group, the OAG, the Suburban Rate Authority, and AARP) proposed at least four different class revenue apportionments.

The parties disputed the significance of the class-cost-of-service studies (CCOSS) in establishing class revenue apportionment. Most parties agreed that rates should be moved closer to cost of service identified by a CCOSS. They disagreed about how closely the apportionment should match the CCOSS. The OAG supported an apportionment method that relies primarily on the apportionment approved in the Company's last rate case.

Adding to the complexity of the apportionment issue, the parties did not agree on how to adjust the class revenue apportionment if circumstances warranted changes to the company's revenue requirement or CCOSS. In prior rate cases, the Commission has applied a formula to adjust the apportionment proportionally, or has required the company to rerun its CCOSS with updated figures. Both methods were suggested as possibilities in this case.

B. Positions of the Parties

1. The Company

Xcel recommended an apportionment based on its CCOSS as a starting point, with modifications for noncost factors such as mitigating rate shock and ability to pay. It proposed an apportionment and stated that its proposal was based on the following parameters:

- Move the Residential class 75% closer to cost, as measured by the Company's proposed CCOSS;
- Set the Commercial and Industrial (C&I) Non-Demand class apportionment at the cost-based level, as measured by the Company's proposed CCOSS;
- Maintain the current level of Lighting class revenues; and
- Recover the remaining revenue requirement from the C&I Demand class.

The Company recommended that adjustments to apportionment in response to Commission revenue- or CCOSS-related decisions should be made using an adjustment formula.

2. The Department

The Department based its proposed apportionment on its own CCOSS. The Department recommended additional non-cost-based adjustments to reduce the magnitude of increases for certain classes.

Relative to the Company's proposal, the Department recommended that the Residential and Commercial and Industrial Non-Demand classes bear less of the rate increases in 2014 and 2015, and that the Commercial and Industrial Demand class bear more. The Department also recommended an increase for the Lighting class in 2015.

If Commission decisions on revenue requirement or CCOSS make adjustment necessary, the Department joined the Company's recommendation to adjust the class revenue apportionment using an adjustment formula.

3. The OAG

The OAG argued that after recommended adjustments are made, the CCOSS demonstrates that the residential and small business classes are paying more than the cost to serve them. The OAG proposed an apportionment based on the previous rate case's apportionment. The OAG argued that this approach (and its result) was warranted because class-cost-of-service studies are imprecise, and because it gives appropriate weight to relevant noncost factors.

The OAG recommended that revenues be apportioned according to the following general principles:

- Increase the revenues apportioned to the Residential and Commercial and Industrial Non-Demand classes by the Company's claimed deficiency percentage (6.91%);
- Maintain the current level of Lighting class revenues; and
- Recover the remaining revenue requirement from the Commercial and Industrial Demand class.

AARP supported the OAG's recommendation and advocated that customer classes should share equally in any overall rate increase.

4. The Chamber, the Commercial Group, and XLI

The Minnesota Chamber of Commerce, the Commercial Group, and the Xcel Large Industrials all recommended that the classes be apportioned revenue as close as possible to CCOSS class costs. They argued there was no noncost factor that justified departing from CCOSS-determined costs.[79] They also recommended that the CCOSS be rerun in the event of revenue or CCOSS changes.

5. The SRA

The Suburban Rate Authority opposed rate increases for the Lighting class, particularly the increases recommended by the Department in the 2015 Step. The SRA argued that the Company's CCOSS demonstrated that the Lighting class costs of service in 2014 and 2015 were below the rates charged to it.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission adopt the Department's proposed CCOSS methodology, with one modification. The ALJ recommended shifting the Department's proposed increase for the Lighting class in 2015 to the other classes, stating that the Department's recommendation would cause the Lighting class to pay above its cost in 2015. She also recommended adjusting the apportionment using the proportional-adjustment methodology supported by the Company and the Department.

[79] The Commercial Group did not oppose Xcel's proposal for a 75% movement to cost for the Residential class in the event that Commission decisions result in adjustments to the relative costs of the rate classes.

D. Commission Action

The Commission will adopt a slightly modified version of the apportionment method described by the Company. It will require Xcel to rerun the CCOSS in accordance with all Commission decisions in this docket that affect the CCOSS, and to set the class revenue apportionment by applying the following methodology to the revised CCOSS:

- Set the Commercial and Industrial Non-Demand class apportionment at the cost-based level indicated by the revised CCOSS;
- Move the Residential class 75% closer to cost—unless the revised CCOSS shows the Residential class is contributing more than its share of cost—in that case, set the Residential class apportionment at the cost-based level;
- Maintain the current level of Lighting class revenues; and
- Recover the remaining revenue requirement from the C&I Demand class.

The Commission believes this apportionment best balances the interests relevant to establishing just and reasonable rates. Apportioning revenues in accordance with class costs serves important principles by aligning revenue responsibility with cost causation, and thereby encouraging efficient use of resources. But it is appropriate to use CCOSS results as a starting point. Revenue apportionment affects rate-setting considerations beyond matching costs to causers, such as gradualism and ability to pay.

In this case, the Commission believes that the classes can reasonably be set at—or significantly closer to—their CCOSS-indicated cost. But, in the interest of protecting against rate shock from a possibly significant and sudden increase, any upward adjustment to the Residential class will be limited to 75% of the difference between that class's updated present revenue figure and its revised CCOSS-indicated cost.

Rather than apply a proportional-adjustment formula to determine class revenue apportionment, the Commission will require that the Company rerun its CCOSS with modifications required by this order, and calculate the apportionment based on that revised CCOSS. The Commission is not persuaded that in this case the formula adjustment recommended by the Company and the Department would produce a fair and reasonable result.[80]

XXXV. Method of Recovering CIP Costs

A. Introduction

Xcel and the Department agreed that when the final rates set in this case go into effect, the Company will stop recovering its Conservation Improvement Program (CIP) Costs through base

[80] Xcel's proposed adjustment formula shifts relative revenue responsibility based in part on initial revenue estimates. Because the Company's revenue estimates have changed, applying the formula in this case could result in an unintended allocation. For example, it appears that the adjustment formula would shift revenue responsibility to the Residential and C&I Non-Demand class above the cost attributed to them in the Department's CCOSS. The result would be to recover tens of millions of additional dollars from Residential and C&I Non-Demand customers rather than C&I Demand customers (who would be responsible for an allocation below their CCOSS-estimated cost).

rates, subject to true-up through an automatic-adjustment mechanism or rate rider, and start recovering them entirely through the rider. They stated that this ratemaking treatment would be more efficient than continuing to recover CIP costs through base rates subject to true-up.

The Administrative Law Judge treated this as a settled issue and made no findings on it.[81]

The Commission will not accept the parties' resolution of this issue, but will require that CIP costs continue to be recovered through base rates, subject to true-up by rider, as explained below.

B. CIP Costs and Their Current Method of Recovery

CIP expenses are an integral part of the cost of service. The CIP program encompasses most of the State's energy-conservation and energy-efficiency initiatives, from energy audits and appliance rebates to energy-efficient construction guidelines and manufacturing process improvements.

CIP costs are recovered differently than most other test-year costs. Most utility costs are built into rates using the test-year concept—they are built in at amounts determined to be reasonable and prudent by examining all utility costs over the course of a representative one-year period, the test year. While actual costs going forward will differ from test-year costs to some extent in every category, the careful scrutiny these costs receive during a rate case is expected to ensure that these cost differences will be essentially symmetrical, favoring neither the Company nor ratepayers in the aggregate.

As a matter of public policy, the Legislature has determined that utilities should generally be permitted to recover their CIP costs dollar for dollar, instead of relying solely on test-year rate recovery. CIP costs are therefore recovered in two ways: through the Conservation Cost Recovery Charge (CCRC), a component of base rates that recovers baseline, test-year CIP costs, and through the Conservation Cost Recovery Adjustment (CCRA), an automatic rate-adjustment mechanism that trues up differences between actual CIP costs and those recorded in the CCRC.

In Xcel's case, the CCRA is part of a larger rider, or automatic rate-adjustment mechanism, the Resource Adjustment Charge, which includes the costs of other programs and investments mandated under State energy-policy statutes.

C. Commission Action

The Commission will not approve removing CIP costs from base rates and recovering them entirely by rider.

Riders are regulatory tools for use in essentially two situations: (1) when the delay implicit in normal test-year treatment of costs could defeat or frustrate important public-policy objectives, such as prompt construction of essential transmission or renewable-energy facilities,[82] and (2) when large costs, such as fuel costs, fluctuate so substantially that relying solely on base-rate recovery would necessitate nearly constant rate cases.[83]

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[81] ALJ's Report, Attachment A, "Resolved Issues and Undisputed Corrections," Issue 39.

[82] Minn. Stat. §§ 216B.16, subd. 7b, .1645, subd. 2.

[83] Minn. Stat. § 216B.16, subd. 7.

Riders are used with care because cost-recovery inquiries in rider proceedings are necessarily less thoroughgoing than those in general rate cases—potentially jeopardizing ratemaking accuracy—and because conducting cost-recovery inquiries in both rider proceedings and rate cases complicates ratemaking and reduces regulatory efficiency. That is why the Commission's Multiyear Rate Plan Order requires filing utilities to disclose, examine, rationalize, and simplify existing riders.[84]

The Commission continues to view reduced dependence on rate riders and their continuing simplification as important regulatory goals and will not authorize rate recovery of the Company's CIP costs through a rate rider alone.

Further, a rate-design change of this magnitude requires more thorough review than can be conducted in a rate case; it merits consideration in a separate proceeding with broad stakeholder participation. For all these reasons, the Company should continue to recover those costs in base rates, subject to true-up by rider.

XXXVI. Residential and Small-General-Service Customer Charges

A. Introduction

Xcel's Residential and Small General Service customers pay both an energy charge and a customer charge. The energy charge is a per-kWh charge based on electricity use. The customer charge is a fixed monthly charge assessed without regard to usage level. It is designed to help recover fixed customer-related costs such as the cost of billing, meters and meter reading, and the minimum distribution facilities required to provide service.

The Company's 2014 class-cost-of-service study estimated that the average fixed monthly cost of serving a residential customer is $15.86 and that the average fixed monthly cost of serving a small general-service customer is $16.84.

Xcel's current Residential and Small General Service customer charges are lower than the cost of service estimated in the Company's class-cost-of-service study. Xcel proposed to increase the Residential customer charge by $1.25 and the Small General Service customer charge by $1.50 to move them closer to cost and minimize intraclass subsidies.

Xcel's current and proposed customer charges for these classes are as follows:

Service	Current Charge	Proposed Charge
Residential Overhead	$8.00	$9.25
Residential Underground	$10.00	$11.25
Residential Electric-Heat Overhead	$10.00	$11.25
Residential Electric-Heat Underground	$12.00	$13.25
Small General Service	$10.00	$11.50

[84] Docket No. E,G-999/M-12-587, Multiyear Rate Plan Order at 7–8, 12, 14.

B. Positions of the Parties

The Department agreed with Xcel that the Residential and Small General Service customer charges should be increased. The Department shared the Company's concern that current rates result in intraclass subsidies. Because the current customer charges do not reflect the full fixed cost of service, it argued, some fixed costs are recovered through the energy charge, and high-usage customers end up paying more than their share of fixed costs. According to the Department, some of these high-usage customers are low-income customers with a limited ability to absorb a rate increase.

Although it agreed that the customer charges should be raised, the Department recommended a more modest increase of $0.50 per month. The Department noted that a customer-charge increase would follow closely on the previous increase in Xcel's last rate case, which was implemented in December 2013. The Department argued that an increase of $0.50 per month appropriately balances reducing intraclass subsidies and maintaining affordability.

The remaining parties commenting on this issue—the OAG, the Clean Energy Intervenors, the Energy CENTS Coalition (ECC), AARP, and the Suburban Rate Authority—all recommended leaving the customer charges at their current level.

These parties' arguments for retaining the current charges fell into the following broad categories: (1) the need to maintain affordability, (2) the need to encourage energy conservation, and (3) doubt as to whether Xcel's class-cost-of-service study accurately reflects the fixed cost of serving a customer.

As to affordability, several parties argued that an increase in the Residential customer charge would place an undue burden on low-usage residential customers. The OAG in particular was concerned about the cumulative impact of multiple increases to the Residential and Small General Service charges in recent years and argued that it was more important to protect ratepayers from the impact of frequent increases than to move the charges closer to cost.

Second, parties argued that retaining the current charges would further the rate-setting goal of encouraging energy conservation.[85] Holding the customer charges steady will shift the impact of any increase in these classes' revenue responsibility into the per-kWh energy charge, giving customers a greater ability to avoid the increase by using less electricity. Several parties argued that a decision to implement revenue decoupling would further support holding the customer charges steady, since decoupling would remove the risk of Xcel under-recovering its revenue requirement as a result of reduced energy sales.

Finally, the OAG and the Clean Energy Intervenors argued that Xcel's class-cost-of-service study is not a reliable measure of fixed customer costs because it classifies as customer-related significant costs that do not vary directly with the number of utility customers. The Clean Energy Intervenors argued that the actual fixed cost of serving a residential customer is less than $6.51 per month. Thus, according to them, low-usage Residential customers are currently paying more than their fixed cost of service.

[85] *See* Minn. Stat. § 216B.03.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that, in this case, the need to maintain affordability and promote conservation outweighed the need to move rates closer to Xcel's class-cost-of-service study's estimate of the fixed cost of service.

The ALJ was persuaded by the Clean Energy Intervenors' and the OAG's arguments that Xcel's class-cost-of-service study did not present a reliable estimate of fixed costs. She therefore gave the study less weight than in prior proceedings. The ALJ gave significant weight to the fact that there have been a number of customer-charge increases in recent years. And she found that if the Commission adopts a decoupling mechanism, it would remove the need to increase the customer charges to support Xcel's revenue stability.

For these reasons, the ALJ recommended that the Commission retain the current Residential and Small General Service customer charges.

D. Commission Action

The Commission concurs with the ALJ and adopts her recommendation to retain the existing customer charges for residential and small general-service customers.

In setting rates, the Commission must consider both ability to pay and the need to encourage energy conservation.[86] The Commission must balance these factors against the requirement that the rates set not be "unreasonably preferential, unreasonably prejudicial, or discriminatory"[87] and the utility's need for revenue sufficient to enable it to provide service.[88]

The Commission concludes that raising the Residential and Small General Service customer charges, even by the smaller amount the Department recommends, would give too much weight to the fixed customer cost calculated in Xcel's class-cost-of-service study and not enough weight to affordability and energy conservation.

The Commission notes that Xcel's Residential Overhead Service customer charge nearly doubled between 2004 and 2014, with four of the increases coming in just the last five years. The Commission concurs with the OAG that this circumstance highlights the need for caution in making any decision that would further burden low-income, low-usage customers, who are unable to absorb or avoid the increased cost.

The Commission also concludes that a customer-charge increase for these classes would place too little emphasis on the need to set rates to encourage conservation. This is particularly true where the Commission has approved a revenue decoupling mechanism that will largely eliminate the relationship between Xcel's sales and the revenues it earns. As several parties have argued, decoupling removes the need to increase customer charges to ensure revenue stability.

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[86] *See* Minn. Stat. §§ 216B.16, subd. 15, 216B.03.

[87] Minn. Stat. § 216B.03.

[88] Minn. Stat. § 216B.16, subd. 6.

Xcel and the Department argued that the current customer charges are set below cost and will result in intraclass subsidies. However, the Clean Energy Intervenors and the OAG have cast doubt on the validity of Xcel's class-cost-of-service study as a means of apportioning intraclass responsibility for fixed costs. Therefore, the Commission, like the ALJ, gives the study limited weight.

For the foregoing reasons, the Commission will require that Xcel retain the existing customer charges for Residential and Small General Service customers.

XXXVII. Interruptible-Service Discounts

A. The Issue

Customers who take interruptible service agree to have their service interrupted when called upon by Xcel or face high penalties. The Company and its ratepayers benefit from interruptible load by not having to build or acquire the additional generation to serve it.

Xcel sets interruptible-service discounts at the lowest level it believes will attract enough interruptible load to meet short-term load-shedding needs and permit long-term planning. To maintain an optimal supply of interruptible load, Xcel proposed to increase the discount for each of the six interruptible-service classes by an average of 5.15%.

The Chamber and XLI recommended increasing interruptible discounts beyond the level Xcel proposed, emphasizing the benefit of interruptible load to Xcel's system and the possibility that customers will drop out of the program if the discount is not increased.

The Department recommended a more modest increase of about 3%. It argued that a smaller increase was appropriate given the limited number of service interruptions over the last several years and the Company's claim that it currently has sufficient levels of interruptible load.

The ALJ agreed with the Department, finding that the other parties had failed to demonstrate that a larger increase was necessary to maintain an optimal supply of interruptible load.

B. Commission Action

The Commission concurs with the ALJ and adopts her findings and recommendation. The Department's proposal to increase the C-class interruptible-service discounts by 3% and increase the remaining discounts proportionately appears reasonably targeted to maintain a sufficient level of interruptible load.

The Chamber argued that a greater increase was necessary to maintain adequate interruptible load, asserting that Xcel has lost interruptible customers in recent years. However, the Chamber did not provide evidence linking the decrease in interruptible customers to the discount level. Moreover, interruptible load is closely monitored by the Company, and the discounts are examined in every rate-setting proceeding. Thus, any significant downward trend in interruptible load can be timely addressed.

XXXVIII. Inclining-Block Rates

A. The Issue

The Clean Energy Intervenors proposed a four-tier inclining-block-rate (IBR) structure for the residential customer class. Under the proposal, per-kWh energy rates would rise as a customer's usage passes three thresholds: 350 kWh, 700 kWh, and 1,200 kWh.[89] The Clean Energy Intervenors argued that the IBR structure would encourage conservation and was in the public interest.

Xcel initially opposed an IBR structure but later entered into a stipulation with the Clean Energy Intervenors, ECC, and the Suburban Rate Authority asking the Commission to open a separate docket to give the parties more time to develop an IBR proposal. The stipulation allows Xcel to submit one alternative to the Clean Energy Intervenors' proposal but does not expressly permit any other party to submit an alternative.

The Department did not sign the stipulation but agreed that the issue of inclining block rates would be better resolved outside this rate case. It committed to hold stakeholder meetings to review IBR proposals and issue a report to the Commission.

The OAG opposed the Clean Energy Intervenors' proposal, arguing that it would have negative consequences for certain ratepayers, particularly those with limited ability to alter their energy consumption. Further, the OAG argued that the stipulation was too restrictive in limiting the discussion to only the Clean Energy Intervenors' and the Company's IBR proposals.

The Administrative Law Judge agreed with the parties to the stipulation that inclining block rates would be an effective tool to promote conservation and that the issue warrants further review. The ALJ suggested two modifications to the process set forth in the stipulation: (1) allow all parties to submit alternative IBR proposals and (2) require that the parties to the stakeholder meetings specifically address potential impacts on high-use, low-income ratepayers.

B. Commission Action

The Commission concurs with the ALJ's recommendation to approve the stipulation, and will do so with the modifications outlined below.

The Commission agrees that inclining block rates should be examined in a separate docket. A separate proceeding, without the time pressure of a rate case, will allow careful consideration of the Clean Energy Intervenors' proposal and the effect an IBR structure would have on low-income customers who are unable to limit their usage in response to the conservation price signals sent by the inclining blocks.

Further, the Commission concludes that the discussion should be expanded to include consideration of other possible alternative rate designs that promote energy conservation, reduce peak demand, and/or send more accurate, useful price signals to customers. Facilitating a broader discussion of alternatives will create the best possible chance of the process resulting in a

[89] These thresholds apply during the summer season. The proposed winter IBR thresholds are 300 kWh, 600 kWh, and 1,000 kWh.

proposal that is acceptable to all parties and that treats all customer classes in a fair and equitable manner.

So that any proposal by Xcel may be informed by the stakeholder meetings and the Department's resulting report, the process should begin with stakeholder meetings. The Department should complete stakeholder meetings and issue a report to the Commission on the stakeholder process within 180 days of this order. Once the Department's report is filed, the Commission will determine whether to require Xcel to file a proposal for an IBR structure or any rate-design alternative that furthers the goals identified above.

XXXIX. Coincident-Peak Billing

A. The Issue

The Chamber proposed that the Commission require Xcel to modify its tariff to facilitate coincident-peak billing. Under coincident-peak billing, Xcel would aggregate the meter readings of customers with multiple metered locations on a single business site, including meters on contiguous properties. This billing method would reduce the total billed demand of customers with multiple demand-billed meters on a single site.

Xcel opposed the Chamber's proposal, arguing that coincident-peak billing would be costly to implement and would benefit only nine large commercial and industrial customers. The Company also argued that coincident-peak billing was unnecessary because large customers already have the ability to change their wiring configuration to facilitate aggregated demand billing through a single meter.

The Administrative Law Judge noted that the Commission had declined to adopt a similar proposal by the Chamber in Xcel's last rate case because it was not sufficiently developed. While she found the current proposal to be an improvement, the ALJ concluded that it was still not sufficiently developed to show that coincident-peak billing will result in reasonable rates.

B. Commission Action

The Commission concurs with the ALJ and adopts her recommendation to deny the Chamber's proposal for coincident-peak billing.

The Chamber has not fully addressed who will bear the cost of its proposal, stating only that it is not opposed to a reasonable meter charge to recover billing-process changes. Nor has the Chamber demonstrated that it would be cost-effective for any of the nine potentially eligible customers to implement coincident-peak billing if the customer is responsible for the cost of the new meters as well as a reasonable meter charge.

For these reasons, the Commission concurs with the ALJ that the Chamber's proposal for coincident-peak billing is still not sufficiently developed to demonstrate that it will result in reasonable rates.

XL. Definition of "Contiguous"

A. The Issue

Xcel's tariff provides that a customer may combine electric service for two or more buildings located on the same parcel or on contiguous parcels.[90] The tariff does not define "contiguous."

The Chamber claimed that Xcel has been interpreting "contiguous" to deny applications for combined electric service when property lines are interrupted by roadways and other rights of way. It asked the Commission to require Xcel to adopt the definition of "contiguous property" set forth in Minn. Stat. § 216B.164, subd. 2a(e): "property owned or leased by the customer sharing a common border, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way."

Xcel opposed the Chamber's request. The Company stated that it understands "contiguous" property to be "a single physical customer site or location, as distinct from customer accounts at different geographical locations." Xcel argued that there is no need to further define "contiguous," since a customer is free to wire its site in a way that presents one metered service location.

The Administrative Law Judge concluded that the Chamber's request to incorporate the statutory definition of "contiguous property" into Xcel's tariff was reasonable.

B. Commission Action

The Commission declines to adopt the Administrative Laws Judge's recommendation to require Xcel to incorporate the definition of "contiguous property" from Minn. Stat. § 216B.164, subd. 2a(e), into its tariff. The Commission is concerned that this definition, which comes from a statute governing distributed generation, may not be ideally suited to other contexts and may result in unintended consequences.

However, the Commission agrees that all parties would benefit from clarity and consistency in the definition of "contiguous property" in Xcel's tariff. The Commission will therefore require Xcel to file a definition of the term "contiguous property" as used in section 6, sheet 19.3 of the Company's Electric Rate Book.

XLI. Renewable-Energy-Purchase Tariff

A. The Issue

XLI asked the Commission to require Xcel to develop a tariff for buying and selling renewable energy directly to qualifying large high-load-factor customers. While the Company has a voluntary wind-energy purchase program (Windsource), the rates are higher than non-Windsource rates. XLI asked that Xcel be required to work with interested parties to develop a renewable-energy-purchase tariff to be filed no later than the Company's next rate case.

[90] Minnesota Electric Rate Book section 6, sheet 19.3.

Xcel is interested in discussing a renewable-energy-purchase tariff with XLI and other interested stakeholders. However, the Company opposed setting a deadline, anticipating that developing a tariff proposal will take substantial time.

The Administrative Law Judge recommended that Xcel be required to propose a renewable-energy-purchase tariff in its next rate case.

B. Commission Action

While the Commission agrees that XLI's renewable-energy-purchase tariff proposal merits further discussion, the Commission declines to set a specific deadline for Xcel to present a new tariff. Instead, the Commission will order the Company to work with XLI and other interested stakeholders to develop a renewable-energy-purchase program that addresses the goals outlined by XLI in this case.[91] The program should also address the goals of creating demand for renewable energy beyond that required by the Renewable Energy Standard, Minn. Stat. § 216B.1691, and of meeting the reasonable-rate requirements of Minn. Stat. § 216B.03.

[91] The final tariff may, but need not, comply with the specific recommendations provided by XLI in Exhibit 260 (Pollock Direct) at pages 61–62.

FINANCIAL SCHEDULES AND COMPLIANCE

XLII. Overall Financial Schedules

A. Gross Revenue Deficiency

The above Commission findings and conclusions result in a total gross revenue deficiency of $58,908,000 for the 2014 test year and $105,854,000 for the 2015 Step as shown below:

Revenue Deficiency - Minnesota Jurisdiction
Test Year Ending December 31, 2014 & 2015 Step
($000's)

Line No.		2014 Test Year		2015 Step	
1	Average Rate Base	$	6,493,649	$	584,573
2	Rate of Return		7.34%		7.37%
3	Required Operating Income	$	476,634	$	43,083
4	Operating Income before AFUDC	$	407,232	$	(13,470)
5	AFUDC	$	34,864	$	(5,509)
6	Total Operating Income	$	442,096	$	(18,979)
5	Income Deficiency	$	34,538	$	62,062
6	Gross Revenue Conversion Factor		1.705611		1.705611
7	Gross Revenue Deficiency	$	58,908	$	105,854

B. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the 2014 test year is $6,493,649,000 and $584,573,000 for the 2015-Step additions as shown below:

Rate Base Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2014 & 2015 Step
($000's)

Line No.		2014 Test Year	2015 Step
	ELECTRIC PLANT IN SERVICE		
1	Production	$ 7,952,590	$ 642,103
2	Transmission	1,999,645	101,145
3	Distribution	3,019,969	(1,828)
4	General	499,761	12,133
5	Common	454,709	0
6	Total Utility Plant In Service	$ 13,926,674	$ 753,553
	RESERVE FOR DEPRECIATION		
7	Production	$ 4,452,331	$ 54,929
8	Transmission	566,980	(48,565)
9	Distribution	1,184,480	(79,218)
10	General	179,709	(1,480)
11	Common	243,128	1,391
12	Total Reserve For Depreciation	$ 6,626,628	$ (72,943)
	NET PLANT IN SERVICE		
13	Production	$ 3,500,259	$ 587,174
14	Transmission	1,432,665	149,710
15	Distribution	1,835,489	77,390
16	General	320,052	13,613
17	Common	211,581	(1,391)
18	Net Utility Plant In Service	$ 7,300,046	$ 826,496
19	Construction Work in Progress	$ 529,838	$ (111,525)
20	Accumulated Deferred Income Taxes	$ (1,604,789)	$ (126,206)
21	Cash Working Capital	$ (74,321)	$ (4,192)
	OTHER RATE BASE		
22	Materials & Supplies	$ 116,514	0
23	Fuel Inventory	74,663	0
24	Non-Plant Assets & Liabilities	(12,904)	0
25	Prepayments	14,103	0
26	Nuclear Outage Amortization	82,801	0
27	Customer Advances	(3,301)	0
28	Customer Deposits	(2,763)	0
29	Sherco 3 Deferral	10,250	0
30	Black Dog Reg Asset Amortization	2,961	0
31	PI EPU Amortization	55,349	0
32	Other Working Capital	5,202	0
33	Total Other Rate Base	$ 342,875	0
34	TOTAL AVERAGE RATE BASE	$ 6,493,649	$ 584,573

C. Operating Income Summary

Based on the above findings, the Commission concludes that the appropriate operating income for the 2014 test year under present rates is $442,096,001 and for the 2015-Step additions is $(18,979,000) as shown below:

Operating Income Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2014 & 2015 Step
($000's)

Line No.		2014 Test Year		2015 Step	
	UTILITY OPERATING REVENUES				
1	Retail Revenue	$	2,826,039	$	622
2	Interdepartmental		962		0
3	Other Operating Revenue		621,402		56,829
4	Total Operating Revenue	$	3,448,403	$	57,451
	EXPENSES				
	Operating Expenses				
5	Fuel & Purchased Energy	$	1,086,327		0
6	Power Production		697,188		4,379
7	Transmission		191,916		0
8	Distribution		103,490		(173)
9	Customer Accounting		48,552		0
10	Customer Service & Information		92,987		0
11	Sales, Econ Dvlp & Other		101		0
12	Administrative and General		190,225		0
13	Total Operating Expenses	$	2,410,786	$	4,206
14	Depreciation Expense	$	273,308	$	81,958
15	Amortization	$	31,300		0
	Taxes:				
16	Property	$	154,355	$	4,016
17	Deferred Income Tax & ITC		161,968		14,815
18	Federal &State Income Tax		(19,955)		(34,074)
19	Payroll & Other		29,409		0
20	Total Taxes	$	325,777	$	(15,243)
21	TOTAL EXPENSES	$	3,041,171	$	70,921
22	AFUDC	$	34,864	$	(5,509)
23	TOTAL OPERATING INCOME	$	442,096	$	(18,979)

XLIII. Compliance Filing Required

The Commission will require the Company to make a compliance filing within 30 days of the date of this order showing the final rate effects of the decisions made here and proposing a plan for refunding the difference between the amounts it collected in interim rates and the amounts it is authorized to collect in final rates. The Commission will establish a brief comment period to give interested persons a chance to review and comment on that filing.

ORDER

1. Xcel's Electric Utility is entitled to increase Minnesota jurisdictional revenues by $58,908,000 to produce jurisdictional total retail-related revenue of $2,885,909,000 for the test year ending December 31, 2014 and to produce jurisdictional total retail-related revenue of $2,992,385,000 for the 2015 Step.

2. The Commission accepts, adopts, and incorporates the findings, conclusions, and recommendations of the Administrative Law Judge, except as set forth in this order.

3. Xcel shall exclude the 2014 depreciation expense and return on the Monticello EPU from the 2014 test year based on a 50% allocation to the EPU. Xcel is authorized to recover the EPU costs in the 2015 Step, but if the EPU is not in service by January 1, 2015, the Company shall refund any excess amounts collected through the refund mechanism for the multiyear rate plan.

4. The disallowance of 2014 Monticello EPU depreciation expense shall be a permanent disallowance. The Company shall reduce Construction Work in Progress by this amount, or if the plant is shown as being included in Plant in Service, the disallowed depreciation expense will remain in the depreciation reserve. Xcel shall make a compliance filing within ten days of this order providing the accounting entries and explaining how this permanent disallowance is reflected in its accounting records.

5. Xcel is authorized to recover $950,000 in Monticello prudency-review costs with a two-year amortization period. If the Company does not file its next rate within this two-year period, it shall return any over-recovery to customers when it files its next rate case.

6. The Company shall use 5.05% (a five-year average of discount rates determined under Financial Accounting Standard 87) as the approved discount rate to determine its XES Plan pension costs for ratemaking purposes.

7. The Company shall apply the rolling five-year average FAS 87 discount rate when determining the XES Plan cost subject to deferral (or reversal) in subsequent years (i.e., non–rate-case test years) as the 2012 mitigation established in Docket No. E-002/GR-12-961 continues.

8. The Commission adopts ALJ Finding 126, excluding the following sentence: "For that reason, use of the FAS 87 bond-matching discount rate will help ensure that the XES Plan, which is subject to FAS 87, is fully funded."

9. The Commission adopts ALJ Finding 157 with the following modification:

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

10. The qualified pension asset and associated deferred-tax amounts shall be included in rate base. For rate-base purposes, the pension asset is to reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost determined under the ACM/FAS 87 methods since plan inception, not to exceed the Company's filed request. The Company shall provide a detailed compliance filing which explains the calculated amount within ten days of the Commission's decision.

11. In the initial filing of its next electric rate case, the Company shall

    a. Address why the target asset allocations for its pension fund are reasonable, including ages of retirees and employees. The Company must provide an update to its existing Exhibit 31 (Tyson Rebuttal), Schedule 1 and expand it to include this demographic information.

    b. Provide testimony on its investment strategies and target asset allocations for the qualified pension fund and the justifications for those decisions, for the period from 2007 to the date of its next filing.

    c. Provide copies of the actuarial reports used to determine employee benefit costs, including its schedules denoting each subsidiary's cost assignments for each benefit. The Company must also include workpapers that show the derivation of the jurisdictional portion of each benefit cost.

    d. Provide testimony that identifies and discusses each non-qualified employee-benefit cost included in its test years.

    e. Include testimony identifying the basis used for its requested rate-base impact related to pensions. Additional schedules must be included that reflect the underlying calculation of the qualified pension asset (or liability) balances requested for rate-base inclusion.

12. The Commission approves including the identified 2008-market-loss amortized amounts in the calculated pension and retiree medical benefit costs.

13. The discount rate used to calculate retiree medical benefit costs for ratemaking purposes shall be set to equal 5.08%, the five-year average of the FAS 106-based discount rates.

14. Any amount by which the qualified pension expense allowed in rates exceeds future years' qualified pension expense (calculated using the Commission-approved discount-rate point of reference) the Company shall apply toward the recovery of the accumulated deferred XES Plan costs. "Future years" includes 2015, and each subsequent year's qualified pension expense if not a rate-case test year. The recoverable XES Plan expense

amount shall be calculated using the proximate measurement date appropriate for each operating year (12/31/2013 for 2014; 12/31/2014 for 2015, etc.) until the next rate case. The Company shall file annual compliance reports which provide its pension plans' cost-calculation reports, the XES Plan accumulated deferred balance, and the excess rate-level recovery applied toward satisfying the deferral. Deferred amounts shall not be included in rate base.

15. The Commission approves the retiree medical benefit cost level in rates that is the calculated average of the annual projected benefit cost over the expected two-year rate life. Each year's projected cost amount subject to averaging must be calculated using the Commission-approved assumptions and the most proximate measurement date applicable to each year.

16. In the initial filing of its next electric rate case, the Company shall

    a. discuss the cost components of the postretirement benefits plans cost (other than pensions) affecting Minnesota rates, particularly the drivers of the amortization of net gain/loss amount and the reasons this component amount has varied since its last rate case (Docket No. E-002/GR-13-868); and

    b. provide the report of future years' actuarial cost projections of the postretirement benefits (other than pensions), clearly identifying the assumptions and measurement point used to develop these projections.

17. In its next rate case the Company shall provide historical active health care costs since 2011 for each calendar year, including both the per-book amount and the actual claims expense. The Company shall also provide information detailing the annual year-end Incurred But Not Reported (IBNR) accruals and subsequent reversals.

18. The Company shall reduce its 2015-Step rate base by $535,552 to reflect 2015 capital retirements of transmission and distribution facilities.

19. The 2014 and 2015 revenue requirements shall be calculated using the 2014-test-year and 2015-Step replacement projects specified in Ms. Perkett's Rebuttal Testimony, Schedule 11.

20. The Company may include the unamortized nuclear-refueling-outage costs in rate base and earn the overall allowed rate of return on that balance.

21. The Company shall recover the cost of its Pleasant Valley and Border Winds facilities through base rates, using the average of the beginning- and end-of-year plant balances, consistent with the treatment of other capital investment, and subject to true-up in its Renewable Energy Standard rider.

22. The Company shall include in base rates the production tax credits associated with the operation of the Pleasant Valley and Border Winds facilities, in the amount disclosed in nonpublic Exhibit 432, Schedule NAC-7, which reduces the 2015-Step revenue requirement by $11.093 million.

23. The Company shall notify the Commission and report and capture potential cost reductions or other forms of compensation that may result from contract changes or contractors' failure to meet contract terms for either the Pleasant Valley or the Border

Wind projects. Such cost reductions and compensation payments will be subject to Commission review for potential credits or refunds to ratepayers.

24. By September 1, 2015, or in its next Renewable Energy Standard-rider filing, the Company shall report the results of stakeholder discussions on alternative cost-recovery formulas for the Pleasant Valley and Border Winds projects designed to allocate risks and create incentives.

25. Because the Company's 50% cost reduction to the jurisdictional corporate-aviation costs does not capture the removal of flight costs that were incurred for reasons other than for the provision of utility service, the Commission does not adopt ALJ Finding 559. Allowable corporate-aviation costs shall be further reduced by the cost of flights categorized by the following business-purpose reasons:

    a. Personal Travel (34 total company flights);

    b. Investor Relations (45 total company flights).

26. The following reported business purposes for corporate travel are insufficient and do not permit the Commission to determine if the expense was reasonably and necessarily incurred for the provision of utility service, fail to meet the requirements of Minn. Stat. § 216B.16, subd. 17, and are disallowed. The Company shall reduce the corporate-aviation costs further by the cost of flights for each flight with the stated description:

    a. Business Area Travel (1,668 total company flights);

    b. Director Travel (615 total company flights);

    c. Manager Travel (55 total company flights);

    d. Xcel Executive Business Travel (831 total company flights).

27. The Commission does not adopt ALJ Findings 562 and 563 but adopts the following in the place of ALJ Finding 562:

> 562. Minnesota law requires Xcel to provide information about the "business purpose" of each flight before recovery is permissible. Xcel did not meet this requirement because the "business purpose" descriptions in Xcel's flight log do not provide any information to determine the true business purpose of the flights. Because Xcel has not demonstrated that the flights coded as Executive Business Travel, Director Travel, Manager Travel and Business Area Travel have a "business purpose" that indicates they are necessary for the provision of utility service, they must be disallowed. The Company is required to conduct an annual shareholders' meeting and documentation shows the designated "Shareholders Meeting" travel occurred close in time to the annual meeting.

28. The Commission adopts ALJ Finding 564 modified to read as follows:

> The Commission orders the Company in future rate cases seeking recovery of corporate aviation to provide more detailed, accurate records of the actual business purpose for flights that are scheduled, rather than reducing all flights to a generic "code."

29. The Company has complied with the filing requirements set in its last rate case (Docket No. E-002/GR-12-961) regarding its Annual Incentive Compensation Program and shall continue to provide similar information and documents in any future rate case in which it seeks rate recovery of incentive-compensation costs.

30. In its next electric rate case, the Company shall

    a. present a new key performance indicator (KPI) for transmission O&M costs;

    b. provide a comparison study of its transmission O&M costs by using appropriate peer companies, along with justification for why certain utilities were included or excluded; and

    c. propose a new cost control KPI at the vice-presidential level for overall transmission costs.

31. Upon resolution of the lawsuit involving Babcock & Wilcox Nuclear Energy, Inc., the Company shall make a compliance filing providing all relevant information as to costs and interest paid and discuss what costs were included as Plant in Service in this rate case.

32. Any costs included in rate base but not paid shall be refunded as part of either the 2014 or 2015 refunds. If the lawsuit is not resolved at either of those times, then the refund should be made within 60 days after the lawsuit is resolved.

33. The Company shall make a compliance filing within 30 days of completing the refund. The compliance filing should provide information detailing the refund and about the resolution of the lawsuit. The compliance filing should describe the amount not paid to Babcock & Wilcox that remains in rate base and the revenue-requirement effect of that amount so the Commission can consider whether to require Xcel to track that amount for return to ratepayers in Xcel's first rate case subsequent to the resolution of the lawsuit.

34. The Commission adopts the weather-normalized sales data in Xcel's January 16, 2015 compliance filing for rate-making purposes.

35. Xcel shall modify its 2014 and 2015 class-cost-of-service studies to classify the costs of the Grand Meadow and Nobles wind farms on the same basis as its other fixed production-plant costs using the plant-stratification method.

36. Xcel shall modify its 2014 and 2015 class-cost-of-service studies to use the location method rather than the predominant-nature method to allocate other production O&M costs.

37. In its next rate case, Xcel shall refine its class-cost-of-service study cost-allocation method by identifying any and all other production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators, while allocating the remainder of other production O&M costs on the basis of the production plant.

38. In its next rate case the Company's class-cost-of-service study shall include an explanatory filing identifying and describing each allocation method used in the study and detailing the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered by the Company, whether those methods are based on the Manual of the National Association of Regulatory Utility Commissioners or the Company's specific system requirements, its experience, and its engineering and operating characteristics. The Company shall also explain its reasoning in cases in which it did not consider alternative methods of allocation or classification.

39. In its next rate case, Xcel shall provide parties with data sufficient to verify and reproduce its minimum-system study and shall file a zero-intercept analysis of distribution costs, or explain why it was not able to collect the data necessary to do so.

40. Xcel shall implement its proposed revenue decoupling mechanism (RDM) for its residential and small business customer groups with the following modifications:

    a. *Pilot Program*: Xcel shall implement its revenue decoupling mechanism as a three-year pilot program.

    b. *Start of energy-consumption measurement*: Xcel may begin calculating its over- or under-recovery of nonfuel costs after the final compliance order authorizing implementation of final rates in this proceeding, but not before new rates take effect, and no sooner than January 1, 2016.

    c. *Limits on upward rate adjustments*:

        - *Energy savings requirement*: In any year in which Xcel fails to achieve energy savings equal to 1.2% of retail sales, Xcel will forgo the opportunity to make an upward rate adjustment via the revenue decoupling mechanism in the following year.

        - *Cap*: In any year in which the revenue decoupling mechanism would authorize an upward adjustment to recover more than 3% of a customer group's base revenues (excluding consideration of Xcel's fuel clause or other riders), Xcel may implement a 3% adjustment. Xcel may also petition to use the following year's decoupling adjustment to recover costs that were excluded from recovery by this cap. In the petition, Xcel must demonstrate that Xcel's demand-side-management programs and other company initiatives were a substantial contributing factor to the declining energy sales triggering the rate adjustment, and that other nonconservation factors were not the primary factors for the declining sales.

d. *Customer education*: Xcel shall file a plan for implementing an education and outreach program for its customers explaining the goals and operations of its RDM program.

e. *Annual report*: Xcel shall submit an annual report to the Commission by February 1 of each year prior to any application of a RDM adjustment factor on April 1. The report shall include the following information:

i. Total over- or under-collection of allowed revenues by customer class or group;

ii. Total collection of prior deferred revenue;

iii. Calculations of the RDM deferral amounts;

iv. The number of customer complaints;

v. The amount of revenues stabilized and how the stabilization impacted Xcel's overall risk profile;

vi. A comparison of how revenues under traditional regulation would have differed from those collected under partial and full decoupling;

vii. A description of all new and existing demand-side-management programs and other conservation initiatives Xcel had in effect for the year covered by the report;

viii. A description of the effectiveness of all new and existing demand-side-management programs and other conservation initiatives Xcel had in effect for the year covered by the report; and

ix. Other factors that may have contributed to a decline in energy consumption, including weather and the economy.

41. The Company shall continue its current practice of collecting Conservation Improvement Program (CIP) costs through base rates, subject to true-up through the Resource Adjustment Charge.

42. The Company shall not change historical data in Windsource and Fuel Clause Adjustment filings without identifying and providing a justification for the changes. The Company shall clarify in each Fuel Clause Adjustment and Windsource filing what costs are included in the Windsource Contract Payments.

43. The Company shall address the issues raised by Mr. Schedin in his testimony in this case as part of the Commission's generic proceeding on standby service, Docket No. E-999/CI-15-115.

44. Xcel shall increase the Level C Performance Factor interruptible-service discounts by 3% and institute corresponding increases for the other performance factors to maintain the current relationship between tiers.

45. The Commission approves the process and substance outlined in the IBR Stipulation, with the following additional modifications:

    a. In addition to IBR, the process should consider other alternative rate designs that result in rates that promote energy conservation, reduce peak demand, and/or send more accurate, useful price signals to customers.

    b. In order to allow a potential proposal to be informed by the stakeholder meetings and the Department's resulting report, the process should begin with stakeholder meetings convened by the Department.

    c. The Department should complete stakeholder meetings and issue a report to the Commission on the stakeholder process within 180 days of this order.

    d. After the Department's report is filed, the Commission will determine whether to require the Company to file a proposal for an IBR structure or any alternative rate-design proposals that further the goals identified above.

    The Commission delegates to the Executive Secretary the authority to modify the timelines set forth above as necessary. The Commission does not adopt Finding 841 of the ALJ's Report to the extent that it is inconsistent with the preceding decisions.

46. Xcel shall file a definition of the term "contiguous property" for application in the Company's Electric Rate Book section 6, sheet 19.3.

47. Xcel shall work with XLI and other interested stakeholders to develop a renewable-energy-purchase program that addresses the goals outlined by XLI in this case, such as increasing the competitiveness of industrial rates. The program should also address the goals of creating demand for renewable energy beyond that required by the Renewable Energy Standard, Minn. Stat. § 216B.1691, and of meeting the reasonable-rate requirements of Minn. Stat. § 216B.03. The final tariff may, but need not, comply with the specific recommendations provided by XLI in Exhibit 260 (Pollock Direct) at pages 61–62.

48. The Company shall rerun the CCOSS in accordance with all Commission decisions in this docket and the Monticello docket that affect the CCOSS, and set the class revenue apportionment by applying the following methodology to the revised CCOSS:

    a. Maintain the current level of Lighting class revenues;

    b. Set the C&I Non-Demand class apportionment at the cost-based level;

    c. If the revised CCOSS shows that the Residential class is currently contributing more than its share of cost, set the Residential class apportionment at the cost-based level;

    d. If the revised CCOSS shows the Residential class is currently contributing less than its share of cost, move the Residential class 75% closer to cost; and

    e. Recover the remaining revenue requirement from the C&I Demand class.

49. The Company shall make a filing within 30 days of the final determination in this case if final authorized rates are higher or lower than interim rates. The filing shall contain a proposal to make adjustments of interim rates consistent with the Commission's decision in this proceeding, to affected customers. The Company shall calculate the following amounts:

    a. The refunds due for 2014, based on the interim-rate collections during 2014 and final rates in effect as of January 1, 2014; and

    b. The amount of under-collection or over-collection for 2015, based on the interim-rate collections in 2015 through the date of the Commission's final determination, compared with each of the following:

        i. the final dates for 2015, if effective on January 1, 2015; and

        ii. the final rates for 2015, if effective on the date of the Commission's final determination.

50. Parties wishing to comment on the interim-rates-proposal filing discussed above shall file comments within 20 days. Comments should address the Company's proposal, including whether the proposal is consistent with

    a. The interim-rate statute, Minn. Stat. § 216B.16, subd. 3, including the provision in Minn. Stat. § 216B.16, subd. 3(c), for implementation of the new revenue requirement ("If, at the time of its final determination, the commission finds that the interim rates are less than the rates in the final determination, the commission shall prescribe a method by which the utility will recover the difference in revenues between the date of the final determination and the date the new rate schedules are put into effect.");

    b. Minn. Stat. § 216B.16, subd. 3(b), prohibiting changes in rate design while interim rates are in effect. ("[T]he interim rate schedule shall be calculated using the proposed test year cost of capital, rate base, and expenses, except that it shall include . . . no change in the existing rate design.");

    c. The multiyear-rate-plan statute, Minn. Stat § 216B.16, subd. 19, and the Commission's June 17, 2013 Multiyear Rate Plan Order (Docket No. E,G-999/M-12-587); and

    d. The various approved extensions to the length of this proceeding.

51. The Company shall provide a refund to ratepayers if the Company's actual capital-related revenue requirement is less in total in 2014 than the Commission authorizes for the 2014 test year. Such a refund would be based on the Company's total actual capital revenue requirements compared to the Commission's authorized amount, but would not be done on a project-by-project basis.

52. The true-up for capital costs in 2015 shall be conducted on a project-by-project basis for those project costs included in the 2015 Step. If the total actual 2015-Step revenue requirement is lower than the total test-year 2015 Step authorized by the Commission, the Company shall provide a refund to customers.

53. Within 30 days of the date of this order, the Company shall make the following compliance filings:

    a. Revised schedules of rates and charges reflecting the revenue requirement and the rate-design decisions herein, along with the proposed effective date, and including the following information:

        i. Breakdown of Total Operating Revenues by type.

        ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to

            - Total revenue by customer class;

            - Total number of customers, the customer charge, and total customer-charge revenue by customer class; and

            - For each customer class, the total number of energy- and demand-related billing units, the-per unit energy and demand cost of energy, and the total energy- and demand-related sales revenues.

        iii. Revised tariff sheets incorporating authorized rate-design decisions.

        iv. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

    b. A revised base cost of energy, supporting schedules, and revised fuel-adjustment tariffs to be in effect on the date final rates are implemented.

    c. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

    d. A computation of the Conservation Cost Recovery Charge (CCRC) based upon the decisions made herein for inclusion in the final order. The filing shall include a schedule detailing the CIP tracker balance at the beginning of interim rates, the revenues (CCRC and CIP Adjustment Factor) and costs recorded during the period of interim rates, and the CIP tracker balance at the time final rates become effective.

54. Any comments on compliance filings shall be filed within 30 days of the date of the compliance filing. Comments are not necessary on the Company’s proposed customer notice.

55. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

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