BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	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: February 28, 2023

DOCKET NO. E-015/GR-21-335

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

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PROCEDURAL HISTORY

I. Initial Filings

On November 1, 2021, Minnesota Power (or the Company) filed this general rate case seeking an annual increase in electric rates of $108.3 million, or 17.58% above present rate revenues of $615.9 million.

On December 30, 2021, the Commission issued three separate orders in this case: one finding the rate case filing substantially complete and suspending the proposed final rates; one referring the case to the Office of Administrative Hearings for contested case proceedings; and one setting interim rates for the period during which the rate case was being resolved.

II. The Parties and Their Representatives

The following parties appeared in this case:

- Minnesota Power, represented by David R. Moeller, Senior Regulatory Counsel and Matthew R. Brodin, Senior Attorney, Minnesota Power; and Elizabeth M. Brama, Valerie T. Herring, and Kodi J. Verhalen, Taft Stettinius & Hollister LLP.

- Department of Commerce, Division of Energy Resources (the Department), represented by Richard E. Dornfeld, Katherine M. Hinderlie, and Allen Cook Barr, Assistant Attorneys General.

- The Office of the Attorney General—Residential Utilities Division (the OAG), represented by Peter G. Scholtz, Travis Murray, and Joseph C. Meyer, Assistant Attorneys General.

- Large Power Intervenors (LPI), represented by Andrew P. Moratzka and Riley A. Conlin, Stoel Rives, LLP.[1]

- Citizens Utility Board of Minnesota (CUB), represented by Brian Edstrom, Senior Regulatory Advocate, and Annie Levenson-Falk.

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

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) James R. Mortenson to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings and initial and reply briefs after the close of evidentiary hearings. The ALJ held virtual evidentiary hearings on June 13, 14, and 15, 2022.

The ALJ also held public hearings in the case, as set forth below:

- Two public hearings were held virtually via Webex on July 19, 2022.

- Two public hearings were held on July 20, 2022, in Hermantown, Minnesota and virtually via Webex, in the afternoon and in the evening.

Approximately 50 members of the public attended the public hearings or filed written comments. Nearly all comments opposed the proposed rate increase, citing adverse financial impacts and hardships that the increase would impose.

IV. Proceedings Before the Commission

On September 1, 2022, the Administrative Law Judge filed his Findings of Fact, Conclusions and Recommendation (the ALJ's Report).

On September 23, 2022, the Company, the Department, the RUD, LPI, and CUB filed exceptions to the report of the Administrative Law Judge under Minn. Stat. § 14.61 and Minn. R. 7829.2700.

On January 18 and 23, 2023, the Commission heard oral argument from and asked questions of the parties.

On January 23, 2023, the record closed under Minn. Stat. § 14.61, subd. 2.

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[1] Large Power Intervenors is an ad hoc consortium of industrial Large Power and Large Light and Power customers of Minnesota Power and includes Blandin Paper Company; Boise Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Cleveland-Cliffs Minorca Mine Inc.; Enbridge Energy Limited Partnership; Gerdau Ameristeel US Inc.; Hibbing Taconite Company; Northern Foundry, LLC; Sappi Cloquet, LLC; USG Interiors, Inc.; United States Steel Corporation (Keetac and Minntac Mines); and United Taconite, LLC.

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

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

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

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

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, from the accuracy of the financial information provided by the utility to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking, the Commission acts in both its quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its

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

[3] *In the Matter of the Request of Interstate Power Company for Authority to Change its Rates for Gas Service in Minnesota*, 574 N.W.2d 408, 410 (Minn. 1998).

institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained:

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

C. The Burden of Proof

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

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court in a civil case, 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 Supreme Court has explained:

> 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. “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

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[4] *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722-723 (Minn. 1987).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

consumers of utility services shall be furnished such services at reasonable rates."[7] (Citation omitted.)

II. Summary of the Issues

The parties worked effectively to narrow the issues in this case, and by the date of oral argument, only the issues listed below remained contested:

Financial Issues

- Prepaid Pension Asset–should the Company's requested 13-month average of its 2022 test year pension plan accumulated contributions in excess of net periodic benefit cost (the "prepaid pension asset") of $80,424,617 (total company), $71,506,571 (Minnesota jurisdictional), be included in the working capital section of rate base?

- Prepaid Other Post-Employment Benefits Assets (OPEB)—Should the Company be authorized to include a prepaid OPEB asset in rate base?

- Utility Plant Balance—Beginning of Year Balance–Should the Company's utility plant balance as of the beginning of the test year be set based on the Company's projected costs?

- Taconite Harbor Energy Center—How should the Company's Taconite Harbor Energy Center costs be treated for ratemaking purposes?

- Bad Debt Expense—What amount of bad debt expense should be included in the test year?

- Employee Count and Compensation—Is the Company's test-year compensation and benefits budget reasonable?

- High Performance Awards—How should the Company's high-performance awards budget be calculated?

- Defined Contribution Plan—Is the Company's test-year amount reasonable?

- Healthcare Plan—Is the Company's test-year expense reasonable?

- FERC Accounts 923, 924, and 925—What method should be used to set the Company's FERC account expense levels?

- Dues and Memberships—Are the Company's membership dues and expenses reasonable?

- Employee Expenses—Are the Company's employee expenses reasonable?

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[7] *In the Matter of the Petition of Minnesota Power & Light Company, d.b.a. Minnesota Power, for Authority to Change its Schedule of Rates for Electric Utility Service Within the State of Minnesota*, 435 N.W.2d 550, 554 (Minn.App. 1989).

- Economic Development Expenses—What amount of the Company's economic development expenses should be recoverable?

  UIPlanner—What amount, if any, of the Company's investments in UIPlanner software is recoverable?

Sales Forecast

- Sales Forecast—Are the Company's test-year forecasted sales volumes for Mining and Metals Customers and Residential Customers reasonable? Is the Company's ST Paper and Husky/Cenovus test-year sales forecast reasonable?

Cost of Capital

- Return on Equity—What rate of return on common equity is currently appropriate for Minnesota Power?

Class Cost-of-Service Study

- CCOSS—What action should the Commission take, if any, with respect to the class cost-of-service studies proposed in this case? What requirements, if any, should be established for future rate cases?

Rate Design

- Revenue Apportionment—should the Commission adopt the Company's proposed revenue apportionment, residential customer service charge increase, and other customer charges?

- Should the Commission eliminate the Energy-Intensive Trade-Exposed rider?

- Should the Commission approve the Company's proposed sales and property tax true-ups?

III. Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held three days of evidentiary hearings, two public hearings via WebEx, and two public hearings in Hermantown, which were also accessible via WebEx. He reviewed the testimony of some 26 expert witnesses and examined approximately 93 exhibits. He made some 739 findings of fact, 7 conclusions of law, and recommendations on all stipulated and contested issues based on those findings and conclusions.

Having itself examined the record and having considered the ALJ's Report, the Commission concurs in most of his findings and conclusions. On a few issues, however, the Commission reaches different conclusions, as set forth below. On all other issues, the Commission accepts, adopts, and incorporates his findings, conclusions, and recommendations. The issues disputed among the parties are addressed below.

FINANCIAL ISSUES

IV. Prepaid Pension Asset

A. Introduction

In most years, Minnesota Power makes contributions to its pension plan to ensure adequate funding for future employee-benefit obligations. Since the pension plan's inception, the Company has contributed more to the plan than it has expensed, which has resulted in a positive balance that the Company calls a "prepaid pension asset."

The Company seeks recovery for the prepaid pension asset by adding $43,705,383 to its rate base.[8]

B. Positions of the Parties

1. Minnesota Power

The Company argued that it should be able to include prepaid pension funds in rate base for the following reasons:

- These costs are not discretionary because federal law requires a certain level of pension contribution, and the costs are necessary to provide electric service;
- Contributions made by shareholders benefit customers by lowering expenses and decreasing liabilities;
- Including these costs in rate base is consistent with standard ratemaking treatment when contributions and expenses differ significantly for any cost of providing utility service; and
- There is precedent in Minnesota and nationwide that support the Company's request.

The crux of Minnesota Power's argument is that it is entitled to earn a fair return on the prepaid pension asset because it is an expense reasonably and necessarily incurred in the provision of utility service.

2. The Department

The Department recommended excluding the prepaid pension asset from rate base for the following reasons:

- Under generally accepted accounting principles (GAAP), return on a regulatory asset is only permitted if the Company has properly recorded the regulatory asset—as Minnesota

[8] The Company requested that the 13-month average of its 2022 test year pension plan accumulated contributions in excess of net periodic benefit cost (the prepaid pension asset) of $71,506,571 (Minnesota jurisdiction) be included in the working capital section of rate base. This would result in a net increase to rate base of $43,705,383 (Minnesota Jurisdiction) for accumulated contributions, net of accumulated deferred income taxes (ADIT).

Power did not record this purported prepaid asset, its request for a return on the "prepaid pension asset" is inconsistent with GAAP requirements as there is not truly a "prepaid asset";

- Even assuming that the prepaid pension asset is properly characterized as a prepaid asset, it is not funded one-hundred percent through investor funds because the Company has not consistently contributed to the fund and annual market returns on the pension plan trust asset are reinvested into the trust;
- Company financial statements indicate the pension fund is underfunded by $206.2 million making it a liability;
- The balances in the prepaid pension asset are temporary, variable, and fundamentally different from typical rate-base assets on which utilities earn a return; and
- Ratepayers already pay for pension expense through rates, so they should not also pay a return on the Company's supposed prepaid asset.

Moreover, the Department noted that its position is supported by multiple Commission decisions that rejected utilities' attempts to include these types of prepaid assets in rate base.

3. LPI

LPI explained that the Company must show that the prepaid pension asset is solely funded by investor capital to justify adding it to rate base. LPI contended that Minnesota Power failed to show that the prepaid pension asset was funded by shareholders rather than pension trust returns. Additionally, LPI noted that the Commission has repeatedly denied requests to include similar prepaid assets in rate base, so the Commission should reach the same outcome here.

For these reasons, LPI recommended removing the prepaid pension asset from rate base.

C. Recommendation of the Administrative Law Judge

The ALJ recommended including the prepaid pension asset in the rate base in the amount of $43,705,383. He reached this conclusion by finding that the Company reasonably incurred these costs as necessary to provide utility service, the Company's payments benefit customers, and the Company is entitled to just compensation for these funds that is not provided by the inclusion of the present pension expense in rates.

Additionally, the ALJ distinguished prior Commission rate-case decisions and noted that the traceability of funds in this record justified the outcome because that element was absent in prior Commission decisions disallowing rate-base treatment for prepaid pension assets.

The ALJ found that the entire prepaid pension asset that the Company seeks to include in rate base resulted from investor contributions, but he also explained that it was unreasonable to exclude the prepaid pension asset from rate base simply because it is impractical or impossible to separate from the prepaid amount market returns attributed to the Company's contributions from those attributable to customer contributions.

D. Commission Action

The Commission concurs with the Department and LPI 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 from test-year rate base.

The accounting asset identified by the Company is distinct from assets typically 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. Here, the Commission concurs with the Department and LPI that Minnesota Power has failed to satisfy its burden to show that the prepaid pension asset is entirely funded by shareholders and not partially by market returns.

The Administrative Law Judge supported including the prepaid pension asset in rate base because he found the facts in this case were more similar to those addressed in the Commission's decision in Xcel Energy's 2013 rate case than to the facts in Minnesota Energy Resources Corporation's 2015 rate case disallowing rate-base treatment.

The Commission does not find this justification persuasive as the disputed issue here—whether to include the prepaid pension asset in rate base—remained uncontested in Xcel Energy's 2013 rate case, so the Commission's decision did not directly confront this important threshold issue.

Furthermore, the Commission has articulated the reasons for excluding this type of asset from rate base in several previous orders, including the order in Minnesota Power's last rate case.[9] The circumstances that warranted denying a return on the asset in those cases are present here.

As the Commission has recognized, pension-plan assets and benefit obligations fluctuate up and down, depending on funding or market conditions.[10] 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.

For these reasons, the Commission respectfully declines to adopt the recommendation of the Administrative Law Judge and will deny Minnesota Power's request for rate-base treatment of the prepaid pension asset.

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[9] *In the Matter of the Application of Minnesota Power to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, Findings of Fact Conclusions, and Order, at 16–17 (March 12, 2018). *See also 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).

[10] *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).

V. Prepaid Other Post-Employment Benefits Asset

A. Introduction

In addition to providing a pension for its employees, Minnesota Power also incurs costs for other post-employment benefits (OPEB) related to medical, dental and life. To provide consistent treatment of similar assets, Minnesota Power requested rate-base treatment for prepaid costs related to OPEB (prepaid OPEB asset) and has included $13 million in its rate base. While there are several differences between the prepaid OPEB asset and prepaid pension asset, there are significant similarities, and the positions of the parties are consistent as applied to both prepaid assets.

B. Positions of the Parties

Minnesota Power explained that OPEB funds are held in a Voluntary Employees' Beneficiary Association (VEBA) trust that is a separate entity from the Company. Any VEBA funds reverting to the Company impose a 100% excise tax, so it is impractical for Minnesota Power to use OPEB funds for anything other than qualified benefits. Since 2013, the OPEB expense has been negative, which is treated as income. The Company explained that if it funds this negative expense through customer rates, funds should be withdrawn from VEBA to pay customers through reduced rates; however, because of the cost-prohibitive tax penalty of accessing these funds, the Company has paid the negative expense to customers. The Company contended that customers benefit as earnings on the accumulated contribution in excess of net periodic benefit cost reduces OPEB expense, but shareholders' capital remains stuck in VEBA unable to earn a return. As the Company expects this situation will persist for the foreseeable future, it requested to include the prepaid OPEB asset in rate base.

As with the prepaid pension asset, the Department contended that it is unreasonable to include the prepaid OPEB asset in rate base because customers have already paid for OPEB expense through rates, and the contributions or funds are not investor-supplied as market returns are reinvested into the plan assets and the negative OPEB expense has contributed to the prepaid OPEB asset. Additionally, the similarities between this prepaid asset and prepaid pension assets that the Commission has routinely excluded from rate base support not including a prepaid OPEB asset in rate base.

LPI also argued that Minnesota Power failed to make the necessary showing that the prepaid OPEB asset is being created with investor capital that would allow it to be included in rate base.

C. Recommendation of the Administrative Law Judge

Similar to the prepaid pension asset, the ALJ found that the record supported the Company's request for inclusion of the prepaid OPEB asset in rate base, net of ADIT, and would be reasonable for ratemaking.

Given that the cash from the earnings in VEBA cannot be withdrawn, the contributions (Company's investment) portion of the prepaid OPEB asset remain invested in the plan. The ALJ therefore asserted that investor-supplied funds that cannot be used by shareholders, and which benefit customers by lowering future rates, should be eligible for a reasonable return.

The ALJ reasoned that denying compensation to shareholders for this use of their money negatively impacts Minnesota Power's financial ratios and was identified by the credit rating agencies as a contributor to Minnesota Power's negative outlook.

Consequently, the ALJ found that denial of a return on the OPEB accumulated contributions in excess of net periodic benefit cost asset precludes the Company from a reasonable opportunity to recover its cost of service and earn its authorized rate of return.

D. Commission Action

The Commission concurs with the Department and LPI that the Company has not satisfied its burden to show that it is reasonable to include the prepaid OPEB asset in rate base.

The prepaid OPEB asset is sufficiently similar to the prepaid pension asset that the Commission's justification for excluding the prepaid pension asset in rate base also supports the exclusion of the prepaid OPEB asset.

In particular, the Company has failed to show that the prepaid OPEB asset is entirely funded by shareholders. For example, the Company submitted testimony that the OPEB expense turned into a benefit in 2013 "primarily due to benefit reductions and $145 million of largely customer-funded contributions through 2013 and the related earnings[.]"[11] The evidence in the record creates doubt that shareholders are the sole source of the funds for the prepaid OPEB asset, and the Commission resolves any doubt as to reasonableness in favor of the ratepayer.

For these reasons, the Commission respectfully declines to adopt the recommendation of the Administrative Law Judge and will exclude the $13,018,104 prepaid OPEB asset from rate base.

VI. Utility Plant – Beginning of Year Balance

A. Introduction

Like most electric utilities, Minnesota Power continually upgrades and extends its transmission and distribution systems to maintain reliability and serve new load. These types of investment funding capital projects are a part of the rate base on which the Company earns a return. The term "plant in service" describes facilities or equipment available and reasonably necessary to provide efficient, reliable service to customers. When plant is in service, the Company is entitled to earn a rate of return on its corresponding capital investment. Minnesota Power proposed a $3,133,963,314 (total company) and $2,707,710,895 (Minnesota jurisdictional) utility plant balance for the start of the 2022 test year.

B. Positions of the Parties

1. The Department

Minnesota Power overestimated its rate base beginning balance by $6.66 million in its initial rate case filing when compared to the actual balance at the start of the test year. The Department therefore recommended that Minnesota Power's beginning of year rate base balance reflect

[11] Ex. MP-23 at 85 (Cutshall Direct).

actual utility plant in service at the start of the 2022 test year, rather than the estimated value the Company proposed. The Department calculated the difference between the 2021 year-end projection and the 2021 year-end actual to reduce the 2022 test year rate base beginning balance by $6,657,334 (total company) and $6,690,538 (Minnesota jurisdictional). By carrying the adjustment through the test year, the Department also supported reducing associated depreciation and amortization expenses, as reflected in its recommendation to adjust depreciation expense by $218,538 and accumulated deferred income tax by $14,367 (both values are Minnesota jurisdictional).

The Department argued that using known actual data, where available, leads to more accurate results and expressed concern that a significant number of capital projects that the Company planned to complete in 2021 remained construction works in progress when the test year started. Noting Minnesota Power's inaccurate projection for the end-of-December 2021 plant balance in its November 2021 filing, the Department questioned the Company's assertion that the ending test-year balance would increase from the initial estimates and justifies utilizing the Company's start and end projections to accurately reflect a test year balance.

2. Minnesota Power

Despite the $6.66 million difference between its projection and the actual value, the Company argued that utilizing its projected test-year start and end values to calculate the test year's utility plant balance provided a reasonable representation of test-year data and yielded more accurate and representative results than the methodology proposed by the Department. It reasoned that any impact of its projected start balance exceeding the actual is sufficiently offset because the end-of-year actuals are on pace to exceed the Company's projected end balance.

The Company explained that it may need to adjust its capital portfolio at times to respond to changing circumstances. Specifically, it noted that it experienced unprecedented uncertainty with timing of capital projects because of supply chain unpredictability and related issues. While these challenges impacted its ability to complete projects as scheduled in 2021, the Company noted that these projects were all complete or scheduled for completion in early 2022. The Company also asserted that it was ahead of schedule for the planned 2022 projects and expected to have more plant in service at the end of the test year than initially projected.

Minnesota Power explained that the Department's method unreasonably reduces the test-year rate base by adjusting the beginning of the test year value while ignoring record evidence that justifies increasing the projected value at the end of the test year.

Ultimately, the Company recommended calculating the test-year balance by using the actual start balance as proposed by the Department, but also increasing the test-year end balance by an equal adjustment because evidence showed that the year-end balance would exceed the Company's projection. The result of this recommendation is no adjustment to the Company's proposed test-year rate base. Alternatively, the Company recommended using the average of its forecasted starting and ending utility plant balances for the test year.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company provided comprehensive evidence concerning its capital additions during the test year. While recognizing that the beginning test-year plant in service amount was lower than initial projections, the ALJ noted that the record demonstrated that the ending test-year plant in service amount was on track to well exceed the initial projections. The ALJ determined that the overall average amount proposed by the Company remained reasonable and supported by evidence. The ALJ recommended rejecting the adjustment proposed by the Department.

D. Commission Action

The Commission concurs with the recommendations of the ALJ and finds the Company's proposed method of calculating the test year utility plant balance is reasonable for ratemaking purposes.

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 plant balance. The Commission has previously recognized the benefit of updating predicted values with actual values once they become known; however, as applied to this record, the methodology proposed by the Department fails to generate a representative test-year plant balance as it utilizes the actual starting value but fails to account for evidence showing that the actual year-end value is likely to exceed the Company's forecasted amount. This unidirectional adjustment reduces the plant balance and fails to reflect a reasonable test-year amount.

The Company's initial forecast did not accurately predict the actual starting balance in the test year because of delays to projects that pushed their completion into 2022. But the evidence showed that these projects were completed and in service during the test year and that the Company expected all of its planned 2022 plant additions to be in service by the end of the test year. Additionally, the Company presented evidence that the forecasted costs of its 2022 projects would exceed forecasts because of increasing costs of materials and labor, as well as inflationary pressure.

For these reasons, the Commission will approve the beginning-of-year utility plant balance of $3,133,963,314 (total Company) and $2,707,710,895 (Minnesota jurisdiction) for the test year.

VII. Taconite Harbor Energy Center

A. Introduction

Taconite Harbor Energy Center (THEC) is a coal-fired generation facility located near Schroeder on the North Shore of Lake Superior. THEC originally had three coal-fired units and an output capability of 225 MW. Minnesota Power ceased coal-fired generation at THEC Unit 3 in 2015, and the unit was retired in place. The Company idled THEC Unit 1 and Unit 2 in the fall of 2016 with Commission approval. Minnesota Power set up a Community Advisory Panel of regional North Shore leaders from 2012 to 2016, which offered a communication platform for operating decisions. Since 2016, this group has met annually to discuss facility updates, security, and potential repurposing and redevelopment options. To date, none of these options appear viable, and Minnesota Power determined that retirement in 2021 is the best course of action in the interest of its customers and the site itself, while still maintaining the depreciable life of THEC until 2026. The Company included the retirement of THEC as an issue in its 2021 integrated resource plan (IRP) proceeding, and in January 2023, the Commission issued an order in that proceeding and approved THEC's retirement.[12]

B. Positions of the Parties

1. Minnesota Power

The Company included THEC in its test year rate base and proposed recovery of unrecovered or abandoned costs of THEC over five years. The total of these proposed test year revenue requirements is $14,924,168 (total company) and $13,120,314 (Minnesota jurisdictional).

Minnesota Power attempted to justify including THEC in the test year rate base on equitable grounds noting similarities in THEC's current operational status with those present in the Company's 2016 rate case where, according to the Company, the Commission only adjusted restart/re-idling costs and did not remove THEC from the rate base. While the Company has not used THEC to provide service to its customers in several years, the Company noted that THEC remains idled and not retired. Even though the Company requested approval in its 2021 IRP to retire THEC no later than September 2021, it contended that it was not permitted to retire THEC until the Commission provided authorization in the January 2023 order, which occurred after the test year concluded.

The Company argued that because the record shows THEC remained idle and not retired and has ongoing activities for compliance and safety during the test year, it should remain in its rate base.

2. The Department

The Department opposed inclusion of THEC in the test year rate base noting that it is inappropriate to include utility property in rate base unless it is used and useful. It explained that property is "used and useful" when it is in service and reasonably necessary to the efficient and reliable provision of utility service. As the record demonstrates that there is no expectation THEC will be in service during the test year and Minnesota Power has not used it to provide service to its customers for at least five years, the Department contended that THEC satisfies neither required condition.

The Department contended that the Company's initial investment in THEC was not unreasonable, and it should be able to collect depreciation expenses for the facility through 2026.

Overall, the Department recommended that the Commission:

- Find that THEC is not used and useful for the 2022 test year and exclude THEC from test year rate base.
- Authorize Minnesota Power to recover THEC's remaining positive net book value through depreciation expense, inclusive of the cost of removal, net salvage.

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[12] *In the Matter of Minnesota Power's 2021–2035 Integrated Resource Plan*, Docket No. E-015/RP-21-33, Order Approving Plan and Setting Additional Requirements (January 9, 2023).

- Require Minnesota Power to remove from the 2022 test year all THEC revenue requirements, except the facility's depreciation expense, property tax, and property insurance.
- Require Minnesota Power to establish a sunset provision ending December 31, 2026, for the Company's recovery of THEC's remaining depreciation expense.

3. LPI

LPI shared the Department's recommendation and rationale for excluding THEC from test year rate base but contended it would be equitable for the Company to include the abandoned plant cost of the THEC amortization expense and carry it at a zero percent cost of capital. However, if the Commission allows the Company to earn a rate of return on THEC, LPI argued that a declining balance cost recovery methodology is inappropriate for recovery of abandoned plant costs.[13] As an alternative, LPI proposed a levelized cost-recovery mechanism, which it asserted is more equitable because it equalizes the burden on all generations of customers that will pay for these sunk plant investments through 2026 and prevents the Company's over-recovery of its costs.

C. Recommendation of the Administrative Law Judge

The ALJ found that that while THEC is idled and has ongoing activities for compliance and safety, the core issue based on prior Commission decision-making is whether the THEC facility is "used and useful" during the 2022 test year. There is no dispute that the facility will not provide service to customers in 2022. Further, there is record evidence demonstrating that THEC has not provided service to customers in at least five years. Therefore, the ALJ concluded that THEC is not "necessary" for efficient and reliable provision of utility service and, as result, should be removed from rate base.

The ALJ recommend that the Commission (1) find Taconite Harbor is not used and useful for the 2022 test year and, therefore, deny Minnesota Power's request to earn a return on it; (2) authorize Minnesota Power to recover its depreciation expense through December 31, 2026; and (3) allow recovery of O&M, property tax, and property insurance costs until decommissioning begins.

D. Commission Action

The Commission concurs with the ALJ, the Department, and LPI in finding that THEC is not used and useful and should be removed from rate base but that Minnesota Power is entitled to cost recovery as indicated below.

The Company contended that THEC is used and useful because it could have restarted the facility if the Midcontinent Independent System Operator (MISO) required its operation.[14] This argument is unavailing. Under general principles of utility law, the used and useful standard

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[13] LPI explained that the Company's recovery proposal sets cost of service for THEC's abandoned plant costs highest in the test year, which unnecessarily inflates the test-year revenue requirement and allows for over-recovery of these costs through increased rates.

[14] As the administrator of the wholesale transmission grid for 15 states and the province of Manitoba, MISO designates the generators that will operate at any given moment.

simply requires (1) that the property be in service, and (2) that it be reasonably necessary to the efficient and reliable provision of utility service.[15] The record shows that THEC's test-year status satisfies neither of the necessary conditions, and the Commission will properly exclude it from test year rate base.

Despite finding THEC was not used and useful during the test year, the Commission will allow recovery of the Company's expenses related to THEC's annual depreciation, O&M expenses, property taxes, and property insurance; however, recovery of these expenses will be limited by sunset provisions to ensure that the Company's recovery does not extend in perpetuity. The Company must cease recovery of its remaining depreciation expenses by December 31, 2026. Similarly, the Commission will require the Company to institute a sunset provision and cease collecting O&M expenses once it begins decommissioning the facility.

VIII. Bad Debt Expense

A. Introduction

Bad debt expense is the amount deemed uncollectable that customers owe for utility service rendered. For ratemaking purposes, an average bad debt expense calculated from a representative timeframe typically applies to the test year. Minnesota Power requested a bad debt expense of $1,255,608 for the 2022 test year.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power contended that atypical data in 2019 and 2020 justifies its proposed calculation based on a modified five-year average of bad debt expense using years 2014–2018. Minnesota Power noted that the 2019 bad debt expense decreased because of customer refunds related to its 2016 general rate case while the 2020 level increased due to the COVID-19 pandemic, which impacted customers' ability to pay and resulted in new consumer protections that limited utilities' standard debt-collection mechanisms. Arguing that these two years provide unrepresentative data, the Company proposed averaging data from years 2014–2018 and increasing that average by fifty percent to reflect ongoing pandemic-related impacts on bad debt expense. The Company argued that the Department's proposed calculation of bad debt expense averaging the four years prior to the test year inadequately accounts for the continued impact of COVID-19 consumer protections into the 2022 test year.

2. The Department

The Department recommended using an average of the four years immediately preceding the 2022 test year (2018–2021) and applying the Minnesota jurisdictional allocator of 99.18% to calculate a bad debt expense of $771,130 for the test year. It argued that it is better to use recent data, noting that the older range of years proposed by Minnesota Power covers years included in its previous rate case. The Department recognized the decreased bad debt balance in 2019 but contended that rate refunds are normal activity even if not occurring annually. Similarly, the

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[15] *Senior Citizens Coal. of Ne. Minnesota v. Minnesota Pub. Utilities Comm'n*, 355 N.W.2d 295, 300 (Minn. 1984).

Department noted that 2020 and 2021 reflect the impacts of COVID-19 on bad debt expense that may continue into 2022 and contended that the fifty percent upward adjustment requested by Minnesota Power was unsupported and unreasonable.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that it was unlikely the Company's proposed method using older data from 2014–2018 would be any more representative of the Company's 2022 bad debt expenses than the four-year average of recent actuals from 2018–2021 proposed by the Department. The ALJ noted that Minnesota Power failed to explain how the Company developed the proposed 50% increase, what justified that specific level of increase rather than some other percentage, and why an increase is even needed when the data used predates the years containing atypical data. Given the older data and lack of rationale for the Company's 50% increase, the ALJ found Minnesota Power's approach speculative. Finding that the Department's method utilizes recent data that is likely to reflect current trends and does not rely on an unsupported adjustment factor, the ALJ recommended setting Minnesota Power's bad debt expense at $771,000.

D. Commission Action

The Commission agrees with the ALJ and the Department and finds that the Company failed to demonstrate why its proposed calculation for bad debt expense in the 2022 test year yields a more representative value than applying an average of the four years preceding the test year. Importantly, as emphasized by the ALJ, Minnesota Power failed to adequately explain why its method utilized the 50% adjustment factor, and the Commission finds that its inclusion lacks evidentiary support. While noting the annual variance of the 2018–2021 range and factors contributing to the minimum and maximum values, Minnesota Power failed to adequately justify excluding any of the four years' data from those used to calculate an appropriate average for the test year. The Commission will use Minnesota Power's bad debt expense calculated as an average of the 2018–2021 actual values adjusted by the Minnesota jurisdictional allocator to apply a $771,130 bad debt expense to the 2022 test year.

IX. Employee Count

A. Introduction

Minnesota Power aims to continue providing safe, reliable, and cost-effective electricity, and to deliver one hundred percent carbon-free electricity by 2050, through heightened efforts to acquire and retain a skilled workforce. Minnesota Power's budget for the 2022 test year expects to provide jobs for 1,063 fulltime and part-time employees as of year-end 2022. This would be an increase of 64 employees over the 2021 year-end headcount of 999 employees. The Company's employees perform an array of functions that support its ability to supply retail electric service to over 145,000 customers and wholesale service to an additional fifteen Minnesota municipalities. Since the 2016 Rate Case, the Company's employee headcount has decreased by 92 (full-time and part-time when comparing January 2017 to 2022 test year), or approximately eight percent of its workforce, at a time when customer expectations and system needs continue to increase. At issue is the number of employees to include in the Company's test-year budget.

B. Positions of the Parties

1. Minnesota Power

The Company's proposed 2022 test year budget contemplates 1,063 fulltime and part-time employees by the end of 2022. To implement this increase from the 999 employees it had at the end of 2021, the Company budgeted to gradually hire new employees expecting approximately five hires per month in 2022. The Company noted that as of the end of May 2022, it was adding employees according to this schedule and had 1,024 employees with approximately 15 in prescreening or scheduled to start.

Minnesota Power explained that its employee count decreased between 2017 and 2022 primarily because of the outcome of its 2016 rate case but also due to retirement of Boswell generating units and impacts of COVID-19. The Company undertook significant cost reduction after its previous rate case by reducing employee headcount, freezing hiring, and reallocating funds to areas experiencing significant under-recovery. According to the Company, the main justification for its current efforts to increase employee head count is that its employees have complained of being spread thin and the Company does not believe that its current staffing levels are sustainable.

The Company contested the Department's assertion that Minnesota Power should not need as many employees because its generation has shifted from coal to power purchase agreements and renewables. The Company noted that the number of employees needed to operate generation facilities is not the main driver of employee head count and explained that it is attempting to fill open positions in areas such as finance, accounting, and cybersecurity. Additionally, the Company noted that the Department made no specific recommendations as to the number of employees the Company needs to effectively operate.

Minnesota Power addressed LPI's opposition to increasing the Company's headcount by explaining that past hiring challenges do not show a current or future inability to fill open positions. The Company contended that it was on pace to hire the targeted number of employees by the end of 2022 despite ongoing challenges in the labor market.

2. The Department

The Department contended that Minnesota Power had overestimated its employee count for the 2017 test year in its last rate case. Because the Company significantly over-recovered employee expenses in 2017–2021, the Department argued that employee count and related employee expenses should not increase and recommended that they remain at the 2021 level, which is representative of the Company's recent actual expenses.

Additionally, the Department explained that because of the Company's move to carbon-free renewables, changes in generation, and rollout of advanced metering and distribution systems, the Company does not need to increase employee headcount. The Department stated it understands the importance of staffing related to cyber security, yet these needs are not new, and the related costs should already be reflected in the Company's current budget. Also, Minnesota Power's deployment of advanced metering and distribution systems offer the benefit of needing fewer employees in the field to check meters and thus reduced employee headcount.

3. LPI

LPI also expressed concerns about Minnesota Power's history of budgeting for positions that it never filled. LPI stated that it was unlikely Minnesota Power would be able to fill sixty vacant positions in 2022 because it had struggled to do so in the past. Additionally, LPI noted that attrition of current employees is likely during the test year, which would increase the likelihood of the Company overestimating its head count.

Recognizing that the Company had made progress in hiring to start 2022, LPI revised its recommended adjustment to $2.8 million asserting that it is not known or measurable if the Company will be fully staffed by the end of 2022. LPI emphasized that the Company making some progress to meet its hiring goal does not satisfy the Company's burden of proof, especially when considering its history of over-recovering this expense.

C. Recommendation of the Administrative Law Judge

The ALJ recognized three reasons that the Company's overall number of employees decreased significantly from January 2017 to the 2022 test year: changes in the Company's portfolio of generation resources, the effects of the 2016 rate case, which required the Company to undertake significant cost-cutting; and the COVID-19 pandemic. As a result, during 2020 and 2021, the Company was below its budgeted headcount, which stretched employees in a way that is not sustainable over the near-term. The Company undertook a comprehensive workforce review, and it has been engaged in a broad array of efforts and initiatives to recruit and retain employees.

The ALJ noted that Minnesota Power's 2022 budget for employee expense was less than its 2017 actuals, which showed that the Company was attempting to right-size its employee expenses. Additionally, the ALJ found that Minnesota Power was on pace to achieve its end-of-year employee head count goal. The ALJ determined that the Company's proposed employee headcount was reasonable.

D. Commission Action

The Commission agrees with the ALJ and will approve Minnesota Power's proposed head count budget of 1,063 full-time and part-time employees for the 2022 test year.

The Company undertook significant cost reduction after its previous rate case by reducing employee headcount, freezing hiring, and reallocating funds to areas experiencing significant under-recovery. This occurred while the Company was transitioning away from more labor-intensive resources and facing the onset of the COVID-19 pandemic in 2020.

Noting that its previous staffing levels were not sustainable, Minnesota Power is on track to achieve its goal of 1,063 employees by the end of 2022.

However, the Commission shares the concerns of the Department and LPI about Minnesota Power's history of maintaining staffing levels consistently under its budgeted head-count levels. To provide additional transparency for Minnesota Power's employee budget, the Commission will require that the Company file an annual compliance filing beginning on February 28, 2023, reporting its number of employees and the associated base compensation amounts.

X. Dues and Memberships

A. Introduction

Under Minn. Stat. § 216B.16, subd. 17, the Commission may not permit recovery of a utility's travel, entertainment, and related employee expenses, including "dues and expenses for memberships in organizations or clubs," unless the Commission finds these expenses are reasonable and necessary for the provision of utility service. Minnesota Power included costs associated with organizational dues and memberships in its test year, and it has the burden to establish the reasonableness of these costs.

B. Positions of the Parties

1. The OAG

The OAG objected to Minnesota Power recovering dues and membership payments for four specific organizations and also recommended normalizing annual dues for the 2022 test year by basing the expense on the average of dues payments in previous years.

The OAG recommended the following disallowances:

- • $266,662 (Total Company) for Edison Electric Institute (EEI) dues;
- • $55,000 (Total Company) for Western Coal Traffic League (Western Coal) dues;
- • $29,981 (Total Company) for Minnesota Utility Investors (MUI) dues;
- • $1,250 (Total Company) for American Gas Association (AGA) dues; and
- • $67,655 (Minnesota jurisdiction) to normalize organizational dues in the test year.

OAG argued that EEI and Western Coal are both trade associations that engage in lobbying and related policy advocacy on behalf of their members. OAG noted that EEI represents all U.S. investor-owned electric companies and Western Coal was founded to advocate for the interests of consumers of western coal. While Minnesota Power excluded the amounts earmarked for "lobbying" as stated on the invoices from these organizations from its requested recovery, OAG explained that the invoice categorization of lobbying and non-lobbying funds is based on an underinclusive federal tax definition of "lobbying," and that the percentage of dues identified on the invoices as "lobbying" fails to capture the full extent of these organizations' policy-advocacy efforts. OAG also argued that Minnesota Power has failed to demonstrate how these organizations' activities benefit ratepayers.

OAG suggested that regulators are becoming more skeptical of the activities of industry associations like EEI and Western Coal and that there is increasing nationwide concern about trade organizations' lack of transparency that justifies heightened scrutiny of whether their activities benefit ratepayers. OAG urged the Commission to find that Minnesota Power failed to engage in necessary due diligence to examine funding for EEI's and Western Coal's range of advocacy activities (rather than taking their delineation between lobbying and non-lobbying funds at face value) and therefore, the Company failed to justify its membership dues and these costs should be disallowed.

OAG also contended that dues paid to MUI and AGA should be disallowed because Minnesota Power failed to show how membership in these entities provides benefit to ratepayers. OAG explained that MUI's activities are intended to benefit shareholders, not ratepayers and noted that AGA represents interests of companies that deliver natural gas, not interests of electric utilities like Minnesota Power. OAG argued that MUI and AGA provide no direct benefit to Minnesota Power's ratepayers and dues paid to them should be disallowed.

Noting the annual variance in dues payments from 2017–2021, OAG also recommended reducing the test-year amount by $67,655 to $732,259 (Minnesota jurisdiction) to reflect the average spending in 2018–2021.

2. Minnesota Power

Minnesota Power contended that the dues and membership amounts it included in its rate request are reasonable and related to the Company's delivery of reliable electric service in Minnesota.

Minnesota Power justified its membership in EEI by explaining that membership provides educational opportunities and expertise related to various aspects of the electric industry that allow the Company and its employees to continue to deliver efficient service to its customers. It noted that members can access critical industry data, strategic business intelligence, training, public policy leadership, state and federal regulatory developments, and conferences, which can all be valuable, especially for smaller utilities like itself where in-house creation and deployment of similar resources may be cost prohibitive.

Similarly, Minnesota Power explained that Western Coal advocates for the interests of coal consumers and provides its members with information and updates on developments in the coal industry and advocates for continued access to affordable fuel, which benefits ratepayers as increases in fuel costs are typically passed on to consumers.

Furthermore, the Company contended that it seeks recovery only for memberships and dues that are reasonable and necessary and provide value to customers. Minnesota Power explained that it had removed certain organizations' dues related to lobbying from the test year and made efforts to comply with applicable Commission guidance including its decision in the Company's 2016 rate case. For example, both Western Coal and EEI engage in lobbying and provide invoices to Minnesota Power that indicate the portion of dues or membership fees that support lobbying, and those amounts are not included in the Company's recovery request.

The Company requested recovery for dues paid to MUI and AGA. It noted that its MUI membership provides benefit to ratepayers by allowing it to attract necessary investments and AGA provides benefit because two of Minnesota Power's generators utilize natural gas.

Minnesota Power argued that the OAG's cost-normalization proposal to average previous years' annual dues payments does not provide the best method to reflect similar costs in the test year. The Company contended that using an average that includes 2020 levels, when employee expense spending decreased due to the onset of the COVID-19 pandemic, skews the result as it relates to anticipated future spending in this area. Removing the 2020 year from the average decreases OAG's proposed adjustment by 40% and demonstrates an increasing trend year-to-year that the Company contended is muted by lingering impacts of the pandemic in 2021.

C. Recommendation of the Administrative Law Judge

The ALJ did not recommend normalizing annual membership and dues for the test year by applying an average cost calculated from previous years as proposed by the OAG. The ALJ found that Minnesota Power had failed to establish that its membership in AGA is reasonable and necessary for the provision of utility service as AGA does not represent the interests of ratepayers or electric utilities like Minnesota Power. Similarly, noting that MUI's "activities focus on empowering shareholders in the legislative and regulatory processes to advance policies that benefit shareholders, not ratepayers," the ALJ found that the Company failed to establish that the benefits it receives from MUI are sufficient to support rate recovery of its dues. The ALJ recommended disallowing recovery for Minnesota Power's dues payments of $31,231 to AGA and MUI.

In making recommendations related to recovery of membership payments to EEI and Western Coal, the ALJ repeatedly noted that Minnesota Power's current treatment of these payments remained consistent with Commission-approved methods in the Company's previous rate case, which did not require Minnesota Power to audit or investigate the organizations' activities. Because these organizations separate out the portion of dues used for lobbying expenses on their invoices and Minnesota Power has not requested recovery for these amounts, the ALJ found that the Company properly adjusted the allowable dues for EEI and Western Coal for the 2022 test year and allowed recovery.

D. Commission Action

The Commission agrees with the ALJ and will disallow recovery for Minnesota Power's dues payments to AGA and MUI totaling $31,231.

AGA and MUI advocate for the interests of their members, and these interests appear unrelated, or even contrary, to the interests of ratepayers. The Commission is unconvinced that Minnesota Power's affiliation with these entities provides benefit to ratepayers or that the Company's membership is reasonable and necessary for the provision of utility service.

Minnesota Power did not seek recovery for the portion of its dues payments to EEI and Western Coal that those entities' invoices show designated for lobbying activities. OAG argued that trade organizations like EEI and Western Coal use non-lobbying funds to engage in a wide-variety of lobbying-related policy activity and urged the Commission to find that Minnesota Power has not justified its dues recovery because it has failed to adequately assess trade organizations' range of activities and how non-lobbying dues payments may fund policy advocacy that provides no benefit to ratepayers. While the Commission notes the concerns OAG expressed about allowing recovery for payments that support policy advocacy that falls short of a technical definition of "lobbying," Minnesota Power explained how membership in EEI and Western Coal is reasonable and necessary to serve its customers that benefit from these memberships and accounted for its dues payments in the same manner that the Commission previously approved.[16] Given the

[16] *See In the Matter of the Application of Minnesota Power to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, Findings of Fact Conclusions, and Order, at 41 (March 12, 2018) ("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.").

demonstrated benefits Minnesota Power receives from EEI and Western Coal, the Commission will approve the Company's request to recover the portion of its dues payments from those organizations designated as funding non-lobbying activities.

XI. Outside Services Employed (FERC Account 923), Property Insurance (FERC Account 924), and Injuries and Damages (FERC Account 925)

A. Introduction

Minnesota Power included amounts in its adjusted test year for spending associated with various FERC Accounts.[17] The Department analyzed Minnesota Power's historical spending and recommended decreases to test year expenses in three areas—Outside Services Employed (FERC Account 923), Property Insurance (FERC Account 924) and Injuries and Damages (FERC Account 925).

B. Positions of the Parties

1. The Department

The Department compared Minnesota Power's 2022 test year amounts for its FERC Accounts with the approved test year amounts in the Company's 2017 rate case and the average annual amounts in years 2018–2021. The Department utilized this data to analyze the extent the Company over or under recovered these costs through its base rates and noted that the Company has overestimated some of these expenses in the past. It contended that the Company's proposed test year amounts for FERC accounts 923, 924, and 925 represent significant (greater than 5%) increases over the four-year average. Because Minnesota Power failed to adequately explain its spending in these areas, the Department argued that the amounts should be reduced. The Department recommended decreasing the test year amounts for accounts 923 and 924 to their four-year averages, which is an approximate $848,000 reduction to account 923 and an approximate $2 million reduction to account 924. For account 925, the Department recommended using the actual 2021 expense and increasing it five percent resulting in an approximate $680,000 reduction.

The Department emphasized that its recommended calculations provided the best-available forecast for the test year because the Company failed to support more precise amounts by producing relevant evidence of cost such as price quotes, estimates, retainer agreements, invoices, receipts, insurance contracts, or premium statements. It noted that the Commission has previously approved of setting test year expenses derived from an average of recent years and recommended setting expenses for these three accounts based on the Company's previous spending.

2. Minnesota Power

The Company contended that the Department's recommendations fail to account for information the Company incorporated into its estimated costs for the test year and provide insufficient funding for expenses it is likely to incur in the test year.

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

First, Minnesota Power contended that the use of multi-year averages for setting test year expenses fails to accurately capture the reality of the test year and emphasized that this effect is exacerbated by including the atypical data from 2020 when the COVID-19 pandemic significantly impacted businesses' operations and expenses. The Company noted that its forecasts carefully consider system and Company needs as well as known impacts that multi-year averages do not reasonably capture.

Second, the Company argued that it is not appropriate to assess absolute values of each expense category in isolation as reduced spending in one may create an increase in another account with similar expenses. The Company provided the example of external legal costs, which may be assigned to account 923, but could also be assigned to account 929 if the legal work corresponds to a specific docket. In applying this concept more broadly, the Company argued that the Department's oversimplified method constitutes single-issue ratemaking as it only considers one expense rather than an overall revenue requirement.

FERC account 923 corresponds to outside services expense. The Company asserted that it expects to have higher costs for non-regulatory legal services, benefit-related professional services, and safety-related training services in the test year. As the costs of these professional services relate to paying a person or entity to provide the services, the Company explained that it has incorporated the compounding effect of inflationary increases, noting predictions for 3.4% wage inflation in 2022 on top of a 2.8% increase in 2021.

FERC account 924 reflects the expense of property insurance. Based on history and actual conversations with insurance providers and brokers, the Company contended that it is reasonable to expect that property insurance premiums (assuming similar coverage and deductibles) will rise in the future. The Company also explained that property insurance premiums increase when it places new property into service. The Company referenced several industry reports and assessments that noted recent and forecasted increases for property insurance premiums in the 10–20% range. The Company also noted that its actual spending for property insurance premiums is trending upward, but the Department's recommended test year amount is a decrease from the Company's 2021 expense.

FERC account 925 reflects costs for insurance premiums other than property insurance and includes premiums for policies such as excess liability, executive risk program, and cyber liability insurance. The Company noted that the overall premiums for its 2022 Executive Risk insurance program increased 8%. It also explained that Cyber liability premiums through industrial mutual insurance programs are trending to follow the broader commercial market's 20–30% premium increases in 2022. From 2019–2021, the average annual increase in premiums included in account 925 was 8%. Given the evidence of increasing costs, Minnesota Power contended that the Department's recommendation for a 5% increase of the Company's 2021 costs is arbitrary and insufficient as applied to the test year.

3. LPI

LPI noted that Minnesota Power compensates for vacant employee positions by increasing employee overtime and use of contract labor costs. LPI explained that the Company's forecast does not reflect these tradeoffs and historical data from 2017–2021 does not demonstrate the correlation between contractor labor costs and vacant employee positions. As the Company proposed hiring 64 new employees in 2022, LPI expressed concerns that labor expenses for overtime, contractor labor, and employees may be overstated in the test year.

C. Recommendation of the Administrative Law Judge

Regarding FERC account 923, the ALJ found that the Company considered its system and Company needs as well as known impacts, including consulting industry resources and its own experience in market trends, and the Department's four-year average did not account for these costs. Consequently, the ALJ found that the record supports the Company's forecasted FERC account 923 expenses for outside services employed.

Additionally, the ALJ recounted that Minnesota Power has budgeted for an increase in its property insurance premiums in 2022 compared to 2021, based on its recent history with property insurance premiums and expectations for continued premium increases. The ALJ also noted that the Department's proposed adjustment would result in a lower expense for the 2022 test year than the 2021 actual expense for property insurance. The ALJ ultimately found the Company demonstrated reasonable estimated trends in the insurance market that supported the Company's budgeted level of FERC Account 924 property insurance expense as reasonable for purposes of setting rates.

The ALJ noted insurance premium increases related to FERC account 925 experienced by the Company and supported by market trends. For example, the Company renewed its Executive Risk insurance program on May 1, 2022, with an eight percent overall premium increase. Cyber liability renewal premiums with the Company's industry mutual insurers are starting to trend toward the broader commercial market with 20–30% premium increases as insurers pay out breach claims and social engineering losses. Based on the market trends and the Company's increasing premiums, the ALJ found the Company's forecasted costs reasonable and the Department's recommendation unreasonable.

D. Commission Action

The Commission agrees with the ALJ's recommendations and finds that the internal and external source information and qualitative information produced by the Company supports allowing a recovery of these test year expenses. The market and actual trends demonstrate increasing insurance premium and labor costs sufficient to support Minnesota Power's proposed test year costs related to FERC accounts 923, 924, and 925. The expenses allocated to each of these accounts are reasonable for the purpose of rate setting. While the use of historical average costs may provide a useful method for test year estimates, the Department's proposed methodology is not likely to accurately reflect test year costs. Additionally, applying a five percent increase to the Company's 2021 costs in account 925 is unlikely to sufficiently fund test-year expenses.

XII. Employee Compensation – Base Compensation and Benefits, High-Performance Awards, Defined Contribution Plan, and Health Care Plans Expenses

A. Introduction

Minnesota Power incurs costs to compensate the employees it needs to provide safe, reliable, and cost-effective electric service to its customers. To attract and retain a skilled workforce, the

Company must offer competitive employee compensation and benefits. Minnesota Power proposed the following test year expenses:

- Base Compensation and Benefits: $68,384,774 (total company) and $60,762,402 (Minnesota jurisdiction)
- High-Performance Awards: $350,880 (total company) and $311,972 (Minnesota jurisdiction)
- Defined Contribution Plan: $6,828,196 (total company) and $6,071,037 (Minnesota jurisdiction)
- Health Care Plans: $7,963,772 (total company) and $7,080,648 (Minnesota jurisdiction)

Compared to previous years, these proposed expenses represent increases to employee compensation expenses.

B. Positions of the Parties

1. The Department

The Department compared Minnesota Power's actual annual employee compensation expenses to the amounts approved in the 2017 test year and concluded that the Company had over-recovered in every category each year from 2017 through 2021, totaling $86,275,342. As Minnesota Power has overestimated its employee headcount over the past five years, the Department argued that this trend would continue in the test year rendering the Company's employee compensation expenses excessive and unlikely to represent test-year spending. The Department proposed setting the test-year expenses for high performance awards, defined contribution, and healthcare plan categories based on a four-year average of the Company's actual annual spending in each expense category. The Department recommended setting the test-year expense for employee base compensation at the 2021 actual increased by three percent.

2. Minnesota Power

According to Minnesota Power, increases in the four employee compensation expense categories are necessary to address impacts of inflation and are also justified by its increasing employee head count in the test year.

Minnesota Power explained that it set test-year base compensation using salaries from the budgeted employee headcount for 2021 and applied merit increases of 3% for non-bargaining employees and 2.75% for bargaining employees. The test-year expense also included the addition of sixty employees as strategic hires.

High-Performance Awards are performance-based pay that are designed to reward the top-ten percent of non-bargaining unit, non-management employees, who have exhibited exceptional performance that materially contributed to achievement of ALLETE Inc.'s (Minnesota Power's parent company) strategic goals. Minnesota Power contended that this expense is essential for attracting and retaining qualified and talented employees noting that reducing this expense would necessitate increasing base compensation to remain competitive in the hiring market.

The Company explained that its defined contribution plan has features of both an employee stock ownership plan and a 401(k) retirement savings account. Minnesota Power's contribution and contribution match amounts vary depending on when it hired the employee. Additionally, Minnesota Power is continuing to transition from a defined benefit plan to the defined contribution plan, so costs will increase as it hires new employees who are only eligible for the defined contribution plan.

Minnesota Power's healthcare plan is funded by contributions from employees and the Company. The Company calculated the test year amount using information from its benefits consultant to determine the average cost per employee. The test year amount reflects increases to prescription and healthcare costs including increased service availability, reversion to pre-pandemic healthcare habits, deferred care from 2020 and 2021, and increases in mental and behavioral health treatment.

Minnesota Power argued that the four-year average proposed by the Department was unlikely to represent test-year employee compensation expenses because the annual spending levels in previous years do not reflect the circumstances in the test year and noted several key differences between test-year and prior-year spending.

First, the Company explained that the 2017 test year overstated its employee headcount in subsequent years because the outcome of its previous rate case required the Company to implement cost-saving measures that included reducing its workforce. Minnesota Power noted that these reductions created untenable staffing levels and led the Company to increase its headcount in the test year to levels that are more sustainable.

Second, the COVID-19 pandemic exacerbated the impacts of the Company's workforce reductions in 2020 and generally disrupted employment markets. The unique circumstances present in 2020 are unlikely to significantly impact the test year. Third, the record demonstrated that inflationary impacts in the test year are likely to increase costs more significantly than in previous years.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge noted that the Department's use of a four-year average did not consider the Company's headcount needs, the downsizing the Company undertook during the averaging period, the unforeseen global pandemic, rising medical expenses for the healthcare plan, and the changing plan design for defined contribution. To keep up with rising expenses and remain market competitive, the ALJ found that the record supported the Company's proposed level of base compensation, high performance awards, defined contribution plan, and healthcare plan as reasonable for setting rates.

D. Commission Action

The Commission agrees with the recommendations of the ALJ and finds that the Company's proposed employee compensation expenses for base compensation, high-performance awards, defined contribution plan, and healthcare plan are reasonable for the test year.

As explained in the employee count discussion, the Commission finds that the record shows that it is likely Minnesota Power will be able to achieve its test-year hiring goals, which will increase employee-related costs, including employee compensation. The Department's recommendation is unreasonable as applied here because it would likely underestimate employee compensation costs in the test year. To attract and retain skilled employees, the Company must offer competitive compensation, consistent with the Company's proposed test-year employee compensation expense.

XIII. Employee Expenses

A. Introduction

The recovery of employee expenses falls under Minnesota Statutes section 216B.16, subdivision 17 (Employee Expense Statute). Employee expenses are those expenditures incurred by employees in the course of their employment and in support of the Company's business, such as travel, meals, lodging, and similar expenses. Minnesota Power uses a software called Oracle Payables to process all invoices, employee expense reimbursements, and company credit card reconciliations.

Minnesota Power requested recovery of $4,739,674 for test year employee expenses.

B. Positions of the Parties

1. Minnesota Power

Minnesota Power noted that it employs a zero-based budgeting philosophy for O&M expenses that are not labor related. This approach requires building the budget from a baseline, while reviewing historical amounts and activities as well as expected operational changes in the business to inform the budgeting process. The Company developed its 2022 budget using assumptions that the meeting and travel restrictions imposed in 2020 and 2021 due to the COVID-19 pandemic would be lifted.

Minnesota Power explained that it tracks employee expenses in its expense reporting system that includes expenditures for airfare, hotel stays, car rentals, parking, meals for business purposes, and recognition of its employee efforts to provide safe and reliable services to customers. According to the Company, it only included in the test year employee expenses that are necessary for the provision of utility service, which it often incurs when employees are working in the field or at remote locations, meeting with customers or other stakeholders, or attending conferences or trainings that support their work. The Company also claimed expenses related to its board of directors that include costs of a meeting at a resort in Wisconsin, which it explained gives board members the opportunity to meet in person to discuss business without the interference of outside distractions.[18]

The Company noted that employee expense adjustments for the test year are typically based on a review of those expenses in the most-recently completed fiscal year, which for its 2022 test year is 2020. Minnesota Power contended that its spending for 2020 decreased significantly because of the COVID-19 pandemic and does not accurately reflect its expected future spending on employee expenses. The Company explained that limiting its recovery based on 2020 spending

[18] Minnesota Power agreed to remove $1,500 of costs it initially claimed that are related to an executive that was not affiliated with the Company.

would effectively penalize it for taking thoughtful action to minimize risks and protect the health and welfare of employees and the communities they serve. Rather than using anomalous and unrepresentative 2020 data, it proposed calculating adjustments based on 2018 actual employee expenses.

Minnesota Power also emphasized that the Employment Reporting Statute only requires it to file itemized detail of actual expenses for 2020, the most recent fiscal year, but it does not require utilizing that data as the basis for its test year.

2. OAG

OAG proposed a significant reduction to employee expenses in the test year by basing it on 2020 spending levels and removing specific expenses that it contended are inappropriate to recover from ratepayers.

OAG asserted that it is appropriate to use 2020 data because the COVID-19 pandemic has permanently altered employees' work habits, and it argued that these changes should be reflected in rates. The OAG argued that the Company inadequately explained how it developed its 2022 budget and that Minnesota Power should only be able to recover costs that are essential for the provision of utility service. OAG argued that the Commission should exclude the Company's costs for a retreat for the board of directors, gift cards, certain clothing, a cell phone case, and various subscriptions to news media.

Overall, OAG recommended reducing the Company's proposed budget request by approximately $2,469,964.

C. Recommendation of the Administrative Law Judge

The ALJ found that the Company complied with its statutory obligation to file the most recently completed fiscal year by filing the 2020 data, but OAG's proposal to use 2020 as the basis for the 2022 test-year budget would result in an employee expense budget that is far too low to be reasonable, which is unreliable for setting future rates. The ALJ noted that the pandemic-related impacts in 2020 made that year unique and markedly different from the past, present, and future in terms of business and travel activity, so OAG's assertion that 2020 practices will continue in perpetuity is unreasonable.

The ALJ concluded that Minnesota Power demonstrated that the employee expense budget was reasonable, but he excluded claimed expenses for years-of-service awards. The ALJ found all other costs were necessary for the provision of utility service.

D. Commission Action

The Commission finds that Minnesota Power's proposed 2022 budget is generally reasonable and seeks recovery of costs that are necessary for the provision of utility service. The Company explained the process it used to create the 2022 test year budget. Its proposed adjustments, which are derived from 2018 data, reasonably account for unrecoverable expenses so that the adjusted test-year budget is likely to reflect accurate future spending levels. OAG's recommendation to base test year employee expenses on 2020 spending is not reasonable.

The Commission appreciates OAG's efforts to identify costs that may not be necessary, but the Commission generally finds that these expenses are reasonable and necessary for the provision of utility service. The board of directors provides essential Company oversight, and Minnesota Power justified its off-site meeting as allowing the board members to effectively conduct business and serve the Company without distractions or interruptions that may occur with virtual or on-site meetings. Similarly, additional expenses noted by OAG including clothing, cell phone case, and subscriptions to news services are reasonably included and necessary for the provision of utility service.

However, the OAG identified two expenses that the Commission agrees are unjustified and will exclude. First, the Company claimed approximately $36,000 for gift cards given to employees as awards for certain periods of service. While this practice may provide some degree of benefit in attracting and retaining employees, the Commission finds Minnesota Power did not satisfy its burden to show that these expenses are reasonable and necessary for the provision of utility service. This type of bonus is distinguishable from bonuses that employees receive for accomplishing goals or achieving benchmarks that specifically increase productivity or safety, which are more likely to provide benefit to customers. Minnesota Power failed to show how service-time-recognition awards encourage or promote similar results. Second, Minnesota Power agreed to remove the $1,500 expense incurred by a non-Minnesota Power executive, and the Commission agrees to exclude that cost.

For these reasons, the Commission agrees with the ALJ's recommendation to authorize recovery of the Company's proposed test-year employee expenses except for costs of employee-service awards and the $1,500 unrelated executive expense.

XIV. Economic Development Expenses

A. Introduction

Minnesota Power's economic development team provides outreach to communities and private entities in its service territory in attempts to promote economic development. If successful, these initiatives provide benefits to shareholders, the communities served, and ratepayers, so the Commission has historically allowed utilities to recover half of their economic development expenses. According to Minnesota Power, its efforts are now more focused on enabling a just transition for communities most impacted by the state's decisions to move away from fossil fuel electric energy. Because of the potential benefits to communities and ratepayers, the Company requested recovery of all of its economic development expenses.

B. Positions of the Parties

1. Department

The Department recommended allowing recovery of fifty percent of Minnesota Power's economic development expenses. It noted that its recommendation is consistent with Commission decisions in Minnesota Power's past three rate cases as well as in Otter Tail Power Company's most-recent rate case. The Department recognized Minnesota Power's claim that the Company's efforts have potential to benefit customers but noted that maintaining or increasing customer base is fundamental to a utility's ability to generate revenues and profits that attract and retain investors. The Department contended that a fifty-percent recovery is justified here because it is consistent with prior Commission action and reasonably reflects the distribution of potential benefits from Minnesota Power's economic development expenses.

2. OAG

OAG noted that economic development activities typically focus on attracting and retaining business, creating jobs, and fostering other economic opportunities. OAG contended that this type of economic growth within a utility's service territory tends to increase electric energy usage by residential, commercial, and large industrial customers, which also increases the utility's revenue and profits. Emphasizing the shareholder benefit created by increased economic activity, the OAG argued that the Company should share in the costs of economic development efforts and recommended allowing a fifty percent recovery of these costs.

3. Minnesota Power

Minnesota Power contended that its unique and important efforts to promote economic development to facilitate customer and job growth, especially its efforts supporting a just transition in host communities with declining employment in the Company's coal-fired generating facilities as Minnesota transitions away from fossil fuel generation, justify deviating from the past Commission practice that splits these costs equally between ratepayers and shareholders. The Company explained that the new focus on enabling a just transition for communities expands on its traditional efforts of load growth and customer retention. Because these efforts are likely to create positive impacts for the target communities and ratepayers generally, the Commission should allow recovery of one hundred percent of Minnesota Power's economic development expenses.

C. Recommendation of the Administrative Law Judge

The ALJ found that Minnesota Power's economic development investments have been valuable to the region, will be increasingly important as the clean energy transition continues, and are appropriate for cost recovery in this proceeding. The ALJ determined that the record supports fifty-percent cost recovery of economic development expenses as routinely adopted by the Commission.

The ALJ recognized the merits of the Company's argument that its unique efforts help the northern Minnesota region, which could warrant distinguishing past Commission cost-recovery decisions that have only permitted recovery of fifty percent of economic development expenses. He noted the proposed development work aims to bring customers who are not legacy industries into the Company's portfolio, which is a policy warranting reasonable recovery for the Company because of the likely positive impact to the community and ratepayers in general; however, the record lacked the evidence for the ALJ to make a true comparison between Minnesota Power's efforts and other utilities' economic development efforts and their impacts. The ALJ noted that the Commission, which has the necessary expertise and perspective, is in the best position to determine whether Minnesota Power's activities warrant a change to its past practice.

D. Commission Action

The Commission recognizes the value to communities and ratepayers that is created by Minnesota Power's Economic Development team and notes the important role it is playing during a time of significant change and transition to clean energy that is uniquely impacting some communities in the Company's service territory. While the record demonstrates that the Company is now focusing efforts on enabling a just transition away from fossil fuels that benefits communities, the potential positive impacts of the Company's efforts will also benefit its shareholders. The Commission notes the rationale outlined in prior decisions addressing recovery of these costs, and it does not find that the current record justifies deviating from its previous practice of allowing half of these expenses to be recovered from ratepayers. While Minnesota Power's efforts on this front create important and beneficial impacts for communities, the value created also benefits the Company's shareholders.

The Commission agrees with the ALJ and finds it is not warranted for ratepayers to pay for the full cost of expenditures that will likely benefit Company shareholders, so it will allow Minnesota Power to recover fifty percent of its economic development costs.

XV. UI Planner

A. Introduction

A class cost-of-service study (CCOSS) is used to accurately identify the responsibility of each customer class for each cost incurred by a utility in providing service. In Minnesota Power's 2016 rate case, in response to concerns raised about the accuracy and transparency of the Company's CCOSS, the Commission ordered the Company to consult with other interested parties and either improve the transparency of its existing Excel-based CCOSS model or adopt a new CCOSS model. In 2019, Minnesota Power decided to acquire and implement UIPlanner software for CCOSS modeling. The Company has requested recovery for $1.9 million spent on UIPlanner.

B. Positions of the Parties

1. CUB

CUB argued that Minnesota Power's procurement of UIPlanner was unreasonable and imprudent because the Company failed to conduct a formal business case to analyze costs and benefits, failed to adequately evaluate alternatives, and failed to adequately explain increases to UIPlanner cost estimates.

CUB explained that a business case is a form of analysis used by utilities to evaluate expenditures and investments. CUB contended that Minnesota Power's failure to implement a business case (or a similar documented process) creates a gap in the evidentiary record that makes it difficult to assess whether and how the Company examined the functionalities it was purchasing to ensure UIPlanner would produce sufficient benefits to make the software worth its cost. CUB argued that the lack of evidence relating to Minnesota Power's decision to acquire UIPlanner warrants determining that the Company failed to show the UIPlanner purchase was reasonable and necessary and denying recovery of the $1.9 million expense.

Similarly, CUB argued that Minnesota Power failed to produce evidence that it adequately considered any other options that could meet its CCOSS needs. CUB contended that it appears Minnesota Power did not comply with its own purchasing manual, which requires that all business units obtain competitive quotations on all purchases of materials and services exceeding $10,000. CUB noted that Minnesota Power did not issue an RFP for CCOSS modeling services and contacted only one potential CCOSS vendor, UI Solutions Group, who ultimately provided the UIPlanner software purchased by the Company. CUB noted that at least several other providers create CCOSS models, and Minnesota Power should have compared the costs and benefits they could provide before moving forward with its UIPlanner acquisition.

CUB also raised issues with the Company's cost estimates and contested the characterization that the ultimate $1.9 million reflected an under-budget outcome. CUB referenced the Company's November 5, 2018 estimate of approximately $600,000 to purchase, maintain in year one, and implement UIPlanner and noted that just ten days later, the Company estimated the same purchase, maintenance, and implementation costs to be $1.05 million. The final cost rose to $1.9 million, which the Company claims is lower than its $2.4 million budget, but CUB questioned when and how the Company arrived on a $2.4 million budget. CUB contended that such drastic cost increases, with some occurring over such short duration, further demonstrate an unreasonable procurement process lacking the prudence necessary to justify incurring UIPlanner's $1.9 million expense.

2. Minnesota Power

Minnesota Power outlined the process it used to decide on and ultimately implement UIPlanner to improve its CCOSS model as directed by the Commission.

The Company explained that it commissioned a cross-functional internal team to evaluate potential methods to improve the functionality and transparency of the CCOSS model that included analyzing the costs and benefits of different methods. The team evaluated continued use of the Excel-based system, development of a new CCOSS modeling system in house, and acquisition of a new CCOSS modeling system from an outside vendor, and it ultimately concluded that the superior option was to acquire a new CCOSS software modeling system. This team also determined that UIPlanner was the only software modeling option available at that time designed to develop a CCOSS model and also asserted that it was the best option for improving the efficiency, accuracy, and transparency issues of its previous Excel-based model.

While Minnesota Power had already determined that UIPlanner was the only then-available software that would meet its needs, the Company explained that it conducted additional due diligence, which included consulting with other utilities that use UIPlanner for CCOSS to determine if those utilities were satisfied with the product. Minnesota Power determined that UIPlanner was a best practice for CCOSS models in the electric utility industry and highly valued by other companies. The Company further vetted UIPlanner during a four-day workshop with UI Solutions Group to review the specific functionality of the software and confirm that UIPlanner would satisfy the Company's criteria for its new CCOSS model. After the workshop, Minnesota Power's internal team again assessed whether UIPlanner was necessary to achieve the desired functionality or if the Company could develop an alternative internal solution using existing software.

Minnesota Power argued that its procurement planning demonstrates a sufficiently thorough process and record justifying its decision to purchase and implement UIPlanner.

The Company explained its internal requirement for multiple bidders is contingent on the existence of more than one supplier and that it did not contact any other CCOSS software vendors or issue an RFP because it could not find any other comparable CCOSS vendors. The Company also noted that it decided not to pursue in-house solutions to its CCOSS model because those options required completion of complex, unfamiliar tasks for which it lacked expertise. It decided that in-house development involved more risk and uncertainty related to costs and timing, and the Company had a relatively short timeline as the new CCOSS model needed to be available to support the development of the 2019 rate case filing.

C. Recommendation of the Administrative Law Judge

The ALJ noted that the need to replace the Company's prior Excel-based CCOSS model, which had been in use since 1996, was discussed at some length in the Company's 2016 Rate Case and not challenged. He also noted that the Commission directed the Company to update its CCOSS in some manner. The ALJ determined that Minnesota Power conducted extensive due diligence and evaluated several alternatives prior to selecting the UIPlanner software, and after selecting the UIPlanner software, Minnesota Power took steps to minimize the costs associated with implementing the new software such that the final costs for this project came in under the original budgeted amount. Finding support for the prudent and reasonable procurement of UIPlanner to meet the Company's CCOSS needs, the ALJ recommended allowing Minnesota Power to recover UIPlanner costs of $1.9 million.

D. Commission Action

The Commission finds that Minnesota Power failed to demonstrate that it adequately considered alternative CCOSS modeling solutions that had the potential to be more cost effective than UIPlanner. The record lacks essential information that would allow the Commission to assess and verify certain Company decisions during its procurement process. Without a sufficient record of the variables considered by the Company, the Commission is unable to authorize recovery of the entire $1.9 million expense because it cannot confirm that the Company's procurement process was entirely reasonable. In balancing the Company's actions during the entire procurement process, the Commission concludes that Minnesota Power has demonstrated that it should be allowed to recover half of the $1.9 million UIPlanner expense.

The Company provided no evidence on how it estimated projected costs of contemplated solutions to enable meaningful comparisons or even if such cost projections exist. Additionally, the Company failed to specifically note the functionality it required in a CCOSS modeling system, so its assertion that UIPlanner was the only viable third-party option that could meet its needs is conclusory. CUB noted that other providers are available to create CCOSS models, and Minnesota Power failed to present any cost or capability comparisons that evaluate the pros and cons, including price, of the options it considered.

The Commission finds this especially problematic as it concerns the different iterations of the UIPlanner budget. Initially, the expected cost was approximately $600,000 to purchase, maintain in year one, and implement UIPlanner. Just ten days later, the Company received updated information from the vendor and the Company estimated the same purchase, maintenance, and implementation costs to be $1.05 million. According to the Company, the final $1.9 million cost was under the $2.4 million budgeted for UIPlanner's acquisition and implementation, but the Company failed to explain when it set the $2.4 million budget or how it determined that it was a reasonable cost to incur to generate a CCOSS model with the functionality it required. The record's lack of meaningful comparisons of cost or functionality between potential CCOSS modeling options leads the Commission to question whether Minnesota Power prudently incurred this $1.9 million expense. It is unclear if the Company's decision makers rejected alternative solutions once they reached an estimated cost of $350,000, $700,000, $1.5 million, or some other number. Similarly, the Commission is unable to determine the functionality lacked by other potential solutions that caused the Company to reject them.

Nevertheless, Minnesota Power's actions demonstrate that it understood that UIPlanner's implementation would comply with the Commission's directive to improve its CCOSS modeling system. Although the record lacks important details about the initial stages of the planning process, the Company's acquisition and implementation of UIPlanner was far from haphazard. The process occurred over a period of months in consultation with various stakeholders including Commission staff, the Department, OAG, and LPI. During these conversations, Minnesota Power received suggestions for what features it should incorporate in its updated CCOSS model. Importantly, none of the participating stakeholders expressed concern about Minnesota Power's procurement process, recovery of expenses, or implementation of the UIPlanner system.

The Company also asked other utilities about their own CCOSS modeling systems. The utilities that replied utilized either an Excel-based model or UIPlanner, and those using UIPlanner reported higher satisfaction. Minnesota Power followed up with UIPlanner users to gather information about their experiences with and opinions of the software, and recommendations for the Company, which helped inform the purchase decision.

The Company made a good-faith effort to comply with the terms of the Commission's order to improve aspects of its CCOSS. The record shows that UIPlanner represents a significant upgrade to the previous modeling system, and Minnesota Power made its purchasing decision informed by recommendations from multiple stakeholders, other utilities, and a diverse internal team assigned to investigate potential options. The record is unclear the extent to which any of these recommendations considered the cost of the new modeling system or compared those costs to other alternatives.

Once the Company decided to acquire UIPlanner, it attempted to reduce the costs of implementation by tailoring the functionality to its specific needs, using in-house labor when possible, and developing a statement of work with the vendor to manage costs and timelines.

The Commission is not concluding that UIPlanner's $1.9 million cost or even the $2.4 million budget is excessive or that the UIPlanner was not the best cost and functionality option to achieve the Company's goals. Rather, the Commission finds that Minnesota Power did not produce sufficient evidence for the Commission to conclude that UIPlanner's $1.9 million cost was reasonable and necessarily incurred to allow recovery of its entire cost from ratepayers. The conclusory nature of Minnesota Power's decision to purchase UIPlanner and the lack of specific evaluative criteria used to inform the decision leaves a void of important details that would assist the Commission in substantiating the Company's claims and authorizing full recovery of its costs. For these reasons, the Commission respectfully declines to adopt the recommendation of the Administrative Law Judge.

RATE OF RETURN

XVI. Capital Structure

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. The Company's actual capital structure is therefore 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.

The ratio of long-term equity is one measure of a company's profitability. It reflects the return shareholders earn on their investments. It also reflects risk; the higher the percentage of equity financing, the lower the Company's debt, and consequently, overall risk.

A. Positions of the Parties

1. Minnesota Power

Minnesota Power proposed a long-term equity ratio of 53.81% and a long-term debt ratio of 46.19%; the Company does not use short-term debt financing.

The Company made its proposal based on two primary factors. First, its proposed capital structure is equal to the Company's existing capital structure. Second, the Company stated that a higher equity ratio ensures a higher cash flow, which increases the Company's leverage to fund capital expenditure plans necessary to reduce greenhouse gas emissions and improve safety and reliability. In turn, increasing the cost of debt increases the risk to investors because more of the Company's cash flow is used to meet its debt obligations. According to the Company, its proposed equity ratio best balances the Company's risk with its need for equity financing.

Based on the Company's data, the table below shows the range of equity ratios for vertically integrated electric utilities at the national level between 2016 and 2021.[19]

[19] Vertically integrated electric utilities are distribution companies that also own generation and transmission facilities.

Table 1 Equity Ratios of Vertically Integrated Electric Utilities				
Year	**Mean**	**Median**	**Minimum**	**Maximum**
2016	50.04%	50.00%	40.25%	57.16%
2017	50.99%	50.03%	48.00%	58.18%
2018	51.38%	52.00%	41.68%	57.10%
2019	52.33%	52.00%	49.38%	57.02%
2020	52.13%	52.50%	46.00%	56.83%
2021	51.16%	51.96%	43.25%	55.00%

As a federally recognized credit ratings agency firm, S&P Global Ratings (S&P) evaluates the financial stability of firms and governments, rating them on a scale of AAA to D. The Company stated that to maintain a BBB credit rating, Standard & Poor's (S&P) requires a company's funds-from-operations (FFO) to exceed 17 % of its debt and expects a ratio that is between 18 and 20%.[20]

According to the Company's analysis, its combination of a 53.81% equity ratio and a return on equity of 10.25% would result in an FFO to total debt ratio of 20.10%, well within the parameters expected for maintaining a credit rating of BBB.

2. The Department

The Department recommended that the Commission approve the Company's proposed capital structure but did so with the caveat that a higher equity ratio justifies a lower return on equity because it reduces the Company's cost of equity, an issue discussed separately below.

The Department did not otherwise dispute the Company's request to maintain its existing capital structure but stated that the proposal is significantly above the group average for comparable utilities.

3. LPI

LPI contended that the Company's proposed equity ratio of 53.81% is excessive based on a comparison of the book value of common equity for its proxy group companies and authorized equity ratios for electric utilities. According to LPI, the average equity ratio of electric utilities since 2016 is approximately 50.60%. LPI recommended an equity ratio of 52.00%.

LPI's initial analysis included calculations for the Company's Minnesota jurisdictional costs. But after LPI updated its analysis to include company-wide data, the results corroborate the Company's FFO results, reflecting the parties' cost-of-equity recommendations. Under LPI's and the Company's analyses, the Company's capital structure proposal results in an FFO of 20.1%; under LPI's proposal, the FFO is 18.3%; and under the Department's proposal, the FFO is 19.1%.

[20] The FFO is used by credit ratings agencies to assess whether a company can pay off its debt using net operating income.

LPI emphasized that its recommended equity ratio is sufficient to protect the Company's financial integrity while avoiding excessive rate impacts on the Company's ratepayers.

B. Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with the Company that its proposed equity ratio is reasonable and supported by the record. He stated that the proposal is consistent with past equity ratio determinations made by the Commission and with the actual equity ratio maintained by the parent company, ALLETE. In addition, it is within the range established by the mean and high equity ratios for the operating companies owned by the proxy group companies. And, he stated that considering the Company's overall risk profile, setting the equity ratio somewhat above the mean of the proxy group and within this range is reasonable and appropriate.

C. Commission Action

The Commission recognizes the importance of the FFO to total debt ratio in this case and its potential impacts on credit standing. The Commission is not persuaded, however, that the Company has a demonstrated need for an equity ratio of 53.81%. Although this percentage reflects the current equity ratio, the Company bears the burden to demonstrate the reasonableness of its proposal. In its last general rate case, the Company stated that an equity ratio of 53.81% would be central to maintaining a BBB+ credit rating, a position that, in large part, informed the basis of the Commission's decision authorizing the existing capital structure. Since that time, however, the credit rating was downgraded to BBB. And while the Commission understands that there are potential ratepayer impacts on both sides of the debt/equity equation, the Company has not demonstrated how its proposed equity ratio is necessary to maintain the current credit rating while protecting ratepayers from unreasonable rates and providing necessary financing for capital projects.

For all these reasons, the Commission respectfully declines to adopt the recommendation of the Administrative Law Judge and will instead approve an equity ratio of 52.50%, which is above the average equity ratio for vertically integrated electric companies every year between 2016 and 2021 and is at or above the median equity ratio for these same years. Absent persuasive record support or other compelling reason to set the equity ratio at the Company's higher, proposed level, the Commission declines to do so on the basis of the information in the record. This ratio, and the Commission's decision on the cost of equity as discussed separately below, protects the financial integrity of the Company while also protecting ratepayers from unreasonable costs.

The Commission's adjustment to the cost of equity corresponds to an upward shift in the debt ratio to 47.50%, as shown in the table below.

Table 2	
Capital Structure	
Long-Term Debt	47.50%
Common Equity	52.50%

XVII. Rate of Return on 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*.[21]

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 has no publicly traded common stock. Its cost of common equity—essential to determining overall rate of return and the final revenue requirement—must therefore be inferred from market data for companies that present similar investment risks (referred to as a proxy group). Using a proxy group also moderates the effects of one-time events on a given company's stock.

B. Analytical Tools

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

They also used the Capital Asset Pricing Model (CAPM) as a secondary, corroborating resource, consistent with the Commission's historical treatment of this model. Minnesota Power and LPI both conducted a third analysis using the Bond Yield Plus Risk Premium Model, which the Commission has historically relied on less heavily, considering the model is 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," 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

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

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.

The Empirical CAPM model addresses the tendency of the CAPM to underestimate the cost of equity for companies with lower beta coefficients (in effect, lower return potential) such as regulated utilities. It recognizes the results of academic research showing that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.

The Bond Yield Plus Risk Premium (or 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.

The variations in the parties' return-on-equity recommendations are primarily the result of two factors—proxy groups and long-term (perpetual) growth rates used in the DCF analyses.

C. Proxy Groups

One of the key differences between the parties' modeling results and return-on-equity recommendations stems from the screening criteria they used to establish their proxy groups for ascertaining the Company's risk level and corresponding ability to attract capital from investors.

After applying screening criteria to a list of companies, Minnesota Power compiled a proxy group that included 15 companies with profiles similar to its own. The Department conducted a similar analysis. Ultimately, the Department's and Company's proxy groups were similar, but there were two meaningful differences: the Department's inclusion of Hawaiian Electric, which the Company excluded; and the Department's inclusion of Pinnacle West Capital Corporation (Pinnacle West), which the Company initially included but subsequently removed from its proxy group.[22]

Hawaiian Electric was included in the Department's proxy group because it has a credit rating between A- and BBB. But Hawaiian Electric was excluded from Minnesota Power's proxy group because it did not meet Minnesota Power's fuel-mix screen of at least 5% coal generation (Hawaiian Electric does not generate any electricity using coal). According to the Department, its screen accounts for Hawaiian Electric's unique geographic risks due to its island location as well risks associated with its percentage (33%) of operating income from unregulated operations (concentrated in the banking sector). The Company maintained, however, that Hawaiian Electric is too dissimilar to be included in its proxy group.

Although Minnesota Power initially included Pinnacle West in its proxy group, Minnesota Power removed it after the Arizona Corporation Commission authorized a return of 8.70% for Pinnacle West, a decision that resulted in a credit rating downgrade of debt, and consequently, a fall in share price. Minnesota Power stated that the decision amounted to a transformative

[22] Initially, the Department had excluded American Electric Power, which Minnesota Power had included; the Department subsequently included American Electric Power in its proxy group but stated that including the company made little difference in its DCF analysis results.

transaction having a significant effect on share prices, an event that, under Minnesota Power's screening criteria, justifies removing the company from its proxy group.

The Department disagreed with that rationale, stating that Pinnacle West's return of 8.70% did not amount to a transformative event warranting removal from the proxy group, but rather, it reflects the Company's cost of equity as determined by the Arizona Commission. In continuing to include Pinnacle West in its proxy group, the Department stated that the DCF analyses correct for the reduction in stock prices by replacing the growth rate. And, the Department noted that Minnesota Power's screen to exclude any company from the proxy group with a return under 7.00% would have otherwise accounted for a change in circumstances warranting removal.

LPI used the same proxy group as Minnesota Power in its analyses but did not remove Pinnacle West.

D. Growth Rate Estimates

The Company utilized long-term earnings growth rate estimates from several sources in its constant growth DCF analysis, including: Zacks Investment Research; Thomson First Call (provided by Yahoo! Finance); and Value Line Investment Survey. The Company then developed a two-stage DCF analysis that applied a statistical approach to address sustainable growth rates, as well as moderate growth rates to account for less sustainable growth over the long-term. The Company stated that the purpose of the two-growth DCF model is to account for (remove the effect of) growth rates that may not be sustainable over the long-term by using a second growth stage, or longer-term growth rate, analysis. As a result, it is not necessary to remove a company perceived by analysts as having an unsustainable growth rate because doing so would alter the results of the analysis by affecting the calculation of the average and standard deviation for the proxy group.

The Department conducted three DCF analyses—a constant-growth-stage analysis; a two-stage growth analysis; and a multi-stage growth analysis with three stages. One of the distinguishing differences in the Department's approach compared to the Company's is its use of Gross Domestic Product (GDP) to estimate long-term growth in its multi-stage DCF analysis. The Department explained that GDP is a more reliable predictor of the long-term cost of equity compared to earnings estimates. For this reason, the Department relied on the results of its multi-stage DCF analysis in recommending an ROE.

The Department's multi-stage DCF analysis incorporates three stages of growth, the first of which includes five years of growth informed by earnings estimates, a second five-year stage of growth informed by earnings estimates with a transition into GDP, and a third stage of growth that relies solely on GDP data from the Energy Information Administration, the Social Security Administration, and the Congressional Budget Office to estimate long-term growth.

LPI used earnings growth rate estimates for near-term growth and used GDP to estimate long-term growth rates in its analyses.

E. Positions of the Parties

1. Minnesota Power

Minnesota Power conducted two DCF analyses, as discussed above, as well as a CAPM, an Empirical CAPM, and a bond yield plus risk premium analysis. Based on the results of its five analyses, Minnesota Power proposed a return on equity of 10.25%.

The Company's proposed return considers current capital market conditions; the Company's customer concentration; the regulatory environment in which the Company operates; the Company's adjustment mechanisms; and the Company's rate design. In particular, the Company stated that its earnings volatility risk due to its large industrial customer concentration along with a period of market underperformance by utilities justifies placing greater weight on the mean high results of the constant growth and two-growth DCF analyses.

The following table shows the results of the Company's analyses, including updated market data as of March 21, 2022.

Table 3			
Results of Minnesota Power's Analyses			
Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.72%	9.48%	10.43%
90-Day Average	8.75%	9.52%	10.47%
180-Day Average	8.81%	9.56%	10.51%
Two Growth DCF			
30-Day Average	8.48%	9.43%	10.35%
90-Day Average	8.52%	9.47%	10.39%
180-Day Average	8.46%	9.51%	10.43%
Capital Asset Pricing Model			
	Current Risk-Free Rate	Q3 2022 – Q3 2023 Projected Risk-Free Rate	2023-2027 Projected Risk-Free Rate
Value Line Beta	11.38%	11.47%	11.51%
Bloomberg Beta	10.53%	10.69%	10.74%
Long-Term Avg. Beta	9.88%	10.08%	10.16%
Empirical Capital Asset Pricing Model			
Value Line Beta	11.70%	11.77%	11.80%
Bloomberg Beta	11.07%	11.18%	11.23%
Long-Term Avg. Beta	10.58%	10.73%	10.79%
Bond Yield Plus Risk Premium			
	Current Risk-Free Rate	Q3 2022 – Q3 2023 Projected Risk-Free Rate	2023-2027 Projected Risk-Free Rate
Risk Premium Results	9.68%	10.00%	10.13%

While the Company stated that the national average authorized return on equity for a vertically integrated electric utility company since January 2018 is 9.66%, the Company also stated that inflation, which is the result of higher interest rates, increases the cost of equity to a level in the range recommended by the ALJ (9.80%) and the Company (10.25%). The Company reiterated the importance of accessing capital in a timely manner with favorable terms and stated that its proposed return recognizes its achievements in exceeding conservation goals and in leading Minnesota in the percentage of renewable generation.

In response to the Department's recommended return of 9.30%, Minnesota Power contended that the model relied upon by the Department does not effectively quantify the cost of equity and that the model's results are below the return authorized for any vertically integrated utility company since 2009. Although the Department recommended a return higher than the modeling results, the Company stated that the Department's recommended return would significantly disadvantage the Company financially.

2. The Department

The Department relied on the results of its multi-stage growth DCF analysis in support of its recommended return of 9.30%. The results show that excluding Hawaiian Electric increased the mean by only two basis points from 7.69% to 7.71%. The Department focused its analysis on the premise that the cost of equity is a starting point but that a final decision should be informed by additional factors, including decisions in other jurisdictions, recent trends in capital markets, and regulatory norms that place greater weight on earnings estimates, rather than GDP growth estimates. This approach, the Department stated, balances the need for a return that enables the Company to attract capital while ensuring that ratepayers are protected from unreasonable and excessive rates.

Separately, the Department's *two-growth* DCF analysis, updated to exclude Hawaiian Electric, shows the following results:

Table 4
The Department's Two-Growth DCF Results including Flotation Costs[23]

	Low	Mean	High
As Filed	8.46%	9.09%	9.78%
Updated to exclude Hawaiian Electric	8.66%	9.21%	9.65%

In response to the Company's position that the average return for vertically integrated utilities is 9.66% since 2018, the Department noted that for rate cases decided in 2021, the average return for such utilities was 9.41% and contended that the Company should have given the earlier decisions less weight when calculating the average. The Department also stated that its recommended return of 9.30% factored into account the Company's request for an equity ratio of 53.81%, which the Department separately supported. The Department stated that with a higher equity ratio, the Company was in a position of lower risk and therefore did not require a return on equity greater than 9.30%.

[23] Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs. None of the parties opposed authorizing Minnesota Power to recover flotation costs.

3. LPI

Similar to the Department, LPI used a multi-stage DCF model reflecting three growth periods: a short-term growth period consisting of the first five years; a transition period, consisting of the next five years (6 through 10); and a long-term growth period starting in year 11 and extending into perpetuity. The results of this analysis, along with the two-stage DCF model results are shown in the table below.

Table 5		
LPI's DCF Analyses Results		
Description	**Average**	**Median**
Constant Growth DCF Model (Analysts' Growth)	9.14%	9.38%
Two-Growth DCF Model	9.16%	9.28%
Constant Growth DCF Model (Sustainable Growth)	8.19%	8.00%
Multi-Stage DCF Model	7.79%	7.83%

Based on the results of its analyses, LPI recommended a return of 9.40%. LPI stated that the results of the Company's updated analysis confirm the reasonableness of this recommendation. Those results, LPI emphasized, show the mean growth rate of the Company's two-stage DCF analysis, based on a thirty-day growth rate, at 9.43% with flotation costs included. LPI also contended that considering the general downward trend in authorized utility returns, the Company's financial integrity would be maintained with a return of 9.40%. According to LPI, the average electric utility return in 2016 through 2021 was between 9.38 and 9.67%; the mean of returns in that time period was between 9.48 and 9.65%.

LPI also disagreed with the Company's contention that inflation increases the cost of equity, stating that utility valuations remain robust. Since the end of the second quarter of 2021, utilities have, in general, significantly outperformed the market as measured by the S&P 500 (a stock market index tracking the stock performance of 500 large companies listed on stock exchanges in the United States), as well as the Nasdaq 100 (a stock market index made up of 101 equity securities issued by 100 of the largest non-financial companies listed on the Nasdaq stock exchange).

F. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended an ROE of 9.80%, finding that the Company's two-stage DCF analysis is a reliable methodology for setting the cost of equity.

In support of his recommendation, he explained that 9.80% is the mid-point between the various two-growth DCF models from March 2022, derived from the mean and mean high results. He also found that this return effectively recognizes and supports the Company's achievements in leading the state in percentage of renewable generation, in exceeding conservation goals, and in the quality of customer service. He stated that a 9.80% return would also support the Company's credit metrics at reasonable levels, thereby enabling the Company to maintain its current credit ratings. He found that it would also enable the Company to attract capital to finance investments at reasonable rates, which would provide long-term benefits to ratepayers by limiting the long-term cost of capital.

G. Commission Action

The Commission concurs with the Administrative Law Judge that the Company's methodology is well supported by the record and provides a well-reasoned basis for setting the cost of equity.

The Department's recommended cost of equity of 9.30% is informed by an underlying assumption that the cost of equity and the return on equity are distinct concepts in the sense that utility earnings exceed the cost of equity over time. This understanding, according to the Department, undermines the reliability of earnings' estimates in predicting long-term growth and instead justifies the use of a multi-stage DCF analysis that uses GDP to forecast the long-term cost of equity.

The Commission does not share this concern. While general statements about GDP and earnings estimates may offer broad perspectives on their overall usefulness, the parties' positions reflect philosophical and methodological differences that are qualitative in nature. But the Department has not demonstrated inaccuracies in Minnesota Power's earnings estimates in this case to justify dismissing them from consideration. The investment community relies heavily on earnings estimates, which are rigorously audited to ensure compliance with accounting principles. And in the case of utilities, earnings estimates reflect industry-specific considerations, include assumptions based on quantitative market data, and have not been shown to produce unreasonable returns.

One shortcoming of the Company's approach, however, is the decision to remove Pinnacle West from its proxy group. As the Department explained, Pinnacle West's drop in stock prices is not the result of a transformative market event. The precipitating event was the Arizona Corporation Commission's decision authorizing a return of 8.70%, a percentage that did not trigger Minnesota Power's screen to exclude companies whose returns are below 7.00%. The two-stage DCF analysis uses two distinct growth rates to account for changes in short-term and long-term growth. After updating the growth rates in its two-stage DCF analysis to account for the market reaction to the Arizona decision, the results show a downward adjustment to the mean of returns, including flotation costs, from 9.43% (without Pinnacle West) to 9.28% (including Pinnacle West).

As stated above, the Company's two-growth DCF analysis, even without accounting for the change in Pinnacle West's share prices, shows the mean of returns at 9.43%. Approval of a lower equity ratio than requested by the Company, however, increases risk and weighs in favor of a return higher than the mean. Yet the Commission is not persuaded that setting the cost of equity at 10.25% is needed to enable the Company to attract capital at reasonable rates, maintain its credit rating and financial integrity, and provide returns commensurate with those earned on other investments with equivalent risks. Although Minnesota Power speculated that a return of 9.56% or lower, for example, would erode the Company's financial health, there is no specific information in the record explaining how such a return would hinder the Company's ability to raise capital.

The Commission also notes that the national average return of vertically integrated utilities since 2018 is 9.66%. And, while the decisions of other jurisdictions are not binding and have limited persuasive value because of the fact-intensive nature of cost-of-equity decision-making, they do provide a check, of sorts, on reasonableness.

For all these reasons, the Commission respectfully declines to adopt the recommendation of the Administrative Law Judge and will instead set the cost of equity, including flotation costs, at 9.65%—twenty-two basis points above the mean of the Company's two-stage DCF analysis, when excluding Pinnacle West, or thirty-seven basis points above the mean when including Pinnacle West.

XVIII. Final Capital Structure and Overall Rate of Return

The final capital structure and overall rate of return resulting from the decisions made herein are set forth below, rounded to the second decimal place.

Table 6
Rate of Return

Type of Capital	Capital Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	47.50%	4.33%	2.05%
Short-Term Debt	0.00%	0.00%	0.00%
Common Equity	52.50%	9.65%	5.07%
Total	100.00%		7.12%

SALES FORECAST

XIX. Sales Forecasts

A. Introduction

Minnesota Power prepared a forecast of retail megawatt-hour (MWh) sales and customer counts for the 2022 test year. The Company forecasted energy use and customer counts for each of its five retail customer classes: Residential, Commercial, Industrial, Public Authorities, and Lighting.

Given its size, the Industrial class is further segmented into four sectors for forecasting purposes: Mining and Metals, Forest Products, Pipelines, and Other Industrial sectors. Minnesota Power's 2022 test-year sales forecast was produced by combining the Company's 2021 Annual Forecast Report's (2021 AFR) econometric approach to modeling Residential, Commercial, and small Industrial sales with a bottom-up, customer-by-customer approach to forecasting the Company's large power customers.

The Company's 2022 test-year retail sales forecast of 8,160,738 MWh is 3.4% higher than 2020 actual retail sales (7,889,945 MWh) and about 5.4% lower than a historical five-year average (2016-2020).

The Company's 2022 test year energy forecast, inclusive of resale energy sales, of 9,579,277 MWh is 3.8% higher than 2020 actual retail and resale sales (9,230,235 MWh) and 5.8% lower than a five-year historical average of actual retail sales (10,167,369 MWh).

Disputed among the parties is the Mining and Metals customer test-year sales forecast; the Residential customer test-year sales forecast; and test year sales to ST Paper and Husky/Cenovus.

B. Mining and Metals Customer Test-Year Sales Forecast

The Company's projections for Mining and Metals customers were developed in cooperation with each customer, taking into account the nuances of the individual customer's operation. Once the individual customer estimates were totaled for each class, the results were checked against the econometrically produced AFR forecast.

1. Positions of the Parties

Minnesota Power argued that changes in the taconite industry justify reducing the assumed output from a single customer in the test year because it may be offset by other outages even if the customer is still operating at full capacity.

The Department opposed the Company's position, stating that its count is unreasonably low. The Department filed an alternative sales forecast that included higher taconite production assumptions for Keetac and Hibtac, while also reducing taconite production levels for the Northshore facility, which idled during the test year. The Department's forecast proposes an increase of $13,471,693, down from the initial $25 million increase based on a taconite production forecast of 37.9 million tons.

The Department stated that Minnesota Power had attempted to tether taconite production to the share of blast furnaces in steel production, an approach that is not borne out by the data. The Department stated that while the steel industry is changing, the changes do not appear to be impacting taconite production or Minnesota Power's sales to the extent the Company has claimed. The industry changes do not therefore support Minnesota Power's low sales-forecast for its Mining and Metals customers in the test year.

The Department stated that its recommended number is consistent with average taconite production for 10-, 15-, and 20-year periods, whereas Minnesota Power's forecasted taconite production levels are significantly lower than either a three- or five-year average. The Department's forecast also excluded years that were not representative of the conditions occurring in the test year.

2. Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with the Department that the Company's sales forecast is unsupported by the record and recommended that the Commission adopt the Department's proposed sales forecast.

He stated that the Commission had rejected a similar argument from Minnesota Power in its last rate case, stating that the Commission found it unreasonable to reduce a known test year revenue amount for specific customers as a proxy for a proposed load-factor adjustment for an entire industry. He found that the Company had not demonstrated with new evidence or information that Keetac would be idled at any point during the test year, and that it was unreasonable to reduce Keetac's production as a proxy for speculative reduced production in the entire industry.

3. Commission Action

The Commission concurs with the Administrative Law Judge that the Department's sales forecast is a more accurate representation of the Mining and Metals customer class and that the Company has not provided information that persuasively demonstrates otherwise. Although the Company challenged the Department's forecast as overstating revenues, the Company has not developed a more reasonable forecast. The Commission will therefore adopt the Department's Mining and Metals Customer test-year sales forecast.

C. Residential Customer Test-Year Sales Forecast

The Company forecasted residential sales of 1,037,401 MWh for an average of 8.38 MWh per residential customer. The Company's residential sales forecast is lower than actual residential sales since 2017 and lower than the Company's forecasted residential sales in the 2020 rate case. It is also lower than actual recorded sales between 2017 and 2021.

1. Positions of the Parties

LPI recommended that the Commission reject the Company's proposed Residential customer test-year sales forecast and adjust the forecast to account for additional revenue of approximately $4.3 million, which reduces the Company's projected revenue deficiency. LPI's proposal relies on the normalized 10-year average residential use per customer, a range that captures both abnormally high- and low-usage periods. Applying a 10-year, weather-normalized average results in a forecasted test year value of 8.61 MWh per residential customer.

The Company countered LPI's proposal, stating that LPI's proposal, based on a 10-year average, does not account for the cumulative impact that energy efficiency measures have had on residential customer energy usage. The Company stated that the success of energy efficiency measures has had a profound impact on residential energy usage and has resulted in declining "use-per-customer" and in residential sales since 2009. The impact of energy efficiency measures is also cumulative as the incremental success of each year's energy efficiency achievements leads to greater energy savings, and, in turn, reduced residential usage over time.

2. Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with LPI that the Company had not demonstrated the reasonableness of its proposal, which contained flaws in weather normalization. He also found that the COVID-19 pandemic had increased residential sales. He therefore recommended that the Commission adopt LPI's proposal.

3. Commission Action

The Commission respectfully disagrees with the Administrative Law Judge that the Company did not demonstrate the reasonableness of its Residential customer sales forecast. As the Company stated, its regression model includes data from 1990-2020, a longer time period than the 10 years used by LPI. Further, the Commission concurs that LPI's averaging method does not take into account the impact of energy efficiency on residential sales.

The Company's forecast is based on a sound methodology with weather normalized data, though the Company acknowledged a limitation in the modeling, namely that long-term models cannot fully normalize for extreme and short-term weather events like the polar vortex in the winter of 2013-2014. The Commission is not persuaded that the proposal put forth by LPI more accurately forecasts sales and therefore declines to adopt this approach. The Commission will instead adopt the Company's Residential customer test-year sales forecast.

D. Test Year Sales to ST Paper and Husky/Cenovus

The Company's test-year sales forecast excluded sales from either ST Paper or the Husky/Cenovus refinery.

The Husky/Cenovus refinery is an oil refinery near Duluth that produces products such as asphalt, gasoline, diesel, and fuel oils. There was an explosion at the refinery in April 2018 that caused a reduction of resale sales through Minnesota Power's contract with Superior Water Light & Power, although the refinery is scheduled to restart in 2023.

Verso Corporation operated a paper mill in Duluth until June 2020 but permanently closed the mill in January 2021. The mill was subsequently acquired by ST Paper, which is working to convert the facility to produce tissue paper. Minnesota Power expects the mill to be operational in early 2023.

1. Positions of the Parties

The Company did not include any test year sales for either ST Paper or the Husky/Cenovus refinery, stating that a delay in their service could cause the Company to lose revenues.

The OAG recommended that the Commission require the Company to reflect sales to these customers in the test year because failing to do so would unduly benefit shareholders when these customers come online.

2. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission require the Company to include sales to these customers. He found it persuasive that both customers are expected to restart by either the end of 2022 or early 2023 and can be expected to operate for the foreseeable future once they restart. Failing to reflect these sales, he found, would unduly benefit Minnesota Power's shareholders by granting them elevated rates that assume these customers are not operating. Further, he found that any doubt about the certainty around the restart date should be resolved in favor of the consumer.

3. Commission Action

The Commission concurs with the Administrative Law Judge that the sales forecast should include sales to these two customers, which are expected to come back online continuously beginning in 2023. The Company's position that a delay in their return could result in lower revenues than the Company actually receives is, as the Administrative Law Judge found, a doubt that should be resolved in favor of the ratepayer. The Commission will therefore require the Company to includes sales to these customers in its test-year sales forecast.

E. Pipeline and Other Industrial Customer Sales Forecast

The parties ultimately concurred on the Company's proposed Pipeline and Other Industrial Customer sales forecast, and the Commission concurs with the Company's sales forecast and will adopt it.

CLASS COST-OF-SERVICE STUDY ISSUES

XX. Cost of Service and Rate Design

A. Introduction

The preceding discussion has sought to quantify the costs that a prudently managed utility serving Minnesota Power's service area would bear. The following sections will address how Minnesota Power may recover those costs from its ratepayers. This process of developing a cost-of-service study, and of designing rates, requires the Commission to exercise policy judgment because there are many ways to set rates to enable a utility to recover appropriate revenues.

A public utility requesting a rate change bears the burden to prove the requested rates are just and reasonable.[24] In setting rates, the Commission considers a variety of factors, including –

- Equity, justice, and reasonableness;[25]
- Avoidance of discrimination, unreasonable preference, and unreasonable prejudice;[26]
- Continuity with prior rates to avoid rate shock;[27]
- Revenue stability;
- Economic efficiency;
- Encouragement of energy conservation;[28]
- Customers' ability to pay;[29]
- Ease of understanding and administration; and, in particular,
- Cost of service.

Estimating the cost to serve any given customer is challenging because a utility will incur different costs to serve different types of customers and will incur many costs that benefit multiple types of customers. Because similar types of customers tend to impose similar types of

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[24] Minn. Stat. § 216B.03; Minn. Stat. § 216B.16, subd. 4.

[25] Minn. Stat. §§ 216B.01, 216B.03.

[26] Minn. Stat. §§ 216B.01, 216B.03.

[27] "Rate shock" describes the adverse reactions customers may experience when a rate increase significantly impacts bills. To mitigate the risk of rate shock, utilities can make efforts to increase rates only gradually so that customers may slowly adjust to any changes.

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

[29] Minn. Stat. § 216B.16, subd. 15.

costs on the system, utilities simplify their analyses 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. Minn. R. 7825.4300(C) directs a utility to file a cost-of-service study by customer class of service, geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class, area, or category, identifying the procedures and underlying rationale for cost and revenue allocations.

For purposes of its class cost-of-service study, Minnesota Power identified five retail customer classes: Residential, General Service, Large Light & Power, Large Power, and Outdoor Lighting.

In addition to selling electricity at retail, Minnesota Power buys and sells electricity on a wholesale basis. The Federal Power Act[30] established FERC to regulate "the sale of electric energy at wholesale in interstate commerce," including both wholesale electricity rates and any rule or practice "affecting" such rates.[31] FERC has authorized the formation of regional transmission organizations[32] such as MISO, which sets the price for wholesale transactions for 15 states and province of Manitoba. In its class cost-of-service study, Minnesota Power treats its wholesale customers as a sixth class of customers—its FERC-jurisdictional customer class.

B. Steps for Conducting a Class Cost-of-Service Study

A class cost-of-service study seeks to identify, as accurately as possible, each customer class's causal responsibility for each cost the utility incurred in providing service. The *Electric Utility Cost Allocation Manual* of the National Association of Regulatory Utility Commissioners (NARUC Manual) recommends conducting a CCOSS in three steps. First, the manual recommends grouping costs according to their function (generation/production, transmission, distribution, customer service/facilities, administrative). Second, the manual recommends classifying costs based on how they are incurred. Third, the manual recommends allocating costs to the various customer classes.[33]

Functionalization: The distribution system carries electricity from the transmission system to a customer's location. Utilities distinguish between the primary distribution system and the secondary distribution system. In the primary distribution system, electricity travels from the high-voltage transmission system to substations, which reduce the voltage and distribute it via lines and poles to the neighborhoods of retail customers. Some large industrial customers purchase power at primary distribution voltages, but otherwise this electricity flows to the secondary distribution system, where distribution transformers again reduce the voltage, allowing it to be distributed via lines and poles to customer premises.

Classification: The cost of a function may be classified as related to energy, demand, customers, or a combination of the three. Energy-related costs increase as a customer's consumption of

[30] 16 U.S.C. §§ 791 *et seq*.

[31] 16 U.S.C. §§ 824(b), 824e(a).

[32] 18 C.F.R. Pt. 35.

[33] NARUC Manual, at 18-23 (January 1992).

energy increases. Demand-related costs increase as the rate at which the customer consumes energy increases, especially during periods of peak demand. Customer-related costs increase as the number of customers increases.

Allocation: The various costs are then allocated to each customer class. The choice of allocator can have important rate consequences. For example, residential customers tend to have a lower load-factor than industrial customers—that is, energy consumption by residential customers tends to fluctuate more than energy consumption by industrial customers. As a result, allocating a given cost based on energy will tend to shift more responsibility toward industrial customers, whereas allocating that cost based on demand will tend to shift cost responsibility toward residential customers.

C. Summary

For purposes of the Company's class cost-of-service study, the Commission concurs with and will adopt the recommendations of the Administrative Law Judge except with regard to the classification of costs associated with advanced metering infrastructure, as set forth below.

XXI. Classification and Allocation of Fixed Production Costs

A. Introduction

According to Minnesota Power, almost 74% of the Company's total revenue requirement for Minnesota reflects production costs. Minnesota Power classifies all its variable production costs—such as fuel and certain operation and maintenance costs that increase as generation output increases—as energy-related. Conversely, Minnesota Power classifies all its fixed production costs—such as the cost of generators, staffing, and maintenance costs that typically increase as the size of the generators increase—as demand-related. The Commission has authorized the Company to use this classification since its 2008 rate case. In this case, this classification results in 56% of production costs allocated to demand and 44% to energy.

B. Positions of the Parties

1. Minnesota Power

While the Company continued to argue for retaining its distinction between variable and fixed production costs, Minnesota Power proposed a new method for apportioning fixed production costs among customer classes.

Historically, Minnesota Power has used the Peak & Average methodology to allocate fixed production demand-related costs and transmission costs to customer classes. This formula allocates part of these costs based on how much each customer class contributes to the average amount of demand on the Company's system, and allocates the rest based on how much energy each customer class consumed during the system's peak hour.

In this docket, however, Minnesota Power proposed a new method for classifying and allocating fixed production costs. The Company claimed that utilities are discontinuing use of the Peak & Average method because it tends to shift an unwarranted share of costs to customers with high load factors. In addition, Minnesota Power argued that data from the peak hour gets included in the calculation of the peak and the average, resulting in unjustified double-counting that skews the results. According to the Company, the combined effect of these problems results in an inequitable allocation of costs among customer classes.

Accordingly, Minnesota Power's class cost-of-service study replaced the Peak & Average method with the Average & Excess method. The rationale for this method tracks much of the rationale for the Peak & Average method—but rather than allocating part of the costs based on each class's share of total demand, the Average & Excess method considers how much each class helps cause peak demand to exceed average demand. Among other advantages, this formula avoids double-counting data because the measure of peak demand reflects only data that exceeds average demand.

In addition, Minnesota Power's new formula measured peak demand not merely for one period each year, but for four peak periods—the peaks in December, January, February, and August. Minnesota Power argued that this method of analysis results in a more representative measure of peak and avoids giving excess weight solely to the Company's one highest peak per year.

2. CUB

The Citizens Utility Board found no merit in the Company's rationale for adopting a new method for allocating fixed production costs among customer classes, and concluded that the Company's prior method better allocated costs on the basis of cost causation.

3. The Department

While the Department agreed that fixed production costs should be allocated based on demand in part, the Department also argued that some of the costs reflect the utility's focus on energy costs. The Department noted that Minnesota Power owns no peaking plants—that is, plants with relatively low capital costs and high operating costs, designed to help a utility meet short-term surges in demand. Rather, the Company has focused on base-load plants—that is, plants with relatively high capital costs and low operating costs, designed to provide a continuous supply of energy at low cost. When a utility chooses between building a peaking plant and building a baseload plant (or some intermediate type of plant), it faces a trade-off between minimizing demand costs and minimizing energy costs. In other words, the choice to build a baseload plant is a choice to minimize energy costs—and therefore, the costs of these choices are partially energy-related.

To recognize this dynamic, the Department recommended allocating part of the Company's fixed production costs as Minnesota Power proposed, and part based on each class's energy consumption. (This would be in addition to allocating variable production costs on the basis of energy consumption.)

4. The OAG

The OAG proposed various changes to Minnesota Power's proposal for allocation of fixed production costs. First, the OAG generally agreed with the Department that only some fixed production costs should be classified solely as demand-related, and the rest should be classified as energy-related.

Second, the OAG supported the Company's proposal to allocate a share of fixed production costs based on each class's usage during peak demand—but argued that the relevant peak demand is MISO's system peak demand, not Minnesota Power's. Minnesota Power has joined MISO and participates in MISO's wholesale electricity markets. Minnesota Power's system peak tends to occur during the winter, whereas MISO's occurs in the summer. This means that when Minnesota Power must meet its peak demand, its neighboring utilities will tend to have excess capacity available for purchase—and likewise, when the neighboring utilities must meet their summer peak demands, Minnesota Power will tend to have excess capacity available to sell. Because the MISO market permits utilities to draw upon the resources of their neighbors, the OAG argued that MISO's period of peak demand represents the more relevant benchmark for allocating fixed production costs. The OAG cited prior Commission orders emphasizing the use of MISO's peak for purposes of allocating costs.[34]

Third, the OAG argued for retaining the Peak & Average method for allocating fixed production costs. According to the OAG, many of the criticisms of the Peak & Average method have little application to high load-factor systems such as Minnesota Power's. Moreover, the OAG argued that the double-counting problem with the Peak & Average method results in only a de minimis distortion to the results, because the data from the peak hour is averaged in with the data from the other 8,759 hours of the year.

5. LPI

LPI stated its support for Minnesota Power's proposed allocator calculated on the basis of four peak periods per year.

LPI opposed the Department's and OAG's allocation of fixed production costs between energy and demand. According to LPI, Minnesota Power incurs fixed production cost to ensure that it has sufficient capacity to fulfill its obligation to MISO to maintain a specified level of resource adequacy—and MISO measures that adequacy based on peak demand, not on energy consumption. Accordingly, LPI argued that the Department's and OAG's proposals would not reflect the principle of cost causation.

In any event, LPI claimed that arguments about the need to allocate a share of production costs based on energy consumption are overstated. According to LPI, measures of average demand closely track measures of energy consumption. So, in effect, the "average" parts of the Peak & Average method and the Average & Excess method already address the parties' objections.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge generally concurred with the Company. Both the Department and the OAG filed exceptions to the Administrative Law Judge's recommendation.

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[34] See, for example, *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-15-826, Finding of Fact, Conclusions, and Order at 46 (June 12, 2017); Docket No. E-017/GR-20-719, Finding of Fact, Conclusions, and Order at 46 (Feb. 1, 2022); *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 63 (May 1, 2017).

D. Commission Action

The Commission concurs with the Administrative Law Judge. Minnesota Power articulates reasonable grounds—based in concerns for equity, efficiency, and cost causation—for favoring the Average & Excess classification method over the Peak & Average method. Both methods recognize that average demand and peak demand warrant consideration. The choice to use peak demand in excess of average demand mitigates the double-counting problem associated with the Peak & Average method. These grounds do not lead the Commission to conclude that all utilities should make the same choice, but they support the Company's choice in this case.

Likewise, Minnesota Power's choice to develop an allocator that reflects four system peaks, rather than just one, reflects a reasonable choice to recognize that utilities must plan not only for their annual peak, but for seasonal peaks. The choice to keep a generator available during seasonal peaks—rather than, say, take the generator out of service for maintenance—may affect a utility's generating costs even if the utility sees no change in its overall system peak demand. Even the Department acknowledged that the Company's proposed methodology is generally supported by the NARUC Manual and "fits well with the Company's situation."[35]

Accordingly, the Commission will affirm Minnesota Power's methodology for classifying and allocating fixed production costs.

XXII. Classification and Allocation of Transmission Costs

A. Introduction

Traditionally, large generators have offered the advantage of economies of scale, but were deemed impractical to locate in urban centers where the demand for electricity is greatest. Transmission facilities permit a utility to move electricity—typically at high voltage—from where it is generated to where it is needed.

While Minnesota Power built its transmission grid to serve its own customers, today that grid is largely administered by MISO. In particular, the Company participates in MISO's Transmission Expansion Planning (MTEP) process where Minnesota Power and MISO ensure that the transmission system has sufficient load-serving capacity to meet the needs of all customers over a range of potential system conditions.

B. Positions of the Parties

1. Minnesota Power

As with fixed production costs, Minnesota Power classified and allocated transmission costs exclusively based on each customer class's contribution to demand, and previously measured that demand using a Peak & Average method. And as with fixed production costs, the Company has now adopted the view that another method would better reflect equity, efficiency, and principles of cost causation. Specifically, Minnesota Power's model reflected allocating costs based on each class's contribution to demand during the period of each month's peak demand—that is, 12 peaks per year.

[35] Ex. DOC-10 at 32 (Zajicek Direct).

In support of this change, the Company argued that this method more closely reflects how it incurs transmission costs; the method is commonly used and well understood in the industry; the method would provide greater transparency and appropriate price signals; and the method would more closely track the revenue requirement of each customer class. In brief, the Company argued that it designed its transmission system to meet customer demand in all 12 months of the year, so it makes sense to measure that demand throughout the year.

According to Minnesota Power, this 12-month method matches how FERC allocates transmission costs to municipal customers, and how MISO allocates transmission costs and revenues to the Company. Finally, Minnesota Power stated that allocating costs based on 12 monthly peaks rather that a single annual peak would tend to reduce the share of costs allocated to residential customers.

2. The Department

The Department acknowledged that the Peak & Average methodology has potential shortcomings. However, the Department argued that the Company designed its system to meet peak demand (plus have a modicum of excess capacity in case of emergencies), and that a single annual peak best measures this dynamic. While MISO may have adopted a 12-peak allocation methodology, that innovation cannot alter the dynamics that motivated the Company's initial transmission planning.

As an alternative, the Department proposed using multiple allocation methods—including methods that consider a single annual peak and methods using 12 monthly peaks.

3. The OAG

As with fixed generation costs, the OAG recognized that transmission costs should appropriately be allocated, in part, based on each customer class's demand. But the OAG noted that some transmission capacity is built to enable Minnesota Power to reach cheaper sources of energy. This occurs when the Company builds a line to a field of new wind turbines, or expands access to an existing low-cost generator that otherwise lacks adequate transmission capacity, or modifies the grid to reduce the amount of energy lost to "friction" ("line losses").

4. LPI

LPI supported Minnesota Power's proposal for classifying and allocating transmission costs, stating that the Company's proposal corresponds with how costs and revenues are allocated in the wholesale market.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with Minnesota Power's analysis and recommended adopting the Company's proposal. The Department and the OAG filed exceptions to the recommendation.

D. Commission Action

Again, the Commission concurs with the Administrative Law Judge.

First, based on the record of this case, the Commission must conclude that demand is the primary driver of transmission costs. While the OAG offered plausible arguments relating transmission costs to energy consumption, the OAG never quantified the relationship—or even offered a proposal for how much of the Company's transmission costs should be classified and allocated as energy-related costs. In the absence of additional evidence, the Commission will decline the OAG's proposal.

Second, the Commission finds that evaluating data from 12 monthly peak demands provides an appropriate way for measuring demand for purpose of classifying and allocating transmission costs. The OAG argued that Minnesota Power initially designed its transmission grid to serve its own customers based on its annual (winter) peak demand. Whatever the merits of this contention, MISO now optimizes the use of the transmission grid for all customers throughout its system—and demand on MISO's grid as a whole differs substantially from the demand on the Company's system in isolation. Minnesota Power has ample cause to measure demand throughout the year—even during periods that do not coincide with the Company's annual peak demand.

Accordingly, the Commission will affirm Minnesota Power's methodology for classifying and allocating transmission costs.

XXIII. Classification and Allocation of Distribution Costs

A. Introduction

Distribution plant provides the bridge connecting the transmission grid to customers. The parties classify these costs as related to both the number of customers and the aggregate demand; they propose a variety of methods for distinguishing between the customer- and demand-related costs; and they identify a variety of ways to measure demand.

B. Positions of the Parties

1. The OAG

The OAG argued for classifying and allocating distribution costs by using the Basic Customer method. This method reflects the assumption that most distribution costs are demand-related costs, and only costs that clearly increase as the number of customers grows—such as the costs of service lines, meters, billing, and collection—should be treated as customer-related costs.

2. Minnesota Power

Minnesota Power proposed using the Minimum System method. This method reflects the premise that a utility builds its distribution plant to serve each customer regardless of the amount of demand each customer puts on the system, so some portion of the plant should be regarded as customer-related. In this method, an analyst estimates the minimum cost to build a system that would connect to all of Minnesota Power's customers, including the average cost of the minimum sized pole, conductor, cable, transformer, and service currently installed. The excess above the cost of this minimum system—that is, the extent to which Minnesota Power built its system larger than strictly necessary to connect to each customer—is classified as demand cost, attributed to Minnesota Power's need to provide the capacity to serve peak load.

The Company opposed use of the Basic Customer method, arguing that it fails to reflect principles of cost causation. Minnesota Power noted that the NARUC Manual states that costs for items such as poles, conductors, underground cable, and transformers should be categorized as at least partially customer-related (because a utility will tend to buy more of these as the number of customers grows), yet the Basic Customer method categorizes these costs as solely demand-related.

3. The Department

Consistent with the Commission's decisions in prior rate cases, the Department recommended that the Company allocate distribution costs among the customer class using a variety of methods. The Department supported the OAG's recommendation to use the Basic Customer method, and also found that Minnesota Power had adequately justified use of the Minimum System method. The Department also explored other methods for classifying costs as either customer-related or demand-related, and explored measuring demand using a single peak period for the year, or using 12 monthly peaks. The Department reasoned that each method has its advantages and disadvantages, so relying on an assortment of methods would permit the strengths to offset the weaknesses.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that, consistent with the Department's recommendation, the Commission use a range of methods that are analytically sound and supported by the record. Minnesota Power filed exceptions.

D. Commission Action

The Commission concurs with the Administrative Law Judge. The Commission has long held that no single cost study method can be judged superior to all others in all contexts, and the choice among methods involves disputes over assumptions, applications, and data.[36] This conclusion is supported by the fact that the NARUC Manual identifies a variety of methods for allocating cost. While evaluating data from a variety of studies will not eliminate any study's weaknesses, it provides a broader range of perspectives from which to evaluate each study and can reduce the impact of any particular study's flaws.

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[36] *See*, for example, *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, Findings of Fact, Conclusions, and Order at 71 (Mar. 12, 2018); *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 62 (May 1, 2017); *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 the State of Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 44–45 (June 12, 2017).

Accordingly, the Commission will direct Minnesota Power to allocate the cost of its distribution plant in its class cost-of-service study by using a range of models that are analytically sound and supported by the record.

XXIV. Classification of Advanced Metering Infrastructure (AMI) Meter Costs

A. Introduction

Meters measure a customer's electricity usage. A traditional residential meter would report only a customer's total energy usage—and then, only when someone took the time to visit the meter. Minnesota Power has already installed technology that permits the Company to read meters remotely.

Minnesota Power allocated traditional meter costs directly to its large power classes and wholesale classes based on the actual cost of the meters used by customers in those classes. The Company allocated other traditional meter costs to the other customer classes based on meter counts. No party disputed this allocation.

But since 2010, Minnesota Power has been installing advanced metering infrastructure (AMI). According to the Company, AMI will help Minnesota Power and its customers more efficiently control the use and production of electricity. The technology allows the Company to automatically and more frequently collect consumption, diagnostic, and status data from meters, providing the Company with easy access to data used for billing, analyzing, and troubleshooting. With this new technology, Minnesota Power expects to be able to better monitor voltage problems and outages, and to be able to offer new rates designed to reward customers that can reduce energy consumption, especially during times of peak demand. Parties disagree about how to classify and allocate AMI costs.

B. Positions of the Parties

1. The OAG

The OAG argued that AMI costs are related to customers, energy, and demand. All parties agreed that the number of customers influences metering costs. But in addition, the OAG argued that Minnesota Power is installing AMI metering to help manage the utility's load and reduce line losses and generation cost, which shows that these costs are also related to the Company's energy and demand costs. If the record fails to quantify how much of AMI costs are customer-related, energy-related, and demand-related, the OAG argued that this omission reflects a failure of the Company to bear its burden in this rate case, and that doubts about the reasonableness of any rate should be resolved in favor of the consumer. In the absence of more precise estimates, therefore, the OAG recommended that the Commission allocate AMI costs equally among customer, demand, and energy factors.

In support of its proposal, the OAG cited two Commission orders. First the OAG noted that the Commission, when considering how Otter Tail Power Company should recover the cost of its advanced metering, recognized that utilities install advanced meters to help manage demand and energy costs:

> [T]he added meter costs borne by subscribers to the Residential-Controlled Demand service are more appropriately understood as demand or energy costs. These costs are incurred to benefit [the utility's] system as a whole, not just the customer receiving electricity through the meter.[37]

And more recently, the Commission adopted an administrative law judge's report concluding that, "[b]ased on the evidence in the record, it appears that the customer cost is more than one-third (for AMI meters), but clearly not 100%."[38]

2. Minnesota Power

Minnesota Power recommended classifying costs related to AMI metering as customer-related costs, just as it has classified other metering costs. The Company argues that meter costs increase as the number of customers increases, but generally do not increase as either energy or demand increases.

The Company opposed the OAG's proposal, arguing that the proposal lacks adequate support in the record. While Minn. Stat. § 216B.16, subd. 4, specifies that the utility bears the burden of proof regarding its proposed rate changes, Minnesota Power noted that it has not proposed any changes to the way it allocates meter costs; rather, the Company argued that the OAG bears the burden to support its own proposal—and that the OAG has failed to do so.

Moreover, Minnesota Power argued that the OAG's proposal would have potentially unintended adverse consequences. According to the Company, the proposal would have the effect of shifting more than $822,000 from the retail to the wholesale jurisdiction. Because wholesale cost recovery is a matter beyond the jurisdiction of the Minnesota Public Utilities Commission, the Company argued, the proposal would leave Minnesota Power unable to recover these costs. In addition, the OAG's allocation would shift over $3 million to a handful Large Power customers who already bear more than the actual cost of their meters.

Nevertheless, if the Commission becomes persuaded that AMI costs should be categorized as related to customers, demand, and energy, Minnesota Power would ask the Commission to defer implementing this policy until the Company's next rate case.

3. LPI

LPI opposed any classification or allocation that would shift the cost of Minnesota Power's AMI program to the Large Power class. According to LPI, the AMI program consists of expanding to other customer classes the use of the kinds of meters that Large Power customers have been using, and paying for, for years—so the Commission should recognize that the Large Power

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[37] *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 75 (May 1, 2017).

[38] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/16-664, Findings of Fact, Conclusions of Law, and Recommendations, Conclusions 83-84 at 49 (November 7, 2017).

customers are not contributing to these new costs. If the new meters permit members of other customer classes to reduce their energy or demand costs, these benefits would accrue to those classes—and so should the costs.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found the OAG's reasoning and analysis persuasive—especially citations to prior Commission decisions affirming that AMI costs bear a reasonable relationship to customer, demand, and energy costs. Minnesota Power and the LPI filed exceptions to the Administrative Law Judge's recommendation.

D. Commission Action

For reasons historical and logical, the Commission has long recognized that a utility's meter costs as driven by the number of customers in each class. But as the OAG and Administrative Law Judge noted, the Commission has also recognized that advanced metering also bears an important role in helping to manage energy consumption and customer demand. The LPI correctly noted that the new meters would primarily serve to help reduce demand and energy for the class of customers receiving the new meters. But the purpose of the meters is to benefit the utility's entire system, and society at large; accordingly, it may well make sense to allocate AMI costs to all utility customers—including wholesale customers.

In the current case, however, the Commission concludes that the record does not adequately document the magnitude of this relationship to justify deviating from the Commission's long-standing practice for allocating metering costs. In the absence of more rigorous analysis, it is difficult to know whether the costs or benefits of AMI demand and energy savings are already accounted for elsewhere. The OAG correctly cites Minn. Stat. § 216B.03 for the proposition that doubt as to a rate's reasonableness should be resolved in favor of the consumer. But that statute has limited application in the context of a class cost-of-service study, which is designed to allocate costs among consumers. For purposes of this case, therefore, the Commission will retain its practice of treating meter costs as customer-related costs; this conclusion will have the effect of increasing the Minnesota jurisdictional revenue requirement by $822,780 and reallocating costs among the retail classes.

But for Minnesota Power's next general rate case, the Commission will no longer give preference to retaining this method of allocating metering costs. Instead, Minnesota Power will have to analyze how AMI meters are associated with customer costs as well as energy costs and demand costs—or, in the alternative, conduct its class cost-of-service study using the premise that AMI costs are allocated equally to customer, demand, and energy factors.

XXV. E8760 Allocator

A. Introduction

The cost to buy or generate a kilowatt-hour of electricity varies over time. To note one dynamic, utilities (and MISO) forecast how much energy they will need to meet customer demand, and then dispatch the generators with the lowest incremental cost until they have enough energy to meet the anticipated need. As demand increases, utilities (and MISO) must dispatch generators with ever higher costs—which results in costs that vary over time.

When allocating the cost of energy among customer classes, therefore, it is not sufficient to know how *much energy* each class consumes; it is also necessary to know *when* the energy was consumed. A customer class that consumes proportionately more of its energy during periods of high demand, when the cost of electricity is higher, should bear a higher cost per kilowatt-hour than a customer class that consumes energy during times of low demand.

To achieve this result, Minnesota Power has developed its E8760 allocator—so named because it calculates a unique energy cost for each of the 8,760 hours in a year. To create the allocator, Minnesota Power combines data about the prevailing cost of energy in any given hour to data about the amount of electricity each class was consuming at that hour. No party opposed Minnesota Power's use of an E8760 allocator in principle—but the OAG raised concerns about the use of the specific allocator calculated in this docket.

B. Positions of the Parties

1. Minnesota Power

For purposes of the current case's class cost-of-service study, Minnesota Power calculated its E8760 allocator using data about the Company's cost of energy during each hour of 2022, as well as the most recent data about consumption patterns for each customer class. For Large Power customers, the most recent consumption data was from 2020; for all other customer classes, the most recent data was from 2013-2014.

Minnesota Power acknowledged that it would ideally calculate its allocator using more recent consumption data for all customer classes, and reported its plans to update the consumption pattern data beginning in December 2023, after the Company has fully deployed its advanced meter infrastructure. In the meantime, the Company provided evidence to demonstrate the reasonableness of relying on an E8760 allocator calculated using the available data; for example, the Company showed that class consumption patterns remain fairly stable over time. On this basis, Minnesota Power argued that its E8760 remains the best energy cost allocator in the record.

2. The OAG

The OAG objected to using an E8760 allocator calculated based on mis-matched data—cost data from 2022, and consumption pattern data from a range of years, none of which were 2022. Rather than rely on a flawed mechanism for allocating energy costs, the OAG recommended that the Company allocate energy costs based solely on the amount of energy consumed by each class—without regard to when the energy was consumed—in this and all future rate cases until the Company acquires updated data.

3. The Department and LPI

The Department and LPI recommended that the Company update its E8760 allocator using more recent consumption data for all customer classes before filing its next rate case—but the parties did not otherwise oppose Minnesota Power's use of its current E8760 in the current rate case. To the contrary, LPI opposed the OAG's recommendation to allocate energy costs based solely on each class's energy consumption.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Minnesota Power had demonstrated the reasonableness of relying on its E8760 allocator for the current case's class cost-of-service study. But the Administrative Law Judge also found it reasonable for the Commission to direct the Company, before its next rate case, to re-calculate the allocator using updated data acquired after its advanced metering technology is fully deployed. The OAG filed exceptions to the Administrative Law Judge's recommendations.

D. Commission Action

The Commission concurs with the Administrative Law Judge, the Department, and LPI that the Company's E8760 allocator, while imperfect, remains the best method in the record for allocating energy costs among customer classes. Imperfect data may introduce a degree of error, but the record does not demonstrate that it introduces bias—that is, results systemically skewed in favor of any customer class in particular. And while Minn. Stat. § 216B.03 directs the Commission to resolve disputes about the reasonableness of rates in favor of the consumer, this admonition has little application in the context of allocating costs among consumers.

The Commission also concurs with the Administrative Law Judge, the Department, and LPI that after the Company fully deploys its advanced metering technology, Minnesota Power should develop future E8760 allocators using updated data.

XXVI. Using Class-Specific Return on Equity (ROE) in Class Cost of Service Model

A. Introduction

As previously discussed, one cost of operating a firm is the cost of providing financial returns to shareholders, thereby ensuring that the company would be able to raise funds by selling shares in the future. The size of the returns must be commensurate with the perceived size of the firm's risks.

Historically, retail electric utilities have operated with lower risk than many businesses because they typically have a monopoly on a necessary service, and a broad range of customers. But as compared to other electric utilities, a larger share of Minnesota Power's sales are made to a small group of large industrial customers—and so the Company's financial health is tied to the health of those customers. The Citizens Utility Board argued that this dynamic makes Minnesota Power riskier, and that this fact should be reflected in the class cost-of-service study.

B. Positions of the Parties

1. CUB

CUB proposed increasing the revenue requirement for the Large Power class by increasing the ROE for the Large Power class within the class cost-of-service study model. Because this customer class has relatively few members representing a large share of Minnesota Power's sales, the Company bears greater risk in serving this class.

In support of its proposal, CUB cited examples where Minnesota Power has taken steps to mitigate risk from its Large Power class. CUB cited the Company's own testimony emphasizing the financial risk associated with meeting its obligation to service this class, and the apportionment of those risks among customer classes. Moreover, the Company proposed a formula for recovering lost revenue if sales fall by at least $10 million; CUB argued that the cost of developing this formula should be directly assigned to the Large Power customers.

2. Minnesota Power

Minnesota Power opposed CUB's proposal, arguing that establishing a separate ROE for each customer class would be impractical and reduce the usefulness of the class cost-of-service study for setting rates. The Company did not deny that it bears risks related to serving its Large Power class, but reasoned that the Commission takes those risks into account when allocating revenue requirements (discussed below).

3. LPI

LPI noted that even CUB's own witness conceded that it is difficult to quantify the risk associated with the Large Power class. LPI also argued that CUB has failed to account for risks emerging from classes other than Large Power. For example, LPI argued that the system demands posed by the Residential class fluctuate greatly in response to the weather, and are just as unpredictable—whereas the Large Power class maintains a more stable demand for electricity and produces a more stable stream of revenues for the Company.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that it is reasonable to explore whether risks associated with serving the Large Power class are being subsidized by other classes. But he ultimately concluded that the record was insufficient to adopt a policy of establishing distinct ROE calculations for individual customer classes within the class cost-of-service study. CUB filed exception to the Administrative Law Judge's finding.

D. Commission Action

The Commission concurs with the Administrative Law Judge. The Commission is not persuaded that the current record is sufficient to warrant adopting CUB's proposal. In short, the Commission is not persuaded that the aggregate costs and benefits of the Large Power class justify the disparate treatment CUB has proposed. And the Commission is not persuaded that CUB has adequately demonstrated how to calculate individualized ROEs for individual rate classes.

First, regarding costs and benefits that each customer class imposes on the others: Generally, customer classes operate in a symbiotic relationship. Minnesota Power's Large Power class gives the Company an enviable load factor; that is, it permits fixed costs to be spread over an unusually large, stable amount of generation. Generally, customers benefit when a utility is able to achieve economies of scale to keep incremental costs low. Generally, a utility benefits from serving a diverse group of customers, where a change by any one customer might coincide with an offsetting change by another.

CUB correctly observes that, while Large Power customers may have relatively stable consumption patterns in the short term, their propensity to ramp up and shut down gives some of them especially unstable consumption patterns in the long run. This creates plausible grounds to look for class cross-subsidization—but not yet sufficient grounds to find it.

Second, as discussed above, establishing a utility-wide ROE is challenging at best, and it remains unclear how to establish a separate ROE for an individual customer class. Again, the economies of scale inherent in operating a public utility may well reflect the stability arising from serving a large, diverse group of customers—and this fact may be reflected in a company's ROE.

On the basis of the current record, therefore, the Commission will decline CUB's proposal to adopt a specific ROE for the Large Power class within the context of the class cost-of-service study.

XXVII. Jurisdictional Allocation

A. Introduction

As previously discussed, the Federal Power Act authorizes FERC to regulate "the sale of electric energy at wholesale in interstate commerce,"[39] including wholesale electricity rates,[40] while states retain jurisdiction over retail rates. But a utility will use the same resources for both wholesale and retail operations. Accordingly, the utility must articulate a formula for allocating the cost of common resources to the state and federal jurisdictions, respectively, and costs assigned to the federal jurisdiction should be excluded from allocation among the retail customer classes.

In this case, Minnesota Power developed its 2022 allocators using the same jurisdictional allocation procedures that the Commission had approved in the Company's last three rate cases. But Minnesota Power acknowledged how various changes altered its allocations since its last case. For example, both wholesale and retail sales declined due to the effects of the COVID-19 pandemic and the decline or closure of certain large industrial customers. In addition, Minnesota Power experienced reduced wholesale sales as various municipalities re-negotiated their contracts with the Company. However, Minnesota Power offset some of these losses by entering into a non-firm retail supply agreement with Silver Bay Power Company, and by adding Brainerd and Dahlberg as customers that acquire their own source of wholesale electricity but pay Minnesota Power to have the electricity delivered to their municipalities.

B. Positions of the Parties

1. LPI

While Minnesota Power claimed that it was using the same allocation formulas as during its prior rate cases, LPI alleged that the Company had changed the manner in which it evaluated production capacity costs. Previously, according to LPI, Minnesota Power allocated production capacity costs to the wholesale jurisdiction based on demand. But in the current docket, the

[39] 16 U.S.C. §§ 791 *et seq*.

[40] 16 U.S.C. §§ 824(b), 824e(a).

Company divides wholesale demand into two components—base demand and incremental demand—and allocates production capacity costs to the wholesale jurisdiction based only on base demand. LPI argued that it is not just nor reasonable to take costs previously associated with wholesale demand and shift those costs to retail customers.

2. The OAG

The OAG noted that Minnesota Power was proposing to use the same allocator formula for 2020 as for 2022. The OAG further noted that Minnesota Power set its 2020 allocators based on forecasted data, that these forecasts proved to be overstated for 2019 and 2020, and that the 2022 forecasted data were higher than the 2020 actual data. The OAG sought information from the Company to test whether the overstated forecasts reflected a systemic bias, but the Company did not provide the information requested. This led the OAG to argue that the Company had failed to demonstrate that its forecasted jurisdictional allocators were reasonable, and to argue in favor of retaining the 2020 allocators—allocators that now reflect actual data rather than forecasts.

3. Minnesota Power

Minnesota Power opposed the OAG's proposal to use the Company's 2020 jurisdictional allocators rather than its 2022 allocators, even if the 2022 allocators are based on forecasts. The Company agreed with the OAG that forecasted data differed from actual data, but noted that this is always true—and was especially true for forecasts made before and during a world-wide pandemic.

Also, Minnesota Power opposed LPI's proposed adjustment to its production demand allocator. The Company clarified that the "incremental" demand described by LPI is non-firm demand—that is, it refers to the demand created by customers that have agreed, in exchange for receiving a discount on electric service, to be subject to having their electric service interrupted. These customers help save costs for the utility and all of its other customers, as follows: A utility must bear the cost to acquire sufficient generation, transmission, and distribution capacity to meet the firm demand of its customers, but the utility need not acquire additional capacity to meet the needs of customers with non-firm demand. Instead, when the demand for electricity strains the utility's capacity, the utility may choose to interrupt service to customers with non-firm demand, thereby reducing total demand on the system. Minnesota Power explained that, for retail customers, it applies the production demand allocator solely to firm demand—and reasoned that the Company should do the same for wholesale customers, too.

Finally, Minnesota Power emphasized that any change to its proposed federal/state allocators would necessarily alter cost allocations to the various customer classes. Finally, Minnesota Power stated that the formulas establishing how much the Company can recover from the federal jurisdiction has already been set, so any changes that would shift costs to the federal jurisdiction would leave Minnesota Power without any opportunity to recover those shifted costs.

4. The Department

The Department ultimately concurred with Minnesota Power's proposal for 2022 federal/state allocators for this rate case. But the Department rejected the argument that this Commission should constrain its analysis of jurisdictional allocations based on Minnesota Power's federal allocations.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that Minnesota Power made a persuasive case in support of using its 2022 jurisdictional allocation factors, and therefore recommended that the Commission authorize their use in this case. LPI and the OAG filed exceptions to the ALJ's recommendation.

D. Commission Action

The Commission concurs with the Administrative Law Judge about the merits of authorizing the use of Minnesota Power's jurisdictional allocator factors. The Commission is persuaded that it is appropriate to apply these factors based on firm demand, not non-firm demand, because Minnesota Power has incurred production costs primarily to meet the firm demand of its customers—and not necessarily to meet the non-firm demand.

Moreover, the Commission finds that Minnesota Power's proposed 2022 allocation factors are the most reliable allocators in the record, even if based on forecasted data. In general, the OAG makes a plausible argument that we should expect actual data to be more credible and predictive than forecasted data. But where the actual data reflects electricity consumption during the peak of the COVID-19 pandemic, the Commission is not persuaded that this data would be representative of future electricity consumption.

RATE DESIGN

XXVIII. 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.[41]

B. Positions of the Parties

Minnesota Power recommended an equal increase across all General Rates, which at its proposed revenue requirement would amount to an 18.22% increase. The Company explained that it typically tries to align rates with its CCOSS results, but doing so in this case would require a 51.69% increase for the Residential class. Minnesota Power noted that its recommendation included a decrease in Dual Fuel rates to increase competitiveness with alternative fuels, along

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

with an adjustment related to recently approved Large Power demand response changes. The Company argued that the Residential increase should be considered in light of the existing 7.11% interim rate increase and emphasized the importance of bringing Residential rates closer to cost. Minnesota Power argued that LPI's recommendation did not adequately consider Residential customers' ability to pay, and the Department, CUB, Energy CENTS Coalition (ECC), and the OAG did not make recommendations that would adequately bring Residential rates closer to cost. Lastly, the Company noted that its Residential rates are currently among the lowest in Minnesota and well below the national average.

The Department's recommendation was based on its revenue-requirement calculation and would increase residential rates by 6.0% and all other classes by 6.8%. If the Commission chose a different revenue requirement, the Department suggested adjusting the revenue apportionment to maintain the same proportion between Residential and other classes. The Department argued that the Residential class should receive a lower increase in order to avoid rate shock because of rate changes occurring outside of the rate case, including the transition to time-of-day rates, discussed further below.

The OAG argued that flaws in the Company's CCOSS should preclude it from guiding revenue apportionment, and policy considerations justify a smaller increase for the Residential class. The OAG recommended a 5.6% Residential increase and 6.4% increase for all other classes except Dual Fuel, for which a slight decrease is warranted.

CUB argued that risk from Large Power customers is unfairly socialized across all rate classes, noting that Large Power causes higher load forecasts and more energy procurement without a corresponding increase in demand along with a higher ROE that is allocated across all classes. CUB recommended that due to ongoing exigent circumstances, any Residential rate increase should be limited to the lesser of 7.11% or half the final rate increase approved for other classes.

LPI argued that Large Power customers have subsidized other classes for decades, particularly the Residential class. LPI noted that Large Power customers are the economic engines of Northern Minnesota and deviation from cost puts pressure on these companies. LPI proposed a phased-in Residential rate increase of 17.9%, then 5.7% and 5.4% in the subsequent two years. Large Light & Power would receive an 11% increase and Large Power would receive a 3.6% increase.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed with the Department that moderating the rate increase to the Residential class is necessary to prevent rate shock in light of the other changes that classes' rates are currently undergoing. Accordingly, the Administrative Law Judge recommended that the Commission proportionally adjust Minnesota Power's rate increases for each class in accordance with the ratio proposed by the Department to increase residential rates by 6.0% and all other classes by 6.8%.

D. Commission Action

When setting interim rates for this rate case, the Commission found that exigent circumstances caused by the COVID-19 pandemic had imposed a significant burden on Minnesota Power's residential customers, necessitating a lower interim rate increase for the Residential class. The Commission acknowledges that many of the conditions that caused exigent circumstances for interim rates—such as labor disruption and inflation—continue to impact Minnesota Power's residential customers. These circumstances implicate the ratemaking factors of customers' ability to pay and avoidance of rate shock. To apportion the revenue requirement and establish reasonable rates, the Commission balances these factors against other relevant considerations including cost of service, equity, and avoidance of discrimination between customer classes.

Minnesota Power's CCOSS shows that Residential rates would need to increase significantly to cover the cost of service. LPI argues that the Residential class should be apportioned over 50% of the total revenue requirement, phased in over three years. This dramatic rate increase would almost certainly cause rate shock and does not adequately account for residential customers' ability to pay.

The Administrative Law Judge found the Department's recommendation to apportion a smaller share of the rate increase to the Residential class the most reasonable, while the OAG recommended an even smaller share of the rate increase to those customers. CUB argued that the rate increase for the Residential class should not exceed the interim rate increase. The Commission concludes that these proposals do not go far enough to bring Residential rates closer to cost, and therefore do not adequately account for cost of service, equity, and avoidance of discrimination.

Minnesota Power proposed to equally apportion the revenue requirement to all rate classes. Under this proposal, each class would receive an 9% rate increase as a result of the Commission's revenue-requirement decisions described above. For the Residential class, this would represent an approximately 2% increase above interim rates. Furthermore, Minnesota Power agreed that it would not seek to surcharge residential customers for the difference between interim rates and final rates.

The Commission concludes that an equally apportioned 9% rate increase with no surcharge on Residential ratepayers for the difference between final and interim rates strikes the right balance between the competing factors that the Commission weighs in apportioning the revenue requirement. This approach will bring Residential ratepayers closer to cost and will avoid rate shock by limiting the increase on Residential rates to approximately 2% above what residential customers are currently paying in interim rates, with no surcharge for the difference. For these reasons, the Commission respectfully declines to adopt the recommendation of the ALJ and will therefore adopt the revenue apportionment proposed by Minnesota Power, reflecting an across-the-board even allocation to all rate classes with the understanding that the Company will not surcharge Residential ratepayers for the difference between interim and final rates.

XXIX. Monthly Customer Charges

A. Introduction

While revenue apportionment focuses on how revenue responsibility should be divided among customer classes, setting the customer charge addresses how revenues are collected within each customer class. Each customer pays the same customer charge as others in their class, and this charge is intended to cover the utility's fixed costs that do not vary with the amount of energy used.

B. Positions of the Parties

Minnesota Power, CUB, and ECC came to a partial settlement where Minnesota Power agreed to 1) increase the budget of its Customer Affordability of Residential Electricity (CARE) program in order to increase the CARE flat discount and extend the CARE flat discount/affordability credit to low-income customers that are not enrolled in the Low Income Home Energy Assistance Program (LIHEAP); and 2) increase the amount of its existing low-income, usage-qualified discount from 35% to 40% of the standard Residential rate on the first 600 kilowatt-hours. In exchange, CUB and ECC agreed not to oppose a $1 increase in the monthly Residential customer charge from $8 to $9. All three parties recommended adoption of the partial settlement.

Minnesota Power also proposed increasing the Residential–seasonal customer charge from $10 to $15, General Service from $12 to $15, and Commercial Electric Vehicle (EV) from $12 to $15. In response to the OAG's arguments, Minnesota Power argued that the OAG failed to include all customer costs in its recommendation.

The OAG argued that customer charges should be reduced because the Company's CCOSS overestimates customer-related costs. The OAG cited various benefits of reduced customer charges, including encouragement of energy conservation and customer investment in renewables, as well as giving consumers more control over their energy bills.

The Department recommended maintaining the Residential customer charge at $8 and approving the other increased customer charges, arguing that other changes to Residential rates justify a steady customer charge. The Department did not object to the partial settlement.

C. Administrative Law Judge Recommendation

The Administrative Law Judge found that an increase of the Residential service charge from $8.00 to $9.00 is reasonable and should be approved. The Judge noted that the change reflects a reasonable resolution of this issue between the Company, ECC, and CUB, and will also result in improvements to the CARE program.

The Administrative Law Judge also recommended approval of the proposed monthly service charges for all other classes as just and reasonable.

D. Commission Action

The Commission appreciates the efforts of ECC, CUB, and Minnesota Power to arrive at the partial settlement whereby ECC and CUB agreed not to oppose a $1 increase to the Residential service charge if Minnesota Power implements certain improvements to the CARE program and other low-income programs. These proposed improvements for low-income customers could help mitigate the impact of the rate increase by increasing the discount amounts and expanding eligibility, while raising the low-usage discount can also promote energy conservation.

The Administrative Law Judge found this settlement to be a reasonable resolution of this issue and recommended approval, and the Commission agrees. The Commission will adopt the Residential service charge of $9.00 per month and will require Minnesota Power to implement the low-income, low-usage rate proposed by ECC. The Commission expects Minnesota Power to request an increase to the CARE program budget to implement additional improvements contemplated under the partial settlement in Docket No. E-015/M-11-409.

The Commission also agrees with the Administrative Law Judge and the Department that Minnesota Power's proposed increases to the monthly service charges for the Residential–seasonal, General Service, and Commercial EV customer classes are reasonable. The OAG's recommendation regarding these customer charges does not appear to include all relevant costs and is therefore not reasonable. The Commission will approve Minnesota Power's proposed monthly service charges for all other classes.

XXX. General Service and Large Light & Power Interruptible Tariff

A. Introduction

A customer taking service under Minnesota Power's interruptible tariff agrees to interrupt or curtail its electric usage when called upon by the Company in exchange for an 11% discount to base-rate demand and energy charges. Minnesota Power proposed changes to its General Service and Large Light & Power Interruptible tariff to reflect current market parameters for interruptible service, while LPI argued that the interruptible discount should be increased.

B. Positions of the Parties

LPI argued that the interruptible discount should be structured similarly to the value of new combustion turbine capacity to more closely align with the long-term avoided cost. LPI recommended using the MISO Zone 1 auction clearing price as a reasonable proxy for a short-term product, equal to approximately $7.20 per kilowatt-month (kW-month) and higher than the 11% discount currently provided.

Minnesota Power argued that LPI's recommendation does not align with the nature of interruptible service. The Company explained that the General Service/Large Light & Power Interruptible service is a short-term capacity product requiring only a one-year commitment from interruptible customers, while a combustion turbine has a decades-long operating life. Minnesota Power argued that it would not be reasonable to provide a discount of a magnitude achieved only when a long-term commitment is made by customers when the tariff commitment to interruptible operation is for a one-year period.

C. Administrative Law Judge Recommendation

The Administrative Law Judge found that Minnesota Power did not address LPI's argument that the Large Light & Power interruptible credit should be aligned with the MISO Zone 1 auction clearing price. The Judge concluded that the Company failed to meet its burden of proof to justify maintaining the smaller 11% discount and recommended that the Large Light & Power interruptible credit be aligned with the MISO Zone 1 auction clearing price, currently approximately $7.20 per kW-month.

D. Commission Action

The Commission respectfully disagrees with the Administrative Law Judge that Minnesota Power did not fully address LPI's argument that the Large Light and Power interruptible credit be aligned with the MISO Zone 1 auction clearing price. The MISO Zone 1 auction clearing price is the price associated with long-term (20–30 years) investment in generation, while interruptible customers only make short-term (1 year) commitments under the tariff. The Commission agrees with Minnesota Power that it would be inappropriate to give interruptible customers a discount associated with the long-term commitment represented by the MISO Zone 1 auction clearing price.

For these reasons, the Commission respectfully declines to adopt the recommendation of the ALJ and will instead approve the General Service and Large Light & Power Interruptible tariff language changes proposed by Minnesota Power and recommended for approval by the Department, as well as maintain the General Service and Large Light & Power discount at 11%.

XXXI. Fuel and Purchased Energy Rider

A. Introduction

Minnesota Power's Fuel and Purchased Energy rider is a fuel clause adjustment mechanism that enables the Company to automatically adjust charges for the cost of fuel. In this rate case, LPI recommended developing separate on- and off-peak Fuel and Purchased Energy rates for the Large Light & Power time-of-use customer class, and Minnesota Power opposed that change.

B. Positions of the Parties

LPI argued that as more Large Light & Power customers transition to the time-of-use rate schedule, time-differentiated energy rates will improve the accuracy of the allocation of fuel and purchased energy costs within the class and provide better cost-based signals, thereby encouraging and incentivizing customer responses. LPI noted that there is currently only one customer taking service under the Large Light & Power time-of-use rate, which should not require a significant administrative inconvenience for the Company. LPI also noted that, as customers continue transitioning to advanced meters, implementation of more complex rate structures will become easier to administer and bill.

Minnesota Power argued that any changes recommended for the Fuel and Purchased Energy rider should be handled in a fuel clause adjustment related docket, and not as part of the rate case. The Company also argued that this change would be an administrative burden due to fuel and purchased energy true-up calculations, and any customer that takes service on the Large Light & Power time-of-use tariff would require additional configuration in Minnesota Power's billing system. Minnesota Power maintained that its efforts to give customers accurate price signals that are reflective of costs must be balanced with the objectives of simplicity and avoiding unnecessary administrative complexity.

C. Administrative Law Judge Recommendation

The Administrative Law Judge concluded that LPI's proposed changes to the Fuel and Purchased Energy rates for the Large Light & Power time-of-use customer class are best developed in a Fuel Adjustment Clause related docket.

D. Commission Action

The Commission agrees with the Administrative Law Judge that LPI's proposed changes to the Fuel and Purchased Energy rider for the Large Light & Power time-of-use class are best developed in a fuel clause adjustment docket. The Commission has recently implemented significant changes to the operation and review of electric utility fuel clause adjustments, and therefore any changes to the Company's Fuel and Purchased Energy rider should be considered in the context of a fuel clause adjustment docket.

XXXII. Large Power – Other Energy Revenues

A. Introduction

Large Power – Other Energy is a category consisting of charges and credits for several Large Power customer programs: Pool within Pool Service Fee, Economy/Non-Firm Energy, Incremental Production Service, Replacement Firm Power Service, Fixed Price Contract, and several demand-response programs. Minnesota Power accounts for these revenues as a revenue credit in the CCOSS.

B. Positions of the Parties

The OAG argued that Minnesota Power had not adequately justified excluding Large Power – Other Energy revenues from the revenue apportionment. The OAG argued that rate increases are presumably contemplated when negotiating Large Power electric service agreements, and the variable incremental energy costs have a fixed-cost component that could increase in accordance with the rate increase.

Minnesota Power argued that its treatment of Large Power – Other Energy revenues was reasonable for four reasons: 1) revenues from several programs are based on charges established in electric service agreements that do not change as a result of a rate case; 2) a portion of the revenue is based on incremental energy costs that vary monthly and even hourly, and is associated with service for non-firm energy products; 3) these revenues are treated as revenue credits to all customer classes within the CCOSS rather than Large Power rate class revenue; and 4) customers being charged for certain services have their own generation to serve a portion of their load, and Minnesota Power accredits this generation with MISO.

C. Administrative Law Judge Recommendation

The Administrative Law Judge found that the OAG's assumption was not supported on the record and found that the Company has demonstrated that it is reasonable and consistent with past practice to exclude certain Large Power – Other Energy revenues from the overall revenue apportionment.

D. Commission Action

The Commission agrees with the Administrative Law Judge that Minnesota Power has appropriately handled Large Power – Other Energy revenues. Minnesota Power's exclusion of these particular Large Power revenues from the overall revenue requirement is consistent with past practice and accounts for the fact that these revenues are based on charges negotiated in separate agreements that do not change with a rate case. Furthermore, a portion of this revenue is based on incremental energy costs that vary monthly and even hourly. The Commission concludes that Minnesota Power's treatment of these revenues is reasonable.

XXXIII. Large Power Sales True-Up

A. Introduction

Minnesota Power proposed a sales true-up mechanism that would annually track base-rate revenues for the Large Power class and any margins the Company receives from wholesale sales enabled by lost Large Power load and would then compare those revenues to a baseline level established from the 2022 test year. If the base-rate and sales revenue in future years were at least $10 million higher or lower than the baseline, the Company would propose a rider on all customer bills for 12 months to credit or surcharge customers for the difference between the actual revenue and the baseline.

B. Positions of the Parties

Minnesota Power argued that its sales true-up was a simple and balanced method to manage the risks and benefits of Large Power sales volatility that occurs between rate cases. The Company noted that the mechanism is designed to be symmetrical—meaning that if the Large Power sales forecast approved in the current rate proceeding is a fair representation of ongoing Large Power operations, the potential future impact on customers is just as likely to reduce future rates as to raise them. The Company argued that this mechanism could reduce the incidence of future rate cases and could enable Minnesota Power to have a similar risk level and ROE to other utilities. The Company maintained that wholesale market sales have not been enough to recoup lost retail sales from the Large Power class.

The Department recommended denial of Minnesota Power's proposed Large Power sales true-up. The Department argued that the proposal was inconsistent with basic utility ratemaking principles. The Department maintained that Minnesota Power is not guaranteed a certain return but must prudently operate its business and navigate changing economic conditions just like any other firm. The Department noted that it is unlikely that ratepayers would benefit from a credit as a result of this mechanism and are much more likely to be surcharged. The Department also noted that the proposal could aggravate the situation it was designed to address by shifting the burden of one plant closure onto the remaining Large Power and other customers, which could cause additional closures.

The OAG recommended denial of the proposal, arguing that any benefits to customers are unlikely to materialize and the mechanism is unlikely to prevent a future rate case. The OAG noted that a decoupling mechanism, a regulatory tool designed to separate a utility's revenue from changes in energy sales, could achieve Minnesota Power's revenue true-up goals while promoting state policy objectives to reduce energy consumption.

LPI also recommended denial because the true-up inappropriately shifts cost recovery risk from the Company and its shareholders to ratepayers. LPI argued that declines in Large Power demand allow the Company to use transmission and production infrastructure in wholesale transactions, and the Company has not adequately demonstrated that the absence of a sales true-up will deprive it of the opportunity for a fair rate of return. LPI also noted that similar mechanisms for other utilities have had additional ratepayer protections, such as time limits and cost caps, that are lacking from Minnesota Power's proposal.

C. Administrative Law Judge Recommendation

The Administrative Law Judge found that the Company did not meet its burden to show its proposed sales true-up is reasonable for ratepayers. The ALJ agreed with the Department and other intervenors that the Company's proposal inappropriately shifts business and operations risks properly borne by the shareholders to the customers. The Judge was also persuaded that the proposal, like other rider proposals, would undermine the utility ratemaking framework and disincentivize efficient management by the Company. Finally, the Judge expressed concern with the significant downside risk presented to other customers in the form of large and unexpected surcharges.

D. Commission Action

The Commission agrees with the Administrative Law Judge that Minnesota Power's proposed Large Power Sales true-up is not reasonable and should not be approved. The Company has not adequately demonstrated why the Commission should circumvent traditional ratemaking principles to shift business and operations risk from the Company's shareholders, who earn a rate of return as compensation for that risk, to ratepayers. Other parties have shown how ratepayers would be unlikely to benefit from this proposal and would likely be harmed. The Commission therefore declines to adopt the Large Power sales true-up.

XXXIV. Property Tax True-Up

A. Introduction

Minnesota Power proposed a property-tax true-up mechanism that would compare each year's property tax expense to the 2022 test year baseline and surcharge or credit customers for the difference.

B. Positions of the Parties

Minnesota Power argued that its proposed property tax true-up would be useful because various parts of the valuation analysis are highly discretionary with the Department of Revenue, rendering the property tax expense somewhat unpredictable, and because there is a long lag—around eighteen months—between the estimation of the property tax expense and when the Company receives its actual property tax bills. The Company noted that the true-up it proposed was consistent with the true-up processes that Xcel Energy and CenterPoint Energy Resources d/b/a CenterPoint Energy Minnesota Gas (CenterPoint) use.

The Department recommended denial of the proposal, arguing that it was inconsistent with ratemaking principles and unnecessary given the predictability of Minnesota Power's annual property tax obligations. The Department explained that true-up mechanisms or riders should be used sparingly because they circumvent the ratemaking process by only accounting for fluctuations in certain costs, allowing for the opportunity for further recovery without facing scrutiny of other costs, which may be lower than test-year costs. The Department further explained that riders should only be used in situations where costs change dramatically and unpredictably, are substantial in magnitude, and are due to factors beyond the utility's control. The Department noted that in the past five years, the Company's property taxes have only twice changed by more than five percent, and only after significant investments in utility plant. In addition, the Department's expert found that the Minnesota Department of Revenue's annual market value determination (which is used by local governments to assess property taxes) is highly correlated to the original cost of Minnesota Power's investment. The Department distinguished the circumstances behind Xcel Energy's and CenterPoint's property tax true-ups.

C. Administrative Law Judge Recommendation

The Administrative Law Judge found that Minnesota Power's proposed property tax true-up was supported by the record, reasonable, and should be approved. He found that the Company has strong incentives to prudently manage and mitigate its property tax expense because it is accountable to its customers and its shareholders, as well as the Commission and found persuasive the fact that the Company advocates and negotiates with the Department of Revenue every year to ensure it pays the lowest property taxes possible.

D. Commission Action

The Commission respectfully disagrees with the Administrative Law Judge that the property tax true-up is reasonable and should be approved. The Commission is persuaded by the Department's arguments that the true-up is unnecessary due to the relative predictability of the Company's annual property tax obligations. As the Department notes, in the past five years, Minnesota Power's property taxes have only twice changed by more than five percent, and these two increases coincided with Minnesota Power making significant capital investments in utility plant.

The Commission seldom approves tracker mechanisms or riders such as the one proposed by Minnesota Power because they undermine the traditional ratemaking framework by only accounting for fluctuations of certain costs outside of a rate case. Riders are reasonable when costs change dramatically and unpredictably, are substantial in magnitude, and are due to factors beyond the utility's control. Minnesota Power's property tax expense does not meet these criteria, and therefore the Commission will not approve the proposed property tax true-up mechanism.

XXXV. Energy-Intensive Trade-Exposed Rider

A. Introduction

Minn. Stat. § 216B.1696 allows utilities to propose alternative rate schedules designed to ensure competitive electric rates for energy-intensive trade-exposed (EITE) customers. The statute defines EITE customers to include large industrial facilities such as iron mining facilities, paper mills, wood products manufacturers, and steel mills.

Minnesota Power's EITE rider had an initial term of four years with an expiration of February 1, 2021. The Commission then granted Minnesota Power's petition to extend the EITE rider until final rates are implemented in this rate case.

B. Positions of the Parties

LPI opposed discontinuing the EITE rider. LPI argued that it would be inconsistent with state policy to discontinue the EITE Rider, since Minn. Stat. § 216B.1696 states that the energy policy of the state is to "ensure competitive electric rates for energy-intensive trade-exposed customers." LPI argued there is no basis to ignore this policy and the undisputed fact that existing rates for EITE customers are well above the national average and rising. At a minimum, LPI argued that elimination of the EITE rider should be a factor in mitigating the impact of the Company's proposed increase in Large Power rates.

The Department supported elimination of the EITE rider and argued that LPI did not adequately develop its opposition to the elimination of the EITE rider in witness testimony or during the evidentiary hearings.

C. Administrative Law Judge Recommendation

The Administrative Law Judge recommended approval of the Company's proposed tariff eliminations.

D. Commission Action

The statute governing EITE rate schedules authorizes Minnesota Power to propose EITE rate options for Commission approval,[42] and Minnesota Power has opted not to request another extension of the EITE rider. The Commission agrees with the Department that an additional extension of the EITE rider was not adequately developed during the evidentiary hearings and the record lacks support for an extension. The Commission agrees with the Administrative Law Judge and will therefore approve Minnesota Power's proposal to discontinue the EITE rider.

XXXVI. Interim Rates Refund

A. Introduction

Once the Commission determines the final rates in a rate case, the utility refunds or surcharges ratepayers for the difference between interim and final rates, depending on whether final rates are higher or lower than interim rates.[43]

B. Positions of the Parties

Minnesota Power proposed to handle final interim rates and any refunds or surcharges after the Commission determines final rates.

LPI asserted that, should an interim rate refund be required in this case, it should be distributed to customers in the same proportion as was previously paid by that customer. LPI requested that all customers receive an interim rate refund in accordance with the interim rates paid, regardless of the potential for surcharges to one class and refunds to others.

[42] Minn. Stat. § 216B.1696, subd. 2.

[43] Minn. Stat. § 216B.16, subd. 3.

C. Administrative Law Judge Recommendation

The Administrative Law Judge concluded that the Commission did not refer the issue of interim rates to the Office of Administrative Hearings and therefore declined to make a recommendation.

D. Commission Action

At the resolution of a rate case, the Commission typically directs the utility to file a compliance filing detailing, among other issues, how the utility proposes to handle any interim-rate refunds or surcharges that are necessary based on the Commission's final rates determination. The Commission sees no reason to deviate from past practice in this case; LPI will have an opportunity to raise these arguments when the Commission considers Minnesota Power's compliance filing. The Commission will therefore direct Minnesota Power to file an interim rate refund proposal addressing the refund issue as appropriate, based on the final revenue requirement and rates ordered in this case.

XXXVII. Resolved Issues

On a number of issues, the parties reached agreement or resolved outstanding issues by the time the Commission met to consider the matter. The Commission concurs on the reasonableness of the resolutions reached by the parties and will adopt them, as set forth in the ordering paragraphs below.

XXXVIII. Motion to Strike

The Department filed a motion to strike information filed by the Company on January 20, 2023, stating that the Company's filing was untimely and that the veracity of the data contained therein on taconite production, bad debt expense, employee head count, and rate base balances could not be corroborated.

The Commission will deny the motion to strike. The Commission carefully weighs all evidence filed by the close of the record and considers the entirety of the record, the positions of the parties, and the ALJ's Report when making final decisions. For these reasons, the Commission is not persuaded that it is necessary to strike the filing, the probative value of which the Commission weighs in light of all other available record information.

XXXIX. Compliance Filings

The Commission will authorize comments on all compliance filings within 30 days of the date they are filed. However, comments are not necessary on Minnesota Power's proposed customer notice.

ORDER

1. The Commission adopts the Findings of Fact, Conclusions of Law, and Recommendations of the Administrative Law Judge of September 1, 2022, except as set forth herein.

2. The Commission denies Minnesota Power's request to include its Prepaid Pension Asset in the 2022 test year rate base.

3. The Commission denies Minnesota Power's request to include its prepaid OPEB asset in the 2022 test year rate base.

4. Based on proposed amounts from initial filing based on projections, the Commission approves the 2022 test year beginning-of-year utility plant balance of $3,133,963,314 for the total company and $2,707,710,895 for the Minnesota jurisdiction.

5. The Commission approves the 2022 test year end-of-year balance for transmission capital projects.

6. The Commission finds that Taconite Harbor is not used and useful for the 2022 test year and denies Minnesota Power's request to earn a return on the facility's remaining net book value.

7. The Commission authorizes Minnesota Power to recover Taconite Harbor Energy Center's annual depreciation expense ($9,485,120), Operations & Maintenance Expenses ($518,522), Property Taxes ($280,018) and Property Insurance ($96,851).

8. Minnesota Power must establish a sunset provision ending December 31, 2026, for the Company's recovery of Taconite Harbor Energy Center's remaining depreciation expense.

9. Minnesota Power must establish a sunset provision for Taconite Harbor Energy Center Operations and Maintenance (O&M) expenses, such that the Company will cease collecting these O&M expenses once it begins decommissioning the facility.

10. Based on a four-year average from 2018–2021, the Commission approves 2022 test year bad debt expense of $771,130.

11. The Commission approves Minnesota Power's proposed increase in employee headcount budget to 1,063 full time and part-time employees for the 2022 test year.

12. The Commission approves 2022 test year expense for Base Employee Compensation of $68,384,774 on a total company level and $60,762,402 on a Minnesota Jurisdictional level.

13. Minnesota Power must report on an annual basis beginning February 28, 2023, the number of employees and the associated base compensation amount that addresses the Company's rate case filing.

14. The Commission approves 2022 test year expense for High Performance Awards of $350,880 on a total Company level and $311,972 on a Minnesota jurisdictional level.

15. The Commission approves 2022 test year expense for Defined Contribution Plan of $6,828,196 on a total Company level and $6,071,037 on a Minnesota jurisdictional level.

16. The Commission approves 2022 test year expense for Healthcare Plan of $7,963,722 on a total Company level and $7,080,648 on a Minnesota jurisdictional level.

17. The Commission approves Minnesota Power's proposed test year expense for Federal Energy Regulatory Commission (FERC) Account 923.

18. The Commission approves Minnesota Power's proposed test year expense for FERC Account 924.

19. The Commission approves Minnesota Power's proposed test year expense for FERC Account 925.

20. The Commission disallows recovery of $31,231 (total Company) related to MUI and AGA dues and memberships costs.

21. The Commission approves Minnesota Power's initial recovery request of $4,739,674 (total Company) including Schedule H-6 and Schedule H-8 amounts, minus the $1,500 (total Company) adjustment agreed to by the Company.

22. The Commission disallows $37,638 in employee recognition expenses.

23. The Commission approves 50% recovery of Minnesota Power's Economic Development, which results in a $171,362 (Minnesota jurisdictional) adjustment.

24. Minnesota Power shall incorporate production tax credits of $39,924,985 into base rates.

25. The Commission approves recovery of 50% of Minnesota Power's $1.9 million UIPlanner costs.

26. Minnesota Power's Test Year Pension Expense is set at $3,588,541 on a total Company basis and $3,190,618 on a Minnesota jurisdictional basis.

27. The Commission approves Minnesota Power's Service Center Sales Adjustment for the 2022 Test Year, of $60,949 total Company ($54,190 Minnesota jurisdictional) as corrected by the Department.

28. The Commission adopts the recommendation of the Office of the Attorney General—Residential Utilities Division that no test year adjustment is necessary for the $3.9 million Thomson Restoration Project overrun.

29. The Commission denies an adjustment related to the Huber Land Sale.

30. A sunset provision applies to the following items: BEC 1 & 2 Regulatory Asset, Rate Case Expense Regulatory Asset, Credit Card Fees Regulatory Liability, Service Center Sales Regulatory Liability.

31. The Commission authorizes a 9.65% return on equity, a 52.50% cost of equity, and a 47.50% cost of long-term debt.

32. The Commission approves Minnesota Power's 2022 test year residential sales forecast of 1,037,401 megawatt hours.

33. The Commission hereby adopts the Department's alternative sales forecast for Minnesota Power's Mining and Metals customers.

34. Minnesota Power shall reflect sales to Cenovus and ST Paper in the test year.

35. The Commission approves Minnesota Power's 2022 test year sales forecasts as follows: pipelines of 316,335 megawatt hours (MWh), other industrial of 286,024 MWh, commercial of 1,184, 475 MWh, government & light of 53,626 MWh, and municipals of 604,042 MWh.

36. The Commission adopts Minnesota Power's method of classifying advanced metering infrastructure (AMI) costs as 100% customer related, increasing the Minnesota jurisdictional revenue requirement by $822,780 and reallocating costs among the retail classes.

37. Minnesota Power must allocate AMI metering costs as 1/3 energy related, 1/3 demand-related, and 1/3 customer related in its next general rate case or propose in its next general rate case filing another allocation method based on the study.

38. The Commission adopts the revenue apportionment proposed by Minnesota Power, reflecting an across-the-board even allocation to all rate classes with the understanding that the Company will not surcharge residential ratepayers for the difference between interim and final rates.

39. The Commission adopts the Residential Service Charge of $9.00 per month.

40. Minnesota Power must implement the low-income, low-usage rate proposed by ECC.

41. The Commission adopts the Customer Service Charges as proposed.

42. The Commission approves the tariff language changes proposed by Minnesota Power and recommended for approval by the Department but leaves the General Service and Large Power and Light discount at 11%.

43. The Commission adopts the FPE rider change to include Fuel and Purchased Energy on customer bills as a separate line item.

44. The Commission denies the Large Power Sales True-up Mechanism, as recommended by the ALJ.

45. The Commission denies the Company's request for approval of a property tax tracker and true-up mechanism.

46. The Commission approves Minnesota Power's test year level of property tax expense.

47. The Commission eliminates the EITE Rider from the Minnesota Power tariff.

48. The Commission adopts increased discount for low-income, low-usage customers to 40% for the first 600 kWh pursuant to the Settlement.

49. The Commission adopts Proposed changes for Dual Fuel and Dual Fuel Plus Customers.

50. The Commission adopts the elimination of the Municipal Pumping Schedule.

51. The Commission adopts the proposed General Service Monthly Customer Service Rate.

52. The Commission adopts the proposed LL&P rate structure.

53. The Commission adopts the proposed Voltage Discounts.

54. The Commission adopts the proposed LL&P Time-of-Usage Rider.

55. The Commission adopts the proposed updates to Foundry, Forging and Melting Rider.

56. The Commission adopts the proposed changes to Non-Metered Rider.

57. The Commission adopts the proposed Lighting Tariff changes.

58. The Commission adopts the proposed Large Power rate structure.

59. The Commission authorizes replacement of the Large Power Interruptible Service Rider with the Large Power Demand Response Rider and adopts related changes.

60. The Commission adopts the proposed changes to Non-Contract Large Power Service rate, set at 20% higher than the standard Large Power demand charge.

61. The Commission adopts the proposed changes to LP Incremental Production Service Rider.

62. The Commission approves the proposed AMI Opt-Out Charge for Residential customers of $20 per month.

63. Minnesota Power must file the following information in its semi-annual reporting on the transition to Time-of-Day rates:

    a. Number of customers opting out of AMI Meter use.
    b. Report of estimated costs associated with opt-out of AMI meter use.

64. The Commission approves the following tariff changes, as detailed in the ALJ's Report:

a. Elimination of the General Service/Large Light & Power Area Development Rider
b. Elimination of the Large Power Area Development Rider
c. Elimination of Miscellaneous Electric Revenue Charges for Transformer Rentals
d. Clarifications to the rules for extensions of service where costs are $30,000 or less
e. Changes to the Rider for Business Development Incentive
f. Changes to the Rider for Released Energy
g. Changes to the Rider for Voluntary Energy Buyback
h. Changes to the Pilot Rider for Residential Time-of-Day Service
i. Closure of the Community-Based Energy Development Tariff to new business due to statute repeal.

65. Minnesota Power must file an interim rate refund proposal addressing the refund issue as appropriate, based on the final revenue requirement and rates authorized in this case.

66. Within 30 days, Minnesota Power must file 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.
   iii. These schedules shall include but not be limited to:
   - Total revenue by customer class;
   - Total number of customers, the customer charge and total customer charge revenue by
   - customer class; and
   - For each customer class, the total number of energy and demand related billing units, the per unit of energy and demand cost of energy, and the total energy and demand related sales revenues.
   iv. Revised tariff sheets incorporating authorized rate design decisions.
   v. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.
b. A revised base cost of energy, supporting schedules, and revised fuel adjustment tariffs to be in effect on the date final rates are implemented.
c. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.
d. A computation of the conservation cost recovery clause based upon the decisions made herein for inclusion in the final Order. Minnesota Power shall file a schedule detailing the Conservation Improvement Program tracker balance at the beginning of interim rates, the revenues (conservation cost recovery clause and Conservation Improvement Program Adjustment Factor) and costs recorded during the period of interim rates, and the Conservation Improvement Program 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.

67. Comments on all compliance filings are due within 30 days of the date they are filed. However, comments are not necessary on Minnesota Power's proposed customer notice.

68. The Commission denies the Department's motion to strike information filed by Minnesota Power on January 20, 2023.

69. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Will Seuffert
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 or speech impairment may call using their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

CERTIFICATE OF SERVICE

I, Robin Benson, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission
FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Docket Numbers: **E-015/GR-21-335**

Dated this **28th** day of **February, 2023**

/s/ Robin Benson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties	450 Syndicate St N Ste 35 Saint Paul, MN 55104	Electronic Service	No	OFF_SL_21-335_21-335
Lori	Andresen	info@sosbluewaters.org	Save Our Sky Blue Waters	P.O. Box 3661 Duluth, Minnesota 55803	Electronic Service	No	OFF_SL_21-335_21-335
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Kristin	Berkland	kristin.berkland@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-335_21-335
David F.	Boehm	dboehm@bkllawfirm.com	Boehm, Kurtz & Lowry	36 E 7th St Ste 1510 Cincinnati, OH 45202	Electronic Service	No	OFF_SL_21-335_21-335
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-335_21-335
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-335_21-335
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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