BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

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

ISSUE DATE: March 12, 2018

DOCKET NO. E-015/GR-16-664

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

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PROCEDURAL HISTORY

I. Initial Filings and Orders

On November 2, 2016, Minnesota Power (the Company) filed this general rate case seeking an annual rate increase of $55,123,680, or approximately 9.1%. 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 December 30, 2016.[1]

Also on December 30, 2016, 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 Application of Minnesota Power for Approval of a New Base Cost of Fuel and Purchased Energy*, Docket No. E-015/MR-16-709, Order Setting New Base Cost of Energy During Interim Rate Period (December 30, 2016).

II. The Parties and Their Representatives

The following parties appeared in this case:

- Minnesota Power, represented by David R. Moeller, Senior Attorney; and Elizabeth Brama, Valerie T. Herring, and Kodi J. Verhalen, Briggs & Morgan, P.A.

- Minnesota Department of Commerce (the 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.

- Minnesota Chamber of Commerce (the Chamber), represented by R. Cameron Winton, Director of Energy and Labor Management Policy.

- Large Power Intervenors (LPI), represented by Andrew P. Moratzka and Sara Johnson-Phillips, Stoel Rives LLP.

- Minnesota Center for Environmental Advocacy, Fresh Energy, Sierra Club, and Wind on the Wires (together, the Clean Energy Organizations or CEO), represented by Attorneys Leigh Currie, Kevin Reuther, and Hudson Kingston.

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

- Sam's West, Inc. and Wal-Mart Stores, Inc. (Wal-Mart), represented by Allen Jenkins, Jenkins at Law, L.L.C.

- The Fond du Lac Band of Lake Superior Chippewa (the Fond du Lac Band), represented by Seth J. Bichler, Staff Attorney, and Philip R. Mahowald, The Jacobson Law Group.

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

- Citizens Utility Board of Minnesota (CUB), represented by Kristin Munsch, Deputy Director.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Jim Mortenson 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 8 through 11, 2017. After the hearings the parties filed initial briefs, and reply briefs.

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

- Range Recreation Civic Center, Eveleth—June 19, 2017
- Inn on Lake Superior, Duluth—June 20, 2017
- Continued Learning Conference Center, Grand Rapids—June 21, 2017
- Morrison County Government Center, Little Falls—June 22, 2017

IV. Public Comments

At the four public hearings, the Company, the Department, the OAG, and the Commission's staff were available to make presentations and field questions from members of the public.

All public comments are filed in the case record. Written comments are labeled "Public Comment," of which the Commission received several dozen. The overwhelming majority of public comments opposed a rate increase. A thorough, detailed summary of the public comments in the proceeding is attached to the ALJ's report.

V. Proceedings Before the Commission

On November 7, 2017, the Administrative Law Judge filed his 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 Clean Energy Organizations, the Large Power Intervenors, AARP, Wal-Mart, CUB, and the Minnesota Chamber of Commerce.

On January 11, 18, and 30, 2018, the Commission heard oral argument from and asked questions of the parties. On January 30, 2018, 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

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

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

> 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.

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 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]

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

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.

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

Minnesota Power seeks an annual rate increase of $49,194,824, or approximately 8%.[8] The Company also proposed to modify its rate design to increase the rates for residential customers—initially by about 18%—in order to bring the revenue from that class of customers closer to what it claimed were the costs to serve that class.

Parties generally agreed that it would be reasonable to modify the revenue allocation among classes in a way that would increase the percentage apportioned to residential ratepayers, but disagreed about the appropriate magnitude of that shift.

Not long after Minnesota Power filed this rate case, it learned of a substantial increase in its expected sales revenue because a large industrial customer planned to, and did, resume

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

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

[8] As revised in the surrebuttal testimony of Marcia Podratz (July 21, 2017).

operations. This resulted in changes to the Company's anticipated test-year revenue deficiency and its requested interim rate while the case proceeded. The effects of this change in circumstances are discussed in the relevant sections, below.

The Company used a projected 2017 test year, based on actual data from fiscal year 2015 and projected data from 2016.

III. Summary of the Issues

Many initially contested issues were resolved in the course of evidentiary proceedings. The Administrative Law Judge did not address the resolved issues or make recommendations concerning them. The Commission, having found the agreements of the parties on the resolved issues to be reasonable in light of the entire record and the Commission's final decisions on disputed issues herein, will accept them.

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

General Issues

- ***Minn. Stat. § 216B.1696*—**What effect does implementation of a rate schedule, tracker, and rate recovery rider under the statute have on this proceeding?

Financial Issues

- ***Boswell Remaining Lives*—**Should Minnesota Power be authorized to extend the accounting lives of Boswell Energy Center's generating units and common facilities as a rate-mitigation measure?
- ***Prepaid Pension Asset*—**Should the Company earn a return from ratepayers on prepaid pension amounts?
- ***Generation O&M Supervision & Engineering and Distribution Meter Reading*—**Is the test year amount for these accounts reasonable?
- ***Transmission Capital Projects*—**Is the test year amount for these projects reasonable?
- ***Generation Capital Projects*—**Is the test year amount for these projects reasonable?
- ***Taconite Harbor Restart/Re-Idle*—**What amount should be included in the test year to reflect the need to restart and re-idle this facility?
- ***Third-Party Transmission Revenues and Expenses*—**What is the appropriate amount of test-year net revenue for third-party transmission revenues and expenses?
- ***Transmission O&M*—**Is the test year amount of these expenses reasonable?
- ***Storm Response Budget*—**Should the Commission approve a budget for storm restoration?
- ***Credit Card Processing Fees*—**Should the Company be permitted to recover the cost of processing credit card bill payments from all ratepayers?

- ***AIP, EDA, and EIP*****—**Should the Company be permitted to include in the test year expenses for certain compensation plans for high-level employees?
- ***Spot Bonuses*****—**Should the Company be permitted to include expenses for "spot bonuses" in the test year?
- ***Retirement Savings & Stock Ownership Plan*****—**Should the test-year retirement savings and stock ownership expenses be determined by a three-year historical average?
- ***Other Employee Benefits*****—**Should the category of expenses labeled "other employee benefits" be determined by a three-year historical average?
- ***Employee Gifts*****—**Are these expenses reasonable and necessary for the provision of utility service?
- ***Travel, Entertainment, and Related Employee Expenses*****—**Should the test-year amount of these expenses be determined by a three-year historical average?
- ***Membership Dues*****—**Should the test year include the Company's trade-organization membership dues?
- ***Charitable Contributions*****—**Should the allowable test-year charitable contribution expense be based on a three-year historical average? Should it include administrative expenses?
- ***Cash Working Capital*****—**Are the Company's lead/lag study and method of calculating cash working capital reasonable?
- ***Fuel Clause*****—**Which, if any, Company proposals for adjusting the fuel clause rider calculation should the Commission adopt in this proceeding?
- ***Keetac Test Year Revenue*****—**Should revenue from Keetac be annualized in the test year? Should the test year sales forecast reflect 12-months of sales to Keetac?
- ***Interim Rate EITE Tracker Balance Accrual***—How should Minnesota Power recover approved EITE tracker balance amounts from the appropriate customers that arise during the unique circumstances of this case's interim rate period?

Cost of Capital Issues

- ***Capital Structure*****—**What percentages of equity, long-term debt, and short-term debt should make up the Company's capital structure?
- ***Cost of Debt*****—**What is the Company's cost of debt?
- ***Cost of Equity*****—**What is a fair and reasonable rate of return on equity for this Company, on this record, at this time?
- ***Overall Rate of Return*****—**Based on determinations of each component, what is a fair and reasonable overall rate of return for this Company, on this record, at this time?
- ***Annual Rate Review Mechanism*****—**Should the Commission approve the Company's proposed annual rate review mechanism?

<u>Class Cost of Service Study (CCOSS) Issues</u>

- ***CCOSS*—**What action, if any, should the Commission take with respect to the class cost of service studies proposed in this case?
- ***Cost Allocators: Production, Transmission and Distribution*—**How should costs of various utility system components be allocated?

<u>Rate-Design Issues</u>

- ***Interclass Revenue Apportionment*—**What percentage of the revenue requirement should be allocated to each customer class?
- ***Residential Block Rate Design*—**How should the Company's residential block rate design be modified?
- ***Residential Customer Charge*—**At what level should the Commission set the fixed monthly charges for the residential class?
- ***CARE Rider*—**Which, if any, proposed changes to the CARE Rider should the Commission approve?
- ***Late Payment Assessment*—**Should the Company's proposal to remove the minimum $1.00 late payment charge be approved?
- ***Reconnect Pilot*—**Should the Commission approve the Company's proposed remote reconnection pilot?
- ***Miscellaneous Rate Proposals*—**Should the Commission approve requests concerning certain tariffed rates for customers receiving the following services: Seasonal Residential, Municipal Pumping, Duel Fuel, and Residential and Commercial Controlled Access?
- ***Fixed and Variable Rates*—**At what level should the Commission set the fixed monthly charges and the variable charges for the remaining customer classes?
- ***Large Light and Power Rider*—**Should the Commission approve changes to the Large Light and Power tariff, including changes to the Time-of-Use rider?
- ***Interruptible Large Power, Large Light and Power Rates and Tariffs*—**Should the Commission approve or require changes to the Company's Interruptible Large Power and Large Light and Power rates and tariffs?
- ***Large Power Service*—**Are proposed changes to these services reasonable?
- ***Power Factor Adjustment*—**Should the Company be permitted to revise its power factor threshold for certain service schedules?
- ***Back-up Generation Program*—**Under what conditions should the Commission approve a pilot program to facilitate customers who wish to integrate back-up generation that the Company would own, install, maintain, and operate?
- ***Business Development Incentive Rider*—**Is the Company's proposed Business Development Incentive Rider consistent with the public interest?
- ***Grid Resilience and Innovative Demonstration (GRID) Pilot*—**Is the Company's proposed GRID Pilot consistent with the public interest?

- ***Green Pricing*****—**Is the Company's proposed green pricing program consistent with the public interest?
- ***Decoupling*****—**Should the Commission require the Company to propose or implement a revenue-decoupling rate design?
- ***SES Capacity Energy Benefits*****—**Which method of allocating the solar capacity of the Camp Ripley solar project is most reasonable?
- ***US Steel Electric Service Agreement*****—**Is the contract provision concerning demand charge credits consistent with the public interest?

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 ALJ held four days of formal evidentiary hearings and four public hearings. He reviewed the testimony of the parties' expert witnesses and related hearing exhibits. He reviewed the written comments submitted by members of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties. He made findings of fact and conclusions of law and made recommendations on 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 many of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission makes different findings, is compelled to restate an applicable legal standard or evidentiary burden, draws different conclusions, or reaches a similar conclusion for different reasons, as delineated and explained below.

GENERAL ISSUES

V. Minn. Stat. § 216B.1696

Minnesota Power has implemented a rate discount for "energy-intensive trade-exposed" (EITE) customers authorized under Minn. Stat. § 216B.1696 (the EITE statute).

The Company's implementation of the rate discount relies on an EITE rate schedule and a cost-recovery rate rider authorized by the statute. Details of the implementation under section 216B.1696 have been addressed in a series of decisions in Docket No. E-015/M-16-564.[9]

How the EITE statute fits together with a general rate determination is a matter of first impression for the Commission. At least one party has acknowledged that the relationship between these subjects is "complex."[10] Parties offered arguments—across a broad range of issues presented in this proceeding—on how the Commission might integrate implementation of the EITE statute with general rate setting.

The Commission does not adopt the ALJ's policy statements concerning the EITE statute nor his conclusions regarding its implications for this Minn. Stat. § 216B.16 proceeding. The ALJ's conclusions concerning the EITE statute are variously overbroad, erroneous, or inconsistent with the Commission's statutory obligations, either under the EITE statute or in a general rate proceeding.

For example, the ALJ suggested that the Commission should reduce rates for EITE customers through rate design, and that the resulting outcome "should drive whether the PUC continues to use the EITE credit as a device to accomplish the legislature's goal with regard to supporting EITE customers."[11] But under the EITE statute, the Commission "shall" approve an EITE rate schedule in a proceeding under section 216B.1696 upon a finding of net benefit to the utility or the state. So the legislature has made clear that an EITE rate schedule, not rate design in a general rate case, is the mechanism by which the Commission is directed to "achieve [the statute's] objective."[12]

Because the Commission lacks discretion to disapprove a statutorily adequate EITE rate schedule proposal, an effort to accomplish the purposes of the EITE statute through rate design would likely be duplicative and result in unjust rates—there is no adjustment that can be made in this proceeding that would not be subject to further modification by an EITE rate schedule.

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[9] *In the Matter of Minnesota Power's Revised Petition for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider*, Docket No. E-015/M-16-564, Order Approving EITE Rate, Establishing Cost Recovery Proceeding, and Requiring Additional Filings (December 21, 2016), Order Authorizing Cost Recovery with Conditions (April 20, 2017), Order Excluding Rider Revenue from 2016 Baseline Calculation and Setting Parameters to Identify Exempt Customers (October 13, 2017), and Order Denying Reconsideration (February 7, 2018). These orders are the subject of an appeal. *See* Minn. Ct. App. Case No. A18-0382.

[10] Initial Brief of the OAG, at 22.

[11] ALJ's Report, at 153.

[12] Minn. Stat. § 216B.1696, subd. 2(a)–(c).

If the legislature had intended for the EITE statute to override the framework for ratemaking, it would have said so expressly.[13] Instead, it is consistent with the EITE statute to clearly maintain a distinction between concepts that could easily be conflated, such as a utility's EITE rate schedule under subdivision 2(b), the amounts required to be tracked and recovered or refunded under subdivision 2(d), and rates duly established for a utility in a general rate proceeding under clearly applicable statutory and regulatory criteria.[14]

To the extent implementation of the EITE statute has an effect on a specific issue raised in this proceeding, it will be discussed in that issue's section, below.

FINANCIAL ISSUES

VI. Boswell Energy Center Remaining Lives

A. Introduction

Boswell Energy Center (Boswell) is Minnesota Power's largest power plant, with a total capacity of more than 1,000 megawatts (MW). Boswell has four coal-fired generating units (Units 1–4) and common facilities with the following currently approved remaining accounting lives:

Table 1: Boswell Energy Center Remaining Lives[15]

	Retirement Year
Units 1 and 2	2024
Unit 3	2034
Unit 4	2035
Common Facilities	2030

In this rate case, Minnesota Power has proposed to extend the accounting lives of all Boswell components to 2050 as a rate-increase-mitigation measure. The Company's proposal would reduce the test-year revenue requirement in this case by $22.7 million, primarily by decreasing depreciation expense.

[13] Minn. Stat. § 216B.1696, subd. 2(b), constrains the Commission's discretion to disapprove an EITE rate schedule and corresponding rate, but not other Commission functions, such as approving a tracker/rider implementation under subd. 2(d), or conducting general rate proceedings arising under Minn. Stat. § 216B.16.

[14] These criteria include those in Minnesota Statutes, sections 216B.03,.05,.06,.07, and .16, which require that rates be just and reasonable; not be unreasonably preferential, unreasonably prejudicial, or discriminatory; and be set to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, .241, and 216C.05.

[15] *See generally In the Matter of Minnesota Power's 2015 Remaining-Life Depreciation Petition*, Docket No. E-015/D-15-711.

“Depreciation” refers to an asset’s loss of value over time due to wear and tear, weathering, obsolescence, changes in demand, requirements of public authorities, and other factors.[16] The Commission’s depreciation-accounting rules generally require that the cost of an asset be amortized over its “probable service life,” which extends from “the date of its installation to the forecasted date when it will probably be retired from service.”[17]

The Company does not claim that 2050 marks the end of the Boswell units’ probable service lives. To the contrary, the Company plans to retire Units 1 and 2 by the end of 2018 and does not intend to operate Units 3 and 4 beyond 2034 and 2035, respectively. However, the Company provided an opinion letter from an engineering firm finding “no technical reasons” that, with appropriate maintenance and investments into replacements and upgrades, the plant could not be operated until 2050. The opinion did not consider limitations due to future environmental regulations, nor did it consider the economics of such operation.

B. Positions of the Parties

1. The OAG and CEO

The OAG and CEO argued that the Company’s rate-mitigation proposal conflicts with the Commission’s depreciation-accounting rules. Because Units 1 and 2 will be retired in 2018, and Units 3 and 4 are not expected to run past 2035, there is no basis to find that any of the units will “probably be retired from service” in 2050, they contended.

These parties acknowledged that the Commission has the ability to vary its rules under certain circumstances but argued that a variance would not be justified in this case. They cited, among other concerns, that current ratepayers would pay less at the expense of future ratepayers, that extending the lives would increase returns to shareholders, and that extension could impact future decisions about retiring Units 3 and 4.

CEO and OAG’s concerns stem in large part from the fact that setting Boswell’s depreciation life longer than its actual life means that some depreciation expense will remain unrecovered at the time of its retirement.

Therefore, if the Commission ultimately grants a variance and approves Minnesota Power’s proposal, the OAG and CEO would recommend that the Company be required to explore “securitizing” any unrecovered investment at the time Units 3 and 4 are retired. As envisioned by CEO, securitization would involve the following steps:

- The Commission would authorize formation of a special-purpose vehicle to issue bonds and repay bondholders;
- The Commission would approve a dedicated charge on customer bills for the purpose of paying interest and principal on the bonds issued;

[16] *See* Minn. R. 7825.0500, subp. 6.

[17] *Id.*, subp. 10; *see also id.*, subps. 2, 7 (defining “amortization” and “depreciation accounting”).

- Proceeds from the issuance of the bonds would be provided to the Company for the unrecovered plant balance and decommissioning costs resulting from the early retirement; and
- The dedicated customer charge would be used to pay off the bond over time.

According to CEO and the OAG, securitization holds the potential for significant ratepayer savings in the recovery of stranded investments in fossil-fuel-based generation.

2. The Department

The Department recommended setting Unit 1 and Unit 2's remaining life to end in 2022, consistent with the Commission's order on Minnesota Power's most recent resource plan.[18]

And the Department supported extending Unit 3, Unit 4, and the Common Facilities' remaining lives to 2050 as a rate-mitigation measure. The Department agreed with the Company that these components *could* operate until 2050, due to recent environmental-compliance retrofits, and that setting their remaining lives accordingly was consistent with generally accepted accounting principles. The Department emphasized that this extension would be solely for ratemaking purposes and would not determine the actual life of the units.

3. The Chamber and LPI

The Chamber and LPI supported Minnesota Power's proposal to extend Boswell's remaining lives to 2050, arguing that the proposal was a reasonable way to mitigate near-term rate impacts. LPI also voiced strong support for the securitization framework advanced by CEO, and recommended that the Commission direct Minnesota Power to pursue securitization as an alternative to ratepayers' continuing to pay for retired units in the long term.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that Units 1 and 2 be depreciated until 2022, consistent with the Commission's direction to retire the units by 2022 in the Company's most recent resource-plan proceeding. And he recommended that Units 3 and 4 and the Common Facilities be depreciated until 2035, Unit 4's currently approved remaining life. He reasoned that 2035 reflected their probable service lives, and that extending their remaining lives to 2050 would shift shareholder risk to ratepayers and cause future ratepayers to pay for assets from which they will not benefit.

D. Commission Action

Having reviewed the record and the arguments of the parties, the Commission concludes that the remaining accounting lives for Boswell Units 1 and 2 should be set at 2022, and that the remaining accounting lives for Units 3 and 4 and the Common Facilities should be set at 2050. The Commission finds that a variance to its depreciation-accounting rules is justified under the circumstances and will grant one for the reasons explained below.

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[18] *See In the Matter of Minnesota Power's 2016–2030 Integrated Resource Plan*, Docket No. E-015/RP-15-690, Order Approving Resource Plan with Modifications (July 18, 2016).

The Commission agrees with the Department and the ALJ that Unit 1 and 2's life should be set in accordance with Minnesota Power's approved resource plan, which requires these units to be retired no later than 2022. And the Commission finds that Units 3 and 4 and the Common Facilities' remaining lives should be extended to 2050 to provide rate moderation.

The change to Unit 3 and 4's remaining lives will require a variance to the Commission's depreciation-accounting rules, since the new remaining lives do not match these units' probable service lives. The Commission must grant a variance to its rules when it determines that the following requirements are met:

1. enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;
2. granting the variance would not adversely affect the public interest; and
3. granting the variance would not conflict with standards imposed by law.[19]

The Commission finds that enforcing Minn. R. 7825.0500 would impose an excessive burden upon ratepayers by contributing close to $22 million to the overall rate increase in this case. This burden would fall most heavily on the Residential customer class by virtue of the rate-design decisions outlined later in this order.

The Commission further finds that granting the variance will not adversely affect the public interest. The Commission has carefully considered the intergenerational-equity concerns raised by the OAG and CEO—that ratepayers now are being granted rate mitigation at the expense of future ratepayers—as well as their argument that any unrecovered balance that remains in 2034 and 2035 would create pressure to keep Units 3 and 4 running. The Commission concludes that these concerns will be mitigated by requiring the Company to pursue securitization.

CEO have put forward the outlines of what securitization would look like, but much work remains to be done to flesh out the details of a plan. In particular, Minnesota Power has argued that legislative approval may be needed for securitization to work, while other parties dispute this contention.

Finally, the Commission finds that varying Minn. R. 7825.0500 will not conflict with any standards imposed by law. CEO argue that operating Boswell until 2050 would be incompatible with the state's goal of encouraging the use of renewable energy to the maximum reasonable extent.[20] To be clear, however, the Commission is only extending the units' *accounting* lives; this extension does not extend the service or operational life of these facilities.

For these reasons, the Commission will vary the rules that require Unit 3 and Unit 4's accounting lives to match their probable service lives. This variance will remain in effect until terminated by the Commission. In the meantime, the Commission will direct Minnesota Power to develop a securitization plan for the Boswell units to address any depreciation expenses that will remain

[19] Minn. R. 7829.3200, subp. 1.

[20] *See* Minn. Stat. § 216B.03.

unrecovered at the end of Unit 3 and 4's expected service lives, and to file it within two years of the final order in this case.

The Commission looks forward to receiving the Company's proposal, informed by the input of stakeholders including the OAG and CEO, and to working with the parties to find a solution to the problem of stranded fossil-fuel investments.

VII. Prepaid Pension Asset

A. Introduction

In most years, Minnesota Power makes contributions to its pension plan to ensure adequate funding to cover future benefit obligations to its employees. The Company has contributed more to the pension plan than it has expensed since the plan's inception, resulting in a positive balance that the Company refers to as a "prepaid pension asset."

Minnesota Power would like to earn a return on this prepaid pension amount, which is not currently a part of its rate base. The Company seeks to include approximately $60 million in pension funds in rate base, offset by some $31.9 million in associated tax savings, for a net after-tax increase to rate base of approximately $27.8 million.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power argued that it should be allowed to include prepaid pension funds in rate base for the following reasons:

- The Company funds its pension plan at the level required by federal law, and no party has argued that the plan is overfunded;
- The prepaid amount earns a return that benefits ratepayers by reducing annual pension expense; and
- The Company has lost the use of prepaid funds without receiving any compensation for them.

However, the Company acknowledged that in all recent rate cases where rate-base treatment of prepaid pension assets has been a contested issue, the Commission has ruled that these costs should not be included in rate base.[21]

2. The Department

The Department recommended that the prepaid pension asset be removed from rate base, for the following reasons:

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[21] *See, e.g.*, *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-017/GR-15-1033, Findings of Fact, Conclusions, and Order, at 25–26 (May 1, 2017).

- The concept of calculating the difference between plan contributions and actuarially calculated pension expense is an obsolete concept no longer used under Generally Accepted Accounting Principles (GAAP);
- It is unreasonable to allow the Company to place a prepaid pension asset, as defined by outdated GAAP guidance, into rate base to earn a guaranteed return while the pension plan is actually underfunded; and
- The prepaid pension asset is different from typical prepaid assets because it does not necessarily represent cash outlay by the Company, nor does it depreciate or amortize over time like other assets.

Moreover, even assuming the Company does have a prepaid pension asset, the Department argued that it should not be included in rate base because the prepaid funds are not 100% Company-paid but are also supplied by ratepayers and include market returns on plan assets.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the prepaid pension asset not be included in the test-year rate base. He reached this conclusion based on prior Commission rate-case decisions, and in particular based on his finding that it would be impracticable, if not impossible, to tease out the prepaid amount attributable solely to the Company's contributions.

D. Commission Action

The Commission concurs with the Administrative Law Judge and the Department that Minnesota Power has not justified rate-base treatment of prepaid pension funds. Accordingly, the Commission will require the Company to remove the prepaid pension asset, along with the associated tax savings, from test-year rate base.

The Commission has articulated the reasons for excluding this type of asset from rate base in several previous orders.[22] The circumstances that warranted denying a return on the asset in those cases are present here, and so the Commission adopts the same rationale for excluding it.

Minnesota Power recovers its allowable pension expense from ratepayers and is not denied recovery of this operating cost.

The accounting asset identified by the Company is distinct from assets that typically are included in rate base. The asset already earns a return in the form of investment returns, it fluctuates in value, and is misleading in that it does not account for the funding status of the entire pension plan.

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[22] *See, e.g.*, *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-011/GR-15-736, Findings of Fact, Conclusions, and Order, at 8–11 (October 31, 2016); *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 22–24 (October 28, 2014).

Further, as the Commission has recognized in previous cases, pension-plan assets and benefit obligations fluctuate up and down, depending on funding or market conditions. The balances in the prepaid pension asset are temporary, and fundamentally different from typical rate-base assets on which the Company earns a return on investment. The Commission concurs with the Department and the ALJ that it would be impractical, if not impossible, to equitably separate the prepaid amount attributable solely to Minnesota Power's contributions from that attributable to ratepayer contributions and market returns.

For these reasons, the Commission will deny the Company's request for rate-base treatment of the prepaid pension asset.

VIII. Generation O&M Supervision & Engineering and Distribution Meter Reading

A. Introduction

In reviewing Minnesota Power's proposed operation and maintenance (O&M) expenses for the test year, the Department observed several FERC accounts whose budgeted costs were substantially above actual spending in recent years.[23]

These accounts fell into two broad categories—(1) generation O&M supervision and engineering costs and (2) meter-reading costs. The Department observed a trend of overbudgeting in both categories:

Table 2: Comparison of Actual and Budgeted O&M Expenses, 2015–2017[24]
(% increase)

	2016 Actuals to 2016 Budget	2015 Actuals to 2016 Budget	2016 Actuals to 2017 Budget	2015 Actuals to 2017 Budget
Generation O&M Super. & Eng'g	84%	49%	89%	53%
Meter Reading	235%	189%	251%	203%

[23] "FERC accounts" refers to the utility-cost-classification system established by the Federal Energy Regulatory Commission.

[24] *See* Ouanes direct, at 31.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power proposed to include its full 2017 budgeted amounts of approximately $21.4 million in generation O&M supervision and engineering expenses and $1.1 million in meter-reading expenses in the test year, on a total-company basis.[25]

Minnesota Power argued that the Department's focus on FERC cost categories was misplaced because the Company budgets for O&M expenses by "responsibility center" rather than by cost category. (Each generation plant is a separate responsibility center.) And it contended that the Department's review overlooked additional related accounts that would have provided a better perspective of the Company's O&M spending.

Minnesota Power stated that the bulk of the variances observed by the Department related to changes in labor spending, caused by (1) temporarily assigning O&M employees to work on capital projects and (2) the approaching retirement of Units 1 and 2 at its Boswell Energy Center. The Company argued that it had already reduced its test-year O&M expenses by $3.4 million (total company) to account for the latter.

Finally, Minnesota Power stated that its proposed test-year O&M expenses help ensure safe and reliable electric service to its customers and argued that any further reduction could jeopardize its ability to provide this service.

2. The Department

The Department recommended reducing Minnesota Power's test-year O&M expenses by $6.781 million (Minnesota jurisdiction) to reflect a five-year average level of generation O&M supervision and engineering and meter-reading expenses.

The Department argued that Minnesota Power had failed to carry its burden to show that its test-year budget for these O&M expenses was reasonable. The Department reasoned that Minnesota Power is in the best position to explain its process for developing the test-year budget but, even when pressed, failed to provide much more than a very high-level summary.

Responding to Minnesota Power's argument that it already reduced test-year O&M expenses, the Department maintained that the Company had not shown that there was any overlap between that adjustment and the $6.781 million adjustment the Department is recommending. The Department also contended that there was no evidence that a further reduction in test-year O&M expenses would impact the Company's ability to provide electric service.

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[25] The Company presented test-year costs in two formats: "total company" and "Minnesota jurisdiction." A cost presented on a "total company" basis reflects the entire amount incurred by the utility. A "Minnesota jurisdictional" cost is the portion allocated to Minnesota ratepayers. The Company was not always consistent in providing both amounts, and other parties used one or the other depending on what was available. This order endeavors to specify the format of the cost under discussion where doing so would provide clarity.

The Department argued that, because the actual expenditures in these categories have been trending down over the past five years, it would be reasonable to use actual 2016 spending as the 2017 test-year amount. But to be conservative, the Department recommended using a five-year average, which results in a smaller reduction.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the Company's approach to budgeting resulted in just and reasonable O&M expenses. The ALJ reasoned that the Department simply approached budgeting from a different perspective than the Company, and that the issue was not which approach is better but rather whether Applicant's proposed test year budget is necessary and reasonable to provide electric service to customers at reasonable rates.

D. Commission Action

Having reviewed the record developed by the parties on this issue, the Commission agrees with the Department that Minnesota Power has not carried its burden to show that its budgets for test-year generation O&M supervision and engineering and meter-reading costs are reasonable. The Commission will therefore require the Company to set the test-year budget for these costs at their five-year historical average, a $6.781 million reduction in test-year O&M expense.

The Commission disagrees with the ALJ's conclusion that the reasonableness of the Company's test-year O&M budget can be judged without reference to the Department's approach. The Commission concludes that the Department's criticisms are valid and that Minnesota Power did not offer an adequate response.

During discovery, the Department raised concerns about the consistent over-budgeting it observed in three O&M expense categories related to generation O&M and meter reading. At Minnesota Power's request, and to gain a more complete picture of related O&M spending, it extended its review to seven FERC accounts. The over-budgeting trend was still apparent under this broader scope of review.

In response to Department information requests, Minnesota Power provided only a high-level description of its budgeting process, and the Department was left unable to determine the basis for or reasonableness of the Company's budgets. As a result, the Department appropriately concluded that test-year expense should be set at the five-year average of historic, actual spending.

Minnesota Power argues that it does not budget by FERC cost categories but by responsibility center, and that any analysis of the reasonableness of its O&M expenses must examine FERC accounts at the responsibility-center level. The Commission disagrees. It is reasonable to examine costs on a FERC-account basis regardless of how a utility budgets, because it aids in the identification of company-wide spending trends such as those discovered by the Department in this case.

Minnesota Power also argues that it has already made a downward adjustment to O&M expenses to reflect reduced payroll expenses at one of its plants, and that further reduction in test-year O&M spending could threaten its ability to provide reliable service. However, the Company has not shown that the Department's proposed adjustment overlaps with the adjustment already made, or that the proposed adjustment will affect its ability to reliably serve ratepayers.

IX. Transmission Capital Projects

A. Introduction

Like most electric utilities, Minnesota Power continually upgrades and extends its transmission system to maintain reliability and serve new load. These transmission investments are known as transmission capital projects and are a part of the rate base on which the Company earns a return. Minnesota Power's test-year rate base included $31.95 million (total company) of transmission capital additions, net of retirements.

B. Positions of the Parties

After reviewing the Company's initial filing and conducting discovery, the Department concluded that at least two major transmission capital projects—the 5-Line Reconductor and Hoyt Lakes Ring Bus Reconfiguration—were unlikely to enter service in 2017 and thus should be excluded from rate base. This change would reduce the test-year revenue requirement by approximately $140,000 on a Minnesota-jurisdictional basis.

Minnesota Power agreed that these two projects would not enter service in 2017. However, in discovery responses, the Company contended that these two projects needed to be deferred to allow six higher-priority projects to be completed in 2017.[26] Because the combined cost of these high-priority projects exceeded the cost of the two deferred projects, the Company argued that no adjustment to the test-year rate base or revenue requirement was necessary.

The Department responded that it was not appropriate for Minnesota Power to supplement its filing with new capital projects to replace those that it agreed should not be part of test-year rate base. Providing such information late in the proceeding, the Department argued, posed a challenge to parties trying to review the Company's expenses and could result in rates that are too high. And it argued that, in any event, Minnesota Power had not provided sufficient information to support the new projects.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Minnesota Power was entitled to replace the two deferred transmission capital projects with the higher-priority projects, relying on the Commission's 2015 order in an Xcel Energy rate case, in which the Commission allowed that utility to substitute new projects for delayed or canceled capital projects.[27]

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[26] *See* Campbell direct, at 25–26. In rebuttal testimony, the Company identified still more major transmission capital projects that were scheduled to be in service in 2017. *See* Fleege rebuttal, at 21–22.

[27] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, at 26–27 (May 8, 2015) [hereinafter "2015 Xcel rate-case order"].

D. Commission Action

The Commission agrees with the Department that, in this case, Minnesota Power has not met the standard for substituting new capital projects for the deferred projects removed from test-year rate base. Therefore, and as further explained below, the Commission will require the Company to remove the 5-Line Reconductor and Hoyt Lakes Ring Bus Reconfiguration projects from the revenue requirements for the 2017 test year.

Minnesota Power conceded that the 5-Line Reconductor project and Hoyt Lakes Ring Bus Reconfiguration projects would not be in service in 2017 and that they therefore should not be included in the test-year rate base. However, the Company sought to supplement its initial rate-case filing with replacement projects that it asserted would be in service in 2017. The Company argued that replacing delayed projects with new projects was supported by a prior Commission order.

In the 2015 Xcel rate-case order, the Commission allowed Xcel Energy to supplement its initial filing with additional capital projects to replace certain projects that the utility acknowledged would not be in service during the test year. In reaching this result, the Commission concurred with and adopted an administrative law judge's finding that a utility should be permitted to substitute replacement projects only if:

- The utility has shown that the replacement projects are necessary, the costs are prudent, and the projects will be in-service during the test year; and
- The other parties have had sufficient time to review the proposed replacement projects.[28]

In other words, it is not enough for a utility to assert that it intends to spend a certain amount on capital projects in the test year. The utility must demonstrate that its proposed recovery of capital costs for particular projects is reasonable, and it must provide that information in a timely fashion so that the Department and other stakeholders can perform their due-diligence review of these costs.

The Commission finds that in this case, Minnesota Power made it impossible for the Department to review its requested transmission capital costs by filing, in rebuttal testimony, a new proposal indicating that there were now eight major capital projects (each of whose cost exceeded $1 million) to be placed in service in 2017. This left the Department without sufficient time to review this new information, along with other contested issues, and to provide an assessment in its surrebuttal testimony.

The Company is the only party with access to all the relevant data, as well as complete control over when it files its rate case. It is reasonable to expect that Minnesota Power would be able to file a more complete proposal, or at least provide any major supplements much earlier than its rebuttal testimony. Under the circumstances, the Commission will deny the Company's request to add new transmission capital projects to its test year.

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[28] *See id.* at 26.

X. Generation Capital Projects

A. Introduction

Generation capital projects represent a utility's efforts to maintain and improve its fleet of power plants and other generating facilities. Minnesota Power initially included 68 generation capital projects in test-year rate base, with a total cost of $27.7 million.

During this proceeding, the Company provided updated information indicating that 7 of the 68 generation capital projects planned for 2017 had either been postponed or cancelled and would no longer be completed during the test year. The Company identified six higher-priority projects that it planned to complete in 2017 in place of the seven postponed or cancelled projects.

B. Positions of the Parties

The OAG recommended that the original seven projects be removed from test-year rate base and no new projects added. The OAG argued that Minnesota Power failed to sufficiently explain the need for the six replacement projects, and that, in any event, their combined cost was less than the combined cost of the original seven. The revenue-requirement reduction resulting from the OAG's recommendation would be about $107,000 (Minnesota jurisdiction).

Minnesota Power maintained that its generation capital additions should remain at $27.7 million, arguing that this figure was a reasonable representation of its costs during the test year. The Company stated that it typically does its budgeting work in June of the prior year, and that it is not possible at that time to predict with precision every capital project that will be needed during the test year. The Company contended that generation needs change throughout the year, and that it had provided sufficient information about need for the replacement projects.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission make no change to test-year rate base to account for the delayed or postponed generation capital projects. He reasoned that Minnesota Power was entitled to offer evidence of replacement projects, that the Company had adequately supported the replacement projects, and that the difference between the cost of the replacement projects and the original projects was de minimis.

D. Commission Action

The Commission agrees with Minnesota Power that the Company's budgeted generation capital additions of $27.7 million are a reasonable representation of the Company' capital investments for 2017 and will allow the Company to include that amount in rate base.

The goal in ratemaking is to establish a representative amount of costs to be included in rates prospectively, until the utility files another rate case. This includes establishing a representative amount for test-year capital projects. With respect to such projects, the Commission has concluded that, if it is to consider changes to in-service dates provided during the course of the proceeding, it should also consider a utility's candidates to replace delayed projects, provided that the utility has supported the replacement projects and other parties have had sufficient time to review them.[29]

In this case, there is no claim that the OAG or other parties lacked an opportunity to examine the replacement projects.[30] Rather, the OAG argues that Minnesota Power has not adequately explained the need for the replacement projects. The Commission disagrees; the Company provided details on each of the six projects, explaining why they were necessary. For example, the need to replace the Boswell Unit 3 elevator hoist and motor was brought to the Company's attention in late 2016, after it had developed its 2017 budget. And, given that the elevator is critical to efficient operations at Unit 3, this need required immediate action.

The OAG also argues that Minnesota Power's rate base should be adjusted to reflect the difference between the cost of the replacement projects and the original projects. This argument ignores that a rate-case capital budget in a projected test year is intended to reflect a representative amount of costs, and not actual costs, which in any event would only be fully ascertainable well after the close of the test year.

The Company has shown that its initial request, $27.7 million, is representative of its capital investment for 2017, and the Commission will allow this amount to be included in rate base.

XI. Taconite Harbor Restart

A. Introduction

In the fall of 2016, Minnesota Power idled two coal-fired generators (Units 1 and 2) at its Taconite Harbor Energy Center, and the Company plans to cease coal-fired operations at the plant entirely by the end of 2020. Until their decommissioning in 2020, Units 1 and 2 will remain available to run if needed to maintain grid reliability or if chosen in MISO's annual capacity auction.[31]

Regardless of whether they are actually called upon to run, the units will need to be restarted twice—once in 2017 and once in 2020—for the purposes of demonstrating compliance with environmental permit conditions and maintaining their capacity accreditation. Minnesota Power included $1.25 million (Minnesota jurisdiction) in the test-year revenue requirement as the representative cost of a single restart/re-idle sequence.

B. Positions of the Parties

The OAG argued that $1.25 million does not represent the annual cost of a restart/re-idle sequence since this event will not occur every year (that is, a restart will occur in 2017, but not in

[29] *See, e.g.,* 2015 Xcel rate-case order, at 26.

[30] The Company first provided information about the replacement projects in May 2017, almost a month before intervenor direct testimony was due.

[31] The Midcontinent Independent System Operator, or MISO, operates the Midwestern transmission system. MISO also operates an energy market designed to effectuate the cost-effective dispatch of generation resources connected to that system.

2018 or 2019). The OAG therefore recommended that Minnesota Power be allowed to recover the cost of the 2017 restart and re-idle, but spread out over three years. Thus, the test year would include only one-third of the cost requested by the Company, or $416,666.

In its prefiled rebuttal testimony,[32] the OAG also recommended that the Commission order a "sunset" provision such that recovery of this cost would automatically end after the total estimated cost of $2.5 million for the two restart events is recovered, even if the Company has not filed another rate case by that time.

Minnesota Power responded that Units 1 and 2 will be restarted a minimum of two times between 2017 and 2020—and likely more if they are called upon to address reliability issues or if they are selected in MISO's annual capacity auction. Thus, the Company argued that $1.25 million was reflective of the likely test-year costs of restarting the units.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Minnesota Power had demonstrated that it will likely incur at least $1.25 million to restart and re-idle Units 1 and 2 in each of the next four years. He therefore recommended that the Commission grant the Company's request to include that amount in the test-year revenue requirement.

D. Commission Action

The Commission concurs with the OAG that Minnesota Power has not justified recovery of the full annual cost of restarting/re-idling Taconite Harbor Units 1 and 2 in the 2017 test year. The Commission will require the Company to amortize this cost over three years, reducing the test-year amount by $833,334. The Commission will also order that Taconite Harbor-restart costs be removed from rates once the total estimated cost of $2.5 million for the two restarts has been recovered.

Minnesota Power argues that the two identified restarts represent the minimum number of times the units will need to be restarted by the end of 2020. But the Company has not made any effort to quantify the likelihood that additional restarts will occur. It states only that a restart will be needed *if* the units are called upon to preserve system reliability in the face of an unspecified contingency, or *if* the units are selected in the annual MISO capacity auction. This is not a sufficient basis to impose costs on ratepayers.

The Commission notes that to the extent that the shutdown of Units 1 and 2 causes local system-reliability issues, the Company has been ordered to remedy these issues.[33] Thus, it is unclear what unaddressed reliability issue would require restarting these units.

Moreover, as to the Company's claim that the units may be selected to run through the MISO capacity auction, the Commission makes two observations: First, the Commission notes that

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[32] Lee rebuttal, at 5.

[33] *See In the Matter of Minnesota Power's 2016–2030 Integrated Resource Plan,* Docket No. E-015/RP-15-690, Order Approving Resource Plan with Modifications, at 5, 14 (July 18, 2016).

while the Company did offer Units 1 and 2 in MISO's capacity auction for 2016–2017 and 2017–2018, the units were not selected to run because the Company's offer price was greater than the clearing price.[34] Thus, it is far from clear that the units are likely to be selected to run before their retirement in 2020.

Second, if the units do happen to be selected in MISO's auction, presumably the cost of restarting them would be factored into the offer price. In that case, the Company would be fully compensated by MISO for any restart costs.

For the foregoing reasons, the Commission will deny Minnesota Power's request to include $1.25 million in the test year for Taconite Harbor restart/re-idle costs, and will instead direct the Company to reduce its request by two-thirds and to remove these costs from rates after the cost of two restarts has been fully recovered.

XII. Third-Party Transmission Revenues and Expenses

A. Introduction

Minnesota Power earns revenue when transmission customers (typically, other utilities) use its transmission system to transport electricity to serve load located elsewhere. And it incurs costs when it uses other utilities' transmission systems to import electricity to serve its own load. These revenues and costs are known as third-party transmission revenues and expenses and are billed through the Midcontinent Independent System Operator (MISO), which operates the Midwestern transmission grid.

After discovery and two rounds of prefiled testimony, the Department and Minnesota Power agreed that $2.24 million (total company) in net transmission revenue should be included in the Company's test-year revenue requirement. This amount reflected an upward adjustment of $1.836 million (Minnesota jurisdiction) to account for the current rate of return on transmission assets approved by the Federal Energy Regulatory Commission.[35]

However, in surrebuttal testimony, Minnesota Power asked to decrease transmission revenues by $6.23 million (total company) to reflect a certain transmission customer's decision to stop using 207 megawatts (MW) of capacity on the Company's system effective June 1, 2017.[36]

B. Positions of the Parties

1. The Department, the OAG, and LPI

The Department, OAG, and LPI moved to exclude Minnesota Power's surrebuttal testimony on this issue, arguing that the evidence of decreased transmission revenues was provided too late in the proceeding, and that allowing it into the record would prejudice them because they lacked sufficient time to analyze and respond to it.

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[34] *See* Minnesota Power's August 1, 2018 compliance filing, Docket No. E-015/RP-15-690.

[35] *See* Campbell direct, at 17; Fleege rebuttal, at 30–31.

[36] *See* Fleege surrebuttal, at 2–4.

On the substance of Minnesota Power's requested $6.23 million adjustment, these parties argued that the Company had not provided sufficient information to support the amount of the adjustment. They pointed to the testimony of a Company witness who conceded at hearing that the Company's prefiled surrebuttal testimony did not include the full calculations necessary to support the $6.23 million figure.[37]

2. Minnesota Power

The Company argued that it was reasonable to base test-year transmission revenues and expenses on the most current data, including the loss of revenue resulting from the transmission customers' June 2017 capacity change. The Company maintained that it only learned of the change from MISO in July and could not have provided the information sooner than its surrebuttal testimony.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge denied the motions to exclude Minnesota Power's surrebuttal testimony but did not make any recommendation as to what amounts of third-party transmission revenues and expenses should be included in the test-year revenue requirement.

D. Commission Action

The Commission agrees with the Department, OAG, and LPI that Minnesota Power has not carried its burden to support its requested $6.23 million downward adjustment to third-party transmission revenues, and will therefore reject the adjustment.

Minnesota Power's third-party transmission revenues and expenses have been a moving target in this proceeding. In response to Department testimony and information requests, the Company revised its revenues and expenses multiple times to correct errors and make other adjustments. Given this history and the time and effort required to review rate-case filings, it is understandable that other parties would object to the Company's request, midway through the test year, to supplement its original filing in a way that would increase the overall revenue requirement.

More importantly, Minnesota Power's request fails on the merits because the Company has not provided a sufficient factual basis for its $6.23 million adjustment. The Company's surrebuttal testimony states that the 207 MW capacity change will reduce transmission revenues by $2.85 million in 2017, or $6.23 million on an annual basis.[38] However, the calculation used to convert $2.85 million to $6.23 million is not in the record, nor is any explanation provided for how the raw MISO data in the supporting schedules result in a $2.85 million revenue loss.

Given the late date at which the Company requested the $6.23 million adjustment, more supporting information should have been provided to establish the reasonableness of the adjustment, and any doubt as to its reasonableness must be resolved in favor of ratepayers. The Commission will therefore reject this adjustment.

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[37] *See* Evidentiary Hearing Transcript, Volume 1, at 134.

[38] *See* Fleege surrebuttal, at 3–4.

Having rejected Minnesota Power's most recently proposed adjustment, the Commission finds that the Department and the Company's previous agreement to include net transmission revenue of $2.24 million in the test-year revenue requirement is supported by the evidence, and will require the Company to increase its operating revenues accordingly ($1.836 million on a Minnesota-jurisdictional basis).

XIII. Transmission O&M Expense

A. The Issue

Minnesota Power requested recovery of transmission O&M expenses of $94.87 million (total company), or $57.24 million (total company) after making adjustments for the Company's transmission-cost-recovery riders. The Minnesota-specific portion of these expenses is $47,345,000.

The Department argued that the test-year transmission O&M expenses were too high compared to actual spending in 2012–2016. It calculated that the test-year request amounted to a 16.39% increase over actual 2016 expenses, while the average year-over-year increase in 2012–2016 was only 10.64%. The Department recommended a $2.339 reduction in test-year expenses to bring the increase in line with this historical average.

The Company responded that the reason for the 16% test-year increase was a change in the jurisdictional allocator used to convert company-wide expenses to a Minnesota-specific amount. The Company pointed out that, viewed on a total-company basis, test-year transmission O&M expenses only increased by 9.15%, less than the average year-over-year increase in 2012–2016.

The Administrative Law Judge did not address this issue in his report.

B. Commission Action

The Commission agrees with the Company that its test-year transmission O&M expense of $47,345,000 is reasonable.

The Department's comparison of the test-year increase to the 2012–2016 average increase is not apples-to-apples. The cause of the larger test-year increase was due to a change in the proportion of total-company expenses allocated to the Minnesota jurisdiction, and no party challenged the Company's change in this jurisdictional allocation factor. The Commission finds the allocation factor reasonable, and will approve the Company's test-year transmission O&M expense.

XIV. Storm-Response Costs

A. Introduction

In July 2016, a major storm in the Duluth area left some 46,000 of Minnesota Power's customers without electric service. In August 2016, the Company filed a petition seeking Commission approval of deferred-accounting treatment for the incremental O&M costs required to restore service to its customers.[39] These incremental storm-response costs included overtime pay for Company employees, as well as payments to contractors and other utilities who aided in the effort.

In November 2016, before the Commission had acted on its deferred-accounting petition, the Company filed this rate case. It included in the test-year revenue requirement $732,272 in deferred 2016 storm-response costs, which represented a four-year amortization of its incremental O&M costs from the Duluth storm. However, the Commission ultimately denied the deferred-accounting petition, finding that the costs involved were not unusual, unforeseeable, or large enough to have a significant financial impact on the Company.[40]

Thereafter, Minnesota Power withdrew its request for $732,272 in deferred, amortized storm-response costs in this rate case. But in rebuttal testimony, the Company sought to add to its test-year O&M expenses an extra $1.68 million (total company) for storm-response-related O&M costs not included in other O&M categories. The Company stated that the $1.68 million test-year amount represented its average incremental storm costs for the years 2014–2016.

B. Positions of the Parties

1. The Department

The Department recommended that the Commission reject the Company's proposed storm-response budget, for three main reasons. First, the Department argued that, consistent with the usual regulatory practice in Minnesota, the Company should not be permitted to recover an expense that was not part of the revenue requirement as initially filed.

Second, the Department contended that the incremental storm-response cost—$1.68 million—was excessive when compared to the amount the Company had initially requested for deferred 2016 storm costs—$732,272. The 2016 storm costs were sufficiently large that the Company took the unusual step of requesting deferred-accounting treatment for them. Yet, that request having been denied, the Company was now requesting twice as much for storm costs generally.

Finally, the Department maintained that Minnesota Power had not provided enough information for other parties to confirm that the requested storm costs were truly distinct from other test-year O&M expense categories, such as Paid Overtime and Contractors/Professional Service, whose budgeted amounts the Company had also increased in this rate case.

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[39] Deferred accounting is a regulatory tool used primarily to hold utilities harmless when they incur out-of-test-year expenses that, because of their nature or size, should be eligible for possible rate recovery as a matter of public policy. Traditionally, deferred accounting has been reserved for costs that are unforeseeable, unusual, and large enough to have a significant impact on the utility's financial condition.

[40] *In the Matter of a Petition for Approval of Deferred Accounting Treatment of Costs Related to the 2016 Storm Response and Recovery*, Docket No. E-015/M-16-648, Order Denying Petition for Deferred Accounting Treatment, at 5 (January 10, 2017).

2. The OAG

The OAG agreed with the Department that the Company should not be permitted to introduce new costs after its initial filing. It also identified two specific concerns with the Company's supporting data: First, the OAG argued that the Company had failed to provide detailed category-by-category cost figures demonstrating how the Company had determined which costs were incremental and which were not. And second, the OAG contended that the Company had not justified its method of dividing storm-response costs between capital costs and O&M costs.

3. LPI

LPI agreed with the Department and the OAG that Minnesota Power should not be allowed to supplement its revenue requirement with new expenses. If the Commission were to consider including these costs in the Company's revenue requirement, however, LPI proposed an alternative that would spread out or normalize the Duluth storm costs over ten years rather than three. LPI's alternative proposal would reduce the Company's requested revenue requirement by $0.7 million.

4. Minnesota Power

Minnesota Power responded that, although it did not include incremental storm costs in its revenue requirement, it did flag the issue in its initial filing and indicate that it would provide an update in rebuttal testimony. The Company contended that the requested amount of $1.68 million was reasonable.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission deny the addition of $1.68 million for storm-response expenses because the request was untimely and the amount was based on an unusual storm event, and because the Commission had previously rejected the Company's request for deferred-accounting treatment of storm-damage costs.

D. Commission Action

The Commission concurs with the ALJ, the Department, the OAG, and LPI that Minnesota Power's request for $1.68 million in test-year storm-response costs should be denied. Minnesota Power has full control over the timing and content of its rate-case filings, and the Company chose not to include a storm-cost budget as part of its revenue requirement. Allowing the Company to supplement, through rebuttal testimony, its initial filing with a major new cost would prejudice intervenors and ratepayers.

And the Company's requested storm-recovery budget is problematic for other reasons. Although the other parties had limited time to evaluate the evidence supporting the proposed budget, they nonetheless identified several shortcomings, including a lack of granular cost details to establish that the claimed storm costs truly were incremental to other test-year O&M costs. This lack of detail is particularly concerning where the test year also showed substantial increases in related cost categories—such as Paid Overtime and Contractors/Professional Service—which describe costs and activities that occur in a storm-recovery effort. Given this and other concerns identified by the Department and the OAG, the Company's incremental-cost figures do not provide a reliable basis for establishing a storm-recovery budget.

For the foregoing reasons, the Commission finds that Minnesota Power has failed to meet its burden to show that its requested storm-recovery budget and the resulting rates would be just and reasonable. The Commission will therefore deny its request.

XV. Credit Card Processing Fees

A. Introduction

Minnesota Power allows its residential and commercial customers to pay their bills using a credit or debit card through a third-party vendor. When a customer uses a credit or debit card to pay a bill, the vendor charges a transaction fee of $2.95 for each payment.

The Company has proposed to eliminate the transaction fee for customers and instead incur the fee itself and treat it as an O&M expense, as it would most other business transactions. For the 2017 test year, Minnesota Power estimates that its cost of processing credit and debit card payments will be $350,000.

B. Positions of the Parties

The Department and the OAG opposed Minnesota Power's request to include $350,000 in the test year for credit-card-processing fees. The Department argued that the Company had not adequately explained how customers who do not use credit cards to pay their bills would benefit from its proposal. And the OAG argued that the Company should be required to investigate the possibility of accepting credit-card payments itself as a way to potentially save costs.

Minnesota Power responded that allowing residential and commercial customers to pay their electric bills by card without a fee would improve customer satisfaction and encourage regular payment of bills. The Company also proposed that an account be established to track over- or under-collection of credit-card-processing expenses and allow those differences to be trued up in a future rate case.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission only allow Minnesota Power to include $175,000, or half, of its requested credit-card-processing fees in the test year.

The ALJ found that the Company's effort to improve customer service was important, and that the expense of processing credit-card payments is likely less than the cost of processing checks. And he concluded that having more customers move from higher-cost payment options to lower-cost payment options was in all parties' interests. He recommended that the Commission allow a portion of the credit card costs to be included in base rates and direct the Company to explore more efficient payment options, including accepting credit and debit card payments directly.

D. Commission Action

The Commission will allow Minnesota Power to include credit-card-processing fees as a test-year O&M expense. The Commission agrees with the Company and the ALJ that allowing customers to pay bills via credit or debit card without incurring a fee will increase customer satisfaction with the utility experience and encourage regular payment of bills, which will reduce collection expenses to the benefit of all customers. The Commission also agrees that all forms of payment carry some cost, and that electronic payment options such as credit and debit cards are likely to reduce these unavoidable transaction costs.

The Commission does not agree with the ALJ that it is appropriate to grant the Company only half of its requested costs. The only amount supported by evidence in the record is $350,000. The Commission acknowledges, however, that this amount is based on an estimate, since Minnesota Power has never before offered customers the option to pay their bills via credit card without incurring a fee. To ensure that ratepayers are not overcharged for card-processing fees, the Commission will accept the Company's proposal to track over- or under-collections for true-up in a future rate case.

The Department argues that including these costs in rates would cause ratepayers to subsidize the subset of customers who use credit or debit cards to pay their bills. However, it is far from clear that any such subsidization would occur. For one thing, all residential and commercial ratepayers will have the option to use a card to pay their bills without a fee. Moreover, every form of payment carries some cost; it is possible that a subsidy already exists but flows in the *opposite* direction—from credit-card-paying customers to those using checks or some other non-credit-card form of payment.

Finally, the OAG argues that the Company should be required to investigate the possibility of accepting credit-card payments directly. It is possible that such an arrangement could save costs. However, the Commission is not convinced that now is the best time to launch an investigation. Rather, this is a possibility that can be explored once the Company has gained experience with customer payments under the new system.

For the foregoing reasons, and conditioned on true-up, the Commission will allow Minnesota Power to include $350,000 in test-year O&M expenses for credit- and debit-card-processing fees.

XVI. High-Level Employee Expenses

A. Introduction

Minnesota Power seeks to recover expenses for three compensation plans available to its managers and other key employees.

The Annual Incentive Program (AIP) is an incentive plan offered to 190 supervisory and key employees to supplement their base pay, and according to the Company is designed to bring compensation more in line with market pay and obtain higher performance from the benefitting employees. AIP compensation included in the test-year revenue requirement is limited to no more than 20% of an individual employee's base salary.

The Executive Deferral Account (EDA) and Executive Investment Plan (EIP) provide utility executives an opportunity to save for retirement through salary or bonus deferrals that exceed federal limits on pretax contributions to deferred compensation plans.[41] EDA is open to current employees, while EIP is a legacy plan in which only retired employees participate.

The Company included approximately $2.4 million in AIP expenses, $1.2 million in EDA expenses, and $150,000 in EIP expenses in the test year. It proposes to refund to ratepayers any AIP costs recovered in rates but not actually paid to employees, as the Commission has required in past rate cases.

B. Positions of the Parties

Minnesota Power argued that AIP provides ratepayer benefits by structuring a portion of employees' compensation as a variable benefit, incentivizing them to achieve specified goals that benefit customers. And the Company contended that the nonqualified deferred-compensation plans are important for attracting and retaining qualified management-level employees in the current labor market, which aids the Company's ability to provide safe and reliable electric service at a reasonable cost.

LPI and OAG recommended that the Commission remove 90% of the AIP costs from the test-year revenue requirement. They argued that only 10% of the AIP performance metrics target goals that directly benefit ratepayers—customer service and "drive to zero injury." The other metrics relate to utility net income, cash from operating activities, strategic goals, and utility competitiveness, which LPI and the OAG argued primarily benefit shareholders.

In addition, the Department, LPI, and OAG recommended removing all EDA and EIP expenses from the test-year revenue requirement. They argued that it would not be reasonable to require ratepayers to fund both executives' salaries and the costs of their nonqualified deferred-compensation plans, and maintained that the Commission had disallowed similar expenses in other recent rate cases. Finally, they argued that the Company had not provided any cost-benefit analysis showing that these plans provide a net benefit to ratepayers.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Minnesota Power had met its burden to show that its incentive program and nonqualified deferred-compensation plans were necessary and reasonable to provide safe and reliable utility service to its customers.

In reaching this conclusion, the ALJ appeared to place the burden on the objecting parties to produce evidence to rebut the Company's request for cost recovery. Specifically, he found that these parties had not presented evidence or argument sufficient to "overcome Applicant's supported positions" or to "show[] that Applicant's claims and evidence . . . [are] not accurate." He concluded that the Company's position therefore "must prevail."[42]

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[41] In other words, EDA and EIP are what are commonly known as "nonqualified" deferred-compensation plans.

[42] ALJ's Report, at 89.

D. Commission Action

As an initial matter, the Commission disagrees with the ALJ's apparent conclusion that parties challenging Minnesota Power's test-year expenses have a burden to produce evidence to rebut the evidence proffered by the Company in support of those expenses.

In a rate case, the burden remains at all times with the utility to convince the factfinder that its claimed costs will result in just and reasonable rates. Thus, to the extent that the ALJ concluded the Company's position "must prevail" simply because other parties did not produce contradicting evidence, his reasoning was erroneous.

On the substance of Minnesota Power's request, the Commission agrees that the Company has adequately supported the reasonableness of its requested AIP expenses. However, the Commission reaches the opposite conclusion as to the nonqualified deferred-compensation plans, EDA and EIP. These conclusions are explained below.

The Commission has routinely approved utilities' requests to recover short-term incentive-plan expenses, including in Minnesota Power's last two rate cases.[43]

In the Company's last rate case, the Commission approved its full request for AIP expenses, with the same 20% cap and refund condition that the Company has agreed to here. The Commission reasoned, in part, that "barring excessive compensation levels, skewed incentives, or other public policy concerns, the Company has the discretion to structure its compensation packages in accordance with its best business judgment."

The evidence in this case establishes that AIP continues to play an important role in delivering reliable electric service at a reasonable cost. Particularly important is the fact that, without AIP, Minnesota Power's total cash compensation for eligible employees would be below the market rate. This fact provides further assurance that the total compensation paid to AIP-eligible employees is reasonable.

With respect to EDA and EIP, however, the Commission concurs with the Department, OAG, and LPI that the Company has not met its burden to justify the reasonableness of its claimed costs. Unlike AIP, Minnesota Power has not shown that EDA and EIP bear any direct relationship to utility performance, and it declined to provide a ratepayer cost-benefit analysis when requested by the Department.

In the absence of any evidence of a measurable ratepayer benefit, the Commission cannot conclude that it is reasonable for ratepayers to shoulder the costs of these plans on top of the executive-salary and executive-incentive costs they already pay.

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[43] *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions, and Order, at 29 (November 2, 2010) [hereinafter "2010 rate-case order"]; *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota*, Docket No. E-015/GR-08-415, Findings of Fact, Conclusions of Law, Order, at 43–44 (May 4, 2009).

For the foregoing reasons, the Commission will approve MP's proposal to include all of the AIP expenses in its revenue requirement, limited to 20 percent of individual base salaries and subject to customer refunds if actual AIP payouts are lower than the approved level, and will require test-year expenses to be reduced by $1,380,313 for the EDA and EIP plans.

XVII. Spot Bonuses

A. Introduction

Spot bonuses are performance-based incentive compensation, paid through payroll or, if small in amount, as gift cards. Minnesota Power uses spot bonuses to recognize employees' extraordinary efforts and accomplishments that go above and beyond normal job duties.

Only non-union, non-management employees are eligible for spot bonuses. After the Company expanded AIP to certain key non-management employees in 2017, a total of 147 employees were eligible to receive both AIP and spot bonuses.

Minnesota Power's proposed test-year budget included $64,802 for spot bonuses paid as gift cards and $60,614 for spot bonuses paid through payroll, for a total amount of $124,966 (Minnesota jurisdiction).

B. Positions of the Parties

The Department recommended reducing spot-bonus expense by $33,741, to exclude bonuses paid to employees eligible for both spot bonuses and AIP and whose spot bonuses were not tied to storm restoration. The Department argued that Minnesota Power had not shown that it was reasonable to require ratepayers to pay for 100% of spot-bonus costs in addition to the other incentive compensation it offers employees.

The OAG argued that spot bonuses paid using gift cards are gifts and should be analyzed under the standard set forth in Minn. Stat. § 216B.16, subd. 17. That is, Minnesota Power must demonstrate that the spot bonuses are reasonable and necessary to providing utility service. The OAG argued that the Company had not met this standard.

Minnesota Power responded that spot bonuses were essential to allow the Company to offer market-competitive compensation to key non-management employees, noting that total cash compensation for its non-management, non-union employees was 5–10% below the market median in 2016. The Company also stated that spot bonuses allow it to recognize and reward individual employees whose contributions exceeded expectations when AIP is not an option because company-wide performance criteria under that program have not been met.

The Administrative Law Judge did not address this issue in his report.

C. Commission Action

The Commission finds that the Company's requested spot-bonus expense, whether the bonuses are paid in the form of a gift card or through payroll, is reasonable and necessary for providing utility service and will allow the Company to include $124,966 in the test-year revenue requirement. The Company persuasively argued that spot bonuses permit it to address below-market compensation for certain key employees, as well as to recognize such employees' contributions where AIP would be inapplicable.

The OAG argues that spot bonuses paid as gift cards are employee gifts and must be justified under Minn. Stat. § 216B.16, subd. 17, which governs the recovery of several types of utility expenses, including gifts. The statute provides that the Commission "may not allow as operating expenses a public utility's travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service."

The Commission does not consider spot bonuses paid through gift cards to be different than payroll spot bonuses. But even if spot bonuses paid through gift cards were classified as gifts, the Commission would conclude that they are reasonable and necessary for the provision of utility service. The reasons for this conclusion are essentially the same as the reasons for concluding that spot bonuses in general are recoverable: They help to address the below-market base compensation of certain key employees, allowing the Company to attract and retain qualified personnel, to the benefit of both the utility and its ratepayers.

For the foregoing reasons, the Commission will allow Minnesota Power to recover $124,966 in spot-bonus expense.

XVIII. Retirement Savings and Stock Ownership Plan

A. The Issue

Minnesota Power's test-year revenue requirement includes $7.148 million in expenses for its employee retirement-savings and stock-ownership plan ("the plan").

The Department reviewed the Company's historical costs for the plan and observed that its costs had fluctuated significantly from 2014 to 2016 and that 2016 costs for the plan were only $6.197 million, or almost $1 million less than the test-year amount. The Department concluded that the test-year amount was too high and recommended using a three-year average of 2014–2016 actuals, or $6.43 million.

Minnesota Power responded that (1) 2016 costs had been unusually low due to a one-time dividend credit, which the Company did not expect to reoccur in the future, and (2) 2017 test-year costs trended higher due to changes in employee salary adjustments, deferral rates, union status, birth dates, and hire dates. The Company therefore opposed using a three-year average, arguing that doing so would not accurately represent test-year costs.

The Administrative Law Judge did not address this issue in his report.

B. Commission Action

The Commission agrees with the Department that the test-year cost of the Company's retirement-savings and stock-ownership plan should be determined based on a three-year historical average. The Commission will therefore require Minnesota Power to reduce these expenses by $0.718 million to $6.43 million.

The Commission not infrequently uses historical averages in ratemaking, because such averages help correct for any outlier data in an individual year, providing a representative amount for the test year. Using a three-year average will smooth year-to-year fluctuations, such as those caused by dividend credits, and will result in a representative test-year amount.

While Minnesota Power asserted that the 2016 dividend credit was a one-time event, the Department persuasively argued that dividend credits are difficult to predict and could reoccur. The Commission will therefore require the Company to reduce its retirement-plan expenses as recommended by the Department.

XIX. Other Employee Benefits

A. The Issue

Minnesota Power's "other employee benefits" include life insurance, flexible compensation, tuition reimbursement, survivor benefits, long-term disability, self-insured worker's compensation, and other miscellaneous expenses, such as administrative costs. The Company included $1.925 million in the test year for these benefits.

As with the Company's retirement-savings and stock-ownership plan, the Department recommended using a three-year average of actual 2014–2016 costs to determine test-year other-employee-benefit expense.

The Department based its recommendation on a review of the Company's historical spending, noting that "other benefit" costs are volatile, fluctuating from year to year and even showing credit balances in some cost categories. The Department also noted that the Company's test-year budget of $1.925 million was higher than any of the three previous years:

Table 3: Other Employee Benefits (2014–2016)
($ millions)

2014 Actual	2015 Actual	2016 Actual
$1.870	$0.912	$1.483

The Department's recommended three-year average—$1.422 million—would result in a $0.503 million downward adjustment to Minnesota Power's other-employee-benefit expenses.

Minnesota Power responded that it developed its test-year budget to account for factors that could impact these "other benefit" costs, such as yearly salary increases and changes in the number of participants. The Company opposed any adjustment to its test-year budget as filed.

The Administrative Law Judge made no findings or recommendation on this issue.

B. Commission Action

The Commission concurs with the Department that a three-year average of other-employee-benefit expenses is the most appropriate basis for determining the test-year expense in this case.

Accordingly, the Commission will require Minnesota Power to reduce these expenses by $0.503 million, to $1.422 million.

As the Department established, this cost category has displayed significant volatility, and the test-year budget is set substantially higher than actual expenditures during 2015 and 2016. Given this volatility, the Commission concludes that a test-year budget based on the three-year historical average is reasonable for ratemaking purposes.

The Company points to several factors that it argues support a higher test-year budget, including increases in salaries and the number of employees participating. However, the Department pointed to factors that would tend to decrease "other benefit" costs, such as the Company's movement toward wind and natural-gas generation, which in general require less staffing than coal-based generation.

The goal in ratemaking is to come up with a representative test-year amount, and the Commission concludes that a three-year average best accomplishes this.

XX. Employee Gifts

A. The Issue

Minnesota Power sought to recover $23,007 (total company) for safety, length-of-service, and retirement awards in the test year. The Company argued that these expenses aid in the efficient provision of utility service by supporting employee retention and the continued safety of the Company's employees and customers.

The OAG argued that these expenses should be removed from the test year because they are not necessary for the provision of utility service. The OAG argued that the Commission applied a similar line of reasoning to disallow expenses for employee-recognition items, such as cards, flowers, food and beverages, gifts, and cake, in Minnesota Power's last rate case.[44]

The Administrative Law Judge concluded that Minnesota Power had established the necessity for and reasonableness of its requested employee-gift expenses and recommended that $23,007 be included in the test-year revenue requirement.

B. Commission Action

The Commission concurs with the ALJ and Minnesota Power that the Company's requested employee-gift expenses are reasonable and necessary for the provision of utility service, and will allow the Company to recover $23,007 (total company) for employee gifts in the 2017 test year.

Minn. Stat. § 216B.16, subd. 17, allows the Commission to grant recovery of employee expenses, including gifts, that are reasonable and necessary for the provision of utility service. Minnesota Power's employee-recognition and safety gift expenses meet this standard and, moreover, benefit ratepayers by promoting employee retention and customer safety.

[44] *See* 2010 rate-case order, at 29–33.

The OAG argues that the Commission's decision in the Company's last rate case supports disallowing these expenses. However, the Commission's decision in that case turned on unique circumstances that are not present here.

The most salient difference is the large amount of gift expenses requested in Minnesota Power's last rate case. In that case, the Company initially requested rate recovery of some $500,000 in expenses for employee-recognition events and gifts, more than 20 times the size of the request in this case. In addition, the record in the last case included evidence of specific costs that were clearly inappropriate for rate recovery, such as travel expenses for employees' family members. No unrecoverable expenses have been identified in this case.

In sum, Minnesota Power's requested gift expenses are reasonable and necessary for the provision of electric service, and the Commission will therefore allow the Company to recover them.

XXI. Travel, Entertainment, and Related Employee Expenses

A. Introduction

Travel, entertainment, and related employee expenses are costs incurred by Minnesota Power's employees in the course of their employment for airfare, hotel stays, car rentals, parking, meals, and related purposes. The Company proposed to include employee expenses of $4.75 million (total company) in the test year.

Minnesota Power calculated the test-year amount by starting with its actual 2015 employee expenses, which totaled some $6.37 million. From that amount, the Company subtracted $1.62 million in expenses that, for various reasons, it deemed inappropriate for rate recovery.

B. Positions of the Parties

1. The Department

The Department recommended that the Commission remove an additional $454,000 (Minnesota jurisdiction) in employee expenses from the test year to bring the total amount in line with the three-year historical average (2014–2016). The Department observed that actual employee expenses had been falling over time, from $7.2 million in 2014 to $5.2 million in 2016 (total company). The agency argued that using a historical average would normalize these costs and provide a representative amount for purposes of ratemaking.

2. The OAG

The OAG recommended that test-year employee expenses be reduced by some $509,000 (Minnesota jurisdiction). It agreed with the Department that a three-year historical average would provide an appropriate baseline for the test year. However, the OAG calculated the three-year average somewhat differently than the Department and therefore arrived at a different amount.

The main difference was that the OAG incorporated unrecoverable expenses into the calculation of the historical three-year average, rather than deducting unrecoverable expenses after calculating the average. The OAG also recommended treating as unrecoverable $27,520 in transactions for which the Company did not provide a vendor name as required by statute.[45]

3. Minnesota Power

The Company argued that using a three-year average was arbitrary and would lead to more rather than less controversy in future rate cases. The Company argued that its employee expenses for 2015 and 2016 were unusually low due to cost-control measures that the Company implemented in 2015 in response to lower demand from its large power customers, making the three-year average artificially low.

In response to the OAG's recommendation that the Commission disallow $27,520 in employee expenses without a listed vendor, the Company stated that these were reimbursements to employees who had used their own credit cards or cash for work-related purchases (such as cab fare while traveling). The Company asserted that in this circumstance, it treats the employee as the "vendor," and it argued that this practice complies with statute.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Minnesota Power had used a reasonable method to determine the amount of travel, entertainment, and related employee expenses. He recommended that the Commission grant recovery of the Company's requested test-year amount, minus $27,520 for expenses for which the Company did not provide a vendor name.

D. Commission Action

The Commission agrees with the Department and the OAG that it is most appropriate in this case to calculate the Company's test-year employee expenses based on a three-year historical average.

Minnesota Power argues that the choice of a three-year average—instead of, for example, a four- or five-year average—is arbitrary. However, the Commission agrees with the Department and the OAG that three years is a reasonable period under the specific facts of this case.

Three years captures the recent downward trend in Company spending while still including one year—2014—in which spending was significantly higher. Moreover, pre-2014 data would be less useful to include, since older data may not be as predictive as more recent data. Finally, a three-year period is consistent with Minnesota Power's own recommendation in at least one other expense category—charitable contributions—in which the Company relied on a three-year average to calculate test-year costs.

As between the Department's and the OAG's recommended adjustments, the Commission finds that the Department's is the more reasonable. In particular, the Commission disagrees with the OAG's recommendation to deduct $27,520 in expenses without associated vendor names.

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[45] *See* Minn. Stat. § 216B.16, subd. 17(b) (requiring a utility to include a vendor name for each employee expense item included in its rate request).

While Minn. Stat. § 216B.16, subd. 17, generally requires a vendor name to be listed for each expense, and while the Company should have done so, the Commission concludes that the Company provided a satisfactory explanation for why it did not include vendor names for this limited subset of employee expenses. Moreover, the statute requires Minnesota Power to list the business purpose of each expense, and the OAG does not argue that the Company failed to provide an adequate business purpose for any of these expenses.

For the foregoing reasons, the Commission will require Minnesota Power to use a three-year average of historical employee expenses, as calculated by the Department, and decrease the test-year budget for these expenses by $454,202.

XXII. Membership Dues

A. Introduction

Minnesota Power's test-year revenue requirement included some $1.24 million (total company) for dues and other expenses associated with membership in various trade organizations. The requested amount reflects adjustments to remove lobbying-related expenses.

B. Positions of the Parties

1. Minnesota Power

The Company maintained that its requested membership dues, less lobbying expenses, were reasonable to recover from ratepayers. It stated that the organizations provide numerous services that benefit both the utility and its ratepayers, including gathering industry data, providing strategic business intelligence, and holding trainings and conferences. Moreover, the Company stated that these organizations are required by federal law to track their lobbying expenses. These expenses were clearly identified on invoices to Minnesota Power, and the Company excluded them from its test-year request.

2. The OAG

The OAG argued that the dues for eleven organizations[46] should be disallowed because the organizations were primarily engaged in lobbying and political activities. It asserted that, when lobbying expenses are commingled with other expenses, past Commission practice has been to place the burden of justifying any requested costs on the utility, and it argued that Minnesota Power had not met that burden in this case.

The OAG contended that the invoices produced by these organizations are not a reliable source of information about what expenses are recoverable. According to the OAG, nonprofit organizations report lobbying expenses according to the federal Internal Revenue Service's definition, but there are other types of activities that do not fall under this definition yet would still be inappropriate for ratepayers to pay for.

[46] Edison Electric Institute, Western Coal Traffic League, Utility Water Act Group, Mining Minnesota, Minnesota Forest Industries, Minnesota Timber Producer Association, National Association of Manufacturers, American Wood Protection Association, National Coal Transportation Association, World Steel Dynamics Incorporated, and National Hydropower Association.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company had met its burden of proof for only three organizations: the Edison Electric Institute, the National Hydropower Association, and the Western Coal Traffic League. He therefore concluded that the non-lobbying portion of the dues for these three organizations—$417,946—should be included in the test year.

D. Commission Action

The Commission finds that Minnesota Power has met its burden to show that lobbying expenses were properly excluded from the Company's requested membership-dues expense and will allow the Company to recover $1,240,619 in test-year membership dues.

Historically, the Commission has excluded lobbying expenses from rate recovery to the extent that the lobbying is not demonstrated to advance ratepayer interests. In this case, Minnesota Power does not request recovery of lobbying expenses; rather, the parties dispute whether the Company excluded all lobbying-related costs from its membership-dues expenses. The Commission finds that it has. By using the organizations' invoices to subtract the portion of its membership dues attributable to lobbying, the Company has reasonably accounted for any non-recoverable lobbying expenses.

Moreover, the Commission concurs with the Company that its remaining membership dues are reasonable and necessary to the provision of utility service. In rebuttal testimony, the Company provided detailed information about each organization and the reason it is a member.[47] For example, the Company's membership in the National Hydropower Association has allowed it to keep abreast of federal policy affecting hydroelectric generation. This is especially important for Minnesota Power because of the significant role of hydropower on the Company's system and Minnesota's emphasis on renewable energy.

The OAG argues that these organizations are primarily engaged in lobbying and political activities, relying on a 2005 audit of the Edison Electric Institute by the National Association of Regulatory Utility Commissioners (NARUC). However, this report is not in the record, is more than ten years out of date, and does not address any organization other than the Edison Electric Institute. It is not sufficient to cast doubt on Minnesota Power's affirmative evidence supporting its membership dues.

For the foregoing reasons, the Commission concludes that Minnesota Power has adequately supported its request for membership dues in this case.

[47] *See* Morris rebuttal, Schedules 2–4.

XXIII. Charitable Contributions

A. Introduction

Minnesota Power seeks to recover $394,280 in charitable contributions made through its Minnesota Power Foundation, representing 50% of annual average contributions in 2013–2015.[48] The Company also seeks $114,597 in foundation administrative costs.

B. Positions of the Parties

1. The Department

The Department recommended that the Commission disallow all administrative costs of the Minnesota Power Foundation. The Department cited recent rate cases in which the Commission denied recovery of administrative costs in the context of charitable contributions[49] and argued that the same rationale for denying these costs applies in this case.

Specifically, the Department argued that while past Commission practice and the law permit partial recovery of charitable contributions, this is not the case with the administrative costs incurred in *distributing* these contributions. Moreover, the agency argued that Minnesota Power's shareholders derive substantial goodwill from the existence of a charitable foundation, making it appropriate for them, and not ratepayers, to bear the foundation's administrative costs.

2. The OAG

The OAG recommended that test-year charitable-contribution expense be based on 2014–2016 spending, arguing that there was no good reason to use a 2013–2015 timeframe since 2016 data were available. Moreover, the OAG argued, using the most recent three-year average would be consistent with the Commission's decision in Minnesota Power's last rate case, in which the Commission set charitable-contribution expense using "the three most recent calendar years."[50] The OAG contended that the Company had not provided a good reason to omit 2016 data.

3. Minnesota Power

The Company argued that it was the OAG, and not the Company, that was being strategic in selecting an averaging period, pointing out that 2016 had the lowest level of charitable contributions since 2012. And responding to the Department's argument that it should not recover administrative costs, the Company asserted that its customers benefit from the administration of its foundation, and that the disallowance of administrative costs in other rate cases should not prevent their recovery here.

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[48] *See* Minn. Stat. § 216B.16, subd. 9 (limiting rate-recoverable charitable expenses to 50% of qualified contributions).

[49] *See, e.g., In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-08-1065, at 22–23 (October 23, 2009).

[50] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions, and Order, at 40 (November 2, 2010).

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended allowing the Company to use 2013–2015 as the basis for its test-year charitable costs. And he recommended that the Company only be allowed to recover half of its claimed administrative costs, reasoning that it was appropriate to allow recovery of these costs in the same proportion as the charitable contributions themselves.

D. Commission Action

The Commission concurs with the OAG that Minnesota Power's test-year charitable-contribution expense should be based on the most recent three-year period for which data are available—2014–2016. The Commission expressed its preference in Minnesota Power's last rate case for setting charitable contributions using the average of the three most recent calendar years, and this remains the Commission's preferred method for calculating these costs. This is because a three-year period is long enough to smooth anomalous data but short enough to capture any recent trends.

The Company argues that the OAG's averaging period unfairly biases the calculation because 2016 contributions were the lowest since 2012. But one could just as easily argue that using a 2013–2015 average artificially inflates the calculation by omitting data unfavorable to the Company. Minnesota Power also asserts that full 2016 data were not available when it filed the rate case; however, this is not a valid basis to exclude reliable record evidence that sheds light on the latest trends in the Company's charitable spending.

The Commission also agrees with the Department that the Company should not be allowed to recover administrative costs. Charitable contributions, whose necessity for the provision of utility service is somewhat questionable, are only partially recoverable under statute.[51] The administrative costs involved in *distributing* charitable contributions are even less related to the business of providing electric service. Thus, before these costs can be recovered from ratepayers, a convincing case must be made that doing so is in ratepayers' best interests. Minnesota Power has not made that case here.

The Company maintains that its charitable giving benefits the communities in which it operates. However, the Company has not shown to what extent this benefit flows to its ratepayers. And, as the Department points out, the foundation benefits shareholders in the form of corporate goodwill and positive publicity. While the Commission commends the Company for its benevolence, the Commission concludes that the equities require that its shareholders bear the foundation's administrative costs.

For the foregoing reasons, the Commission will approve a charitable-contribution expense based on 2014–2016 spending, and will disallow all administrative costs, for a total test-year amount of $359,250.

[51] *See* Minn. Stat. § 216B.16, subd. 9.

XXIV. Cash Working Capital

A. Introduction

Cash working capital (CWC), a component of rate base, represents the amount of money a utility needs to have on hand to cover its operating expenses in the period between when service is provided and when it collects revenues for that service.

The most precise way to measure a utility's CWC requirements is to conduct a "lead/lag study." Minnesota Power based its test-year cash working capital on a lead/lag study it prepared for calendar year 2012.

B. Positions of the Parties

The Department concluded that Minnesota Power's lead/lag study was reasonable and suggested that it would be necessary to recalculate cash working capital to reflect final Commission adjustments to the Company's rate base, revenue and expenses, and capital structure.

LPI argued that the Company's lead/lag study was incomplete because it did not include interest expense. LPI stated that interest expense is collected through customer rates, and that these collections represent a source of cash to the Company prior to being passed on to bondholders. LPI recommended that the Commission reduce rate base by $0.8 million to account for interest expense.

Minnesota Power responded that the 2012 study and resulting capital calculation were consistent with the approach and methodology that the Company used, and the Commission approved, in its last rate case. The Company agreed with the Department that the CWC amount would need to be updated after the Commission determines final adjustments to rate base, weighted cost of debt, and operating income.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Minnesota Power's lead/lag study and resultant CWC adjustment were reasonable and consistent with prior Commission decisions. He recommended that the Commission accept the Company's method of determining cash working capital and require the Company to recalculate the CWC adjustment to reflect the Commission's final determinations on other rate components.

D. Commission Action

The Commission agrees with the ALJ, the Department, and Minnesota Power that the Company's lead/lag study and method of calculating cash working capital are reasonable. The Commission will require the Company to update cash working capital to reflect the rate base, revenue and expense adjustments, and capital structure approved in this proceeding.

Minnesota Power conducted a lead/lag study consistent with the method used in its last rate case, and by other Minnesota utilities. The Department examined the Company's study and found its methodology reasonable, and LPI has not provided any credible basis for rejecting that methodology.

LPI's argument that an interest-expense adjustment to cash working capital is needed appears to be based on the misapprehension that Minnesota Power pays interest expense only twice a year. However, as the Company explained, it makes payments on multiple bonds staggered throughout the year, so interest payments generally match monthly revenue collections.

Accordingly, the Commission will approve the Company's lead/lag study, requiring the Company to update it consistent with the decisions made in this case.

XXV. Fuel Clause Adjustment Mechanism

A. Introduction

Minn. Stat. § 216B.16, subd. 7, authorizes the Commission to allow a public utility to automatically adjust charges for the cost of fuel. Costs typically included in a utility's base fuel cost or "base cost of energy" are fuel and related transportation costs, energy costs of bilateral power purchase agreements, day-ahead and real-time MISO market purchases, and associated MISO market costs.

A utility's fuel-clause adjustment mechanism, or "fuel clause," reflects per-kilowatt-hour deviations from the base cost of energy established in the utility's most recent general rate case. Under the current fuel-clause framework established by the Commission, Minnesota's rate-regulated electric utilities adjust their rates each month and subsequently file monthly and annual reports for the Commission's approval.

In 2003, the Commission opened a docket to investigate potential changes to the fuel-clause framework (the FCA docket), and in December 2017, adopted several modifications to that framework. Starting in July 2019, the Commission will—among other changes—require utilities to stop making monthly fuel-clause adjustments and instead require that fuel-clause rates be approved by the Commission before being charged to customers.[52]

B. Fuel Clause Methodology Change

1. The Issue

Minnesota Power currently uses a historical period in calculating the amount of its monthly fuel-clause adjustment (average cost for the first two of the preceding three months). In prefiled testimony, the Company proposed to change its fuel-clause methodology to use forecasted costs instead of historical costs. The Company claimed that transitioning to using forecasted costs would cause it to under-recover fuel costs by some $18.5 million. It proposed to recover this amount over a 36-month period beginning when final rates go into effect.

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[52] *See In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments*, Docket No. E-999/CI-03-802, Order Approving New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements (December 19, 2017) [hereinafter "FCA order"].

At the evidentiary hearing in this case, the Company requested that the Commission refer its proposal to the FCA docket.[53]

No party objected to Minnesota Power's request to refer its proposal to the FCA docket, but the Department and LPI opposed the Company recovering any fuel-clause-transition costs. The Department argued that the Company's proposal was based on the flawed assumption that the Company is entitled to recover its actual fuel costs, including a "fuel cost recovery delay amount" arising from the transition to a forecasted adjustment.

The ALJ recommended that the Commission grant the Company's request to refer these issues to the FCA docket.

2. Commission Action

The Commission agrees that Minnesota Power's proposed fuel-clause methodology change will be most efficiently addressed in the FCA docket. The FCA order directed utilities to make compliance filings implementing specified fuel-clause changes. To the extent that Minnesota Power believes its proposal is consistent with the changes required by the FCA order, the Company can include its proposal in a compliance filing for review by the Department and the Commission.

However, the Commission rejects Minnesota Power's claim that a "fuel cost recovery delay" or recoverable "delay amount" results from the current fuel-clause methodology. The Commission's fuel-clause rules allow a utility to recover an "average" amount of energy costs that exceed the base cost, not its actual costs.[54] Minnesota Power has always been allowed to recover a representative amount of energy costs through its fuel clause, and would continue to do so under any change to the mechanism. And the fact that the Company's current fuel clause uses a historic average does not change the situation.

C. Base Cost of Energy

1. The Issue

Minnesota Power initially sought to increase its base cost of energy from 1.018 cents per kilowatt-hour (kWh) to 2.103 cents per kWh; during the course of this proceeding, that request increased to 2.121 cents/kWh. However, as with its proposal to change its fuel-clause calculation methodology, the Company now asks that its new base cost of energy be determined in the FCA docket.

The Department agreed that Minnesota Power's base cost of energy should be increased to 2.121 cents/kWh, reasoning that this change would better reflect the Company's annual energy costs.

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[53] *See* Evidentiary Hearing Transcript, Volume 1, at 188–89.

[54] *See* Minn. R. 7825.2600, subp. 2 (providing that the fuel-clause rate is the sum of the "current period" cost of energy purchased and cost of fuel consumed, less the base cost per kWh); Minn. R. 7825.2400, subp. 13 (defining "current period" as a two-month moving average).

The ALJ recommended that the Commission grant Minnesota Power's request to defer a base-cost-of-energy determination to the FCA docket. Alternatively, he recommended that the Commission grant the Company's request to increase its base cost of energy.

2. Commission Action

The Commission agrees with the ALJ, the Company, and the Department that the Company's base cost of energy should be increased to 2.121 cents/kWh. Increasing the base cost of energy will not change the total revenue that Minnesota Power collects; rather, by better reflecting the Company's actual energy costs, it will reduce the size of future adjustments through the fuel clause.

Minnesota Power would prefer that its base cost of energy be set in the FCA docket, and suggests that doing so would avoid customer confusion by limiting the number of times its fuel clause needs to be changed.

However, utilities' base energy costs are ordinarily set in a rate case, and the FCA order does not alter this practice. Moreover, since changing the base cost of energy does not change the overall fuel cost paid by customers, it is unclear how changing that base cost, even multiple times, would lead to customer confusion.

In sum, the record in this case supports increasing Minnesota Power's base cost of energy, and no compelling basis exists to defer that decision. Accordingly, the Commission will increase the Company's base cost of energy to 2.121 cents/kWh, update the class-specific cost factors, and incorporate them into the base rates for the test year.

D. Reagent Costs

1. The Issue

Minnesota Power uses reagents and other chemicals to reduce pollution from its power plants. The test-year cost of reagents is approximately $4 million and is included in the Company's O&M budget.

Minnesota Power seeks permission to recover reagent costs through the fuel clause, arguing that such recovery is authorized by Minn. Stat. § 216B.16, subd. 7, which provides that the Commission "may permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in . . . prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility."

The Department opposed fuel-clause recovery, arguing that limiting recovery of reagent costs to base rates gives Minnesota Power an incentive to minimize these costs between rate cases. The ALJ agreed and recommended that the Commission deny the Company's request.

2. Commission Action

The Commission concurs with the ALJ and the Department and will not allow Minnesota Power to include reagent costs in the fuel-clause adjustment.

Minn. Stat. § 216B.16, subd. 7, allows the Commission to permit fuel-clause recovery of prudent reagent costs but does not require it to do so. The Commission concludes that permitting such recovery is not in the public interest because it removes a major incentive for the Company to limit such costs between rate cases.

If an operational cost is recoverable solely through base rates, a utility can increase its profits only by minimizing that cost. However, if a cost is recoverable through the fuel clause, a utility knows that it can recover prudent costs that exceed the base costs, and thus has less incentive to control costs. For this reason, the Commission will deny fuel-clause recovery of reagent costs.

E. Business Interruption Insurance

1. The Issue

Minnesota Power maintains business-interruption insurance coverage on its direct current (DC) line that transports electricity from its Bison wind farm in North Dakota. This insurance is intended to help offset any energy-replacement costs, as well as the lost value of production tax credits from the Bison wind farm.

Minnesota Power seeks permission to recover the cost of the business-interruption insurance premiums through the fuel clause, and to refund any insurance proceeds through the same mechanism. The Company argued that fuel-clause recovery of business-interruption insurance would allow any insurance proceeds to be allocated symmetrically to the customers who paid for the insurance.

The Department opposed fuel-clause treatment of business-interruption insurance for the same reason that it opposed fuel-clause recovery of reagent costs—because doing so would remove an incentive for the utility to control costs. The Department also pointed out that Minn. Stat. § 216B.16, subd. 7, does not list business-interruption insurance as a cost that the Commission may permit a utility to recover through the fuel clause.

The ALJ agreed with the Department and recommended that the Commission deny Minnesota Power's request to recover the cost of business-interruption insurance through the fuel clause.

2. Commission Action

The Commission concurs with the ALJ and the Department and will require Minnesota Power to continue recovering business-interruption insurance premiums through base rates to incentivize the Company to manage its insurance costs prudently. The Company argues that, ideally, both insurance costs and proceeds would be recovered/refunded through the same mechanism so that costs and benefits are allocated symmetrically among ratepayers. However, this matching principle does not outweigh the public's substantial interest in incentivizing cost control.

For these reasons, the Commission will deny Minnesota Power's request to recovery business-interruption insurance proceeds through the fuel clause.

F. Nitrogen Oxide Allowances

1. The Issue

Emissions from power plants are regulated by the U.S. Environmental Protection Agency (EPA) through emissions allowances. Allowances play an important role in a utility's environmental-compliance planning because the utility must ensure that it has enough allowances to comply with EPA rules. Unused allowances can be saved or sold with certain restrictions.

The Commission has authorized Minnesota Power to reflect the purchase and sale of sulfur dioxide (SO_2) allowances through the fuel clause.[55] In this case, the Company requests permission to do the same for nitrogen oxides (NO_x), arguing that the two types of allowances should be treated similarly.

The Department opposed Minnesota Power's request, arguing that the Company would have little incentive to manage NO_x-allowance costs if it were allowed to recover them through the fuel clause. The Department also argued that emissions allowances are not a fuel cost as defined under Commission rules, and allowing them to be recovered through the fuel clause would require a variance, which the Company has not requested.

The ALJ agreed with the Department and recommended that the Commission deny Minnesota Power's request to recover the cost of NO_x emissions allowances through the fuel clause.

2. Commission Action

The Commission concurs with the Department and the ALJ, and will deny Minnesota Power's request to debit and credit the purchase and sale of NO_x allowances through the fuel clause.

The primary reason for this decision is the same as that for denying fuel-clause treatment of reagent and business-interruption-insurance costs: allowing the Company to include NO_x-allowance costs in the fuel clause would remove a major incentive to control costs. Moreover, Minnesota Power had neither requested, nor met the prerequisites for, a rule variance under Minn. R. 7829.3200.[56]

Accordingly, the Commission will deny the Company's request.

G. Energy-Market Charges

In its initial filing, Minnesota Power requested permission to include charges from energy-market entities other than MISO—such as the Independent Electricity System Operator (IESO), Southwest Power Pool (SPP), and PJM—in its fuel-clause adjustment.

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[55] *See In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota*, Docket No. E-015/GR-08-415, Order After Reconsideration, at 3 (August 10, 2009).

[56] The Commission must grant a variance to its rules when it determines that (1) enforcement of a rule would impose an excessive burden upon the applicant or others affected by the rule, (2) granting the variance would not adversely affect the public interest, and (3) granting the variance would not conflict with standards imposed by law. Minn. R. 7829.3200, subp. 1.

The Department agreed that the Company should be able to include these charges in the fuel clause, so long as they were for energy and not administrative costs. The Commission agrees and will allow Minnesota Power to include IESO, SPP and PJM market charges in the fuel clause so long as they are for energy only and not for administrative costs.

XXVI. Keetac Test Year Revenue

A. Introduction

When Minnesota Power filed its rate case, the Keewatin mining facility (Keetac) was idle and was expected to remain idle for 2017. In December 2016, U.S. Steel announced its intention to restart Keetac in 2017. Minnesota Power provides electric service to Keetac. The imminent return of sales to this large customer led the Company to revise test year and interim-period revenue projections.

The Company revised its sales forecast for the 2017 test year to account for the increased sales to Keetac by including in its test year nine months of anticipated electricity sales to Keetac in 2017.

At issue is how to account for revenue from Keetac in the test year.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power argued that including nine months of sales revenue from Keetac is reasonable because, when taken with the sales forecasts for other similar facilities, the overall result corresponds to a 90% utilization rate for those customers. According to the Company, "the decision to reflect only nine months of sales to Keetac was not to match specific sales to this customer but rather to ensure that the overall updated test year sales forecast for all taconite customers was reasonable."[57] The Company argued that a 90% utilization rate is reasonable, given historic, current, and future expectations in the steel and mining industries in Minnesota.

Minnesota Power also raised concerns that there is a risk of counting revenue from Keetac twice: once as test-year revenue, and once as part of a required refund or offset under Minn. Stat. § 216B.1696 (the EITE statute).

2. The Department, the OAG, and the Large Power Intervenors

The Department, the OAG, and the Large Power Intervenors opposed limiting the test year revenue for Keetac to nine months, arguing that recognizing only nine months of revenue inappropriately understates the Company's test-year revenue. They asserted that a representative test year should reflect a full year of Keetac revenue, though each party disagreed on the exact adjustment required.

The Department also asserted that the Company's test year revenue amount should be adjusted to reflect the use of some of the increased revenues to offset the costs of the EITE rate schedule as

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[57] Minnesota Power's Initial Post-Hearing Brief, at 34.

required by Minn. Stat. § 216B.1696, subd. 2(d).[58] Specifically, it argued that a portion of the revenue increase attributable to Keetac would be used to offset the cost of the discounted EITE rate given to certain industrial customers, and that it would be inappropriate to count the revenue twice. The Department acknowledged that one option would be to reduce the Company's test year revenue amount only by an amount equal to the amount needed to offset the cost of the EITE rate, leaving the remaining amount to be recognized as test-year revenue in the rate case.

The OAG emphasized that the sales forecast should reflect the amount of energy Keetac will consume annually, not the assumed industry-wide utilization rate. LPI agreed with the OAG, noting that it was inappropriate to compare historical taconite utilization rates with forecasted electric energy sales to taconite customers.

The OAG agreed with the Department's suggestion that the Company's test-year revenue amount should be adjusted to reflect the use of some of the increased revenues to offset the EITE rate as required by Minn. Stat. § 216B.1696, subd. 2(d). But the Large Power Intervenors opposed this adjustment, arguing that revenue from Keetac must be accounted for in this rate case, and *only* in this rate case.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that Minnesota Power appropriately limited its 2017 forecasted sales revenue attributable to Keetac by including only nine months of revenue. He reasoned that volatility in the class of customers to which Keetac belongs—taconite producers—justifies reducing the annual revenue attributable to this customer in the test year.

D. Commission Action

This case is being built upon a forecasted 2017 test year. The Commission concludes that to establish just and reasonable rates based on a 2017 test year, it should consider annualized 2017 sales revenues when there is sufficient record support for annualization. Because evidence in the record supports a conclusion that sales to Keetac will continue for the foreseeable future, the Company will be required to reflect 12 months of sales, and a corresponding $1.8 million revenue increase, in its test year calculations.

Test year figures should reflect only known and measurable changes. The Commission is not persuaded that it is reasonable in this case to reduce a known test year revenue amount for specific customers as a proxy for a proposed load-factor adjustment for an entire industry. There is insufficient proof to support the contention that increased electricity sales arising from the Silver Bay Agreements and Keetac in the test year should be offset by reduced sales attributable to speculated future industry-wide economic developments.[59]

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[58] "In its next general rate case or through an EITE cost recovery rate rider between general rate cases, the commission shall allow the utility to recover any costs, including reduced revenues, or refund any savings, including increased revenues, associated with providing service to a customer under an EITE rate schedule." Minn. Stat. § 216B.1696, subd. 2(d).

[59] For the same reasons, the Commission also concludes that the Company's sales forecast should reflect 12 months of sales to Keetac.

The Commission agrees with the parties that revenues from Keetac should only be recognized once. Concurrent proceedings concerning implementation of the EITE statute and establishing the Company's general rates make this accounting uniquely challenging, but Minnesota Power should not be credited with having received these revenues twice.

And, because the test-year revenue from Keetac must be accounted for as an increase in utility revenue in a tracker established under Minn. Stat. § 216B.1696, and a portion of it must be used to offset the costs of the discounted EITE rate provided under that statute,[60] it is appropriate to reduce the Company's net test-year revenue amount.

That is, the Commission agrees that (1) the Company's test year should reflect the full, annualized amount of sales revenue for Keetac, *and* (2) the net test year revenue amount must also reflect that those revenues are subject to the requirement that certain increased revenues must be separately tracked and are subject to offset or refund under Minn. Stat. § 216B.1696, subd. 2(d).[61]

Accordingly, the Commission will require reduction of net test year revenue by an amount equal to the revenue that must be used as an offset or refund in the section 216B.1696 tracker, on an annualized basis. In this case, that amount is equal to the lesser of (a) the annualized Keetac revenue and (b) the annualized cost of the EITE discount. Revenue not required to cover test-year EITE rate costs will remain in the test year. The net effect is an upward adjustment of approximately $2.6 million in test-year revenue, which will reduce the overall test year revenue deficiency.

The Large Power Intervenors' argument that revenue increases from EITE customers cannot be accounted for in the section 216B.1696 tracker is contrary to the plain language of the statute; Minn. Stat. § 216B.1696, subd. 2(d), requires the utility to track certain revenue increases for refund. Nor does the statute require that test-year revenue accounting in a rate case disregard revenue-increase offsets or refunds provided for by the statute. In fact, the statute provides for tracker recovery or refund to be authorized as part of a general rate case, as the Commission is

[60] "Upon approval of any EITE rate schedule, the utility shall create a separate account to track the difference in revenue between what would have been collected under the electric utility's applicable standard tariff and the EITE rate schedule. . . . [T]he commission shall allow the utility to recover any costs, including reduced revenues, or refund any savings, including increased revenues, associated with providing service to a customer under an EITE rate schedule." Minn. Stat. § 216B.1696, subd. 2(d). *See In the Matter of Minnesota Power's Revised Petition for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider*, Docket No. E-015/M-16-564, Order Authorizing Cost Recovery with Conditions, at 7–8 (April 20, 2017) (establishing EITE tracker calculation components and method); Order Excluding Rider Revenue from 2016 Baseline Calculation and Setting Parameters to Identify Exempt Customers, at 5 and 8, ordering paragraphs 2 and 3 (October 13, 2017) (clarifying EITE tracker calculation components and method).

[61] Colloquially, parties in this proceeding, and the ALJ, have referred to this necessary accounting, which avoids double-counting Keetac revenues, as "moving" the revenues to the EITE docket, or "removing" them from the rate case. The Commission points out that it is not moving or removing revenues from this case, it is establishing a representative net test year revenue amount by netting known revenues and costs.

doing in this case.[62] The Commission concludes that the Large Power Intervenors' interpretation of the statute cannot be correct.

XXVII. Interim Rate EITE Tracker Balance Accrual

A. Introduction

The restart of the Keetac facility also affected calculations of the EITE cost recovery tracker balance during the rate case.[63] Overall, increased sales to Keetac has resulted in increased revenues that are to be tracked and netted with EITE discount costs as required by the statute; but, as explained below, a tracker balance accruing during the interim-rate period will need to be recovered.

Minnesota Power anticipated the need to pass much of the benefit of the Keetac revenue increase to ratepayers, so it preemptively reduced its interim rates. The Keetac sales-revenue increase prompted Minnesota Power to reduce its initial interim-rate increase from $48,632,259 to $34,732,113. The Commission approved the lower interim-rate increase "subject to downward adjustment if supplemental information filed by the Company on or before February 13, 2017 indicates that interim rates were set too high."[64] The Company later requested a further decrease to $32,244,923 based on updated calculations. The Commission approved the reduction.[65]

Because Minnesota Power requested an adjustment to its interim rates before knowing how its EITE tracker accounting would work, Minnesota Power's EITE tracker will accrue a deficit—the cost of the EITE rate discount during the interim rate period.[66]

At issue is whether to permit Minnesota Power to recover approved EITE tracker balance amounts arising during the unique circumstances of this case's interim-rate period, from the appropriate customers, by adjusting the interim-rate refund to those customers.

B. Positions of the Parties

Expecting that the revenue requirement determination in this case would result in an overcollection of interim revenue, which would require a refund, Minnesota Power proposed that the interim revenue refund be used to recoup its EITE tracker balance that had accrued over the interim period. The precise amounts needed to be recouped and refunded would depend on when final rates are implemented. At the Commission's January 30 meeting, the Company offered an

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[62] Minn. Stat. § 216B.1696, subd. 2(d).

[63] *See* Minn. Stat. § 216B.1696, subd. 2(d); *see generally In the Matter of Minnesota Power's Revised Petition for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider*, Docket No. E-015/M-16-564.

[64] Order Setting Interim Rates (December 30, 2016).

[65] Order Authorizing Interim-Rate Reduction (April 13, 2017).

[66] Interim rates went into effect on January 1, 2017, were reduced on May 1, 2017, and will continue until final rates are implemented. Minnesota Power first implemented the EITE rate credit on February 1, 2017, and suspended it on September 29, 2017. Then on January 25, 2018, the Company filed a letter with the Commission stating that it reactivated the rate, effective January 1, 2018.

example calculation based on the assumption that final rates would not go into effect until November 2018.

No party objected generally to the proposal when it was introduced by the Company and considered by the Commission, though the Department, the OAG and the Large Power Intervenors all expressed concern that the calculations be carried out in a way that accurately reflects the timing and amount of revenue collection during the interim period, and that only recovers the EITE tracker balance from the appropriate customers.

C. The Recommendation of the Administrative Law Judge

The ALJ made no findings concerning the interim-rate EITE tracker balance accrual.

D. Commission Action

The Commission concludes that the Company is entitled to recover the $8,636,643.11 in 2017 EITE discount costs that it has identified, and any additional amounts arising in its tracker account during the interim-rate period.

The interim-rate refund to EITE-surcharge-eligible customers will be reduced to the extent possible to provide for the full recovery of that amount. To the extent any portion of that amount is not recovered through a reduction in the interim rate refund, the Company may recover the remaining portion through the surcharge mechanism authorized by the Commission in the EITE docket. This will ensure that Minnesota Power will recover EITE costs not offset by revenue increases, and only from those customers subject to recovery, as provided for in the EITE statute.

The exact amount by which the interim-rate refund will be reduced to accomplish this will be set forth in a compliance filing by the Company, which the parties will have an opportunity to review.

COST OF CAPITAL ISSUES

Utilities meet their capital needs by issuing stock, known as equity, and by incurring long-term and short-term debt; these three components make up a utility’s capital structure. Generally, equity is the most expensive form of financing, followed by long-term debt and then short-term debt. The percentage of the capital structure made up of each of these components therefore has a substantial impact on costs and rates, as does the cost determined for each component during the ratemaking process.

In this case, the contested cost-of-capital issues are the capital structure and the cost of equity. The Company has also proposed a mechanism to annually adjust its rates. The Commission will address each of these in turn.

XXVIII. Capital Structure

A. Introduction

To determine the Company's cost of capital, it is necessary to determine reasonable ratios of long-and short-term debt and common-stock equity, because the costs of each source of financing are different.

Minnesota Power is an operating division of ALLETE, Inc. As an operating division of ALLETE, the Company's actual capital structure is derived from ALLETE's consolidated capital structure, which includes common equity and debt that finances all of ALLETE's business activities, including subsidiary operations. At issue is what capital structure should be adopted for Minnesota Power for ratemaking purposes.

B. Positions of the Parties

1. The Company and the Department

The Company proposed that its capital structure take the following proportions:

Short-term debt:	0%
Long-term debt:	46.19%
Common equity:	53.81%

The Department agreed with the Company's proposal, concluding that an equity ratio of no less than 53.81% would be reasonable and allow ALLETE to maintain a BBB+ Standard and Poor's credit rating. The Department supported its conclusion by comparing the proposed capital structure to a group of comparable companies. The Department asserted that although the proposed equity ratio was on the high end of reasonable, factors such as the ratio required to maintain the Company's credit rating justified the capital structure as proposed.

2. The OAG and the Large Power Intervenors

Both the OAG and the Large Power Intervenors asserted that the Company's proposed capital structure incorporated too much common equity. Both recommended that the ratio of common equity be limited to 51%. The Large Power Intervenors recommended the remainder be allocated to long-term debt, and the OAG recommended that 48.81% be allocated to long-term debt and 0.19% be allocated to short-term debt.

These parties argued that equity is the most costly means of obtaining capital, so a capital structure that over-relies on equity will unreasonably increase rates. They asserted that comparison with similar companies with the same credit rating supported a lower equity ratio.

The OAG further argued that the Company should be required to incorporate short-term debt into its capital structure. Short-term debt is usually the least expensive form of capital, and the OAG's witness testified that it is unusual and unreasonable for Minnesota Power not to carry at least some short-term debt because most utilities do.

C. The Recommendation of the Administrative Law Judge

The ALJ did not appear to recommend a specific capital structure. He did find that the Company's capital structure "may not be reasonable" because it was based on flawed modeling and analysis.

D. Commission Action

The Commission concludes that the Company has established that, on this record, its proposed common-equity ratio and a capital structure without short-term debt are reasonable.

The Commission concludes that the modeling and analysis underlying the Company's proposed capital structure has not produced an unreasonable result. This conclusion is supported by the fact that the Company and the Department, having performed separate analyses, found the proposal to be reasonable, and that the OAG and the Large Power Intervenors objected not over the analytical methodology, but over whether analytical results supported the Company's proposal.

The Commission finds persuasive the Department's witness's testimony that Minnesota Power does not have an incentive to carry "too much" equity, and that, at this time, the goal of maintaining the Company's credit rating justifies an equity ratio that is somewhat higher than comparable companies. And, because the Company does not, in fact, use short-term debt as a financial tool, it is reasonable to reflect that fact in its capital structure.

The Commission therefore agrees with the Company and the Department and so will approve the following capital structure:

Short-term debt:	0%
Long-term debt:	46.19%
<u>Common equity:</u>	<u>53.81%</u>
Total:	100%

XXIX. Cost of Debt

The ALJ appears not to have specifically recommended a cost of long-term debt, a component of calculating the overall cost of capital for the Company. There is no disagreement among the parties that Minnesota Power's rate of 4.52% for the cost of long-term debt is reasonable. The Commission agrees and will adopt it.

XXX. 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*.[67]

One of the critical components of that fair and reasonable return upon investment is the return on common equity, which—together with debt—finances 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. Minnesota Power is an operating division of ALLETE, Inc., and represents approximately 77% of ALLETE's capital value. Because Minnesota Power does not itself offer stock for trade on public markets, its cost of common equity—essential to determining overall rate of return and the final revenue requirement—must therefore be inferred either by reference to ALLETE's, or from market data for companies that present similar investment risks (a proxy group). Using a proxy group can also moderate the effects of one-time events on a given company's stock.

B. The Analytical Tools

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

The Company, the Department, the OAG, and the Large Power Intervenors also performed a Capital Asset Pricing Model (CAPM) analysis. The Company 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 sufficient to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities using three inputs—dividends, stock prices, and growth rates. DCF modeling can be performed using constant, "two-growth,"[68] and multistage dividend-growth assumptions.

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 risk premium determined by subtracting the 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.

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

[68] A two-growth model assumes that dividends grow at one rate for a short time, and then grow at a second, sustainable rate in perpetuity.

The Bond Yield Plus Risk Premium Model determines the cost of equity by adding to the risk-free rate a premium reflecting the greater returns required by equity holders.

C. The Positions of the Parties

1. The Company

The Company proposed a return on equity of 10.15%, based on constant growth, two-growth, and multistage DCF models of a six-utility proxy group, along with CAPM and Bond Yield Plus Risk Premium analyses.

The Company's chosen proxy group started with companies classified by Value Line as "electric utilities," and then screened out companies based on eight screening criteria. The proxy group was then further screened by excluding companies with mean DCF model results of less than 8%.

The Company also advocated for factoring in and adjusting for business risks and other factors specific to the Company, including its highly concentrated customer base, of which a significant percentage are industrial customers in highly cyclical industries. According to the Company, its relevant risk factors distinguish Minnesota Power and justify a high ROE relative to the companies in the proxy group.

2. The Department

The Department proposed a return on equity of 8.70%, the result of applying both a constant- and two-growth DCF model to a proxy group not screened using an ROE floor, using the most recent growth-rate projections for each company in that group, and adjusting the final number to include flotation costs. The Department's proxy group consisted of 17 companies.

The Department noted that it had also conducted a CAPM analysis on the companies as a reasonableness check, and found that the analysis confirmed the general accuracy of its DCF results.

The Department opposed the Company's exclusion of several companies from its proxy group, and disputed the Company's claims that it represents a greater relative investment risk than the companies appropriately in the proxy group.

The Department further criticized the Company's DCF and risk premium analyses for using data that it argued was not reflective of current investor expectations. And the Department contended that the Company's ultimate ROE recommendation of 10.15% relied exclusively on CAPM and risk-premium analyses, and ignored the Company's own DCF analyses. The Department also argued against considering ROEs established in other proceedings for other utilities because they reflect out-of-date information and are not reasonably comparable.

3. The OAG

The OAG also proposed a return on equity of 8.70%, based on a two-growth DCF study using a different proxy group that applied screens intended to ensure that the companies in the proxy group reflected Minnesota Power's level of investment risk. The OAG challenged the

Company's execution of the DCF analytical models, arguing that the Company's proxy group unreasonably screened out relevant comparable companies, and that the Company's DCF modeling used outdated market information and too-long trading periods.

In the OAG's view, Minnesota Power is not riskier than an appropriately-constituted proxy group. The OAG therefore opposed the Company's proposed upward adjustments from mean DCF results for company-specific risk factors—it argued that adjusting a DCF-based ROE for these factors would effectively account for them twice. The Office also argued that it would be unreasonable to selectively focus on factors that can increase risk while ignoring factors that can reduce risk.

The OAG ultimately urged the Commission to base its decision on the mean of the Department's and OAG's DCF analyses.

4. The Large Power Intervenors

The Large Power Intervenors argued that the Company's proposed ROE was unreasonable. To support their recommended ROE of 9.30%, LPI conducted two constant-growth DCF analyses, a multistage DCF analysis, along with CAPM and risk-premium models, all using the same proxy group used by the Company. Ultimately they derived a range of reasonable ROEs from 8.90% to 9.70% and recommended establishing the ROE at the midpoint: 9.30.

In the alternative, LPI recommend that if their analytical approach is not adopted and the Department's more DCF-reliant approach is preferred, and the Commission approves a 53.81% equity ratio, that an ROE in the range of 8.80% to 9.20% would be reasonable.

5. Wal-Mart

Wal-Mart did not conduct a company-specific financial analysis or propose a specific ROE, but did recommend that the Commission consider approved ROEs in other proceedings as evidence to support a conclusion that the Company's proposed ROE is unreasonably high. Based on historical ROEs established in other proceedings, Wal-Mart recommended an ROE between 8.70% and 9.64%.

D. The Recommendation of the Administrative Law Judge

The ALJ determined that DCF modeling generates more consistent outcomes and should be used to determine the Company's ROE. The ALJ recommended that the ROE be established using the midpoint of "the two DCF variants," using the Department's proxy group. The ALJ concluded that the Company's risk level would be appropriately accounted for using the Department's proxy group, and so no further adjustment to ROE would be appropriate.

E. Commission Action

1. The record reflects the diversity of factors and analytical approaches that can be reasonably considered when setting an ROE.

Setting the cost of equity is a fact-intensive and record-specific judgment. The Commission must ultimately establish a reasonable rate of return that is supported by the evidence in the record considered in its entirety.[69] The Commission believes that the record evidence in this case, including the broad diversity of modeling and expert testimony, establishes a range of reasonable costs of equity, within which the Commission must identify one value.

The record does not formulaically dictate a particular ROE to be approved. Instead, the record presents a range of reasonable returns on equity that the Commission has carefully evaluated based on the analyses and arguments in the record. As such, the Commission will set the Company's authorized ROE in light of the record as a whole.

Examples of how a broad range of interrelated factors must be considered when determining an appropriate ROE can be found throughout the record. For example, arguments from the Department and the Large Power Intervenors acknowledged the relationship between the approved capital structure and the appropriate return on equity.

The Department argued that approval of the Large Power Intervenors' recommended capital structure (with less equity and more long-term debt) would require an upward adjustment to the Department's recommended ROE. Likewise, the Large Power Intervenors acknowledged that approval of the Company's proposed capital structure (more equity, less long-term debt) instead of theirs, *and* a reliance on the Department's DCF modeling over LPI's multi-model approach would justify shifting their recommended range of ROEs downward (from between 8.90% and 9.70% to between 8.80% and 9.20%).

The positions of the Department and the OAG concerning the appropriate ROE serve as another example. Both the Department and the OAG asserted that the appropriate ROE for the Company is 8.70%. But the Department recommended 8.70% because in its analysis the figure included an adjustment for flotation costs—the costs of issuing equity, such as legal, underwriting, and registration fees—and the OAG recommended the same figure because in its analysis 8.70% did *not* include a flotation cost adjustment.

And finally, the Company and the Large Power Intervenors argued in support of using multiple methodologies to mitigate the effects of assumptions and inputs associated with any single approach. The Company's witness testified that in his view the DCF methodology may be unreliable under current market conditions.

The wide diversity of analytical methods in the record in this case do not lead to wildly disparate conclusions. The recommendations of the parties all fall into a fairly narrow and often overlapping range, though the DCF analyses tend to support a lower ROE in that range, and CAPM and risk premium models (and blended approaches) tend to support the higher end of the range.

2. The record as a whole supports establishing an ROE of 9.25%.

Using the DCF and other analyses in the record as both a foundation and a guide, the Commission has considered and weighed the relevant factors, which include, but are not limited

[69] *See In re:App. of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, 838 N.W.2d 747, 760 (2013) (describing the substantial evidence test, and citing *Reserve Min. Co. v. Herbst*, 171 N.W.2d 712, 825 (1977)).

to the relative objectivity, transparency, reliability, rigor, and timeliness of the analytical models in the record, and their inputs; the composition and representative nature of the proxy groups proposed in each analysis; the ROEs (or ranges of ROEs) that the parties recommended based on their modeling results; ROEs in other recent proceedings; and the Company's approved capital structure and costs of obtaining equity investment.

Most importantly, the approved ROE must adequately assure a fair and reasonable return in light of the Company's risk profile and costs of obtaining equity investment. In light of the relevant factors, the Commission will approve a cost of equity of 9.25%.

The reasonableness of an ROE of 9.25% is supported by each version of both the Department's and the Company's DCF analyses, and LPI's multi-method analysis, despite their significant differences. A 9.25% ROE falls between the average and higher end of comparable ROEs under the Company's own two-growth DCF analyses, and below the average of the mean-high results in the Department's updated two-growth DCF analysis.

The Commission concludes that it is appropriate to establish an ROE toward the higher end of the DCF-supported results to adjust for the divergence between ROEs supported by the DCF models and the models the Commission has historically relied upon for confirmation of reasonableness—the CAPM and Bond Yield Plus Risk Premium models. In direct testimony, the Department's witness estimated a CAPM rate of return of 9.22% (9.29% after adjusting for flotation costs), and the Company's and the Large Power Intervenors' CAPM results were generally higher.

Therefore, the Commission is persuaded that an ROE supported by the two-growth DCF analyses in the record, but which is also reasonably positioned among the breadth of reasonable DCF, CAPM, and blended-analysis results, is justified in this case. An ROE of 9.25% is sufficient to establish just and reasonable rates, while adequately assuring a fair and reasonable return in light of the Company's unique risk profile, capital structure, and costs of obtaining equity investment.

XXXI. Final Capital Structure and Overall Cost of Capital

The final capital structure and overall cost of capital resulting from the decisions made in this order are as follows:

Component	Ratio	Cost	Weighted Cost
Short-Term Debt	0.0%	-------	0.0000%
Long-Term Debt	46.1892%	4.5170%	2.0864%
Common Equity	53.8108%	9.2500%	4.9775%
Total	100.0000%		7.0639%

XXXII. Annual Rate-Review Mechanism

A. Introduction

Minnesota Power proposed a mechanism to adjust its rates between rate cases when changes in sales or other factors result in significant increases or decreases to its actual ROE. The Company argued that its proposed Annual Rate Review Mechanism (ARRM) would promote rate stability and provide customer protection while allowing the Company to recover costs in the event of an economic downturn. The Minnesota Chamber of Commerce supported a modified version of the proposal, arguing that it would streamline and modernize the regulatory process in a way that protects ratepayers.

The Department, the OAG, the Large Power Intervenors, and Wal-Mart opposed the ARRM proposal, on a variety of grounds, including: the proposal improperly shifts investment risk to ratepayers; it would represent a dramatic shift in the regulatory framework without adequate justification; there are other, better-understood mechanisms to accomplish a similar purpose, such as decoupling and multiyear rate plans; the proposal does not properly align company and ratepayer interests; and the proposal could result in significant rate increases without a full review of costs.

B. The Recommendation of the Administrative Law Judge

The ALJ found that the ARRM proposal would shift risks from the utility and its shareholders to customers, that it was inconsistent with any current state policy, and that the Company had not established that the proposal was just and reasonable. The ALJ recommended that the Commission not approve the proposal.

C. Commission Action

The Commission agrees with the ALJ and the parties that did not support the ARRM proposal, and will reject it. While the Commission values innovative approaches to improve the regulatory process, it has not been established on this record that this proposal for automatic adjustment would properly align the Company's incentives with the public interest or result in just and reasonable rates.

CLASS COST OF SERVICE STUDY ISSUES

XXXIII. Rate Design and Class Cost of Service Introduction

A. Rate Design and Customer Classification

The preceding sections established Minnesota Power's revenue requirement based on a 2017 test year. The following sections will address how Minnesota Power may recover the revenue requirement from its ratepayers. This process of rate design requires the Commission to exercise policy judgment because there are many ways to set rates to enable a utility to recover appropriate revenues.

In designing rates, the Commission considers a variety of factors, including:

- Equity, justice, and reasonableness, and avoidance of discrimination, unreasonable preference, and unreasonable prejudice;[70]
- Continuity with prior rates to avoid rate shock;
- Revenue stability;
- Economic efficiency;
- Encouragement of energy conservation;[71]
- Customers' ability to pay;[72]
- Ease of understanding and administration; and
- Cost of service.

Estimating the cost to serve any given customer is challenging because a utility will incur different costs to serve different customers, and will incur many costs that benefit multiple customers. Because similar types of customers tend to impose similar types of costs on the system, utilities simplify their analysis by first dividing customers into classes—for example, distinguishing residential customers from commercial or industrial customers. Utilities then attempt to determine the amount of revenues they should recover from each customer class.

To aid this analysis, the Commission directs utilities to conduct a class cost of service study (CCOSS). Minn. R. 7825.3400(C) directs a utility to file:

> A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations.

B. Class Cost of Service Studies

According to the *Electric Utility Cost Allocation Manual* of the National Association of Regulatory Utility Commissions (*NARUC Manual*), performing a CCOSS involves three steps. First, costs are grouped according to their function (generation/production, transmission, distribution, customer service/facilities, administrative). Second, costs are classified based on how they are incurred. Third, costs are allocated to the various customer classes.[73]

Functionalization. The utility separates costs according to function, including production, transmission, distribution, customer service, and administrative/general. Cost figures are based on the utility's accounts kept in compliance with FERC's uniform system of accounts. The production function refers to power production from the utility's generating units. The transmission function refers to the assets and costs associated with interconnecting the utility's

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[70] Minn. Stat. §§ 216B.01, .03.

[71] Minn. Stat. §§ 216B.03, .2401, 216C.05.

[72] Minn. Stat. § 216B.16, subd. 15.

[73] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, at 18–23 (January 1992).

system to load centers. The distribution function refers to the system that connects the customer to the transmission system.

Classification. The cost of a function might be classified as related to energy, demand, or customers. Energy-related costs increase as customers' consumption of energy increases. Demand-related costs increase as the rate at which customers consume energy increases, especially during periods of peak demand. Customer-related costs increase as the number of customer accounts increases. According to the *NARUC Manual*, the cost of an electric utility's distribution system is related to energy, demand, and customers.

Allocation. The various costs are allocated to each customer class. For purposes of its CCOSS, Minnesota Power divides its customers into six classes:

- Residential;
- General Service;
- Large Light & Power;
- Large Power;
- Municipal Pumping; and
- Lighting.

XXXIV. Minnesota Power's Class Cost of Service Study – Peak and Average Method

A. Introduction

Minnesota Power used a peak and average (P&A) allocation method for classifying and allocating its fixed production and transmission costs. It used a minimum system method for classifying and allocating its distribution costs.

The P&A method allocates fixed production and transmission costs to each customer class based on (a) each class's average level of demand (level of energy consumption), and (b) the proportion of the Company's capacity that each class requires during the period of peak demand. The Company advocated allocating fixed production plant costs on the basis of both demand and energy. In this case, Minnesota Power's cost study allocates 88% of the revenue requirements based on weighted energy (average demand) and 12% based on demand during the Company's annual system peak (peak demand).

1. Average Demand

As stated above, the Company's P&A allocation method allocates 88% of the revenue requirement based on weighted energy, or, average demand. The *NARUC Manual* characterizes the P&A method as a partial energy-weighting method, in which demand-related costs are allocated using energy consumption even where they are not classified as such. The method is applicable where the impact of average demand on production plant costs is a better allocator of those costs and is therefore weighted more heavily than peak demand.

2. Peak Demand

In addition to considering average demand, the Company's P&A cost allocation method allocates 12% of the revenue requirement based on demand during the Company's system peak, which occurs in winter. The Company used one hour during a winter month in a single year as its peak demand. A particular class's demand—or load—at the time of the system peak is called coincident peak demand. Some cost-allocation methods rely solely on coincident peak demand —to the exclusion of average demand—in their analyses. In these scenarios, the coincident peak could be based on a single peak month (1 CP), the average of three peak months (3 CP), or the average of peaks in twelve months (12 CP).

Demand is likely to be allocated according to the utility's load profile. For example, a utility with a relatively flat load profile during the year is more likely to allocate demand costs on a 12 CP basis. A winter-peaking utility allocating costs using coincident peak might allocate demand costs using peak demand during winter months, for example, three winter months, or 3W CP.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power stated that using the P&A method reflects the nature of the Company's system, which has a high load factor, meaning that its need for generation is driven by customers' energy requirements.

The Company stated that its fixed production and transmission costs are associated with revenues that do not vary with electricity production at the time electricity is produced and are therefore *classified* as 100% demand-related, rather than demand- and energy-related. Consistent with the *NARUC Manual*, however, the Company used the P&A method to *allocate* production plant costs and transmission costs as both energy- and demand-related.

This method involves a two-step process to determine the allocation factor. First, the average demand of each class is weighted by a load factor (average demand divided by peak demand for a given period). Second, the coincident peak demand factor is multiplied by the remaining proportion of production plant (1 minus the system load factor). These two components are added together to determine the total allocator. To calculate the allocation factor, Minnesota Power used its load factor of 88% and its annual system peak, which occurs in winter. As a result, the cost study allocates 88% of the revenue requirement based on average demand and 12% based on peak demand.

The Company compared the results of the P&A method to five other methods that use peak demand, not average and peak demand. Under the P&A method, rates would increase for all classes except the lighting class, with the residential class incurring the largest increase. Under the other five methods, coincident peak varied (either annually, monthly, or with some combination of summer and winter months). In each alternative scenario, rates decreased for the large power class. The results are shown in the table below.

Table 4: Test-Year Revenue Deficiency from Different Cost studies

	Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
Peak & Average	$ 38,769,070	$ 33,749,994	$ 1,662,394	$ 1,167,458	$ 1,826,151	$ 576,053	$ (212,980)
1 CP	38,769,070	51,863,971	4,182,439	(5,311,726)	(13,594,504)	1,131,306	497,583
12 CP	38,769,070	37,310,366	4,295,773	(1,722,143)	(1,712,055)	1,223,652	(626,523)
3W CP	38,769,070	55,245,862	3,977,766	(2,738,119)	(19,388,310)	1,320,196	351,675
3S CP	38,769,070	41,268,326	14,217,626	4,539,775	(21,169,417)	1,182,684	(1,269,925)
3W3S CP	38,769,070	48,074,919	9,233,110	996,365	(20,303,546)	1,248,838	(480,616)

Minnesota Power acknowledged that other methods are valid and reflect some of the Company's operating characteristics but stated that the CP methods allocate more costs to the Residential and General Service classes without a principled reason for doing so. The Company stated that the P&A method is a reasonable approach given the Company's load factor and is consistent with the *NARUC Manual*. The Company also noted that it used the P&A method in its prior two rate cases with Commission approval.

2. The Department

The Department concurred with Minnesota Power that using the P&A method to allocate costs is reasonable in light of the fact that a significant portion of the Company's fixed production costs are energy-related. In support of the Company's method, the Department also stated that use of the Company's annual system peak reflects the fact that most of the costs embedded in the Company's revenue requirement relate to demand during the Company's system peak.

In the Department's view, allocation methods relying solely on peak demand, as shown in the table above, unreasonably disregard the Company's energy-related costs. But the Department also challenged two aspects of the Company's cost study.

First, the Department recommended that the Company modify its cost study to classify fixed production costs as both energy- and demand-related, instead of 100% demand-related, claiming that some production costs do, in fact, vary with electric production.

Second, the Department recommended that the Company modify its cost study to allocate transmission costs using each customer class's peak demand coincident with the Company's annual system peak demand, instead of using the P&A method of allocating 88% of costs using average demand and 12% using peak demand. The Department explained that the Company's transmission costs are driven primarily by demand for electricity at the Company's annual system peak.

3. LPI

LPI opposed Minnesota Power's use of the P&A method, claiming that methods using peak demand to allocate costs are more accurate than the P&A method, which relies primarily on average demand. LPI stated that the P&A method double counts average demand by accounting for average demand separately from peak demand, and again as part of peak demand (average demand plus excess demand). Further, the P&A method reduces the allocation of additional capacity costs the Residential class needs above its average demand to serve its peak demand, resulting in an unreasonably low allocation of costs to the Residential class.

Because Minnesota Power is a winter-peaking utility, LPI recommended that the Company allocate fixed production costs using coincident peak demand in three winter months and one summer month (the 3W 1S allocator). Under this method, LPI asserted, each class pays comparable capacity costs relative to the system average.

LPI further recommended that the Company use a 12-month coincident peak method to allocate transmission costs, consistent with how MISO allocates all transmission capacity; MISO's plans for capacity are based on a coincident peak methodology across rate classes.

4. Energy CENTS Coalition

The Energy CENTS Coalition stated that the Company's method unfairly shifts costs to residential ratepayers because the Company has excess capacity as a result of decreased large power load. Energy CENTS therefore recommended that the Commission consider other factors more heavily than the cost study, including affordability and ability to pay.

5. OAG

The OAG acknowledged the validity of the P&A method but recommended that instead of using its annual system peak demand, which occurs during the winter, Minnesota Power should use MISO's peak demand, which occurs in the summer. The OAG stated that Minnesota Power's peak is caused by the need to meet MISO's peak, making the use of MISO's peak a more accurate reflection of cost. The OAG also opposed using the Company's peak, which is based on one hour in a single year and can cause variable results that call into question the accuracy of the model's results.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Minnesota Power met its burden to show that its use of the P&A method is just and reasonable.

In reaching this conclusion, the ALJ appeared to place the burden on the objecting parties to produce evidence to rebut the Company's cost study results. Specifically, he found that the Company had used an accepted cost methodology and that opposing parties had not presented evidence or arguments sufficient to show that the methodology is no longer accepted or that it was improperly applied resulting in inaccurate numbers. He concluded that the Company's position must therefore prevail.

D. Commission Action

As an initial matter, the Commission disagrees with the ALJ's apparent conclusion that parties challenging Minnesota Power's cost study have a burden to produce evidence to rebut the evidence proffered by the Company in support of its study. In a rate case, the burden remains at all times with the utility to convince the factfinder that its claimed costs will result in just and reasonable rates. Thus, to the extent that the ALJ concluded that the Company's position "must prevail" simply because other parties did not provide contradicting evidence, his reasoning was erroneous.

The Commission concurs with Minnesota Power that the P&A method is consistent with the Company's cost characteristics and is recognized as a valid method by the *NARUC Manual* and will consider it. The Commission will also, however, consider the parties' proposed modifications, as well as the 3W 1S allocator advocated by LPI, in evaluating the Company's proposed revenue apportionment. The range of comments both supporting and opposing the Company's method further inform the record, as do the proposed modifications and alternative methods, all of which illustrate the broad nature of cost studies and the difficulty in accurately determining cost causation.

XXXV. Distribution System Costs

A. Introduction

Minnesota Power used the minimum system method to allocate distribution costs. This method allocates distribution costs between demand-related and customer-related components because a utility builds out its distribution plant to (a) serve each customer regardless of the amount of demand that each customer puts on the system and (b) have sufficient capacity to reliably meet customers' peak demand.

The method estimates the cost to build a system that provides each customer a minimal level of service, i.e., a system with little or no load. The system's facilities include items such as substations, primary and secondary conductors, as well as poles and line transformers that are on a customer's premises. The cost of the minimum system is customer-related. Additional costs related to the need to build capacity to deliver more than minimal service are demand-related.

B. Positions of the Parties

1. The OAG

The OAG claimed that the primary flaw of Minnesota Power's cost study is that it classifies a disproportionally high percentage of distribution system costs as customer-related. The OAG recommended that the Commission consider other methods for classifying distribution costs described in the *NARUC Manual* as FERC accounts 364–370 and ordinarily classified by NARUC in the following manner:

Table 5: NARUC Classification of Distribution Facilities

FERC Account	Description	Demand-Related	Customer-Related
364	Poles, Towers, & Fixtures	Yes	Yes
365	Overhead Conductors & Devices	Yes	Yes
366	Underground Conduit	Yes	Yes
367	Underground Conductors & Devices	Yes	Yes
368	Line Transformers	Yes	Yes
369	Services – overhead lines and underground lines		Yes
370	Meters		Yes

The OAG stated that other methods for classifying costs are supported by the *NARUC Manual* and general economic principles and are equally valid. These methods include a basic customer model that would classify FERC accounts 364–368 as 100% demand-related, FERC account 369 as 100% customer-related, and FERC account 370 as one-third each energy-, demand-, and customer-related. The OAG also recommended that the Commission consider a P&A model that would classify FERC accounts as described under the basic customer model, except that it would classify FERC accounts 364–368 as 88% energy-related and 12% demand-related.

The OAG's particular emphasis was on metering costs. In light of the benefits of Advanced Metering Infrastructure (AMI), the OAG claimed that it is reasonable to modify the classification of metering costs as customer-related. New AMI technology enables two-way communication between customers and utilities, ultimately lowering a utility's demand and energy costs, particularly through time-based customer rates, increased reliability, and improved load control. As a result, the OAG stated that the cost study should be modified to classify the cost of meters as equally demand-, energy-, and customer-related. The OAG noted that the *NARUC Manual* anticipates modifications to its current classification of meters as 100 % customer-related.

The OAG also opposed the Company's functionalization of lines operating at 46 kilovolts (kV) or below as distribution lines. The OAG claimed that lines operating at 46 kV, and some of the Company's 34 kV lines, are transmission lines because they serve transmission-related functions, such as serving multiple communities, connecting multiple substations, or serving wholesale customers.

2. AARP

AARP also challenged the Company's allocation of distribution costs, stating that the minimum system method allocates a significant portion of costs as customer-related, resulting in a disproportionally higher allocation of costs to the Residential class. AARP stated that Minnesota Power should have considered alternative methods for allocating distribution costs as it did when allocating its fixed production and transmission costs.

3. The Department

The Department opposed the OAG's proposal for classifying distribution costs by removing the customer–related component from FERC accounts 364–368. Minnesota Power's cost study classifies those costs as customer- and demand-related, depending on the asset, but with no energy component.

The Department stated that the Company's classification reflects the fact that the number of service lines and the size of the lines increase as the number of customers and levels of demand increase. These factors cause the Company's costs to increase proportionally, justifying classification of a percentage of these costs as customer-related, whereas the OAG's proposal disregards these fundamental characteristics of cost causation.

4. LPI

LPI also opposed the OAG's approach to classifying distribution system costs, stating that the proposal to remove the customer component of those costs is inconsistent with cost causation.

On the issue of functionalizing 46 kV lines as distribution lines, LPI stated that the OAG had not performed an engineering study of Minnesota Power's system and that the record does not support such an outcome.

5. Minnesota Power

Minnesota Power opposed the OAG's proposed modifications to the Company's cost study. The study classified distribution facilities in the following manner: poles and lines (FERC accounts 364–368) are classified as demand- and customer-related because they are needed regardless of demand but are sized to meet the customer's demand; services related to connecting the distribution line to a customer's meter or premises (FERC account 369) are also classified as demand- and customer-related for the same reasons; meters (FERC account 370) are classified as 100% customer-related because the meter measures the amount of energy that flows to a customer regardless of demand.

The Company noted that meters are customer-related whether or not they are AMI meters because the size of the meter does not change based on customer usage. The Company stated that it adjusts the meter price by class based on functionality.

In response to the OAG's recommendation that 46 kV lines and some 34 kV lines be functionalized as transmission lines, the Company stated that there has been no change in the Company's use of those lines since its last rate case in which their functionalization as distribution lines was approved. The Company stated that there is no record support for changing their functionalization in this case.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge addressed three categories of distribution costs–poles, lines, transformers, service lines (FERC accounts 364–369); meters (FERC account 370)–and addressed functionalization of distribution lines.

The ALJ concluded that Minnesota Power met its burden to show that its classification of distribution costs (other than meters) and its functionalization of distribution lines are just and reasonable. In reaching this conclusion, the ALJ appeared to place the burden on the objecting parties to produce evidence to rebut the Company's cost study results. Specifically, he found that the Company had used an accepted cost methodology and that opposing parties had not presented evidence or arguments sufficient to show that the methodology is no longer accepted or that it was improperly applied resulting in inaccurate numbers. He concluded that "other recommended approaches need not be considered" and that the Company's position must therefore prevail.[74]

The Administrative Law Judge separately concluded that Minnesota Power did not meet its burden to show that its classification of AMI meter costs is just and reasonable. In reaching this conclusion, the ALJ stated that the cost of AMI meters is not exclusively customer-related and recommended that the Commission exclude from the calculation of each customer class the cost of meters.

D. Commission Action

As an initial matter, the Commission disagrees with the ALJ's apparent conclusion that parties challenging Minnesota Power's cost study have a burden to produce evidence to rebut the evidence proffered by the Company in support of its study. In a rate case, the burden remains at all times with the utility to convince the factfinder that its claimed costs will result in just and reasonable rates. Thus, to the extent that the ALJ concluded that the Company's position "must prevail" simply because other parties did not provide contradicting evidence, his reasoning was erroneous.

The Commission does not accept the ALJ's conclusion on this issue and will instead continue its practice of considering a range of models to classify FERC accounts 364–369. As the Commission explained in CenterPoint and Otter Tail's recent rate cases, this practice allows the Commission to consider a range of accepted economic theories to develop a better outcome.[75] In this case, the OAG has proposed using the basic system and peak and average models, in addition to the Company's proposed minimum-system model. The Commission finds this proposal reasonable and will consider all of the models proposed in this case.

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[74] ALJ's Report, at 124.

[75] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-017/GR-15-1033, Findings of Fact, Conclusions, and Order (May 1, 2017); *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-15-424, Findings of Fact, Conclusions, and Order (June 3, 2016).

XXXVI. CCOSS Transparency

The Department stated that the format of the Company's cost study did not include Excel versions of tables and schedules that could be used by other parties to efficiently replicate the model and test the data. The Department also stated that locating spreadsheets was difficult and that data on revenue-requirement items was not cohesively presented. As a result, the parties used the discovery process to obtain clarifying information, shortening the time available to conduct analyses. The Administrative Law Judge did not address this issue.

The Department and the Company resolved the issue, agreeing on future improvements, which the Commission will require the Company to follow, including:

- Working with the Department, the OAG, and other interested parties to improve the transparency of the Company's class cost of service studies in the future;
- Filing, within a 12-month deadline, a compliance filing explaining improvements that have been made to the Company's class cost of service study, including the updated version of its CCOSS model and guide, or if not yet competed at the 12-month deadline, a timeline for completion and for future compliance filings;
- Filing a status report within six months of the date of this order identifying the Company's efforts to facilitate review of its class cost of service study model or adopt a new model; and
- Considering the concerns raised by staff.

RATE DESIGN ISSUES

XXXVII. Revenue Apportionment

A. Introduction

After the Commission establishes a utility's revenue requirement, the Commission must design rates that will provide the utility with a reasonable opportunity to recover these costs. The next step in this process is to establish the share of Minnesota Power's revenue requirement to be recovered from each class of customers served by the utility.

In making this apportionment, the Commission considers the totality of the evidence in the record, including evidence on cost causation and non-cost concerns such as: equity, justice, and reasonableness and the avoidance of discrimination, unreasonable preference, and unreasonable prejudice; continuity with prior rates to avoid rate shock; revenue stability; economic efficiency; encouragement of energy conservation; customers' ability to pay; ease of understanding and administration; and cost of service.[76]

[76] Minn. Stat. §§ 216B.01, .03, .2401, 216C.05, 216B.16, subd. 15.

B. Positions of the Parties

Based on the Commission's authorized 1.91% rate increase, the parties proposed updated revenue apportionments.[77] The updated proposals included significantly smaller rate increases than their original proposals, which had been based on the Company's initial rate increase request of 9.1%.

Minnesota Power stated that its recommended revenue apportionment strikes a reasonable balance between moving the classes closer to cost and avoiding rate shock by gradually changing the existing rate structure. Under the Company's proposal, rates for all classes except the Lighting class would increase proportionally, considering the results of the Company's cost study and non-cost factors. The Company cost study results show that only the Lighting class is paying above its costs.

The OAG emphasized the need to mitigate rate increase impacts to low-income and low-usage customers, considering the technical errors included in Minnesota Power's cost study and the manner in which the OAG addressed those errors through its proposed methods for classifying distribution costs. The OAG asserted that other parties relied too heavily, nearly exclusively, on cost analyses, which were flawed. Under the OAG's proposal, the rate increase applied to the Residential class would be higher than all other classes,[78] while the increase applied to the Large Power class would be among the lowest, (only the Lighting class would be lower, and by less than one percent).

The Department recommended that the Commission apportion the revenue requirement consistent with the Department's cost study recommendations, considering cost and non-cost factors. Under the Department's proposal, rate increases would be spread nearly evenly across classes, with each class's rates increasing by less than two percent. Fond du Lac Band recommended that the Commission adopt the revenue apportionment recommended by the Department.

AARP recommended that the Commission adopt the revenue apportionment recommended by the OAG. AARP also maintained that rate increases across classes should be relatively proportionate so that no class would experience a rate increase greater than 150% of the system-average percentage increase and no class would receive a rate decrease.

ECC recommended that the Commission adopt the revenue apportionment recommended by either the Department or the OAG, noting that Minnesota Power's proportion of low-income customers is higher than in other areas of the state.

LPI recommended that the Residential class bear the entire rate increase, along with an additional, separate twenty percent rate increase above the revenue requirement authorized in this rate case to reduce by one percent the rates of large power customers. LPI asserted that the Residential class is paying disproportionally low rates in comparison to its costs, that rates for

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[77] *See* Responses to Commission Staff Information Requests, filed January 29, 2018 (summarized in Handout from January 30 Commission meeting, filed March 5, 2018).

[78] The Municipal Pumping class would receive a nearly identical increase.

large industrial customers have been inappropriately high for years, that only modest movements towards bringing classes closer to cost have been made, and that inability to pay also affects large power customers.

The Chamber of Commerce echoed the concerns raised by LPI, stating that the need to bring classes closer to cost is fundamentally important to a fair outcome, particularly considering the importance of regional economic success, which depends on keeping rates competitive for the commercial and industrial classes. Under the Chamber's proposal, the Residential class would bear the entire rate increase, with an additional, separate five percent increase to reduce by one-half percent the rates of large power customers. Wal-Mart stated that it supported the Chamber's proposal.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Minnesota Power did not meet its burden to demonstrate that its proposed revenue apportionment is just and reasonable, concluding that the rates for the Large Power class should increase the least, if at all, with the remaining amount of the revenue requirement to be spread among the other classes, with no class paying more than a ten-percent increase in rates.

The ALJ reasoned that large power customers are the economic drivers of the region and that limiting their rate increases will "improve economic prosperity."[79] He also found that due to economic gains in the region, it is no longer necessary to protect residential ratepayers from the bulk of rate increases.

D. Commission Action

The Commission respectfully disagrees with the ALJ's recommendation that it would be reasonable to relieve the Large Power class of any rate increase. That approach relies entirely, or nearly entirely, on cost factors for its justification and would result in an unreasonable apportionment among the classes.

The Commission is also unpersuaded by the arguments of LPI, the Chamber, and Wal-Mart that the Residential class should exclusively bear the cost of the rate increase, with an increase in rates that exceeds 100% of the revenue requirement to deliver a rate decrease for large power customers. Their arguments appear to exclude meaningful consideration of non-cost factors and are premised on the assertion that a rate decrease will correct historically and inappropriately high rates for these customers. There is, however, no error in the current rate structure. To the contrary, the Commission's prior rate case decisions established just and reasonable rates after a full consideration of the entire record in those proceedings. The Commission now considers rate design anew, informed by cost and non-cost factors and based on the entirety of the record in this proceeding.

While the parties disagree on revenue apportionment percentages, they do appear to agree that the record supports bringing classes closer to cost by apportioning the highest rate increase to the Residential class. In the proposals of the Department and the OAG, the remaining revenue

[79] ALJ's Report, at 127.

requirement increase is divided proportionally among the other classes. Under the Company's proposal, the remaining revenue requirement would be uniformly apportioned among the classes, except the Lighting class, which, according to the Company, is paying more than its costs. LPI and the Chamber of Commerce proposed rate decreases for some classes.

The Commission concurs that the record supports bringing the classes closer to cost by apportioning an increase to the Residential class that is at least as high as any other class's increase. But the Commission is also mindful that cost studies are imprecise and that allocating the full cost of service to one or two classes to deliver rate decreases to other classes is not a reasonable application of non-cost factors in this case. Ability to pay is particularly relevant to Minnesota Power's customers; a higher percentage of residential customers are low-income compared to the state average. It is therefore reasonable to moderate the apportionment across classes.

For these reasons, the Commission will apportion a 3.5% rate increase to each of the Residential and General Service classes, with the remaining revenue requirement to be apportioned to the other classes consistent with the Company's cost study. This approach balances the need to move the classes closer to cost—limiting the extent of the increase to the Residential class compared to the Company's proposal, and apportioning a higher increase to the Residential class than the Department and the OAG proposals. It also significantly limits the increases to the larger power customers, assigning the smallest increase, less than 2%, to the Large Power class.

XXXVIII. Residential Block Rate Design

A. Introduction

In Minnesota Power's last rate case, the Commission directed the Company to implement a five-block rate design structure that discounts energy rates for lower usage customers by increasing rates under each block as usage increases.[80] The design was approved as a pilot program, with a directive that the Company would report on its effectiveness and include a recommendation in its next general rate case on whether to continue the program. The program was intended to encourage energy conservation by establishing five blocks of graduated rate increases according to energy usage.

Under the existing rate design, the rate blocks are structured as follows:

- Block 1 is usage up to 300 kWh;
- Block 2 is usage between 301 and 500 kWh;
- Block 3 is usage between 501 and 750 kWh;
- Block 4 is usage between 751 and 1,000 kWh; and
- Block 5 is usage over 1,000 kWh.

[80] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions, and Order (November 2, 2010).

B. Positions of the Parties

1. Minnesota Power

The Company recommended that the Commission modify the five-block rate design and transition to a two-block rate design, stating that there is not persuasive evidence that the five-block rate design has achieved the objectives set forth by the Commission, and that its administrative complexity justifies discontinuation and modification. The Company instead recommended that a two-block rate design would be clearer to customers, easier to administer, and reasonable, particularly considering that the existing rate base structure includes a time-of-day rider to incentivize energy conservation and a customer affordability program to assist low-income customers (including higher-usage, low-income customers).

2. Settlement Agreement Signatories

The Department along with the Energy CENTS Coalition, AARP, the Fond du Lac Band, and the Clean Energy Organizations entered into a settlement agreement supporting a four-block rate design structure that aligns with the Commission's objectives in the last rate case while simplifying the existing structure by eliminating one of the five blocks. The settling parties agreed to the following ratios:

Blocks	Inclining Block Adjustment
0 kWh to 400 kWh	76%
401 kWh to 800 kWh	Revenue requirement
801 kWh to 1,200 kWh	124%
Over 1,200 kWh	150 %

The Department initially supported Minnesota Power's two-block proposal in furtherance of the Department's ultimate recommendation to eliminate block rates entirely. But the Department was subsequently persuaded that a four-block rate design structure would better protect low-usage, low-income residential ratepayers.

The OAG challenged the Company's claim that there is no correlation between lower energy consumption by customers and the five-block rate design, stating that a decline in energy consumption by the Company's customers occurred during the time period in which the pilot program has been in effect. The OAG also stated that under the Company's proposal, 80% of customers would experience significant increases in rates relative to the 20% of customers with the highest usage. AARP and the Fond du Lac Band echoed these concerns.

Energy CENTS explained that the proposed settlement agreement reduces the five blocks to four by expanding the upper usage limits in the first two lowest-cost rate blocks, nearly removing the need for a third rate block. Energy CENTS stated that this approach includes more customers in the lowest-cost block, resulting in lower costs for a larger number of customers, with both low- and average-usage levels. It also protects customers in the middle of the usage range from burdensome increases. And, customers in the highest block are more strongly incentivized to conserve than under the current five-block rate design.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Minnesota Power had not demonstrated that its existing five-block rate design failed to achieve the Commission's objectives, and he therefore recommended that the Commission leave the existing five-block rate design in effect. The ALJ did not consider the settlement agreement offered by opposing parties, stating that because Minnesota Power was not a party to the agreement "no further examination of other alternative plans is warranted."[81]

D. Commission Action

As an initial matter, the Commission disagrees with the ALJ's apparent conclusion that the settlement agreement may only be considered if the Company is a signatory. The agreement is, in effect, an alternative proposal offered by several parties in response to the Company's proposal. There is no clear basis for invalidating the parties' positions and the Commission will therefore consider their proposal as it considers the Company's.

The Commission is persuaded by the parties that further refinements to the block rate design are warranted to both simplify the structure and increase its effectiveness. The settlement proposal furthers these goals by decreasing the number of blocks but with an emphasis on increasing the number of customers in the lowest block and further incentivizing conservation for customers with the highest usage. The Commission will therefore require Minnesota Power to implement a four-block rate schedule as proposed by the five signatories to the Settlement, with adjustments to the rates for each block as needed to enable the Company to recover the full revenue requirement allowed by the Commission for the Residential class.

XXXIX. Residential Customer Charge

A. Introduction

While revenue apportionment focuses on how revenue responsibility should be apportioned among customer classes, setting the customer charge addresses how revenues are collected within each customer class. The customer charge is a fixed charge each customer pays, with the remainder of the class's revenue coming from variable charges.

B. Positions of the Parties

Minnesota Power proposed to increase its residential customer charge from $8.00 to $9.00, explaining that its class cost of service study showed that the fixed cost per residential customer per month is $26.35. The Company stated that the request is reasonable and necessary to reflect the actual cost of customer connections, metering usage, and customer service. Without the increase, Minnesota Power stated that those costs would shift to the energy rate (usage-based), therefore inaccurately representing the actual fixed costs of providing service.

The OAG opposed the Company's proposed increase, stating that the cost study is based on embedded costs, instead of marginal costs, and is therefore flawed in its calculation of the fixed

[81] ALJ's Report, at 131.

residential customer charge. The OAG also stated that the charge is greater than the cost of adding each new customer to the system and is therefore not reasonable. By denying the Company's request, the OAG stated that low-usage customers would benefit because the costs would be recovered through the volumetric charge, which encourages energy conservation. Further, the OAG advocated for reducing the customer charge to $6.00.

The Energy CENTS Coalition opposed the proposed increase, stating that low-usage customers are likely to be low-income customers who would be most disadvantaged by it. Low-income customers who are eligible for, but not receiving, energy assistance from the Low Income Home Energy Assistance Program (LIHEAP) use less energy than LIHEAP recipients.

AARP stated that the proposed increase would adversely affect thousands of retired people living alone on fixed incomes. Because these customers tend to be low-usage customers, the proposed increase would result in a higher percent increase for this group of customers.

The Fond du Lac Band echoed concerns of the likely impact on low-income, low-usage customers, noting that consideration of ability to pay under Minn. Stat. § 216B.16, subd.15, should persuade the Commission to deny the Company's proposal.

The Department initially concurred that the request was reasonable but subsequently withdrew support for the proposed increase in light of concerns raised by other parties about the potential impact of an increase on low-usage customers.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission deny the proposal, stating that the Company's cost study is flawed and that the Company did not demonstrate its claim that its cost for serving residential customers totals $26.35.

D. Commission Action

The Commission concurs with the parties opposing the increase that it is likely to result in a higher percentage increase for the lowest-income, lowest-usage customers, a signal that is inconsistent with the policy objective of encouraging energy conservation and an apportionment that unreasonably disadvantages low-income customers who use less energy. For these reasons, the Commission will not approve the Company's request to increase the residential customer charge to $9.00.

XL. Customer Affordability of Residential Electricity (CARE) Rider

A. Introduction

Minnesota Power's Customer Affordability of Residential Electricity (CARE) Rider provides bill discounts to qualifying low-income residential customers and is funded by an affordability surcharge assessed to other customers. The Commission directed the Company to establish an affordability program in its last general rate case and required the Company to file annual compliance reports. The Company developed the program with the help of the Arrowhead Economic Opportunity Agency, which now administers the program, and the Energy CENTS Coalition.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power proposed to change the CARE program to reduce the number of energy charge blocks in the CARE Rider to match the proposed two-block rate design structure the Company proposed in this rate case. The Company also recommended modifying the name of the surcharge and the description of charges to increase clarity. Under the changes, the program surcharge would be titled "Low-Income Affordability Program Surcharge." And the "RATE MODIFICATION" section of the CARE Rider would specify "Customer/Service Charge and Energy Charge discounts", instead of the existing "CARE Customer Charge and Energy Charges."

2. The Department

The Department did not oppose the Company's proposed changes to the CARE program and noted that the program's tracker balance is sufficient to fund the program without further increases to the service charge. The Department also stated that further consideration of program changes could be developed in the Commission's next annual program review.

3. Energy CENTS Coalition

The Energy CENTS Coalition opposed modifying the program to reduce the number of energy charge blocks to two, citing the settlement among several parties on the block rate design for the Residential class.

Energy CENTS recommended that the Commission modify the CARE program to increase discounts to more effectively incentivize participation, which has dropped from 76% in 2015 to 63% in 2016. Energy CENTS recommended that Minnesota Power model the CARE program after Xcel's Power On program, which caps the amount qualifying participants must pay toward the electric costs to no more than three percent of household income.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended approval of the Company's non-substantive proposed changes to the program. He also concluded that it in light of his recommendation against any changes to the Company's existing block rate design structure, the Company's proposal to modify the CARE program by reducing the number of energy blocks to two is not reasonable. He further concluded that Energy CENTS Coalition's proposal to increase discount levels would result in a substantive change to the program, and stated that it "should not be reviewed and considered at this time."[82]

D. Commission Action

The Commission concurs that the proposed revisions to the CARE Rider to clarify language are reasonable. Additionally, the Commission will also direct the Company to reduce the number of energy charge blocks in the CARE Rider rate to conform with the Commission's decision reducing the number of blocks in the Company's block rate design structure from five to four.

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[82] ALJ's Report, at 132.

The Commission appreciates the input of the Energy CENTS Coalition on other possible changes to the program, including discount levels. The Commission is persuaded that it will have the best opportunity for the most effective and comprehensive review of such issues when it conducts its next annual review of the CARE program.[83]

The Commission will also approve the Company's proposal to revise the "rate modification" section of the CARE Rider to specify customer/service charge and energy charges that replace the standard residential service charge and energy charges. The Commission will also approve the Company's request to make the minor changes to the Affordability Surcharge terminology of the CARE Rider, changing it to the more-descriptive "low-income affordability program surcharge." It is to be noted that actions here in no way alter the Commission's directive for a thorough review and reform of the CARE program required in the CARE docket.[84]

XLI. Late Payment Assessment

The Company proposed to modify its tariff governing late payment fees by removing the minimum late payment charge of $1.00. The existing late payment fee is a minimum of $1.00 and a maximum of 1.5% of a delinquent account balance exceeding $10.00. The Company stated that the minimum fee creates confusion and requires unnecessarily technical customization in the Company's Customer Information System. The Company stated that removing the $1.00 minimum late fee and retaining only the 1.5% late payment charge language would simplify the billing process. The Company also initially requested to change the due dates affecting late payment charges in the tariff.

The Department did not oppose removal of the $1.00 late payment fee but stated that the request to change the dates did not comply with Minn. R. 7820.5400, which requires tariff filings to include "substantiating documents and exhibits supporting the finance fee and grace periods proposed." In response to the Department's concern, the Company withdrew its request to change the dates but recommended a clarification stating that payment is due 25 days after the date a bill is rendered. The Energy CENTS Coalition concurred with the Department.

The Administrative Law Judge did not address this issue.

The Commission concurs with the parties and will therefore approve the Company's proposal to remove the minimum late payment fee of $1.00 and the Company's proposed language specifying in the residential tariff sheets that payment is due 25 days after the date a bill is rendered.

XLII. Reconnect Pilot

The Company proposed a reconnect pilot program that would enable remote reconnection of electric service to customers disconnected as a result of non-payment using Advanced Metering

[83] See *In the Matter of Minnesota Power's Fifth Annual Report and Program Changes, and Requiring Meetings*, Docket No. E-015/M-11-409.

[84] *Id.*

Infrastructure (AMI). The Company proposed to include approximately 200 residential customers primarily located in Duluth and Cloquet, based on the likelihood of disconnection. The reconnection fee under the pilot would be $20 at all times compared to the $100 reconnection fee charged after business hours and on weekends and holidays.

The Department supported the proposal, but Energy CENTS raised concerns about the potential for discriminatory treatment of low-income households, stating that the pilot does not increase reconnections and does not satisfactorily address safety concerns. Energy CENTS stated that the Company's efforts should be focused on preventing disconnections through assistance programs, including the Company's CARE program, rather than testing remote disconnections. Further, reconnection of service would not require a physical visit to ensure an adequate safety check of the premises.

The Administrative Law Judge concluded that the Company's proposal is just and reasonable, dismissing the concerns of Energy CENTS. He reasoned that remote disconnection of service is not an issue raised by the Company as part of its pilot and is therefore not under consideration. He also reasoned that because reconnection is initiated via a phone call by the customer to the Company, there is no safety issue. He further reasoned that once customers who are disconnected "get their finances in order sufficient to resume electric service, the pilot benefits them directly by ensuring" reconnection at the same low price that applies during regular business hours.[85]

The Commission is not persuaded by the Administrative Law Judge's reasoning and will not adopt his recommendation. He insufficiently addressed the concerns of Energy CENTS, and as a result, his reasoning is not persuasive.

XLIII. Miscellaneous Requests

A. Introduction

The Company proposed increases to categories of rates affecting seasonal, municipal pumping, dual fuel, controlled access, and general service customers. No party objected to the proposals, which are described below.

1. Seasonal

Minnesota Power proposed to increase the customer charge for seasonal residential customers from $8.80 per month to $10 per month.

2. Municipal Pumping

Consistent with the Commission's directive in Minnesota Power's last general rate case, the Company proposed to close the Municipal Pumping schedule to new customers and set the rates for this class equal to the rates for the General Service class,[86] resulting in an increase in rates for

[85] ALJ's Report, at 140.

[86] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions, and Order (November 2, 2010).

these customers. The Company also proposed to subsequently shift these customers to either the General Service class or the Large Light and Power class, depending on what is most beneficial to the customer. Additionally, the Company proposed to increase the General Service energy charge to 8.572¢/kWh for customers without demand meters and to 5.772¢/kWh for customers with demand meters.

3. Dual Fuel Rates

Minnesota Power proposed to increase the customer service charge from $8.00 to $9.00 for residential dual fuel customers and increase the dual fuel energy rate for secondary voltage service for this class from 5.178¢/kWh to 5.681¢/kWh.

The Company also proposed to increase the customer service charge from $10.50 to $12.00 for the Commercial/Industrial Dual Fuel class to match the General Service class. The Company also requested to increase the energy charge for secondary voltage (low voltage) to 5.681¢/ kWh, and increase the charge for primary voltage to 5.100 ¢/kWh.

4. Residential and Commercial Controlled Access

The Company proposed to increase the Residential Controlled Access service to 5.150¢/kWh and to increase the Commercial Controlled Access Energy Charge for low voltage service to 5.150¢/kWh. The Energy Charge for high voltage Commercial Controlled Access service would increase to 4.669 ¢/kWh. The Service Charge for Controlled Access service would increase to $9.00 per month for the Residential class and to $12.00 per month for the Commercial class.

5. General Service

Minnesota Power proposed to increase the monthly customer service charge from $10.50 to $12.00 and increase the energy charge to 8.572¢/kWh for customers without demand meters and to 5.772 ¢/kWh for customers with demand meters. The demand charge would increase to $6.50 per kW per month.

B. The Recommendation of the Administrative Law Judge

The Administrative Law Judge did not address the Company's proposed increases for these classes of customers.

C. Commission Action

There were no objections to the rates proposed, and the Commission concurs that they are reasonable and that there is no basis to disapprove or modify them. The Commission will therefore approve the following:

- Proposed seasonal residential rates;
- Proposed rate changes to the Municipal Pumping class;
- Proposed Residential and Industrial/Commercial dual fuel rates:
    - Residential customer charge increase (to be the same as the standard residential charge);

- Residential customers per kWh charge (will increase in the same proportion as the increase for standard residential customers);
  - Commercial/Industrial customer charge—both low voltage and high voltage will increase from $10.50 to $12.00 to match the General Service Class; and
  - Commercial/Industrial low voltage and high voltage per kWh charge–will increase in the same proportion as the increase for the General Service class;

- Residential and Commercial Controlled access service rates would change as follows:
  - Residential customer charge will increase to be the same as the standard residential;
  - Residential customers per kWh charge will increase in the same proportion as the increase for standard residential customers

- General Service rates:
  - Commercial will increase to the level set in this rate case to match the General Service Class; and
  - Commercial per kWh charge will increase in the same proportion as that increase for the General Service Class.
  - General Service – approve the Company's proposed modifications to its general service rates.

XLIV. Large Light and Power

A. Introduction

Minnesota Power has a Large Light and Power (LLP) tariff that includes a standard LLP service schedule, as well as a time-of-use (TOU) Rider, which the Company developed as a pilot program in response to a Commission directive in the Company's last general rate case.[87] Since the Rider was approved by the Commission,[88] none of the Company's customers have requested service under the Rider.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power requested changes to its Large Light and Power tariff, including to its TOU Rider.

The Company requested several changes to its standard LLP service schedule, including:

- increasing the demand charge for the first 100 kW of billing demand from $1,100 per month to $1,350 per month;

- increasing the demand charge for all additional demand from $9.30 per kW-month to $11.00 per kW-month; and

- increasing the energy charge from 3.722¢/kW to 3.850¢/kWh.

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[87] *Id.*

[88] *In the Matter of Minnesota Power's Petition for Approval of a Pilot Rider for Large Light and Power Time-of-Use Service*, Docket No. E-015/M-11-311, Order (August 8, 2011).

The Company also requested to allow service under either the LLP TOU Rider or the Rider for Foundry, Forging, and Melting customers, but not both. And, the Company requested approval to modify tariff language that would clarify the LLP 11-month ratchet language in the "DETERMINATION OF THE BILLING DEMAND" section of the tariff. The proposal would clarify that Billing Demand will not be less than the:

> ~~amount by which the greatest adjusted demand during the preceding eleven months exceeds 100 kW, but not more than 75% of such adjusted demand~~ lower of 75 % of the greatest adjustment demand during the preceding eleven months, or the greatest adjustment demand during the preceding eleven months minus 100 kW.

Finally, the Company requested to modify its current TOU Rider, stating that the Rider was initially designed to be revenue neutral (reductions in off-peak rates are offset by increases in on-peak rates). That approach, the Company asserted, contributed to a lack of customer participation, and the Company therefore proposed changes to generate customer interest. Under the proposed changes, the off-peak demand charge would remain at the current level, while the on-peak demand charge would increase by approximately the same percent as the overall rate increase for the standard LLP service schedule. The on-peak energy charge would increase from 4.255¢/kW to 4.619¢/kWh, and the off-peak energy charge would decrease from 3.336¢/kW to 2.576¢/kWh. This is the only disputed issue among the Company's requested changes.

The Company asserted that increasing the difference between on- and off-peak energy rates would likely incentivize participation from customers who could shift usage to off-peak hours, resulting in customer cost savings. Further, the Company noted that, as a pilot program, it is important to take steps that will launch participation and enable the Company to gain valuable information on usage patterns that could lead to additional TOU Rider refinements.

2. The Department

The Department opposed the Company's proposed modifications, stating that the Rider does not require customers to shift their energy usage as a condition of receiving discounts and would therefore be ineffective in achieving conservation, the Rider's intended energy policy goal. The Department recommended requiring the Company to develop a Rider that would eliminate that impediment.

3. LPI

LPI supported the Company's proposal and opposed the Department's recommended changes to the Rider. LPI challenged the Department's characterization that the Rider would not accomplish the goal of energy conservation, stating that the proposed Rider would clearly encourage customers to consume power during low-cost periods and avoid consumption during high-cost periods, making the system more efficient. LPI stated that customers who are already efficient should not be prevented from receiving the discount and that further shifts in their usage should not be required.

4. The OAG

The OAG recommended that the Commission require the Company to develop an opt-out LLP TOU Rider for consideration in the Company's next general rate case. Under the OAG's proposal, all LLP customers who do not opt out of the Rider would participate. The OAG asserted that the goal is to reduce peak energy usage and increase conservation, which can defer the need for additional resources, such as peaking facilities, ultimately lowering overall system costs.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that although the Department and the OAG disputed the Company's TOU Rider proposal, they effectively withdrew their challenges by not addressing the issue in "closing briefs."[89] He concluded that the proposed Rider is reasonably designed to incentivize use of the Rider and that participation would help flatten out on-and off-peak usage, and as a result, the proposed Rider change is reasonable. He therefore recommended that the Commission approve it.

D. Commission Action

The Commission respectfully disagrees with the Administrative Law Judge's conclusion that the Department and the OAG in effect withdrew their challenges to the Rider by not addressing the issue in their closing briefs. The ALJ's reasoning appears erroneous and lacks record support. Each agency addressed the issue in their briefs, and the Commission will consider their stated positions as it considers the Company's proposed tariff changes.

The Commission will approve the Company's proposed standard tariff modifications, approve changes to the LLP–TOU Foundry Rider, and approve the Company's proposed change to the LLP–TOU Rider to simplify existing tariff language. These changes are reasonable, no party objected, and there does not appear to be a basis for denying approval. The Commission is not, however, convinced that the proposed price changes to the LLP–TOU Rider are reasonable. The Commission concurs with the Department that the proposed change does not restructure the Rider to encourage conservation. Rather, the Company's aim is to garner participation in the program. Without a more meaningful effort tied to encouraging energy conservation, the Commission will not approve the proposed change to the LLP–TOU Rider.

XLV. Large Power and Large Light and Power – Interruptible Rates

A. Introduction

Minnesota Power offers a dual-fuel interruptible electric service rate. The Company also offers replacement interruptible service to large power customers under its Large Power Interruptible Service Rider. The Rider authorizes curtailment during a reliability event, which is defined as a period in which the local or regional system is in jeopardy of widespread outage or collapse.

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[89] ALJ's Report, at 135.

B. Positions of the Parties

1. LPI

LPI proposed a Demand Response Rider, stating that interruptible service is a key form of demand response, reducing the utility's need to add electric generating capacity resources and ultimately lowering overall utility system costs. As a result, LPI claimed that lower costs for large power interruptible customers is warranted.

The demand response proposal is modeled after a rider offered by Northern Indiana Public Service Company. It includes five curtailment options with varying terms (one to twelve years), rates, interruption types, and notice requirements. Customers would have the option to choose the curtailment type that best fits their needs, with a maximum interruptible load of 300 MW.

LPI stated that the Company made unreasonable cost assumptions in opposing LPI's proposal and has been reluctant to move forward with a demand response rider. As a result, LPI stated that Commission action is needed to ensure implementation of a demand response program.

2. Minnesota Power

Minnesota Power proposed to eliminate its Interruptible Service Rider because no customers take service under the Rider. The Company opposed LPI's demand response proposal, stating that further development of cost and related issues is needed to better understand the implications of the proposal and how to effectively implement demand response.

3. OAG

The OAG challenged LPI's proposal, questioning LPI's assumptions in estimating a value of interruptible capacity that did not, under the proposal, show an offset of the need for additional capacity generation. The OAG also stated that consideration should be given to a market-based approach in which the Company could seek additional capacity from third-party aggregators or individual customers.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that because the Company had not proposed a change in its "Large Power Interruptible Product, there is no basis to further consider this topic here."[90] He referred the parties to another Commission forum for further discussion.

D. Commission Action

It is apparent from the parties' positions that this topic warrants further discussion. To provide an opportunity for parties to develop the relevant issues and reach consensus, the Commission will require Minnesota Power to work with LPI and other stakeholders to develop a Demand Response Rider based on stakeholder input. The Commission will direct the Company to file the Rider within six months of the date of this order.

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[90] ALJ's Report, at 133.

XLVI. Large Power Service

A. Introduction

Minnesota Power distinguishes between its Large Light and Power Service class and its Large Power Service class. The Company proposed a number of changes to its Large Power Service class affecting standard service; non-contract service; released energy rider; expedited billing procedures; and incremental production service.

B. Positions of the Parties

1. Minnesota Power

The Company proposed the following changes to its Large Power Service:

Standard Service

- Increase the demand charge for the first 10,000 kW or less of billing demand to $214,890, and increase the demand charge for all additional Firm Demand to $25.50 per kW per month;
- Increase the firm energy charge from 1.232¢/kWh to 2.310¢/kWh;
- Include the entire cost of fuel and purchased energy in a separate line item on customer bills;
- Set the fuel and purchased energy cost for Large Power at 2.100¢/kWh; and
- Set the fuel and purchased energy cost for Large Power Firm Energy at 1.102¢/kWh.

Non-contract Service

- Set non-contract Large Power demand charges at 20% higher than the standard Large Power demand charges, or $257,868 for the first 10,000kW or less of billing demand and $30.60 per kW for all additional billing demand.

Released Energy Rider

- Update Rider language and allow Minnesota Power to align the Company's energy supply practices with MISO's business practices more closely. The Rider provides the Company the opportunity to buy Large Power customer energy when the Company is either long or short. The Company then shares a negotiated margin or avoided purchase price with the customer as a monthly released energy credit.

Expedited Billing Procedures

- Modify the Rider for Expedited Billing Procedures to reduce the number of wire transfers sent to customers and to minimize the number of adjustment transactions in customer accounts. Credit customers for amounts less than $100,000. For credits exceeding $100,000, customers may choose either a weekly bill credit or a wire transfer.

Incremental Production Service

- Increase the measured demand in excess of the Incremental Production Service Threshold (IPST) from 110% to 120%.

Of these issues, only the proposed change to the Incremental Production Service Tariff (IPST) was challenged by other parties, specifically the Department and the OAG.

The Company stated that the Large Power Incremental Production Service Rider (LP–IPS Rider) was designed to increase production above historical levels without additional contractual demand commitments.

Measured demand exceeding the IPST that is set under each customer's electric service agreement does not subject the customer to demand charges. Rather, customers pay for energy at the Company's hourly incremental energy cost plus an energy surcharge of 1¢/kWh for Curtailable IPS and 3¢/kWh for Non-Curtailable IPS.

Depending on system load and resource availability, the incremental energy cost is based on either system generation or wholesale market purchases. Under the existing tariff, IPS energy usage is limited to measured demand up to 110% of the IPST. The Company proposed to increase that limit to 120% of the IPST, in effect doubling the quantity of demand and associated demand a customer may take without incurring demand charges.

The Company asserted that the proposed change would increase curtailments and therefore reduce the amount of capacity and associated costs needed to serve peak load. Further, customers taking service under the LP-IPS Rider are using high-cost energy, which is excluded from the cost of firm supply used to determine the fuel clause cost for firm retail sales. It follows that as usage increases under the Rider, more energy is also excluded from firm supply, reducing overall firm energy costs to other customers.

2. The Department

The Department opposed the Company's proposed measured demand increase to its LP-IPS Rider, stating that the Company had not demonstrated the reasonableness of the proposal, particularly in light of legislative policies that mandate efforts to encourage energy conservation and use of renewable energy.[91] The Department also stated that the proposal appears to grant discounts to large power customers at the expense of all other customers.

3. The OAG

The OAG opposed allowing large power customers to receive an additional discount—paying no demand charges on double the amount of demand and energy they purchase compared to the current LP–IPS Rider rates—without clear explanation for why the additional discount in the form of lower rates is needed. The OAG challenged the Company's assumptions that the proposal would result in offsetting costs sufficient to cover the lower rates or that it would achieve cost savings for non-participating customers. Further, the OAG stated that the Company has not demonstrated that it needs additional curtailable load.

[91] *See* Minn. Stat. §§ 216B.03, 216C.05.

4. LPI

LPI disagreed with the OAG that other customers would bear a cost burden for the proposed cost savings to large power customers, stating that only large power customers would incur incremental supply costs for incremental load because the cost of incremental service is incurred entirely by large power customers.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that ensuring that large power customers "have access to a supply of energy that assists their competitiveness in the international marketplace is one of the state's current policies. Applicant's proposal furthers that policy."[92] He also reasoned that taconite producers would benefit from short-term opportunities to increase production without higher costs, and that the average cost for firm energy would be reduced. He recommended that the Commission approve the proposal. And although he considered the OAG's opposition to the proposal, he did not address the Department's position.

D. Commission Action

The Commission concurs with the Company that the proposed tariff changes concerning standard service, non-contract service, the released energy rider, and expedited billing procedures are reasonable and will approve them. The Commission is not, however, persuaded that the proposed LP–IPS Rider change is reasonable.

The Company's proposal assumes cost savings but does not include cost data to support that claim. As a result, it is unclear to what extent any savings could be achieved. Further, the Commission is not persuaded that the combination of additional energy curtailment, along with increased consumption, achieves the goal of the LP–IPS Rider or Minnesota's energy policy goals concerning conservation and renewable energy.

The EITE statute states the following:

> (a) It is the energy policy of the state of Minnesota to ensure competitive electric rates for energy-intensive trade-exposed customers. *To achieve this objective*, an investor-owned electric utility that has at least 50,000 retail electric customers, but no more than 200,000 retail electric customers, shall have the ability to propose various EITE rate options within their service territory under an EITE rate schedule that include, but are not limited to, fixed-rates, market-based rates, and rates to encourage utilization of new clean energy technology.[93]

The Commission respectfully disagrees with the ALJ's conclusions that Minnesota Power has demonstrated the reasonableness of its proposal or that Minnesota energy policy compels

[92] ALJ's Report, at 134 (citing Minn. Stat. § 216B.1696).

[93] Minn. Stat. § 216B.1696, subd. 2 (emphasis added).

approval of a proposal that would benefit an entire class of customers based on a statute establishing a discrete mechanism to advance the needs of a uniquely-situated subset of that class.

For all these reasons, the Commission will not approve the Company's proposed changes to its LP–IPS Rider.

XLVII. Power Factor Adjustment

A. Introduction

Power factor measures the extent to which electric power is consumed efficiently, with a high power factor indicating less wasted energy and a lower cost of service. The Power Factor Adjustment applies a cost adjustment when the power factor falls below a particular threshold for a particular class.

B. Positions of the Parties

The Company proposed revising the existing threshold from 85–90% in its General Service, Large Light and Power, and Municipal Pumping service schedules, stating that the purpose of the revision is to encourage customers to improve efficiency, resulting in lower energy losses. Although energy losses cannot be totally eliminated, the Company stated that as real power (expressed in kilowatts) becomes closer to 100% of apparent power (expressed in kilovolt-Amps, or kVA), efficiency rises and demand on the system decreases.

The Department concurred and recommended approval of the proposal, noting that the Company proposed delaying implementation of the change for one year to allow time for affected customers to make any necessary equipment upgrades.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge did not address this issue.

D. Commission Action

The Commission concurs with the parties' reasoning and will therefore approve Minnesota Power's proposed change to the Power Factor Adjustment.

XLVIII. Back-up Generation Program

A. Introduction

Minnesota Power proposed a new program that would allow customers to install a back-up generator for use during outages. Under the proposal, the Company would own, install, maintain, and operate the generators, which would be interconnected to the Company's distribution system. The service would be available to the General Service, Large Light and Power, and Municipal Pumping classes.

The generators would provide between 250 kW and 1 MW of power, with an aggregate total of 10 MW. Under the pilot program, participating customers would be charged a monthly fee of $6.00 per kW for a minimum initial period of ten years and could utilize the service at all times. The capital investment cost for each generator would be added to rate base in the Company's next general rate case.

B. Positions of the Parties

The Company stated that because the units could be used to meet system peak loads, the program would support grid reliability and that it is therefore reasonable to recover the costs of the program from all ratepayers. The Company requested approval of its proposed tariff, stating that the Commission approved the pilot program as a cost-effective resource for all ratepayers in the Company's 2015 resource plan docket.[94]

The Department opposed the proposal unless the Company would agree to two modifications. First, the Company must also offer the program to the Large Power class, consistent with Minn. Stat. § 216B.03, which prohibits unreasonably discriminatory rates. Second, the Company must only recover the cost of the program from participating customers. The Department stated that Minnesota Power did not demonstrate that reliance on the back-up program would, in fact, alleviate the need for additional generation resources and did not demonstrate that the program would result in cost savings to non-participating ratepayers.

The OAG similarly opposed the proposal, stating that the Company did not demonstrate how the proposal would benefit non-participating ratepayers or that the Company needs the program to serve its peak load. The OAG also challenged Minnesota Power's claim that the Commission approved the plan in the Company's last resource plan proceeding, asserting that the Company merely stated its intention to bring the program forward for Commission approval in 2016.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the Commission previously approved the proposed program in the Company's 2015 resource plan proceeding and that Minnesota Power "convincingly argued that the benefits of the program will be shared by both the participant ratepayers and non-participant ratepayers. In fact, given the rarity of power outages . . . it is likely the primary benefit will be to the grid as a whole when the Program's generators are used to support the system during peak energy usage."[95] The ALJ recommended that the Commission approve the Company's proposal for funding the program.

D. Commission Action

The Commission respectfully disagrees with the ALJ's conclusion that the Company has convincingly argued the benefits of the program to non-participating customers. The Company's assertion of this claim is not supported by facts in the record, as both the OAG and the Department clearly noted. The Company did not offer any projected, calculated, or identifiable cost-savings to non-participating customers that would justify recovering program costs from all

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[94] *In the Matter of Minnesota Power's 2016–2030 Integrated Resource Plan*, Docket No. E-015/RP-15-690.

[95] ALJ's Report, at 137.

ratepayers. Absent any quantification of cost-savings, the Commission will not approve the cost recovery request. Further, resource plan proceedings are not cost recovery proceedings, and the Company's claim that the Commission previously approved the pilot program as a cost-effective resource for all ratepayers is not accurate.

The Commission does, however, concur with the Company and the Department that there is merit to the program and the stated objectives. The Commission will therefore approve the backup generation program with the requirement that the Company modify the proposed rate to ensure that participating customers pay all costs incurred.

XLIX. Business Development Incentive Rider

A. Introduction

The Company's proposed Business Development Incentive Rider (BDIR) would provide fixed discounts, applicable only to demand charges, over a five-year period to large customers who qualify for the rate by expanding their load or becoming a new customer. To qualify, the customer's load must be at least 350 kW. Participating customers would be required to enter into a six-year electric service agreement (ESA), with the discount applying for five of those years at a declining rate over the term, as follows:

- Large Power Service Schedule: Year 1–3 = 30%; Year 4 = 15%; Year 5 = 5%; and Year 6 = no discount.
- General Service and Large Light and Power Service Schedules: Year 1–3 = 50%; Year 4 = 25%; Year 5 = 15%; and Year 6 = no discount.

The Department and the OAG supported the proposal but recommended modifications to which the Company agreed, including the following:

- require the Company to obtain approval of amendments to existing or new ESAs;
- require the Company to file for approval any new or amended ESA within 30 days after signing the agreement;
- require the ESA filing to include the incremental revenue and incremental costs associated with a new ESA;
- require that the ESA is deemed approved if no party objects to the ESA within 30 days of the filing date;
- require the Company to file an annual compliance filing showing the number of customers served on the Rider, together with each customer's incremental revenue and costs; and
- require energy audits of all Rider customers.

The Department analyzed the proposal, stating that the proportion of demand revenues in a total electricity bill is smaller for smaller commercial customers (the General Service and the Large Light and Power classes) than for larger commercial customers (the Large Power class). By accounting for this fact, the Company proposed dollar discounts that are equitable across the classes. Further, the Department stated that the Company reasonably considered the experiences of other utilities and discussed options with potential customers in developing its approach to determine discount levels.

The OAG supported the proposal but recommended ensuring that any increased load be efficient to minimize any negative effects from increasing load.

B. The Recommendation of the Administrative Law Judge

The Administrative Law Judge did not address this issue.

C. Commission Action

The Commission concurs with the parties that the BDIR proposal is reasonable and will therefore approve it, with the modifications suggested by the Department and the OAG, which reasonably address the concerns raised and to which the Company has agreed, including:

- require approval of amendments to any existing or any new ESA;
- require the Company to file any new or amended ESAs for approval no later than 30 days after the Company signs a new ESA to be served under the Rider;
- the ESA filing with the Commission shall contain the incremental revenue and incremental costs associated with the new ESA;
- if no party objects to the ESA within 30 days of the filing date, the ESA would be deemed approved;
- require the Company to file on May 1st each year (in a new miscellaneous docket) an annual compliance filing to show the number of customers served on the Rider, together with each customer's incremental revenue and costs; and
- energy audits should be required for all Rider customers.

L. Grid Resilience and Innovative Demonstration (GRID) Pilot

A. Introduction

The Grid Resilience and Innovative Demonstration (GRID) pilot program would invest in research on grid modernization technologies.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power stated that the GRID pilot proposal is intended to establish funds for demonstrating new grid modernization technologies or innovative projects in collaboration with customers and communities. The program will test the abilities, costs, and benefits of the technologies in a scalable manner. The Company emphasized the need to retain control over final project selection to ensure that the Company has the flexibility it needs to adapt and respond to frequent changes in technology.

The Company stated that the goal of the program is to develop grid modernization, renewable integration, microgrids, and storage, which would affect future rate design and lead to new products and services. The proposal includes a request to recover $2.7 million annually through the Conservation Program Adjustment Rider, which effectively excludes large power customers. The average cost to residential ratepayers would be approximately $7.43 annually.

Specific projects would be identified with the help of an advisory committee that includes Company representatives and interested stakeholders. The Company would consider projects that fall within the following categories: distributed energy resources (such as solar or wind); customer research projects (combining technology and communication); and distribution system efficiency projects that optimize energy flow and asset use.

2. The Department

The Department opposed the proposal to collect costs in the GRID pilot in advance of implementing projects, stating that authorizing the Company to receive money in advance and subsequently identifying qualifying projects without scrutiny is unreasonable. Instead, the Department stated that requiring the Company to recommend projects for Commission consideration is consistent with the rider recovery process in which projects that are not otherwise pursued may be eligible for cost recovery.

3. The OAG

The OAG also opposed the proposal, stating that Minnesota Power has yet to identify any project it would implement if funds are approved. The OAG also stated that the Company did not justify its proposal for excluding Large Power customers from the costs of the pilot program.

4. Energy CENTS Coalition

The Energy CENTS Coalition concurred with the Department's recommendation to deny the proposed request.

5. Citizens Utility Board

The Citizens Utility Board (CUB or the Board) recommended modifications to the proposal to address, in particular, the lack of oversight of project selection. The Board stated that granting the Company the sole authority to select projects based on vague selection criteria would eliminate the Commission's role in scrutinizing the reasonableness of the Company's actions. The Board stated that because the overall funding amount is limited, it is likely that only a small number of projects could be developed, compelling the need for a review process that ensures meaningful stakeholder input on the suitability of projects under consideration.

The Board recommended the following modifications: that the Commission retain authority over project selection; that the advisory committee process be formalized and clearly structured; that project selection criteria be made more specific to align with Minnesota's grid modernization goals; that reporting requirements be set; that low-income customers be exempt from the cost of the program; and that customer bills show the cost as a separate line item.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the pilot should be approved with adjustments, including requiring the Company "to match every dollar raised by the Rider up to the $2.7 million requested."[96] He reasoned that the both the Company and ratepayers will bear the benefits and risks of the research and development, justifying his recommended adjustment. He also recommended incorporating the modifications proposed by CUB to the advisory committee process.

D. Commission Action

At issue is the Company's request for funding, which does not specify clear project selection criteria and does not set forth a defined advisory committee process. The lack of parameters on project criteria, along with the Company's unlimited authority to select projects, hinders scrutiny of the use of ratepayer funds and denies the parties the opportunity to provide input on the reasonableness of the projects before they are selected.

For these reasons, the Commission will reject the GRID pilot without prejudice. The Commission will consider a modified proposal from the Company that addresses this proposal's shortcomings.

LI. Green Pricing Program

A. Introduction

Minn. Stat. § 216B.169, subd. 2, states that "(a) A utility may offer its customers one or more options that allow a customer to determine that a certain amount of the electricity generated or purchased on behalf of the customer is renewable energy or energy generated by high-efficiency, low-emissions, distributed generation such as fuel cells and microturbines fueled by a renewable fuel."

Minnesota Power proposed a modification to its Rider for Residential/General Service Renewable Energy to develop an optional Green Pricing Program, which would allow customers to elect between 25 and 100% of their usage be generated using renewable energy.

B. Positions of the Parties

1. Minnesota Power

The Company's proposal includes a program administrative fee, which the Company stated is the incremental cost of enrolling customers, creating promotional materials, procuring renewable energy, and completing reporting requirements.

The Company stated that it intends to procure renewable energy from intermittent renewable energy resources, meaning that participating customers would continue to benefit from fuel purchases, which are recovered through the fuel clause adjustment (FCA).

[96] ALJ's Report, at 145.

2. The Department

The Department recommended that the Commission approve the program with modifications. First, the Department recommended that the Commission deny the Company's request to recover an administrative fee, stating that the Company did not demonstrate that administrative costs are in fact incremental and not already recovered as ordinary labor costs collected through base rates. Second, the Department recommended that the Commission require the Company to file annual reports on participation and program costs. Third, the Department recommended that the Commission prohibit the Company from applying the fuel clause adjustment to the portion of renewable energy reserved by participating customers.

3. Clean Energy Organizations

The Clean Energy Organizations echoed the Department's concerns about the FCA, stating that the program as proposed would overcharge participating customers by charging them twice for purchased fuel—once under the FCA, and then again in the price of green energy. They therefore recommended that the Commission approve the program with a modification to exclude FCA fuel charges from the bills of participating customers.

4. The OAG

The OAG supported the proposal but raised two concerns. First, the OAG stated that customers may not fully understand that their rates could vary significantly but acknowledged that the proposal allows customers to opt out after one year, an approach that may alleviate this concern. Second, the OAG stated that it does not appear that customers would be compensated for their energy input.

5. Wal-Mart

Wal-Mart stated that the Company's initiative to obtain short-term contracts for procuring renewable energy would not necessarily meet the needs of a large consumer like Wal-Mart, which is committed to reducing its emissions by 18% by 2025. To achieve this goal, Wal-Mart requested that Minnesota Power help identify another program for procuring renewable energy on a larger-scale basis for larger, interested customers. The Company subsequently entered into an agreement with Wal-Mart as follows:

> Minnesota Power shall work with Wal-Mart and any other interested stakeholders to develop one or more renewable programs suitable for large customers and report to the Commission the results of such development within six months of the date of this order.

6. Fond du Lac Band

The Fond du Lac Band supported the agreement between Wal-Mart and Minnesota Power.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the Company's proposal is just and reasonable, with one exception. He recommended that the Company be required to ensure that participating customers are charged only their "pro-rata share of the energy they use that is obtained from non-renewable sources."[97]

D. Commission Action

The statutory provision governing cost recovery, Minn. Stat. § 216B.169, subd. 2, states:

> (b) Rates charged to customers must be calculated using the utility's cost of acquiring the energy for the customer and must:
>
> (1) reflect the difference between the cost of generating or purchasing the additional renewable energy and the cost that would otherwise be attributed to the customer for the same amount of energy based on the utility's mix of renewable and nonrenewable energy sources.

To ensure that the proposal's implementation is consistent with the statutory language above, the Commission will approve the green pricing program, with additional requirements. The Commission will require that the Company not apply the FCA (which includes the base costs of energy at $21.21/MWh and the rider for fuel and purchased power) to the portion of renewable energy reserved by customers participating in the Company's green pricing program.

The Commission will also deny Minnesota Power's proposed administration fee because the Company has not demonstrated that such costs are incremental and not generally applicable to company labor costs that are currently recovered in base rates.

To ensure regulatory oversight, the Commission will also require the Company to provide annual updates about the program (including information on participation, administration costs, and certification costs).

Additionally, the Commission will require the Company to file a proposal addressing the situation where the price of renewable PPAs becomes consistently lower than the price of the Company's overall power mix. In its proposal, the Company must consider whether it is reasonable to charge customers participating in the green pricing program a lower rate if the price of renewable energy resources used for the program drops below the price of the Company's existing resource mix.

Finally, the Commission acknowledges the agreement between Minnesota Power and Wal-Mart, adopts the agreement, and orders the Company to work with Wal-Mart and any other interested stakeholders to develop one or more renewable programs suitable for large customers. The Company must report to the Commission the results of these efforts within six months of the date of this order.

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[97] ALJ's Report, at 139.

LII. Revenue Decoupling Mechanism

A. Introduction

The Clean Energy Organizations proposed a decoupling plan that would separate Minnesota Power's revenue from its sales to eliminate disincentives to promote energy conservation, citing Minn. Stat. § 216B.03, which directs the Commission to set rates to encourage energy conservation to the maximum reasonable extent. CEO stated that decoupling protects ratepayers and the utility alike by enabling a utility to recover the costs of providing service, no more or less, when sales decline. CEO pointed out that the Commission approved decoupling mechanisms for several gas utilities, as well as for Xcel Energy's electric utility service. These programs were developed in response to legislation authorizing the Commission to establish criteria and standards for decoupling proposals and to approve them.[98]

CEO stated that economic incentives driving conservation, such as the Conservation Improvement Program,[99] could diminish, creating the need for a decoupling mechanism that would incentivize utilities to further maximize energy efficiency.

The decoupling proposal would apply to nearly all residential and general service customers. It would include full decoupling, which adjusts under- and over-recoveries of non-fuel revenues regardless of the cause. The amount of revenue the Company recovers would increase or decrease with changes in the number of customers per class to ensure that the Company recovers non-customer-related costs. Rate adjustments would be calculated consistent with other Commission-approved decoupling mechanisms. The adjustments would be made annually, with one adjustment applied to all members of each customer class. A rate cap would apply to under-collected revenues to mitigate rate shock. Annual reporting would be required by February 1 of each year the program is in effect.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power opposed the proposal, stating that there is no need for such a program, considering the potential costs and limited benefits. The Company stated that it considered a decoupling mechanism and decided against proposing one in this rate case for several reasons. The Company stated that it currently exceeds state conservation goals and will continue to do so without decoupling.

Also, because Minnesota Power's total sales from the two intended classes—the Residential and General service classes—are limited to approximately 30% of the Company's total sales (lower than the average for U.S. investor-owned utilities), the program is not likely to achieve the level of success intended. Further, the Company stated that the proposal authorizes inequitable treatment of refunds and surcharges; in years when sales exceed costs, the refunds are higher than the amount of surcharges in years when sales are lower than costs.

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[98] Minn. Stat. § 216B.2412.

[99] Minn. Stat. § 216B.241, subd. 1c(b).

2. The Department

The Department opposed the proposal, concurring with the Company that it is not necessary, particularly considering the high levels of energy savings the Company has achieved in the last seven years. And, the Department stated that there are two potential adverse effects to ratepayers. First, the 5% proposed cap is not, in effect, a cap and would authorize the Company to petition the Commission for the recovery of costs not collected as a result of the program, resulting in a delay of charges to a later date. Second, the 5% cap is higher than the 3% cap approved by the Commission in Xcel's last rate case and would therefore result in higher costs to residential customers.[100]

3. The OAG

The OAG questioned the proposal, stating that the benefits of the proposed decoupling program are unclear and that decoupled utilities have incentives to increase sales to increase rate base investment, on which they earn a rate of return. The OAG emphasized that the proposal is a short-term solution at best.

4. LPI

LPI opposed the decoupling proposal, stating that it would unnecessarily insulate shareholders from the impact of fluctuations from sales and would allow for rate adjustments outside a rate case.

5. Wal-Mart

Wal-Mart opposed the decoupling proposal, stating that many large commercial customers implement their own aggressive energy-efficient measures and should be shielded from the costs of the decoupling program if the Commission approves it.

6. AARP

AARP opposed the structure of the program, recognizing the importance of energy efficiency as a policy objective but stating that the proposal's 5% cap is too generous in allowing recovery of costs for declining sales without scrutiny. For example, if the Company obtains a new customer who builds an energy-efficient home and sales decline, the Company could likely recover the lost revenues even though the Company made no cost-related effort to increase conservation in that example.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that it was unnecessary to consider any other party's proposal where the Company did not initially make a related proposal. He therefore did not consider or analyze CEO's proposed decoupling mechanism.

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[100] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order (May 8, 2015).

D. Commission Action

The Commission respectfully disagrees with the Administrative Law Judge's reasoning that CEO's proposal should not be considered because it was not made in response to an initial proposal by the Company.

The willingness of CEO to develop a decoupling proposal furthers the discussion of this important policy issue and strengthens the Commission's understanding of potential advantages and disadvantages of using this tool to encourage energy conservation, a legislative priority. It also helps ensure that the specific characteristics of this particular utility are more clearly understood in relation to energy conservation.

In various proceedings, the Commission has authorized and approved energy conservation initiatives, including decoupling programs, after careful consideration and helpful input from stakeholders. In this case, the parties generally support the objectives articulated by CEO but raise valid concerns about the potential benefits. In particular, the Company described the potential limitations on achieving energy conservation goals under a plan that applies the decoupling mechanism to only the Residential and General Service classes. Considering that the majority of the Company's sales come from other classes, it is unlikely that the benefits of the proposal would outweigh the costs. Furthermore, efforts of large commercial and industrial customers to independently achieve energy conservation have not been fully evaluated. For these reasons, the Commission will not approve CEO's proposed implementation of a revenue decoupling program.

LIII. Solar Energy Standard (SES) Capacity Benefits

A. Introduction

In a prior separate docket, the Commission approved Minnesota Power's petition concerning costs related to a 10 MW solar photovoltaic project at the Minnesota Army National Guard Camp Ripley training center. The Company proposed the project as part of its Solar Energy Standard (SES) compliance requirement.[101]

In approving the petition, the Commission also approved the Company's proposed Solar Energy Adjustment Rider and a revised Fuel and Purchased Energy Adjustment Rider, finding that they appropriately allocate the costs and benefits of solar power between solar-paying customers and SES-exempt customers.[102] The Commission also accepted the Company's commitment to develop and file a methodology in this rate case for allocating the solar capacity benefits of the Camp Ripley Solar Project between SES-exempt and non-exempt solar-paying customers.

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[101] Minn. Stat. § 216B.1691, subd. 2f.

[102] *In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Camp Ripley Solar Project for Recovery Through Minnesota Power's Renewable Resources Rider Under Minn. Stat. § 216B.1645 and Related Tariff Modifications*, Docket No. E-015/M-15-773, Order Limiting Cost Recovery, Approving Fuel and Purchased Energy Adjustment Rider Revisions, and Approving Proposed Solar Energy Adjustment Rider (December 12, 2016).

B. Positions of the Parties

1. Minnesota Power

Minnesota Power's proposed methodology calculates the value of solar capacity based on the clearing price for capacity in the MISO annual Planning Resource Auction in Local Resource Zone 1.

The Company explained that its demand and capacity resources, including Camp Ripley, are located in Zone 1 and that the value of solar capacity is the lost opportunity to sell excess capacity into the MISO market through the annual Planning Resource Auction. The Company also stated that the auction provides a value for summer capacity within Zone 1, an approach consistent with the functionality of a solar array, which does not provide capacity in winter when the electric system peaks after sunlight hours. Capacity credits for a full year are not justified where the facility does not meet the Company's winter-peaking system needs.

2. Clean Energy Organizations

CEO opposed the proposal to rely on the Planning Resource Auction to value solar capacity, instead recommending that the Company use the Minnesota Value of Solar methodology or its current capacity contract and avoided costs, which are used in setting distributed generation compensation rates. CEO stated that the Company's proposal is not consistent with how the Company values the capacity from its own generation. CEO also recommended that the capacity benefits be allocated to customer classes using demand during the MISO annual peak, to the extent practicable.

3. The Department

The Department opposed the Company's proposal, concurring with CEO's recommendation to use the Company's avoided capacity cost for qualifying facilities. The Department noted that in its prior order approving the Solar Energy Adjustment Rider, the Commission equated SES benefits with costs avoided due to solar generation. Benefits of the Camp Ripley Project include avoided fuel costs, avoided operation-and-maintenance costs, avoided generation-capacity costs, avoided transmission and distribution costs, and avoided environmental costs. SES-exempt customers share in these benefits, although they do not help pay for solar power. Minnesota Power's position contrasts with this approach by focusing the calculation on opportunity costs.

4. The OAG

The OAG concurred with CEO's and the Department's recommended allocation.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that while the Company's approach is not necessarily the best approach identified in the record, it is just and reasonable.

D. Commission Action

The Commission will approve the methodology for allocation of the Camp Ripley solar capacity benefits as recommended by the Department and the Clean Energy Organizations. Their proposal for allocating the solar capacity benefits by using the Company's avoided capacity costs is more consistent with the costs the Company is able to avoid by operation of the Camp Ripley Project and is therefore the most reasonable method to use.

LIV. U.S. Steel Electric Service Agreement

A. Introduction

In 2016, Minnesota Power and United States Steel Corporation (U.S. Steel) reached an agreement on a proposed ESA that defines the terms under which the Company provides service to U.S. Steel's Minntac and Keetac taconite mining facilities. The Commission subsequently approved the ESA, with the exception of one provision, a credit affecting firm demand that is applicable only when both facilities are operating.[103] The Commission requested additional information on the reasonableness of the condition in this rate case.

B. Positions of the Parties

LPI stated that it supports the provision, which was a basis for reopening Keetac, thereby demonstrating the provision's effectiveness.

The Department initially raised concerns with whether the provision would be available to other, similarly situated customers, consistent with the statutory requirement that rates not be unreasonably discriminatory. In response, the Company testified that the provision would, in fact, be available to other similarly situated customers.

The Department also analyzed whether the provision would be cost-effective and therefore in the public interest. The Department stated that without any proposed adjustment to the revenue requirement in this rate case, the Company's ratepayers would continue paying in base rates the Company's costs of providing service whether or not the provision was triggered, resulting in a provision that is not cost-effective. In light of LPI's testimony on the provision's central role in the reopening of Keetac, however, the Department supported approval of the condition as being in the public interest.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the provision is in the public interest and recommended that the Commission approve it.

D. Commission Action

The Commission concurs with the parties that the contract provision governing demand charge credits is in the public interest and will approve it. The provision's significant role in the reopening of Keetac demonstrates its effectiveness. Further, the Company testified that it would make the credit available to other similarly situated customers.

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[103] *In the Matter of a Petition by Minnesota Power for Approval of an Amended and Restated Electric Service Agreement Between United States Steel Corporation and Minnesota Power*, Docket No. E-015/M-16-836, Order Approving in Part Electric Service Agreement, Referring Matter to Rate Case, and Closing Docket (December 29, 2016).

LV. Lighting Rates

The Company requested approval of changes to its tariff governing Lighting Rates to expand light-emitting diode (LED) options for customers. The request included the following changes:

- An Outdoor and Area Lighting 4,675 Lumen (48 watts or less) LED option with a monthly rate of $9.17;
- A Street and Highway Lighting 23,000 Lumen option with a monthly rate of $21.01 per fixture;
- A customer charge of $2.00 for Option 4 Lighting Customers; and
- An Energy Table (in replacement of the current one) that contains monthly kWh usage by fixture type to use daily kWh estimates to match the calculation methodology in the Company's updated Customer Information System.

No party objected to the proposal, and the Administrative Law Judge did not address the issue. The Commission concurs that the Company's proposal is reasonable and will approve it.

LVI. Extension Rules

The Company requested approval of the following changes governing its single-phase and three-phase extension cost allowances:

- For residential single-phase service, change the extension cost allowance from $615 to $750;
- For General Service and Municipal Pumping rate classes, separate the extension cost allowance for single-and three-phase service installations, with the extension cost allowance for single-service to change from $1,545 to $1,000 and the extension cost allowance for three-phase service to be set at $2,800.

No party objected to the proposal, and the Administrative Law Judge did not address the issue. The Commission concurs that the Company's proposal is reasonable and will approve it.

LVII. Non-Metered Service

The Company requested approval of changes to its Rider for Non-Metered Service tariff to modernize and update the language as follows:

- Minor terminology changes;
- Modification of the Item Type to better describe the equipment utilized;
- Replacement of several existing options for Cable Wire with a single new option;
- Removal of the 10 kWh and 50 kWh Crossing Flashes options; and
- Deletion of the Telephone Booths option.

No party objected to the proposal, and the Administrative Law Judge did not address the issue. The Commission concurs that the Company's proposal is reasonable and will approve it.

FINANCIAL SCHEDULES

LVIII. Gross Revenue Deficiency

The above Commission findings and conclusions result in a Minnesota-jurisdictional gross revenue deficiency for the test year of $12,616,113.

Revenue Deficiency - Minnesota Jurisdiction
Test Year Ending December 31, 2017

Description		MP - MN
Average Rate Base	$	2,051,528,097
Rate of Return		7.0639%
Required Operating Income	$	144,917,893
Operating Income	$	137,521,064
Income Deficiency	$	7,396,829
Gross Revenue Conversion Factor		1.705611
Gross Revenue Deficiency	$	12,616,113

LIX. Rate Base Summary

Based on the above findings, the Commission concludes that the average Minnesota-jurisdictional rate base for the test year ending December 31, 2017 is $2,051,528,097, as shown below:

Rate Base Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2017

Description	MP-MN
PLANT IN SERVICE	
Steam	$ 1,377,553,044
Hydro	$ 161,747,996
Wind	$ 682,699,561
Transmission	$ 606,702,164
Distribution	$ 555,361,755
General	$ 173,233,680
Intangible	$ 67,006,652
Total Plant In Service	$ 3,624,304,852
RESERVE FOR DEPRECIATION	
Steam	$ 577,940,284
Hydro	$ 22,350,269
Wind	$ 77,974,321
Transmission	$ 197,328,141
Distribution	$ 260,829,599
General	$ 85,720,752
Intangible	$ 43,727,842
Total Reserve For Depreciation	$ 1,265,871,208
NET PLANT IN SERVICE	
Steam	$ 799,612,760
Hydro	$ 139,397,727
Wind	$ 604,725,240
Transmission	$ 409,374,023
Distribution	$ 294,532,156
General	$ 87,512,928
Intangible	$ 23,278,810
Total Net Plant In Service	$ 2,358,433,644
Construction Work in Progress	$ 21,936,336

Working Capital:		
Fuel Inventory	$	37,891,203
Materials & Supplies	$	25,410,468
Prepayments	$	30,396,543
Cash Working Capital	$	(27,078,373)
Subtotal	$	66,619,841
ADD:		
ARO	$	-
Workers Comp Deposit	$	74,492
Unamortized WPPI Trans. Delivery Chg.	$	(2,150,893)
Unamortized UMWI Transaction Cost	$	1,425,067
Subtotal	$	(651,334)
DEDUCT:		
Customer Advances	$	1,790,064
Customer Deposits	$	240,131
Other Deferred Credits - Hibbard	$	286,114
Wind Performance Deposit	$	125,867
ADIT Net	$	392,368,214
Subtotal	$	394,810,390
TOTAL AVERAGE RATE BASE	$	2,051,528,097

LX. Operating Income Summary

Based on the above findings, the Commission concludes that the Minnesota-jurisdictional net income for the test year under present rates is $137,521,064, as shown below:

Operating Income Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2017

Description	MP-MN	
UTILITY OPERATING REVENUES		
Retail Revenue	$	612,067,661
Dual Fuel	$	10,353,227
Other Operating Revenue	$	190,347,028
Total Operating Revenues	$	812,767,916
UTILITY EXPENSES		
Steam Production	$	41,006,829
Hydro Production	$	5,716,958
Wind Production	$	13,766,390
Other Power Supply	$	(468,020)
Purch. Power & Interchange P.	$	204,620,065
Fuel	$	116,904,313
Total Production	$	381,546,535
Transmission & Regional Mkt.	$	47,345,228
Distribution	$	23,697,619
Customer Accounting	$	6,712,302
Customer Service & Information	$	2,746,697
Conservation Improv. Program	$	10,447,625
Sales	$	40,958
Administrative & General	$	48,386,941
Customer Deposits-Interest-Retail	$	1,071,000
Charitable Contributions	$	394,280
Total O&M Expenses	$	522,389,185
Depreciation Expense	$	104,978,687
Amorization Expense	$	4,217,942
Taxes Other than Income Taxes	$	42,278,734
Total Depreciation & Other Taxes	$	151,475,363
Federal Income Tax	$	737,916

State Income Tax	$	234,580
Provision for Deferred Income	$	46,145,477
Provision for Deferred Income - Cr.	$	(43,003,338)
Interest Synch		
Investment Tax Credit	$	(364,440)
AFUDC	$	(2,367,891)
Subtotal	$	1,382,304
Total Expenses	$	675,246,852
Net Income	$	137,521,064

ORDER

1. Minnesota Power is entitled to increase Minnesota-jurisdictional revenues by $12,616,113 to produce jurisdictional total gross revenue, including Other Operating Revenue, of $825,384,029 for the test year ending December 31, 2017.

2. The final capital structure and overall cost of capital resulting from the decisions made in this order are:

Component	Ratio	Cost	Weighted
Short-Term Debt	0.0%	-------	0.0000%
Long-Term Debt	46.1892%	4.5170%	2.0864%
Common Equity	53.8108%	9.2500%	4.9775%
Total	100.0000%		7.0639%

3. Minnesota Power shall set the remaining accounting lives of Boswell Units 1 and 2 at 2022, and Units 3 and 4 and the Common Facilities at 2050.

4. The Commission varies the rules that require Unit 3 and Unit 4's accounting lives to match their probable service lives. This variance shall remain in effect until terminated by the Commission. The extension of the accounting life of Units 3 and 4 does not extend the service or operational life of these facilities.

5. Minnesota Power shall file a securitization plan for the Boswell units within two years of the date of the final order in this case.

6. Minnesota Power shall extend the depreciation life of the Hibbard Renewable Energy Center to 2029 to match the economic life in the Company's current resource plan.

7. Minnesota Power shall remove the prepaid pension asset and associated tax savings from test-year rate base.

8. Minnesota Power shall reduce test-year pension expense by $519,375.

9. Minnesota Power shall reduce test-year generation supervision & engineering and meter-reading costs by $6.781 million.

10. Minnesota Power shall remove the two capital projects that it deferred and that will not be in service in 2017, the 5-Line Reconductor project and the Hoyt Lakes Ring Bus Reconfiguration project, from the revenue requirements for the test year.

11. Minnesota Power is authorized to include its budgeted generation capital additions of $27.7 million in the test year.

12. Minnesota Power shall amortize the Taconite Harbor restart costs over three years, reducing test-year costs by $833,334.

13. The Commission orders a sunset provision such that recovery of Taconite Harbor restart costs will end after the total estimated cost of $2.5 million for two restart events is recovered.

14. The Commission rejects Minnesota Power's proposal to reduce third-party transmission revenues and expenses by $6.23 million from the net revenue amount requested in the Company's rebuttal testimony. The Company shall instead increase Other Operating Revenues by $1.836 million on a Minnesota-jurisdictional basis.

15. The Commission accepts Minnesota Power's "non-labor" transmission O&M expenses at $47,345,000.

16. Minnesota Power is not authorized to establish a storm-response budget.

17. Minnesota Power shall remove $732,272 of deferred, amortized July 2016 storm costs from the test year, consistent with Commission's December 2016 decision in Docket No. E-015/M-16-648.

18. Minnesota Power shall remove from the test year $232,618 in deferred, amortized Sappi/Cloquet generator expenses.

19. Minnesota Power may include $350,000 in O&M expense in the test year for credit-card-processing fees. The Company shall track over/under-collections for true-up in a future rate case.

20. Minnesota Power shall reduce test-year Administrative and General Expenses for Customer Information System Software and Maintenance by $21,584 (Minnesota jurisdiction).

21. The Commission approves Minnesota Power's proposal to include all of the Annual Incentive Program (AIP) expenses in the revenue requirement, limited to 20 percent of individual base salaries.

22. The Company shall continue to provide customer refunds in the event that actual AIP payouts are lower than the level approved in rates.

23. The Company shall remove $1,380,313 from the test year for the Executive Deferral Account and Executive Investment Plan.

24. Minnesota Power is authorized to include $124,966 in the test year for spot-bonus expense.

25. Minnesota Power shall decrease its retirement-savings and stock-ownership plan expenses by $0.718 million to $6.43 million.

26. The Commission approves test-year high-performance-award expenses of $348,052 (Minnesota jurisdiction).

27. Minnesota Power shall reduce test-year Interest on Benefits and Other Awards by $14,380. The Company shall provide documentation to show that the interest for these benefits applies only to retirees who were not eligible for AIP when they worked for the Company.

28. Minnesota Power shall reduce its other-employee-benefits expenses by $0.503 million to $1.422 million.

29. Minnesota Power is authorized to recover $23,007 (total company) for employee gifts in the test year.

30. Minnesota Power shall decrease test-year employee travel, entertainment, and related expenses by $454,202 (Minnesota jurisdiction) to match the three-year historical average.

31. Minnesota Power shall reduce the test-year employee-compensation costs by $2,969,621 for unfilled positions.

32. Minnesota Power is authorized to recover $1,240,619 in test-year membership dues.

33. The Commission approves charitable-contribution expenses of $359,250, with no administrative costs.

34. The Commission approves test-year economic-development expenses in the amount of $207,749.

35. Minnesota Power shall reduce the test-year conservation improvement program budget from $10,572,625 to $10,447,625 (a reduction of $125,000).

36. Minnesota Power shall reduce its revenue requirement to remove proration of accumulated deferred income taxes (ADIT). Proration of ADIT is required for interim rates.

37. Minnesota Power shall set the 2017 production-tax-credit estimate at $41.830 million (an increase of $1.462 million to the Company's initial proposal), adjust the ADIT asset by $0.731 million, and perform an annual true-up of actual production tax credits through the Renewable Resources Rider.

38. Minnesota Power shall update cash working capital based on the rate base, revenue and expense adjustments, and capital structure approved in this proceeding.

39. Minnesota Power shall recalculate interest synchronization expense based on the Commission determinations in this proceeding for rate base, weighted cost of debt, and operating income.

40. The Commission refers a decision on the appropriate fuel-clause adjustment methodology to Docket No. E-999/CI-03-802.

41. Minnesota Power shall increase the base cost of energy to $21.21/MWh, or 2.121 cents/kWh, update the class-specific cost factors, and incorporate them into the base rates for the test year.

42. Minnesota Power shall not include reagent costs in the fuel-clause adjustment.

43. Minnesota Power shall not include business-interruption insurance premiums in the fuel-clause adjustment.

44. Minnesota Power shall not debit and credit the purchase and sale of nitrogen-oxide allowances through the fuel clause.

45. Minnesota Power may continue accounting for sulfur-dioxide allowance sales and purchases in the fuel clause.

46. Minnesota Power may include IESO, SPP, and PJM market charges in the fuel clause so long as they are for energy charges only and not for administrative costs.

47. The Commission adopts the agreement of the Company, the Large Power Intervenors, and the Department, making no modifications to the Base Rider Cash Collections in this case. In future rate cases, cost recovery for facilities shall be rolled in at the beginning of the rate case, and then no longer be recovered in riders, or facilities and rider collections shall be rolled into the rate case at the end of the rate case if Minnesota Power wants to continue rider recovery.

48. Minnesota Power is authorized to continue combining the conservation-program adjustment with the fuel-clause adjustment on customer bills.

49. Test year revenue shall be reduced by an amount equal to the amount needed to cover the annualized cost of the EITE discount, effective with final rates. The amount of annualized Keetac revenue not required to cover the 2017 EITE discount costs, approximately $2.6 million, remain in the rate case test year as part of the revenue deficiency calculation.

50. MP is entitled to recover the $8,636,643.11 in 2017 EITE discount costs, and any additional amounts arising in its EITE Cost Recovery tracker account during the interim rate period. The interim rate refund to non-EITE-paying customers shall be reduced to the extent possible to provide for the full recovery of that amount. To the extent any portion of that amount is not recovered through a reduction in the interim rate refund, MP may recover the remaining portion through the surcharge mechanism authorized by the Commission in the EITE docket.

51. Minnesota Power's Proposed Automatic Rate Recovery Mechanism is not approved.

52. The Commission concurs with Minnesota Power that the Peak and Average (P&A) method is consistent with the Company's cost characteristics and is recognized as a valid method by the *NARUC Manual*. The Commission will consider the Company's P&A method and will also, however, consider the parties' proposed modifications, as well as the 3W 1S allocator advocated by LPI, in evaluating the Company's proposed revenue apportionment.

53. The Commission does not accept the ALJ's conclusion on distribution system cost studies and will instead continue its practice of considering a range of models to classify FERC accounts 364–369 and will consider all of the models proposed in this case.

54. Minnesota Power shall work with the Department, the OAG, and other interested parties to improve the transparency of the Company's future class cost of service study ("CCOSS"), and submit, within a 12-month deadline, a compliance filing explaining improvements that have been made to the Company's CCOSS and including the updated version of its CCOSS model and guide or, if not yet completed at the 12-month deadline, a timeline for completion and for future compliance filings.

55. The Company must file a status report within six months of this order, which will identify the Company's efforts to that date to facilitate review of its CCOSS model or adopt a new model. The parties must also consider the concerns raised by Commission staff.

56. The Commission adopts a revenue apportionment that increases the revenue responsibility to the Residential and General Service classes by 3.5%, and apportions the remaining revenue requirement to the remaining classes consistent with the Company's CCOSS.

57. The Company shall implement a four-block rate schedule as proposed by the five signatories to the Settlement, with adjustments to the rates for each block as needed to enable the Company to recover the full revenue requirement allowed by the Commission for the Residential class.

58. The Commission rejects the Company's request to increase the residential customer charge to $9.00.

59. The Company must reduce the number of energy charge blocks in the CARE Rider rate to match that approved in this rate case.

60. The Commission grants the Company's request to revise the "RATE MODIFICATION" section of the CARE Rider to specify Customer/Service Charge and Energy Charge discounts instead of the existing CARE Customer Charge and Energy Charges that replace the standard Residential Service Charge and Energy Charges.

61. The Commission grants the Company's request to make minor changes to the Affordability Surcharge terminology of the CARE Rider, changing it to the more descriptive "Low-Income Affordability Program Surcharge."

62. The Commission hereby approves the Company's proposal to remove the minimum late payment fee of $1.00, and specify in the Residential tariff sheets that payment is due 25 days after the date a bill is rendered.

63. The Commission hereby approves the Company's proposed Seasonal Residential Rates.

64. The Commission hereby approves the Company's proposed municipal pumping rate changes.

65. The Commission approves the dual fuel class rates as follows:

a. the Residential Customer Charge will increase the same as the standard residential;
b. the Residential Customers' per-kWh charge will increase proportionately the same as the increase for standard residential customers;
c. the Commercial/Industrial (both low- and high-voltage) customer charge will increase from $10.50 to the level set in this rate case to match the General Service Class;
d. the Commercial/Industrial (both low- and high-voltage) per-kWh charge will increase proportionately the same as the increase for the General Service Class.

66. The Commission approves the Modify Controlled Access Service rates as follows:

a. the Residential Customer Charge will increase the same as the standard residential;
b. the Residential Customers' per-kWh charge will increase proportionately the same as the increase for standard residential customers;
c. the Commercial customer charge will increase to the level set in this rate case to match the General Service Class;
d. the Commercial per-kWh charge will increase proportionately the same as the increase for the General Service Class.

67. The Commission hereby approves the Company's proposed modifications to its General Service customer charge, as well as its proposed tariff change (standard tariff modifications).

68. The Commission hereby approves the Company's proposed standard tariff modifications to its Large Light and Power tariff.

69. The Commission does not approve the Company's proposed price change to its LLP-TOU Rider.

70. The Commission hereby approves the Company's proposed changes to its Large Light and Power tariff to allow service under the LLP TOU Rider or the Rider for Foundry, Forging, and Melting Customers, but not both.

71. The Commission hereby approves the Company's proposed change to its LLP-TOU Rider to simplify existing tariff language.

72. The Company shall work with LPI and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, for submission to the Commission. The record to support the submission to the Commission may be developed in either Docket E015/AI-17-568 - OAH Docket 68-2500-34672 or a new miscellaneous docket. In the event the Company, LPI, and other stakeholders elect to proceed with a new miscellaneous docket filing, such filing shall be submitted for Commission approval within six months after the date of the final written order in this proceeding.

73. The Commission hereby approves the Company's proposed changes to its Large Power Service tariffs governing Standard Service and Non-Contract Service.

74. The Commission hereby approves the Company's proposed tariff changes to its Released Energy Rider and Expedited Billing Procedures.

75. The Commission hereby rejects the Company's proposed changes to its Incremental Production Service tariff.

76. The Commission hereby approves the Company's proposed change to the Power Factor Adjustment.

77. The Commission hereby approves the Back-up Generation Program with the requirement that the Company modify the proposed rate to ensure that participating customers pay all costs incurred.

78. The Commission hereby approves the BDIR as proposed by MP with the following conditions to which it has agreed:

   a. require the Company to obtain approval of amendments to existing or new ESAs;
   b. require the Company to file for approval any new or amended ESA within 30 days after signing the agreement;
   c. require the ESA filing to include the incremental revenue and incremental costs associated with the new ESA;
   d. require that the ESA is deemed approved if no party objects to the ESA within 30 days of the filing date;
   e. require the Company to file an annual compliance filing on May 1st each year (in a new miscellaneous docket) showing the number of customers served on the rider, together with each customer's incremental revenue and costs; and
   f. require that energy audits be conducted for all rider customers.

79. The Commission hereby rejects the GRID pilot at this time, without prejudice.

80. The Commission hereby approves the Green Pricing Program with the following requirements:

   a. deny at this time the Company's proposed administration fee;

   b. require the Company to provide annual updates about the program (including information on the participation, administration costs, and certification costs) to monitor the price of the program;

   c. require the Company to not apply the Fuel Clause Adjustment (which includes the Base Cost of Energy at $21.21/MWh and the Rider for Fuel and Purchased Power) to the portion of renewable energy reserved by customers participating in the Company's green pricing program; and

   d. require the Company to file a proposal as to how to address the situation where the price of the renewable PPAs become consistently lower than the price of the Company's overall power mix, or consider now, or in the future, whether it may be a reasonable policy to charge customers participating in the green pricing program a lower rate if the price of renewable energy resources used for the program drops below the price for the Company's existing resource mix.

81. The Commission acknowledges the agreement between MP and Wal-Mart: "The Commission also adopts the agreement between Minnesota Power and Wal-Mart and orders that Minnesota Power shall work with Wal-Mart and any other interested stakeholders to develop one or more renewable programs suitable for large customers and report to the Commission the results of such development within six months of the date of this order."

82. The Commission hereby rejects the proposed implementation of a revenue decoupling mechanism.

83. The Commission hereby approves the methodology for the calculation and allocation of the Camp Ripley solar capacity benefits recommended by CEOs and the Department.

84. The Commission hereby approves the Demand Charge Credit of the MP/US Steel ESA.

85. The Commission hereby approves the Company's proposed changes to its Lighting Rates tariff.

86. The Commission hereby approves the Company's proposed changes to its Extension Rules tariff.

87. The Commission hereby approves the Company's proposed changes to its Non-metered Service tariff.

88. Within 30 days, Minnesota Power 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:

1. Total revenue by customer class;

2. Total number of customers, the customer charge and total customer charge revenue by customer class; and

3. For each customer class, the total number of commodity 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) Direct Minnesota Power to file a computation of the CCRC based upon the decisions made herein for inclusion in the final Order. Direct Minnesota Power to file 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.

(e) If final authorized rates are lower than interim rates, a proposal to make refunds of interim rates, including interest to affected customers.

89. For 30 days after they are filed, the Commission will accept comments on all compliance filings. However, comments are not necessary on Minnesota Power's proposed customer notice.

90. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

This document can be made available in alternative formats (e.g., large print or audio) by calling 651.296.0406 (voice). Persons with hearing loss or speech disabilities may call us through their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.