May 15, 2026

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**VIA EFILING**

Sasha Bergman
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: *In the Matter of the Application of Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*
MPUC Docket No. E-002/GR-24-320

Dear Ms. Bergman:

Enclosed please find the Exceptions to the Findings of Fact, Conclusions of Law and Recommendations of the Administrative Law Judge filed on behalf of Northern States Power Company d/b/a Xcel Energy in the above-referenced docket. This document has been filed with the eDocket system and served on the attached service list. Also enclosed is our Affidavit of Service.

Very truly yours,

WINTHROP & WEINSTINE, P.A.

*/s/ Eric F. Swanson*

Eric F. Swanson

Enclosures

42849284v1

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## CERTIFICATE OF SERVICE

I, Victor Barreiro, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

**DOCKET NO. E002/GR-24-320**

Dated this 15th day of May 2026

/s/

________________________________

Victor Barreiro
Regulatory Administrator

**BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION**
**121 Seventh Place East, Suite 350**
**Saint Paul, Minnesota 55101-2147**

**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**

**MPUC Docket No. E002/GR-24-320**

# EXCEPTIONS TO THE FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATIONS OF THE ADMINISTRATIVE LAW JUDGE

**MAY 15, 2026**

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**STATE OF MINNESOTA**
**BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION**
121 Seventh Place East, Suite 350
St. Paul, Minnesota 55101-2147


| | |
|---|---|
| Katie Sieben | Chair |
| Hwikwon Ham | Commissioner |
| Audrey Partridge | Commissioner |
| Joe Sullivan | Commissioner |
| John A. Tuma | Commissioner |


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

MPUC Docket No. E002/GR-24-320

**EXCEPTIONS TO THE FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDATIONS OF THE ADMINISTRATIVE LAW JUDGE**

## INTRODUCTION

Northern States Power Company, d/b/a Xcel Energy (Xcel Energy or Company) files these Exceptions to the Administrative Law Judge's (ALJ) April 29, 2026 Findings of Fact (Findings), Conclusions of Law and Recommendations (collectively, the Report) in the above-captioned matter. The Report demonstrates a thorough review of the extensive record in this proceeding. The Report clearly and accurately articulates that Xcel Energy "is entitled to recover necessary, ongoing expenses incurred in the business of providing utility service"[1] and, in nearly 900 specific Findings on disputed issues, found that the Company met its burden of proof on many of the disputed issues, while on others finding the Company failed to meet its burden. As shown in the Company's May 11, 2026

[1] Report at Finding 91.

Financial Schedules Filing, the ALJ Report, if adopted in full, would result in an increase for 2025 of approximately $117.1 million (or about 3.2 percent and an incremental increase of approximately $130.6 million (or about 3.5 percent) in 2026.[2]

Xcel Energy generally agrees that the majority of the ALJ's Findings provide an accurate summary of the record and an appropriate application of Minnesota law to that record. However, the Company takes exception to certain Findings as inconsistent with the weight of the evidence in the record or inconsistent with applicable law and takes exception to those Findings.[3]

Xcel Energy worked throughout this proceeding to explore settlement possibilities and to resolve as many issues as possible with the parties, in an effort to minimize the disputed issues before the Minnesota Public Utilities Commission (Commission). As a result of those efforts, a number of issues were successfully resolved through testimony, as set forth in detail in ALJ Findings 94-320. The Company supports those Findings in their entirety. And while the Report addresses a number of still unresolved issues, a handful of issues account for the key points of dispute between the parties – particularly regarding the necessary and appropriate revenue increase. Those issues include:

- The appropriate return on equity (ROE);

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[2] Xcel Energy Comments – Financial Schedules, eDocket File No. 20265-231675-01 (May 11, 2026). The ALJ Report recommended increases compared to the Company's Rebuttal requests of $208.4 million in 2025 and an incremental $156.9 million in 2026. Exhibit (Ex.) Xcel-16 at 20 (Liberkowski Rebuttal).

[3] The Company focuses on select issues in these Exceptions. Unless specifically stated otherwise, the Company continues to support its position as set forth in its Initial and Reply Briefs and its Proposed Findings, filed on February 25, 2026.

- Employee compensation, including base pay and executive compensation;
- Appropriate ratemaking treatment of the prepaid pension asset;
- Certain operating and maintenance (O&M) expenses; and
- The appropriate ratemaking treatment of the Riverside plant.

As the Commission considers the Report, it may be helpful to first focus on these key issues, and the Company discusses them first, below, including those issues where the Company supports the ALJ Findings. The Company then sets forth its Exceptions to the ALJ Findings on revenue requirements, class cost of service and rate design issues. Finally, the Company addresses certain other Findings on policy-related issues or other forward-looking matters.

## I. KEY ISSUES IN DISPUTE BETWEEN THE PARTIES

### A. Return on Equity (Findings 883-994, pp. 139-159)

The Report provides a comprehensive discussion of the applicable law, the record evidence and Commission precedent regarding the determination of the appropriate return on equity (ROE), with over 100 Findings on this issue alone. Four parties provided substantive ROE testimony in this proceeding – Xcel Energy, the Minnesota Department of Commerce (Department), the Citizens Utility Board (CUB) and Xcel Large Industrials (XLI). In the end, the ALJ recommended no one party's position on this issue. Rather, the ALJ recommended the Commission "rely primarily on the Two-Growth DCF model when setting Xcel's ROE in this proceeding"[4] and establish an authorized ROE of 9.80 percent,

[4] Report at Finding 973.

noting its proximity to the national average authorized for vertically integrated electric utilities of 9.77 percent.[5]

In its discussion of ROE, the Report first summarizes controlling law regarding the establishment of a just and reasonable ROE. As the Report recognizes:

> The United States Supreme Court established the hallmarks of a reasonable return on capital, including a reasonable rate of return on common equity, in the landmark cases of *Bluefield* and *Hope*. The Court has stated, "What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, *having regard to all relevant facts*."
>
> The Court has also stated that:
>
> "From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By this standard the *return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks*. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[6]

The Report further explains that the Minnesota Supreme Court adopted the *Bluefield* and *Hope* requirements in *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n,* 302 N.W.2d 5 (Minn. 1980), including *Bluefield's* command that:

> Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[7]

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[5] Report at Finding 944, g.

[6] Report at Findings 885, 886 (quoting *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679 at 692, 43 S. Ct. 675 at 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 at 603, 64 S. Ct. 281 at 288 (1944) (emphasis added).

[7] Report at Finding 887 (quoting *Hibbing*, 302 N.W.2d at 10).

Finally, the Report notes that the *Hibbing* Court described the establishment of a rate of return as a *quasi-judicial function which involves a factual determination* of "a fair rate of return which will provide earnings to investors comparable to those realized in other businesses which are attended by similar risk,"[8] and that the Commission has similarly observed that "[s]etting the cost of equity is a *fact-intensive and record-specific judgment*."[9]

Much of the ALJ's subsequent ROE discussion and analysis appropriately applies these principles. For example, the Report reiterates the Commission's finding in the Company's last rate case that the Two-Growth DCF model "provides a fundamentally sound framework through which to analyze the Company's relative risk in relation to comparable companies, and through which to evaluate the Company's financial integrity and ability to attract investors in light of current as well as expected market conditions"[10] – precisely the analysis required by the *Hope*, *Bluefield* and *Hibbing* decisions. The Company also agrees with the Report's refusal to adopt the Department or CUB ROE recommendations. As the ALJ appropriately found, neither the DOC nor CUB witnesses demonstrated that "a drastic departure from past Commission practice" in determining the appropriate ROE is warranted.[11]

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[8] Report at Finding 888 (quoting *Hibbing*, 302 N.W.2d at 11) (emphasis added).

[9] Report at Finding 339 (quoting *In re Appl. of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, MPUC Docket No. G-011/GR-17-563, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 26 (Dec. 26, 2018) (emphasis added).

[10] Report at Finding 972.

[11] Report at Finding 927.

The Company takes exception, however, to two aspects of the ALJ Report concerning ROE:[12] (1) the Report's Findings concerning an alleged disparity between "authorized ROEs" and a utility's "cost of equity" and that there "is reason to be concerned that authorized utility ROEs systemically overstate the true cost of equity for rate regulated utilities;"[13] and (2) the Report's recommendation that some weight be given to the Department's Multi-Stage growth DCF analysis.[14] These Findings, as with the testimony of CUB and Department witnesses, imply that regulatory bodies, including this Commission, have been setting ROEs too high for decades. Notably, neither the ALJ Findings nor the record can explain *why* commissions would do so, they just declare it is being done.[15] The record cannot support such Findings.

The ALJ appears to base his concern regarding a gap between "cost of equity" and "authorized ROEs," in significant measure, on what the Report refers to as "empirical evidence that allowed ROEs typically exceed the cost of equity," comprised of third party estimates of the cost of equity.[16] However, the record demonstrates the meaninglessness of this "evidence." Specifically, attempting to rely on these other estimates of cost of equity, including estimates from financial institutions and broad surveys, raises a number of concerns.[17] For example, it is not clear how the survey respondents derived their inputs,

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[12] The Company also takes exception to certain Findings regarding capital structure, as discussed in Section IV, C, below.
[13] Report at Findings 919-927.
[14] Report at Findings 978, 979, 981, 984 -986.
[15] *See*, Ex. DOC-12 at 78 (Addonizio Direct).
[16] Report at Finding 920, citing Ex. DOC-12 at 70-71 (Addonizio Direct).
[17] Ex. Xcel-25 at 37 (Nowak Rebuttal).

such as the [market risk premium] and risk-free rate, as well as estimates for the market return.[18] Further, it is not apparent for what purpose these responses and estimates were developed (e.g., as individual investors or with return requirements used in their specific line of business). This lack of transparency as to how or why the estimates were developed makes it difficult if not impossible to verify the inputs and assumptions relied upon to derive the cost of equity estimates.[19] The Report omits any reference to this record evidence, and to the fundamental and inherent weaknesses in the other estimates, undermining the ALJ Findings on this matter.

As for CUB and the Department, their criticism of decades of regulatory precedent is based on their apparent belief that the Multi-Stage DCF model using projections of average United States Gross National Product (USGDP) growth at the terminal growth rate, *an analysis the Commission has never relied* on in determining the allowed ROE for a Minnesota utility, appropriately determines a utility's cost of equity.[20] This belief in their version of the Multi-Stage DCF leads the these parties to put credence in analytical results for estimating Xcel Energy's ROE that are *more than 100 basis points below any authorized ROE for any vertically integrated electric utility in the decades of available data.*[21] Because of these parties' self-created gap between their analytical results and actual

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[18] Ex. Xcel-25 at 37 (Nowak Rebuttal).
[19] Ex. Xcel-25 at 37-38 (Nowak Rebuttal).
[20] Ex. Xcel-25 at 27-28 (Nowak Rebuttal); Transcript (Tr.) Volume (Vol.) 2 (Dec. 18, 2025) at 464 (Addonizio).
[21] Ex. Xcel-25 at 3 (Nowak Rebuttal).

authorized ROEs, they also must abandon their analytical results in recommending a final ROE, demonstrating the unreasonableness of their analyses.

As Company witness Mr. Nowak explained, rather than question the reasonableness of the inputs and assumptions of their Multi-Stage models, particularly their use of USGDP growth projections, the Department and CUB witnesses conclude that the cost of equity is below the current level of authorized ROEs. However, the suggestion that utility commissions have systematically overestimated the cost of equity in setting allowed returns is inconsistent with reasonable market-based models. In other words, had they used the reasonable, market-based models and inputs traditionally relied on by the Commission, they would not have needed to ignore their analytical results, nor would they have needed to argue that regulatory commissions, including this Commission, have been determining ROEs incorrectly for decades.[22]

To be clear, the Commission has *not* "set allowed ROEs above the cost of equity" in its rate case orders, as alleged by the Department and CUB and suggested by the ALJ Findings.[23] Instead, the Commission has set allowed ROEs consistent with its view of how to best determine the cost of equity – through the use of the Two-Growth DCF model, and informed by other industry-standard models such as the CAPM. Sound and reasonable market-based analysis of the cost of equity, as represented by the Two-Growth DCF model, reveals no significant "gap" between a utility's cost of equity and its allowed ROE. For these reasons, the Commission should not adopt Findings 919-927.

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[22] Ex. Xcel-25 at 3, 63-64 (Nowak Rebuttal).
[23] Ex. DOC-12 at 78 (Addonizio Direct).

Regarding the appropriate cost of equity analysis, the Report accurately notes that the Commission has traditionally relied on DCF analyses and "has long relied on either Constant Growth DCF or Two-Growth DCF models, with consistent preference for the Two-Growth DCF for over the past decade."[24] The ALJ also recognized the Commission has never relied on a Multi-Stage DCF analysis to determine an appropriate ROE.[25] Further, the Report found that the Multi-Stage DCF performed by the Department "represents an over-correction" to perceived weaknesses in the Two Growth DCF.[26]

Nonetheless, the Report recommends the Commission give at least some weight to the Department's DCF analysis in this proceeding for two reasons – "the implicit assumption that the Company will grow faster than the GDP in perpetuity"[27] and concern that analysts growth estimates used in the Two-Stage DCF have an "upward bias."[28] The record supports neither. In fact, the Report itself notes the problem with the Department's use of long-term GDP growth as the terminal growth rate in its analysis and that history demonstrates that industries such as utilities can grow faster than the GDP for extended periods.[29] As for an alleged "upward bias" to analysts' growth forecasts, Company witness Mr. Nowak explained that this outdated argument is no longer supported by real world evidence and has not been for decades. As Mr. Nowak testified, the Global Analysts Research Settlement (the "Global Settlement"), the result of an investigation by multiple

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[24] Report at Finding 971.
[25] Report at Finding 939.
[26] Report at Finding 981.
[27] Report at Finding 978.
[28] Report at Finding 985.
[29] Report at Finding 980.

financial regulators into alleged conflicts of interest between investment banking and securities research at brokerage firms, comprehensively addressed this concern by requiring financial institutions to insulate investment banking from analysis, prohibiting analysts from participating in "road shows," and requiring the settling financial institutions to fund independent third-party research.[30] Mr. Nowak further explained that Regulation AC, which became effective in April 2003, dictated that analysts must certify that "…the views expressed in the report accurately reflect his or her personal views, and disclose whether or not the analyst received compensation or other payments in connection with his or her specific recommendations or views."[31] Finally, a 2010 article in Financial Analysts Journal found that analyst forecast bias declined significantly or essentially disappeared after the Global Settlement. As stated there:

> After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[32]

For these reasons, in addition to taking exception to the ALJ Findings concerning an alleged divergence between "cost of equity" and Commission authorized ROEs, the

[30] Ex. Xcel-25 at 28-30 (Nowak Rebuttal).
[31] Ex. Xcel-25 at 28-29 (Nowak Rebuttal), citing Securities and Exchange Commission, 17 CFR PART 242 [Release Nos. 33-8193; 34-47384; File No. S7-30-02], RIN 3235-AI60 Regulation Analyst Certification.
[32] Ex. Xcel-25 at 29 (Nowak Rebuttal), citing Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010 at 105.

Company takes exception to the ALJ Findings regarding the Multi-Stage DCF analyses presented in this proceeding. Consistent with its precedent, the Commission should not give weight to these analyses in reaching its decision in this proceeding. Rather, to the extent the Commission looks to other analyses, it should consider the Constant Growth, CAPM, Risk Premium and Expected Earnings analyses presented by the Company, each of which supports the reasonableness of the Company's Two-Growth DCF that the ALJ found to be "the most reasonable estimate of the Company's ROE in the record."[33]

While the Company takes exception to these Findings, the record fully supports other key Findings. For example, the ALJ correctly found the record demonstrated that changing market conditions and ROE decisions around the country establish that the Company is entitled to an increase in its currently authorized ROE of 9.25 percent.[34] That record evidence includes:

- At the time of the Company's last rate case filing in October 2021, the 18-month trailing average authorized ROE for vertically integrated electric utility was 9.52 percent. By the time of the Initial Filing in the current case, the average authorized ROEs increased by approximately 30 basis points to 9.83 percent and average returns have remained at that level through 2025.[35]

- Since the Company's 2021 rate case was filed, every subsequent authorized ROE for a vertically integrated electric utility in the country has been higher than the Company's authorized ROE of 9.25 percent.[36]

- At the time of the Company's October 2021 rate case filing, the average yield on the 30-year Treasury was 2.06 percent. By the time of the Initial

[33] Report at Finding 994, c.
[34] Report at Finding 992, a.
[35] Report at Finding 994, a; Ex. Xcel-25 at 3 (Nowak Rebuttal).
[36] Ex. Xcel-25 at 3-4 (Nowak Rebuttal).

Filing in the current case, the average 30-year Treasury yield had risen to 4.54 percent and continued to increase to 4.88 percent in August 2025.[37]

- The 30-year Treasury yield, along with the trailing 18-month average authorized ROEs, has continued to increase since the Company's last rate case, in which the Commission authorized the 9.25 percent ROE.[38]

- In both the prior case and the current case, the Department provided Two-Growth DCF analyses consistent with the Commission's preferred ROE analytical approach. The mean result from the Department's Surrebuttal Two-Growth DCF analysis in this case is 10.57 percent,[39] nearly a 70 basis point increase relative the Department's Surrebuttal Two-Growth DCF analysis in the Company's last case.[40]

- Over the past three years, national average ROEs for vertically integrated utilities have ranged from 9.74 percent to 9.84 percent.[41]

And most notably, the ALJ specifically found:

> *The Two-Growth DCF analysis presented by the Company is the most reasonable estimate of the Company's ROE in the record*. The results of this model imply an ROE of 10.34 percent.[42]

As such, the Company's recommended ROE of 10.25 percent is fully supported and, in fact, a conservative estimate of the Company's appropriate ROE that balances customer and shareholder interests, while meeting the *Hope*, *Bluefield* and *Hibbing* standards.

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[37] Ex. Xcel-25 at 4 (Nowak Rebuttal). (Noting that while there is an expectation for the Federal Reserve to decrease interest rates, consensus projections demonstrate that future reductions in the Fed Funds rate will primarily affect short-term rates, with long-term rates expected to remain near current levels.)
[38] Ex. Xcel-25 at 4, 10 (Nowak Rebuttal).
[39] Ex. DOC-13 at 5 (Addonizio Surrebuttal).
[40] *See* Ex. Xcel-25 at 23 (Nowak Rebuttal) (filed prior to the Department filing its Surrebuttal Testimony in this case).
[41] Ex. XLI-1 at 15 (LaConte Direct); Tr. Vol. 2 (Dec. 18, 2025) at 320-321 (LaConte).
[42] Report at Finding 994, c. (emphasis added).

## B. Employee Compensation and Benefits

### 1. Base Pay (Findings 546-565, pp. 86-89)

The Company supports the ALJ recommendation to approve the Company's request for base pay in the 2025 Test Year and the 2026 Plan Year.[43] The ALJ properly found the information provided in the record sufficient to evaluate the reasonableness of the Company's proposal, and also rejected the Department's request that the Company be required to provide FTE forecasts in future rate cases.[44]

As the ALJ recognized, the proper starting point is to consider how the Company built its budget for base pay. The Company's base pay expense includes wages for bargaining and non-bargaining employees, and paid time off and overtime for all employees.[45] The Company developed its budget for base pay using current salary and headcount data that is fed from the Company's payroll system. Planned headcount additions or reductions in 2025 and 2026 are incorporated into the budget system based on current workforce plans at a business area level.[46] A 3.0 percent merit increase in base pay was applied for both bargaining and non-bargaining employees. The 3.0 percent increase for bargaining employees was based on their union contracts and the 3.0 percent increase for non-bargaining employees was based on a review of market compensation data, economic factors, and budget limitations.[47] The Company's 2025 and 2026 base pay

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[43] Report at Finding 564.
[44] Report at Finding 565.
[45] Ex. Xcel-28 at 25 (Robinson Rebuttal).
[46] Ex. Xcel-28 at 26 (Robinson Rebuttal).
[47] Ex. Xcel-28 at 26 (Robinson Rebuttal); Ex. Xcel-63 at 6-7 (Ly Rebuttal).

budgets include forecasted overtime associated with planned outages and overhauls at two nuclear facilities and Sherco 3.[48] On a year-over-year basis, the Company's 2025 base pay forecast is approximately 3.8 percent higher than its 2024 actual base pay expense, and the Company's 2026 base pay budget is approximately 0.8 percent higher than its 2025 budget.[49]

Despite record information on how the Company developed its budget, the Department argued that because the Company did not provide forecasted FTE count information, the Department was not able to analyze the reasonableness of the Company's base pay proposal.[50] The Department recommended the Company's base pay request be reduced, and recommended the Company be required to include an FTE count on a Minnesota jurisdictional basis in its next rate case.[51]

The ALJ persuasively explained why the Company cannot provide the FTE counts that the Department requested: it allocates labor costs, not employees and therefore FTE counts are not connected to the forecasted rate case base pay amounts.[52] One of the reasons that the Company allocates labor costs rather than employees is because NSPM employees provide services not just to Minnesota customers, but also to North Dakota and South Dakota. Additionally, employees of Xcel Energy Services, Inc. support the Company's

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[48] Ex. Xcel-28 at 26-27 (Robinson Rebuttal).
[49] Ex. Xcel-28 at 26 (Robinson Rebuttal).
[50] Ex. DOC-4 at 8 (Kehrwald Surrebuttal).
[51] Ex. DOC-3 at 14 (Kehrwald Direct).
[52] Report at Findings 555-558.

Minnesota operations, further complicating any attempt to tie FTE counts to forecasted labor costs.

The ALJ also appropriately recognized the absence of any legal authority mandating the Company present FTE counts in the precise manner requested by the Department.[53] The fact that the information does not exist, and is not something the Company can create, supports the ALJ's finding not to require the Company to provide forecasted FTE count information in future rate cases.[54]

### 2. Executive Compensation

#### a. Top Ten Executive Compensation (Findings 595-622, pp. 94-99)

The Commission should decline to adopt the ALJ's recommendation to disallow all compensation for the Company's top ten highest paid employees. This recommendation is inconsistent with the law, unsupported by the evidence presented in this proceeding, and is inconsistent with the Commission's treatment of other similar costs. Instead, the Commission should approve recovery of executive compensation as proposed, or at minimum, adopt an alternative recovery amount of these necessary costs of providing utility service.

There is no dispute on this record that a strong executive leadership team is essential to running a utility and as a result the compensation for these employees is a necessary cost

[53] Report at Finding 562.
[54] Report at Finding 565.

of service that should be allowed to be recovered from customers. As the ALJ expressly acknowledged:

> No party argues, nor could they do so seriously, that customers could enjoy the benefit of safe and reliable electric service without functioning executive leadership. Customers should pay a portion of the costs of that leadership.[55]

Despite this, the ALJ nevertheless recommended complete disallowance of all executive compensation costs while at the same time stating that such a disallowance "in perpetuity would be an unjust and untenable outcome . . . ."[56] The Company agrees and such an outcome would also be inconsistent with the recent direction provided by the Minnesota Court of Appeals in an appeal arising out of the Commission's decision on executive compensation from the Company's last electric rate case (Docket No. E002/GR-21-630).[57] In that decision, the Court of Appeals emphasized that the Commission must provide a result that "meet[s] the needs of the ratepayer *and* the utility."[58] This means that the Commission cannot focus solely on the perceived needs of customers, and wholly disallow these necessary costs of service. And yet, this is what the ALJ recommends in this proceeding.

To support this recommendation, the ALJ claims that three concerns identified in the Commission's decision on executive compensation in the Company's last electric rate case remain "unresolved" by the record in this proceeding.[59] First, the ALJ alleges that the

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[55] Report at Finding 619.
[56] Report at Finding 619.
[57] *In re Application by N. States Power Co. d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, No. A23-1672, 2025 WL 249995 (Minn. Ct. App. Jan. 21, 2025).
[58] *Id*. at *12 (emphasis in the original).
[59] Report at Finding 610.

Company's evidence that its compensation amounts for its executives are in line with the other utility employers in the labor market is "beside the point" and infers that the Company bears the burden of proving which portion of these costs should be borne by customers versus shareholders.[60] The ALJ's central premise is that because the Company did not prove "the amount that customer should pay," "the record supports no other specific level of recovery," thus warranting total disallowance.[61] The problem with this analysis is that it rests on a faulty premise that customers do not need to pay the utility's necessary costs of providing service. The Company's compensation study demonstrates that it pays its executives amounts that are competitive and market based.[62] These individuals possess unique skills for which the Company competes with other potential employers. As a result, the cost of these employees is a necessary cost of providing utility service, and the Company is entitled to recovery of these necessary costs from its customers. The fact that shareholders may also benefit from a specific cost does not mean that it is unnecessary for the provision of utility service.[63]

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[60] Report at Finding 610.

[61] Report at Finding 621.

[62] Ex. Xcel-66 at Schedule 2 (Mustich Direct).

[63] Even if it were appropriate to consider whether shareholders benefit in some measure from these costs, the ALJ's recommendation that all executive compensation costs should be disallowed because executives benefit both customers and shareholders is internally inconsistent with the recommendation that other costs that the ALJ concluded provide a mix a customer and shareholder benefits should be shared, in particular, investor relation costs. The ALJ expressly found that investor relations activities benefit shareholders by supporting access to capital and benefit customers by promoting financial stability and lowering the cost of capital, and on that basis recommended 50/50 sharing of costs rather than a categorical disallowance. Notably, the ALJ did not find that executive compensation costs were imprudent, unreasonable, or exclusively shareholder-oriented, and yet, the ALJ

Second, the ALJ echoes the intervenor theme that the incentive-based executive compensation aligns executives with shareholder interests, meaning their compensation should not be borne by customers.[64] As discussed further in the incentive compensation section of the Company's Exceptions, the Company's incentive compensation goals are customer-centered and include advancing the clean energy transition, improving the customer experience, maintaining affordable bills, and ensuring safety, reliability, and financial health.[65] The one piece of the Company's incentive compensation structure that both parties and the ALJ continue to focus on as evidence of shareholder alignment is the Company's Earnings per Share (EPS) threshold.[66] Yet, as the Company has explained the EPS threshold is simply a gating criteria designed to ensure the Company is performing at a minimum sustainable financial level before incentive compensation is paid out.[67] This financial safeguard benefits customers as well as shareholders by preventing Annual Incentive Program (AIP) payouts in years of financial underperformance.[68] In addition, the Company is seeking the same treatment of incentive compensation for all of employees, including executives. The ALJ has not identified any valid basis for treating executive incentive compensation differently from that of other employees.

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departed from the proportional recovery framework applied to investor relations without providing any support for this distinction.

[64] Report at Finding 611.

[65] Ex. Xcel-62 at Schedule 4 at 6 (Ly Direct); Ex. Xcel-63 at 17 (Ly Rebuttal).

[66] Report at Finding 611.

[67] Ex. Xcel-63 at 17 (Ly Rebuttal) ("the EPS threshold is simply a prudent management tool to ensure that the Company is financially stable enough to pay out AIP.").

[68] Ex. Xcel-67 at 10-11 (Mustich Rebuttal).

Finally, the ALJ states that the Commission's prior concerns about customer affordability from the Company's last rate case remain in this proceeding and warrant disallowance of these costs.[69] While the Company shares the ALJ and parties' concerns about affordability, the legally permissible remedy for such concerns is not to deny a necessary cost of service but to instead offer targeted affordability programs and to make measured changes to revenue apportionment. Minnesota law specifically provides that "ability to pay" should be considered as a factor in setting rates through the "establish[ment of] affordability programs for low-income residential ratepayers," not through denial of a necessary cost—whether tied to executive compensation or any other cost of service.[70]

The ALJ's complete disallowance of the Company's requested amount of executive compensation also ignores the substantial reduction that the Company has already made to these costs. The Company has not sought recovery of nearly 40 percent of its jurisdictionally-allocated executive compensation costs in this proceeding.[71] As a result, the Company's proposed amount for executive compensation is substantially below its actual costs of providing service, and represents a conservative request that should be approved.

Even if the Commission were to reject Xcel Energy's requested amount of executive compensation costs, the proper regulatory response is to determine a reasonable level based

[69] Report at Finding 612.
[70] Minn. Stat. § 216B.16, subd. 15.
[71] Ex. Xcel-63 at 29 (Ly Rebuttal); Report at Finding 596 ("Adjustments to the AIP and LTI compensation paid to these employees removed nearly $4.5 million from the Company's executive compensation request in this case.").

on the record—not to disallow the entirety of these costs. And while the Company believes that this record supports recovery of its requested executive compensation costs, there are alternative levels of cost recovery presented in this proceeding if the Commission wishes to consider them. Minnesota municipal utilities and electric cooperatives provide a relevant alternative compensation benchmark because they are customer-owned or publicly accountable entities. Schedule 6 to Company witness Yen Ly's Rebuttal Testimony provides a compilation of 2023 base pay for the top executive at 14 Minnesota municipal and cooperative utilities, together with those utilities' reported Minnesota electric customer counts, and an approximate annual cost per customer.[72] An excerpt from Schedule 6 is provided below.

[72] Ex. Xcel-63 at Schedule 6 (Ly Rebuttal).

**Excerpt from Company Witness Yen Ly's Rebuttal Schedule 6**

| Utility Name | Name | Title (Top Utility Job) | 2023 Base Pay Only | Approx MN Electric Customer Base Reported | Approx MN Electric Annual Cost/Customer |
|---|---|---|---|---|---|
| City of Anoka | Delbert Vancura | Electric Utilities Director | $145,463 | 12,242 | $11.88 |
| City of New Ulm | Kristine Manderfield | Utilities Director | $150,751 | 7,226 | $20.86 |
| City of Rochester | Tim McCollough | General Manager Utilities | $215,000 | 123,000 | $1.75 |
| Beltrami Electric Coop | Jared Echlemach | CEO | $230,236 | 39,061 | $5.89 |
| Blue Earth-Nicollet-Farbault Coop | David Sundermann | CEO | $269,814 | 18,881 | $14.29 |
| Crow Wing Coop P&L | Bruce Kraemer | CEO | $300,889 | 38,000 | $7.92 |
| Dakota Electric Assoc | Greg Miller | President/CEO | $405,178 | 109,000 | $3.72 |
| East Central Energy | Justin Jahnz | President/CEO | $236,642 | 62,000 | $3.82 |
| Freeborn-Mower Coop | James Krueger | President/CEO | $196,448 | 21,200 | $9.27 |
| Itasca-Mantrap Coop Electric Assoc | Christine Fox | CEO | $142,073 | 11,946 | $11.89 |
| Lake County Power | Mark Bakk | General Manager | $337,315 | 51,487 | $6.55 |
| Mille Lacs Energy Coop | Sarah Cron | CEO | $179,313 | 13,440 | $13.34 |
| Wright-Hennepin Coop | Tim Sullivan | President/CEO | $461,450 | 59,000 | $7.82 |
| Steele-Waseca Coop Electric | Sydney Briggs | General Manager | $205,727 | 11,900 | $17.29 |
| | | Average | $248,307 | 41,313 | $9.74 |
| | | Total (14 Leaders) | $3,476,299 | 578,383 | $6.01 |
| Xcel Energy | Bob Frenzel | Chairman, President & CEO | $432,272 | 1,500,000 | $0.29 |

| | | | NSPM 2025 Budget Estimate* | Approx NSPM MN Electric Customer Base | Approx NSPM MN Electric Annual Cost/Customer |
|---|---|---|---|---|---|
| Xcel Energy | Bob Frenzel | Chairman, President & CEO | $2,494,943 | 1,500,000 | $1.66 |
| Xcel Energy | NSPM Top 10 Total Request | Titles as of 2023 for 2024 filing | $7,301,543 | 1,500,000 | $4.87 |

* Budget Estimate includes NSPM MN Electric allocated Base Salary, AIP (20% Cap) and LTI grant amounts (Environmental and Time-Based)
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Schedule 6 shows that the aggregated annual cost per customer for the base pay of a municipal or electric cooperatives top executive is approximately $6.01, with some paying well over $10 per customer.[73] In contrast, the Company's Minnesota electric jurisdictional share of Xcel Energy's CEO base pay equates to approximately $0.29 per customer annually, and the CEO total compensation included for recovery equates to approximately $1.66 per customer annually.[74] Further, the Company's *total* top ten executive compensation request equates to approximately $4.87 per customer annually.[75]

[73] Ex. Xcel-63 at Schedule 6 (Ly Rebuttal).
[74] Ex. Xcel-63 at Schedule 6 (Ly Rebuttal).
[75] Ex. Xcel-63 at Schedule 6 (Ly Rebuttal).

While the Company initially offered these benchmarks as evidence of the reasonableness of its executive compensation request, the Commission could use this same dataset as record support for an alternative recovery amount for executive compensation. Specifically, the Commission could set the Company's rate recovery in this proceeding by referencing what Minnesota municipal and cooperative customers fund for executive leadership, adjusted for economies of scale where appropriate.

Minnesota ratemaking law requires the Commission to set rates that reflect the reasonable and necessary cost of furnishing service (including prudently incurred labor costs) and executive leadership is a necessary cost. Given this, the ALJ's recommendation to disallow recovery of all compensation for the Company's top executives is neither supported by law nor the record in this case. Accordingly, Xcel Energy requests that the Commission reject the ALJ's recommendation on this issue and instead: (1) allow recovery of executive compensation as proposed by the Company or (2) adopt an alternative recovery amount based on the record provided in this case.

**b. New Proceeding on Executive Compensation (Finding ¶ 622, p. 99)**

The Report also recommends the Commission "initiate a proceeding" to examine the Company's executive compensation and determine the appropriate level of recovery for these costs.[76] While the Commission may open such a docket to examine this issue for future, not yet filed rase cases, it cannot use such a proceeding as the rationale for denying the Company's recovery of a necessary cost of service in this case – especially where the

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[76] Report at Finding 622.

ALJ acknowledges the necessity of executive leadership and its benefit to customers. If the Commission wishes to open a future docket, it should do so while at the same time allowing the Company to recover its proposed executive compensation costs in this case.

### 3. Incentive Compensation

#### a. Long Term Incentive (LTI) Compensation (Findings 566-578, pp 89-91)

LTI is part of Xcel Energy's incentive pay program, which is a critical component of an eligible employee's total, market-based compensation package.[77] The Company requests recovery of only a portion of LTI costs, specifically environmental LTI and time-based LTI, which ties this portion of compensation to goals that directly benefit customers.[78] The ALJ Report found that LTI programs are widely used compensation vehicles that use a combination of performance and time-based awards.[79] Further, the ALJ Report found that time-based LTI, which incents eligible employees to engage in long-term planning that benefits the Company and that they remain with the Company long enough to see those plans through, benefits customers by retaining knowledge and skills necessary to guide, manage, and operate a utility.[80] Importantly, the ALJ made no finding that the amount of LTI requested by the Company was unreasonable.

Nonetheless, the ALJ Report recommends that Xcel Energy not be allowed to recover these market-based compensation costs.[81] The ALJ based this recommendation on

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[77] Ex. Xcel-64 at Schedule 5 (Ly Direct).
[78] Ex. Xcel-62 at 23-24 (Ly Direct).
[79] Report at Finding 573.
[80] Report at Finding 572.
[81] Report at Finding 578.

a finding that the Company had not justified departing from the Commission's conclusions in the Company's last electric rate case that: (1) LTI does not offer a unique benefit above Xcel Energy's legal obligation to pursue environmental goals, and (2) the fact that LTI is paid in stock incents prioritization of shareholder interests.[82] Xcel Energy respectfully takes exception to both the ALJ's recommendation and the findings on which it is based.

First, incentive compensation is necessary for Xcel Energy employees' total cash compensation to be in line with the market. Xcel Energy provided a compensation study that showed without LTI and AIP, Xcel Energy's total cash compensation amounts fell to between 16.7 to 19.9 percent below the median compensation levels of other utility employers.[83]

Second, although Xcel Energy's LTI environmental objectives align with Minnesota's carbon-free standard, the two are not equivalent. The Company's environmental LTI program imposes a more rigorous, year-over-year expectation for carbon emissions reductions associated with the Company's electric service,[84] not just achievement of carbon-free generation targets every five years as set forth in the statute.[85] Additionally, equating the Company's environmental LTI goals with compliance with state law ignores the fact that compliance with Minnesota's carbon-free standard still is not easy, especially given current federal headwinds against coal plant retirement and new renewable

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[82] Report at Finding 577.
[83] Ex. Xcel-64, Schedule 5 at 20 (Ly Direct).
[84] Xcel-62 at 24-25 (Ly Direct).
[85] Minn. Stat. § 216B.1691, subd. 2g.

generation.[86] Further, while Minn. Stat. § 216B.1691, subd. 2g authorizes the Commission to grant utilities delays or modifications if meeting the standard would create significant issues with customer affordability or reliability, or if demand increases substantially due to beneficial electrification,[87] the Company's environmental LTI goals provide no such caveats or leeway. This further demonstrates that achievement of the state's 2040 mandate will be difficult and will require concentrated effort on the part of Xcel Energy's employees to achieve, and that the Company's environmental LTI goals go above and beyond compliance with state law.[88] Contrary to the ALJ finding, this demonstrates that the Company's environmental LTI provides customer benefits and, as such, should be recoverable.

Third, the fact that LTI is delivered in stock is not evidence that LTI is tied to shareholder interests rather than customers' interests. Payment of LTI in the form of stock is common practice among publicly traded utilities and for good reason. Providing compensation in the form of stock gives employees a stake in the Company and provides them an incentive to work for the long-term financial health and stability of the Company, which benefits customers by ensuring that the Company has adequate resources to provide safe and reliable utility service.[89]

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[86] Xcel Reply Brief at 64.
[87] Minn. Stat. § 216B.1691, subd. 2g.
[88] Xcel Initial Brief at 106-107; Xcel Reply Brief at 64.
[89] Xcel Initial Brief at 105-106; Xcel Reply Brief at 65.

For these reasons, the Commission should reject the ALJ Report's recommendation and adopt the Company's proposal to include LTI compensation in the cost of service in this case.

### b. Annual Incentive Program (AIP) Compensation (Findings 579-594, pp 91-94)

The Company requested approval and provided support demonstrating the reasonableness of raising the cap for recovery of AIP from 15 percent to 20 percent of base pay, and that the cap be calculated based on an aggregate basis rather than on an individual employee basis.[90] The ALJ Report recommended that the Commission maintain the 15 percent cap on AIP compensation,[91] basing this recommendation on findings that the Company had not justified departing from the Commission's decision in the last electric rate case. These findings primarily focus on the fact that Commission limited recovery of the Company's AIP based on a 15 percent cap beginning in the early 1990s,[92] and that the Earnings Per Share (EPS) threshold is evidence that AIP compensation is shareholder focused.[93] Xcel Energy respectfully takes exception to both the ALJ's recommendation and the findings on which it is based.

#### i. AIP Cap Amount

First, increasing the cap to 20 percent would better reflect current compensation trends that are more heavily weighted toward incentive compensation rather than base

[90] Ex. Xcel-62 at 17-21 (Ly Direct); Ex. Xcel-63 at 8-20 (Ly Rebuttal).
[91] Report at Finding 590.
[92] Report at Finding 580.
[93] Report at Finding 585.

pay.[94] The 15 percent cap established in the early 1990s does not reflect current compensation trends, meaning that over the past more than three decades, employers have moved a greater percentage of compensation into incentive programs because they drive employee performance and reduce fixed costs.[95] Additionally, a 20 percent cap would be comparable to the AIP recovery percentage the Commission has approved for other Minnesota utilities.[96] Specifically, the Commission previously approved a 20 percent cap for Minnesota Power's short-term incentive, noting that "[p]articularly important is the fact that, without AIP, Minnesota Power's total cash compensation for eligible employees would be below the market rate."[97] This would also be true for Xcel Energy's total cash compensation expense,[98] and the Company is proposing the same treatment.[99]

Further, the ALJ Report referenced the Commission's decision in the Company's last electric rate case, noting that the Commission's decision to deny moving to a 20 percent AIP cap was not based on a concern that 20 percent of an employee's base salary was an unreasonable level for an employer to pay, but a concern about the level of AIP allowed for recovery given that AIP was tied to an EPS threshold.[100] This finding misunderstands

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[94] Ex. Xcel-62 at Schedule 4 (Ly Direct); Ex. Xcel-63 at 9 (Ly Rebuttal).
[95] Ex. Xcel-63 at 9 (Ly Rebuttal); Ex. Xcel-67 at 9-10 (Mustich Rebuttal).
[96] Ex. Xcel-62 at 19-20 and Schedule 6 (Ly Direct).
[97] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015-GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 33 (Mar. 12, 2018).
[98] Xcel Initial Brief at 99. ("Without AIP compensation, the Company's total cash compensation is 12.1 to 13.0 percent below market-level compensation amounts." Ex. Xcel-62 at 31 (Ly Direct)).
[99] *See also* Ex. Xcel-62 at 19-20, providing examples that past levels of Commission-approved short-term incentive compensation have been even higher than 20 percent.
[100] Report at Finding 585.

the function of the EPS threshold as part of the AIP payment determination. The EPS threshold is simply a gating criteria designed to ensure that the Company is performing at a minimum sustainable financial level before AIP compensation is paid, which is a conservative and prudent approach that protects customers from having to pay AIP compensation in years of financial underperformance.[101] The AIP metrics themselves, however, are strictly customer focused, reflecting goals associated with advancing the clean energy transition, improving the customer experience, maintaining affordable bills, and ensuring safety and reliability.[102] This means that reaching the EPS threshold does not guarantee an AIP compensation payout; no AIP will be paid out unless specific customer-focused metrics are also achieved.

The ALJ recommendation also relied on a finding that Xcel Energy points to no evidence that other utilities' AIPs incorporate an EPS threshold.[103] However, the Company noted that in Minnesota Power's AIP, for which the Commission approved a 20 percent cap, 90 percent of the AIP costs were tied to utility net income, cash from operating activities, and utility competitiveness goals.[104] In that case, inclusion of financial metrics as part of the AIP did not result in denial of these reasonable costs. Moreover, no rationale was provided for why Xcel Energy should be treated less favorably than Minnesota Power.

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[101] Ex. Xcel-63 at 17 (Ly Rebuttal).
[102] Ex. Ex. Xcel-62 at Schedule 4 at 6 (Ly Direct).
[103] Report at Finding 587.
[104] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015-GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 33 (Mar. 12, 2018). *See also* Xcel Initial Brief at 100-101 and Xcel Reply Brief at 59-60.

#### ii. AIP Cap Calculation

The ALJ Report recommended that the Commission reject the Company's proposal to administer the cap on an aggregate basis rather than an individual employee basis.[105] Xcel Energy respectfully takes exception to both the ALJ's recommendation and the findings on which it is based. The Company explained that the AIP recovery cap set in this proceeding determines the Company's maximum recoverable amount; any payment of AIP compensation that is less than that amount is refunded to customers. The only thing that changes by allowing the Company to administer AIP on an aggregate basis is the fact that this allows the Company to better tie compensation to performance.[106] This would further strengthen the link between pay and performance and further motivate employees to achieve the Company's customer-focused AIP goals.[107]

For these reasons, the Commission should reject the ALJ Report's recommendation and adopt the Company's proposal include AIP compensation using a 20 percent cap, calculated on an aggregate basis, as part of the cost of service in this case.

### 4. Miscellaneous Benefit, Life and LTD Expense (Findings 631-639, pp. 100-101)

The ALJ Report recommends that the Commission authorize the Company to recover miscellaneous benefit, life, and LTD expenses at a level set by applying the Department's proposed methodology and inflation factor to 2024 actual expenses.[108] The

[105] Report at Finding 594.
[106] Ex. Xcel-63 at 18 (Ly Rebuttal).
[107] Ex. Xcel-63 at 18 (Ly Rebuttal).
[108] Report at Finding 639.

ALJ properly recognized that setting the baseline at the average of Xcel Energy's actual expenses from 2021 to 2024 and then applying an inflator based on the average annual increases from 2021 to 2024, as recommended by the Department, would result in the Company undercovering these expenses.[109] However, the ALJ found that the Company's 2024 forecast was higher than actuals, and on that basis, the ALJ determined that "the Department's proposal to use actual historical data rather than the Company's projection is reasonable."[110]

The Company continues to recommend that the Commission allow it to recover its forecasted miscellaneous benefit, life, and LTD expenses for 2025 and 2026.[111] Each year in a MYRP is a forecast, and actuals will vary between being higher or lower than forecast. Therefore, one year where actuals were lower than forecast should not dictate whether the test year forecast is a reasonable estimate. Indeed, at hearing, Department witness Mary Beth Kehrwald agreed that "in a representative test year some actual costs will be higher than forecast and others will be lower" and that "the purpose of [this rate] case is not to make up for any past actual costs that were higher or lower than forecasted in prior rate cases."[112]

Moreover, no party disputes that the Company's forecasts of its pension and benefit costs, including miscellaneous benefit, life, and LTD expenses, "are formulaic, are calculated in accordance with accounting rules and standards, and are based on actuarial

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[109] Report at Finding 638.
[110] Report at Finding 637.
[111] Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).
[112] Tr. Vol. 2 (Dec. 18, 2025) at 453:7-454:1 (Kehrwald).

assumptions specific to the Company."[113] Xcel Energy's approach to forecasting its costs in this rate case is also consistent with longstanding practice and precedent in the Company's prior rate cases before the Commission.[114] In contrast, the ALJ's recommendation (and the Department's recommendation) has no basis in past Commission practice or precedent. The Company should accordingly be permitted to recover its forecasted miscellaneous benefit, life, and LTD expenses.

### C. Prepaid Pension Asset/Accrued Liabilities (Findings 341-366, pp. 56-59)

Xcel Energy appreciates the ALJ Report's recognition that "[t]he Company is entitled to earn a return…on the prepaid pension asset."[115] In making this determination, the ALJ properly found that the evidence showed that "the prepaid pension asset is of a capital nature" and that "[i]t comprises only shareholder funds."[116] Importantly, not only did the ALJ find that the prepaid pension asset is of a capital nature, but also the Minnesota Court of Appeals has held that the Company's prepaid pension asset is an expense of a capital nature under Minn. Stat. § 216B.16, subd. 6.[117] In addition, no party presented evidence or testimony disputing that the prepaid pension asset is entirely shareholder-

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[113] Ex. Xcel-57 at 7-8 (Schrubbe Direct).
[114] Ex. Xcel-17 at 21-25 (Halama Direct).
[115] Report at Finding 361.
[116] Report at Finding 360.
[117] *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota (Northern States Power Company)*, No. A23-1672, 2025 WL 249995, at *9 (Minn. Ct. App. Jan. 21, 2025) (citing *In the Matter of the Application by Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota (Minnesota Power)*, 12 N.W.3d 477, 493 (Minn. Ct. App. 2024)).

funded. Further, the ALJ found that "[f]unding the asset requires utility shareholders to expend capital for a benefit that will not accrue until a future date, thereby forgoing other potential uses for those funds," and that "[c]ustomers are an eventual beneficiary of the benefit of these funds through reduced future pension expenses."[118] The Company supports this careful analysis in the ALJ Report.

The above findings made by the ALJ support a determination that the Company is entitled to earn a return at the weighted average cost of capital (WACC) on the prepaid pension asset. But the Company agreed to accept a return on the asset equivalent to the cost of long-term debt so long as it was understood that this was solely an effort to limit the issues in dispute in this case.[119] As such, the Company does not dispute the overall recommendation in the ALJ Report that the Company should earn a return equivalent to the cost of long-term debt in this case, and reads the Report as supporting this outcome in large part "in light of the Company's agreement" in this case.[120] However, it is important to further address the portion of the Report finding that this outcome balances the right to a return with "mitigating any concerns about incentives for overfunding the pension trust and recognizing the distinction between the prepaid pension asset and more traditional rate base items."[121]

Importantly, the ALJ does not make a finding that these "concerns" are valid, and the substantial evidence in the record underscores that any such concerns are purely

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[118] Report at Finding 360.
[119] Report at Finding 364.
[120] Report at Finding 366.
[121] Report at Finding 365.

hypothetical and not borne out by any evidence.[122] The Company provided substantial testimony regarding how it determines its pension funding, which shows that contributions to the pension fund are driven by federal law requirements under the Employee Retirement Income Security Act, the Pension Protection Act of 2006, and the Internal Revenue Code, not Company incentives.[123] Xcel Energy also explained that the pension trust is currently underfunded and will be through the MYRP.[124] This is an indisputable, mathematical fact and, as such, the Company is not making contributions in excess of what is needed to fund the trust. If the trust were ever overfunded, that issue could be raised in a future proceeding.

Even if there were any evidence that the pension fund were at risk of being fully or overly funded during the MYRP, it would be detrimental to Xcel Energy to overfund the pension trust with the intent to keep excess funds, as "[a]ny assets returned to the Company upon reversion would be subject to income tax and a significant excise tax."[125] Further, the concern about "overfunding" confuses the pension trust with the prepaid pension asset – the prepaid pension asset is not the entire pension fund, and the Company is not seeking recovery *of* the pension fund (or the prepaid pension asset), but rather a return *on* the prepaid pension asset.[126] Contrary to the Department's claim, the Company is not seeking some financial windfall. The Company is merely asking for its investors to be compensated

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[122] *See* Xcel Initial Brief at 135, 141-42; Xcel Reply Brief at 90; Ex. Xcel-57 at 8-42, 60, Table 12 (Schrubbe Direct); Ex. Xcel-58 at 6 (Schrubbe Rebuttal); Ex. DOC-11, Schedule 3 (Hunt Surrebuttal) (Xcel Responses to DOC IRs 3113 and 3114).
[123] *See* Ex. Xcel-57 at 8-42 (Schrubbe Direct).
[124] *See* Ex. Xcel-57 at 60, Table 12 (Schrubbe Direct).
[125] Ex. DOC-11, Schedule 3 (Hunt Surrebuttal) (Xcel Responses to DOC IRs 3113 and 3114).
[126] Xcel Initial Brief at 141-42; Xcel Reply Brief at 90.

for the time value of their invested capital that has helped create this service-producing asset.

Additionally, any conclusion that there is a distinction between the prepaid pension asset and "more traditional rate base items" warranting a different rate of return, absent Company agreement, is both inaccurate and wholly contrary to the conclusion of the Minnesota Court of Appeals that the Company's prepaid pension asset is an expense of a capital nature under Minn. Stat. § 216B.16, subd. 6, that should be included in rate base[127] (which, as mentioned above, the ALJ acknowledged). In holding that the Company's prepaid pension asset is an expense of a capital nature under Minn. Stat. § 216B.16, subd. 6, the Minnesota Court of Appeals expressly rejected that the prepaid pension asset "is distinct from other assets included in rate base."[128]

Absent Company agreement, a return other than the full rate of return would run counter to the law established in *Hope* and *Bluefield* stating that a utility is entitled to a reasonable opportunity to earn its authorized rate of return on assets used to serve customers.[129] Once an asset is included in rate base, it should earn the Company's authorized rate of return. Minn. Stat. § 216B.16, subd. 6, does not provide for different rates of return for different rate base assets. Rather, a "fair rate of return" under Minn. Stat. § 216B.16, subd. 6, should be "equal to that generally being made at the same time and in

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[127] *Northern States Power Company*, 2025 WL 249995 at *9 (citing *Minnesota Power*, 12 N.W.3d at 493).
[128] *Northern States Power Company*, 2025 WL 249995 at *9 (citing *Minnesota Power*, 12 N.W.3d at 492-93).
[129] *Hope*, 320 U.S. at 603; *Bluefield*, 262 U.S. at 692.

the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties."[130] Further, as the Company has explained, because its assets, including the prepaid pension asset, are financed with a mix of debt and equity, only a WACC return that reflects both components would appropriately compensate the Company for the mix of debt and equity that it needed to finance its investments.[131] Absent the Company's agreement, anything less than a WACC return – including the Department's recommended long-term cost of debt return – would not allow the Company to earn a return on a service-producing asset commensurate with returns authorized for utilities.

In order to reduce the number of items in controversy, in this case alone, the Company does not oppose a return in this case equivalent to the cost of long-term debt rather than the full authorized rate of return. However, the Commission should determine that the ALJ's finding about balancing the parties' concerns is unsupported, and authorize the Company to earn its return equal to the cost of long-term debt, rather than the full WACC, solely on the grounds that the Company agreed to this outcome.

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[130] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 692 (1923); *see also Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); *Minnegasco v. Minnesota Public Utilities Commission*, 549 N.W.2d 904, 908 (Minn. 1996) ("In order to establish 'just and reasonable' retail rates, the MPUC must consider the right of the utility and its investors to a reasonable return, while at the same time establishing a rate for consumers which reflects the cost of service rendered plus a 'reasonable' profit for the utility.").

[131] Ex. Xcel-97 at 1-2 (Schrubbe Revised Witness Summary).

### D. Operating and Maintenance Expenses

#### 1. Distribution O&M Expenses (Findings 456-471, pp. 71-74)

The Company takes exception to the ALJ's recommendation to reduce Distribution O&M vegetation management expenses for 2025 and 2026 by $5.8 million and $8.3 million, respectively, based on a 3 percent year-over-year increase over 2024 actuals.[132] This recommendation fails to take into account the Company's evidence explaining the need for higher vegetation management budgets in 2025 and 2026 and the reasonableness of those costs. [133] If adopted, this recommendation would result in overall Distribution O&M budgets for 2025 and 2026 falling below 2024 actual O&M expense. This is an unreasonable result and the Company asks the Commission to reject both the ALJ's recommendation and the Findings on which it is based.

First, while the ALJ Report finds that the Company has not met its burden to prove that its budgeted vegetation management expenses are reasonable,[134] the Report does not dispute the specific reasons for the increase in vegetation management budgets in 2025 and 2026 provided by the Company, including: (1) work that was prudently deferred in prior years to address higher priority work such as outage restoration; (2) contractor rate increases; (3) additional vegetation growth due to higher-than-average rainfall; and (4) forecasted inflationary increases.[135] The Company also explained that prior year actuals were lower than budgets for vegetation management, due to the Company managing its

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[132] Report at Finding 471.
[133] *See* Xcel Initial Brief at 73-77.
[134] Report at Findings 466-467.
[135] Ex. Xcel-35 at 44-45 (Mensen Rebuttal).

overall O&M budget to address the highest priority needs of its customers. This was especially evident in 2023 when the Company postponed planned vegetation management to reallocate resources for storm restoration work, with costs that exceeded budgets in each of the previous four years.[136]

Additionally, the Company explained why vegetation management costs for 2025 through September 30 were lower than budgeted. While the Company cleared more miles than initially budgeted in 2025, a portion of this work was preparation for distribution line rebuilds and therefore properly included in the capital costs of those projects.[137] But by focusing only on this one component, the recommendation for a reduction to the overall Distribution O&M budget does not acknowledge that the Company manages overall O&M as a whole, and decreasing costs in one area are often balanced by increasing costs in other areas.[138]

For these reasons, the Commission should reject the ALJ's recommendation to reduce 2025 and 2026 vegetation management costs and adopt the Company's proposed Distribution vegetation management budgets for 2025 and 2026.

### 2. Transmission O&M Expenses (Findings 472-489, pp. 74-77)

The Company takes exception to the ALJ's recommendation to limit Transmission O&M expenses for 2025 and 2026 to 2024 actuals of $17.4 million.[139] This recommendation fails to take into account the increasing number of capital projects that

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[136] Ex. Xcel-35 at 47 (Mensen Rebuttal).
[137] Ex. DOC-8 at AAU-S-1, Page 3 (Uphus Surrebuttal); Xcel Reply Brief at 49.
[138] Xcel Reply Brief at 47-49.
[139] Report at Finding 489.

Transmission will be responsible for implementing in 2025 and 2026 as well as the other drivers of O&M increases in these years. The Company asks the Commission to reject these Findings and allow recovery of the Company's budgeted amounts of $18.9 million and $19.4 million for Transmission O&M in 2025 and 2026, respectively.[140]

The Company's Transmission organization is responsible for the construction, operation, and maintenance of the Company's over 8,500 miles of transmission lines and over 550 substations.[141] In 2025 and 2026, the Transmission organization will be implementing a number of key transmission projects that are part of MISO's Long-Range Transmission Planning (LRTP) Tranche 1 and 2.1 portfolios. Due to these MISO-approved projects, as well as other reliability driven projects, Transmission's capital investments will grow considerably in 2025 and 2026 as compared to 2024.[142] Capital investments are a key driver of O&M expenses for Transmission as once a new transmission line or substation is constructed, these facilities will require ongoing costs to operate and maintain these assets.[143] Thus, the substantial increase in capital investments in 2025 and 2026 demonstrates the reasonableness of the requested modest increase in Transmission O&M expenses of $1.5 million in 2025 and $2.0 million in 2026 as compared to 2024 actuals.[144]

In recommending a reduction to Transmission's 2025 and 2026 O&M budgets, the ALJ relies heavily on the fact that Transmission's 2025 actual O&M expenses, through

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[140] Ex. Xcel-43 at 4 (Berklund Rebuttal).
[141] Ex. Xcel-42 at 8 (Berklund Direct).
[142] Ex. Xcel-43 at 10 (Berklund Rebuttal) (Figure 1 shows capital spending increasing from $341 million in 2024 to $552 million in 2025 and $708 million in 2026).
[143] Ex. Xcel-43 at 9 (Berklund Rebuttal).
[144] Ex. Xcel-43 at 9 (Berklund Rebuttal).

September 2025, are more in line with the Department's proposed level of recovery than the Company's proposed 2025 budget.[145] This reliance does not account for the fact that the Company's Transmission organization is only one part of the Company's overall O&M budget and while Transmission O&M may be lower than budgeted, other business areas may have higher than budgeted O&M.[146] Disallowing the Company's budgeted O&M expenses based on such a siloed view eliminates the Company's needed budget flexibility. As the Company explained during the proceeding, this budget flexibility allows the Company the ability to address unforeseen emergent needs for the benefit of customers.[147] Given the need to support the growing work of the Transmission organization and the Company's overall O&M budget, Xcel Energy requests that the Commission adopt its proposed Transmission O&M budgets for 2025 and 2026.

Even if the Commission decides to adopt the ALJ's recommendation to adopt the Department's recommendation to set Transmission's 2025 O&M expenses at $17.4 million, the Commission should, at minimum, authorize additional O&M expenses for 2026 rather than limiting the Company's recovery to $17.4 million for both 2025 and 2026. The ALJ's recommendation to keep O&M flat from 2025 to 2026 ignores the evidence put forth by the Company that its 2026 O&M expenses will be 2 percent higher than its 2025 budget due primarily to annual increases in employee base pay.[148]

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[145] Report at Finding 487.
[146] Tr. Vol. 1 (Dec. 17, 2025) at 233-234 (Berklund).
[147] Ex. Xcel-26 at 30-31 (Robinson Direct).
[148] Ex. Xcel-42 at 82 (Berklund Direct).

### 3. Customer Care O&M (Findings 490-501, pp. 77-79)

Xcel Energy supports the ALJ's recommendations regarding Customer Care O&M issues discussed in this proceeding, and in particular the ALJ's recommendations to reject XLI's "drastic" request to disallow recovery of Xcel Energy's entire Customer Care O&M expenses due to these concerns.[149] As the ALJ accurately noted, no party, including XLI, disputed the costs the Company accrues related to Customer Care O&M.[150] Importantly, as the ALJ recognized, XLI failed to identify the BOMA Greater Minneapolis ("BOMA") members experiencing billing issues to allow Xcel Energy to immediately investigate and address those concerns.[151] This is not to say Xcel Energy has not undertaken independent investigation into commercial and industrial billing issues. The Company sought and continues to undertake alternative means of identifying the impacted BOMA members and address their concerns.[152]

Xcel Energy remains committed to resolving all of its customers' billing concerns. Xcel Energy and XLI agreed to include commercial customers in the Commission's docket investigating residential billing errors, Docket No. E, G002/CI-25-341.[153] Subsequently, the Commission expanded the investigation in that docket to include commercial and industrial customers and required the Company to provide information regarding billing

[149] Report at Findings 499, 501.
[150] Report at Finding 496.
[151] Report at Finding 498.
[152] Report at Finding 495.
[153] Report at Finding 500.

errors impacting these customers.[154] The Company has and continues to provide the requested information in monthly compliance filings in that docket.[155] The ALJ appropriately found that docket will provide the Commission the opportunity to develop a more robust record and tailor a more appropriate and targeted remedy than disallowance of the Company's Customer Care O&M costs.[156]

### E. Riverside Generating Unit (Findings 367-390, pp. 59-62)

The Company takes exception to the ALJ Findings concerning the Riverside Generating Unit (Riverside). The ALJ recommended that the Commission find Riverside was not used and useful after experiencing a fault that tripped the unit, causing it to be unavailable, and recommended removing Riverside from the Company's rate base from May 1, 2025 through May 30, 2025.[157] Despite recommending denial of rate base treatment for the plant, the ALJ also recommended that capacity revenues generated by Riverside continue to be paid to customers throughout this time. The ALJ reasoned that customers would continue to compensate the Company for its investment in Riverside through depreciation expense, justifying customers receiving the entirety of the capacity revenues.[158] Finally, while the ALJ agreed that O&M expenses are recoverable if they are

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[154] *In the Matter of Xcel Energy's 2024 Annual Safety, Reliability, and Service Quality Report*, Docket No. E002/M-25-27, ORDER ACCEPTING REPORTS AND SETTING ADDITIONAL REQUIREMENTS, Order Point No. 17 (Mar. 27, 2026).
[155] *See, e.g., In the Matter of an Investigation into Xcel Energy's Residential Billing Errors*, Docket No. E, G002/M-25-341, Xcel Energy Compliance Filing – Monthly Update (April 16, 2026).
[156] Report at Finding 500.
[157] Report at Finding 383.
[158] Report at Finding 384.

prudently and reasonably incurred, he recommended that O&M expenses should not be recovered at this time and instead, a regulatory asset should be created for these expenses because the record here did not explicitly address the Company's prudence or imprudence related to the Riverside outage.[159] The Company takes exception to each of these Findings.

First, the Commission should find that Riverside is "used and useful," such that it should be included in the Company's rate base. It is undisputed that Riverside generated nearly $26 million in capacity revenues in the 2025-2026 capacity auction.[160] It is equally undisputed that at least some portion of Riverside's capacity will be included in the 2026-2027 capacity auction.[161] Finally, the record establishes the plant was undeniably used and useful for a portion of 2025 and is anticipated to return to service for a portion of 2026.[162] Each of these facts supports rate base treatment of Riverside.

Regarding the treatment of capacity revenues, the Report acknowledges that the Company's argument that it would be inequitable for the Commission to deny recovery of a return on Riverside while crediting revenues "carries intuitive appeal,"[163] recognizing the facial inequity of denying rate base treatment, while crediting customers with capacity revenues. As the Company discussed, it is not aware of any ratemaking treatment that would allow a generation asset to be determined not "used and useful," or essentially non-

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[159] Report at Findings 385-389.
[160] Report at Finding 371.
[161] Report at Finding 372.
[162] Report at Finding 378. In contrast to Riverside, past generating units that have been removed from rate base in rate cases, such as Sherco 3, did not provide any service during the relevant test year.
[163] Report at Finding 384.

existent for rate base purposes, while still recognizing that the same asset is generating capacity revenues and crediting those revenues to customers.[164] The ALJ's answer to this issue – justifying crediting customers with revenues since they will cover depreciation expense under his recommendation – does not answer this concern. While the ALJ is correct that the Company would recover its depreciation expense pursuant to the Report's recommendation,[165] this is irrelevant to the inequity identified by the Company. The recommendation to allow recovery of depreciation expenses simply reflects that such costs are unavoidable and would occur regardless of whether the plant is considered used and useful.[166] The generation of capacity revenues, by contrast, are directly tied to Riverside's operation. It is not equitable, and not supported by standard ratemaking principles, to consider Riverside ineligible for rate base recovery while also crediting customers with the generation of capacity revenues by Riverside.

Finally, because Riverside should be found used and useful, the O&M expenses associated with Riverside are properly included in both the 2025 test year and 2026 plan year. At minimum, the Commission should approve establishment of a regulatory asset for these expenses, as recommended by the ALJ.

The Company does, however, concur with the ALJ Finding that it is premature to initiate a contested case proceeding to evaluate the prudency of the Company's actions preceding Riverside going off-line.[167] Rather, as the ALJ recommends, the better course is

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[164] Ex. Xcel-16 at 23-24 (Liberkowski Rebuttal).
[165] Report at Finding 384.
[166] *See* Ex. DOC-2 at 30 (Johnson Surrebuttal).
[167] Report at Finding 390.

to solicit comments from interested parties as to whether such a proceeding is warranted and, if so, the proper scope of that proceeding.[168]

## II. OTHER REVENUE REQUIREMENT ISSUES

The Company respectfully takes exception to certain ALJ Findings regarding other revenue requirements related issues, where the record of this proceeding and applicable Minnesota law fail to support those recommendations.

### A. Sherco 3 and King Plants

In the Company's most recent integrated resource plan (IRP) the Commission approved shortening the operating lives of the Sherco Unit 3 (Sherco 3) and Allen S. King (King) coal generating plants (collectively "Sherco 3 and King").[169] King will be retired in December 2028, instead of June 2037, and Sherco 3 will be retired in December 2030 rather than December 2034.[170] The Company proposed that Sherco 3 and King continue to be depreciated using their currently-approved remaining lives and when the facilities are retired, any remaining net book value should be transferred to a regulatory asset.[171]

The Department disagreed with this proposal, contending that the depreciation lives of Sherco 3 and King should be adjusted to match Sherco 3's and King's shortened operating lives in this case. Despite the fact that the Department's proposal would increase the Company's revenue requirements in the 2025 test year and 2026 plan year by

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[168] Report at Finding 390.
[169] ORDER APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS, in Docket Nos. E002/RP-24-67 and E002/CN-23-212 (April 21, 2025).
[170] Ex. Xcel-17 at 76 (Halama Direct).
[171] Ex. Xcel-17 at 76 (Halama Direct).

approximately $58.8 million and $55.4 million respectively, the Department took the position that because this increase would be balanced out by the reduction in revenue requirements associated with extending the depreciation lives of the Monticello and Prairie Island Nuclear Generating Plants,[172] no rate shock would result.[173]

The OAG and XLI agreed with the Company that the depreciation lives of Sherco 3 and King should not be extended.[174] The OAG disagreed, however, with the Company's request that the Commission authorize the creation of a regulatory asset at the end of each plant's operating life at this time.[175]

The ALJ recommended that the Commission adopt the Company's recommendation to not adjust the remaining lives for the Sherco 3 and King plants.[176] The ALJ rejected, however, the Company's request that a regulatory asset be created for the Sherco 3 and King plants, based on the Commission's order in Docket No. E-002, E-015, E-017/CI-23-375 (the Early Retirement Docket).[177]

In August, 2023, the Commission initiated the Early Retirement Docket to investigate depreciation accounting and other ratemaking issues as they relate to early-retired electric generating facilities.[178] The Commission issued its Order in the Early Retirement Docket in May, 2025, after the Company had filed this case. The Order

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[172] No party disputes extending the depreciation lives of these two plants.
[173] Ex. DOC-24 at 19 (Jones Surrebuttal).
[174] Ex. OAG-6 at 5-7, 9-10 (Lee Rebuttal); Ex. XLI-5 at 7-9 (LaConte Rebuttal).
[175] Ex. OAG-6 at 10 (Lee Rebuttal).
[176] Report at Finding 339.
[177] Report at Findings 338, 340.
[178] Ex. Xcel-69 at 41-42 (Johnson Direct).

established a four-tiered approach to determining ratemaking treatment of early-retired plants.[179] Tier 1 is a data-gathering phase. Data related to the plant, the impact of retirement on ratepayers and the utility's operation of the plant are considered in Tier 1. In Tier 2, the evaluation focuses on whether the early-retiring asset meets the criteria established for accelerated depreciation. In Tier 3, the evaluation asks whether accelerated depreciation would lead to rate shock. If this is the case, Tier 3 contemplates the creation of a regulatory asset with some type of return. Notably, the Tier 3 analysis specifically is designed to minimize costs to customers while also allowing utility recovery of prudently-invested capital retiring early due to environmental regulation. Tier 4 is reserved for unique assets, situations where an asset is operated imprudently, and plants that are not used and useful at the time of retirement.[180]

The Company does not seek creation of a regulatory asset at the present time, but proposes to establish regulatory assets after the end of the operating lives of Sherco 3 and King. This approach aligns with Tier 3 in the Early Retirement Order. While the Company is not requesting creation of such an asset at this time, the Company requests that the Commission determine that the "Tier 3" approach advanced by the Company here is appropriate and that a regulatory asset should be created for each of these plants upon

[179] ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY-RETIRING GENERATING FACILITIES, *In the Matter of a Commission Inquiry into the Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Electric Utilities*, Docket No. E-002, E-015, E-017/CI-23-375 (May 14, 2025) (hereinafter, the EARLY RETIREMENT ORDER).
[180] Early Retirement Order at 5, 7-8.

retirement subject to the Company's demonstration that the plants remain capable of being used and useful at the time of retirement.

### B. Cost Allocators

#### 1. General Allocator (Findings 503-514, pp. 79-81)

To align the Company's allocations with Minnesota law and to ensure that Minnesota customers are paying the full cost of services rendered for the benefit of the Company's Minnesota customers, the Company requested that the Commission approve the use of the Number of Employees methodology instead of the Full-Time-Equivalent (FTE) Hours methodology for the labor component of the Company's General Allocator.[181] The ALJ report recommends the Commission not approve this request but to continue requiring the Company to use the FTE Hours methodology.[182] The ALJ based this recommendation on finding that the Company had not justified departing from the FTE Hours methodology required in 2011,[183] and on a concern that the Number of Employees methodology would over-allocate costs to the Minnesota jurisdiction.[184]

The undisputed calculations in the record demonstrate, however, that the FTE hours methodology used for the Labor component of the three-part General Allocator actually allocates *more* costs to regulated entities than to unregulated entities,[185] which was the

[181] Ex. Xcel-49 at 26 (Doyle Direct).
[182] Report at Finding 514.
[183] Report at Finding 511.
[184] Report at Findings 512-513.
[185] Ex. Xcel-49 at 20-21 and Table 1 (Doyle Direct).

Commission's concern in 2011.[186] But on closer review, the Commission's concern about over-allocating costs to regulated entities only occurs by deploying an FTE Hours allocator. Specifically, the Company provided the Number of Employees and FTE Hours Allocation Ratios Effective April 1, 2024 Through March 31, 2025 for Xcel Energy Operating Companies. The General Allocator uses Number of Employees (with the 12 common officers assigned to Xcel Energy Inc. as of December 31, 2023), Total Revenues, and Total Assets as the three components of the allocation ratio.[187] Using the Number of Employees methodology as one of these three parts of the General Allocator results in a factor of 0.1501 percent of total headcount to non-regulated subsidiaries.[188] By comparison, the FTE Hours methodology results in a factor of 0.0932 percent of total FTE Hours.[189] In other words, using FTE Hours routinely allocates more costs to regulated entities, and in this case would allocate nearly 40 percent less in costs to non-regulated subsidiaries compared to using Number of Employees allocator.

Second, any increase in allocations to Minnesota customers from using the Number of Employees versus FTE Hours methodology is the result of the employees in NSPM driving support services provided by Xcel Energy personnel to multiple operating companies – not an "over-allocation" to Minnesota customers. In performing the

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[186] Ex. Xcel-49 at 15 (Doyle Direct); Ex. Xcel-50 at 3-4 (Doyle Rebuttal); *In re N. States Power Co.'s Cost Allocation Procedures and General Allocator*, E,G002/AI-10-690, ORDER REQUIRING CHANGE IN GENERAL ALLOCATOR AND REQUIRING FILINGS at 3 (Mar. 15, 2011).
[187] Ex. Xcel-49 at 20 and Table 1 (Doyle Direct).
[188] Ex. Xcel-49 at 20 and Table 1 (Doyle Direct); Ex. Xcel-50 at 9 (Doyle Rebuttal).
[189] Ex. Xcel-49 at 20 and Table 1 (Doyle Direct); Ex. Xcel-50 at 9 (Doyle Rebuttal).

calculation for the FTE Hours adjustment, hours charged to allocators that use the Number of Employees method must be excluded so as not to skew the FTE Hours results.[190] Excluding labor hours that are more properly allocated by ratios using Number of Employees results in the elimination of 17.5 percent of total Service Company labor hours, which includes a significant portion of hours worked by administrative functions such as Human Resources, Accounting, Finance, Legal, and Technology Services on behalf of the employees in NSPM.[191] As a result of excluding these hours, the FTE Hours calculation does not provide for an accurate reflection of the level of support provided to each company by the Service Company.[192]

Finally, the Number of Employees methodology provides the most consistent, cost-causative, and stable metric, and is therefore the most appropriate method to allocate costs. It is intuitive that the number of employees in a subsidiary drives overall administrative work, not the number of hours worked by an employee on behalf of other subsidiaries. Further, the number of FTE Hours an operating company employee works on behalf of other entities can vary greatly from year to year and project to project, such that the FTE Hours allocator is not reliable or stable nor representative of current or future costs. Overall, the record demonstrates that the FTE Hours methodology does not allow all work needed to support NSPM to be included in the ratio calculation, resulting in costs being

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[190] Ex. Xcel-49 at 23 (Doyle Direct).
[191] Ex. Xcel-49 at 23 (Doyle Direct).
[192] Ex. Xcel-49 at 23-24 (Doyle Direct).

under-allocated to Minnesota customers and, as such, the customers in the Minnesota jurisdiction are not currently paying for the full cost of providing these services.[193]

For all these reasons, the Company requests that the Commission approve the use of the Number of Employees methodology in its cost allocations.

### 2. Interchange Agreement Allocator (Findings 515-528, pp. 81-83)

As reflected in the ALJ Report, although Xcel Energy operates separate utilities in Minnesota (NSPM) and Wisconsin (NSPW), the companies function as a single integrated electric generation and transmission system.[194] Costs and revenues are allocated between NSPM and NSPW pursuant to an Interchange Agreement, with allocation factors updated and filed annually with the Federal Energy Regulatory Commission ("FERC").[195] Under the Interchange Agreement, the demand allocator is used to assign shared capital and fixed costs based on each system's share of average monthly coincident peak demand.

Each annual Interchange Agreement update submitted to FERC reflects updated actual and forecasted monthly coincident peak demand for each system used to compute the demand allocator, as well as updates to other billing components, including energy allocators, electric plant in service, allowance for funds used during construction, accumulated depreciation and amortization, insurance, depreciation and amortization

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[193] Ex. Xcel-49 at 24 (Doyle Direct).
[194] Report at Finding 515.
[195] Ex. Xcel-17 at 60-62 (Halama Direct); Ex. DOC-1 at 29-30 (Johnson Direct).

expense, operations and maintenance expense, purchased power costs, taxes and tax credits, and interest expense.[196]

At the time this case was filed, neither the 2025 nor the 2026 Interchange Agreement updates had been filed with FERC. However, the Company computed 2025 and 2026 Interchange revenues and expenses pursuant to the formulas set forth in the Interchange Agreement.[197] For the 2025 test year, the demand allocator was based on 18 months of actual coincident peak demand data through June 2024 and 18 months of forecasted demand through December 2025—the same demand data ultimately reflected in the 2025 Interchange Agreement accepted by FERC in May 2025.[198] As explained in the ALJ's Report, the sole difference between the Company's 2025 demand allocator as filed in this case and the allocator later filed with and accepted by FERC was the use of an updated transmission loss multiplier in the FERC filing.[199] Further, applying the updated

[196] Ex. DOC-2 at MAJ-S-2 (Johnson Surrebuttal) (Xcel's Response to DOC IR 3107); Tr. Vol. 2 (Dec. 18, 2025) at 384-392 (Johnson) (acknowledging the Company will need to provide updated information for 2026 because the interchange agreement changes every year).

[197] Ex. Xcel-17 at 61-62 (Halama Direct); Ex. Xcel-18 at 6-7 and Schedule 17 (Halama Supplemental Direct) (Interchange Demand Allocator).

[198] Ex. Xcel-18 at Schedule 17 (Halama Supplemental Direct) (Interchange Demand Allocator); Ex. DOC-1, Schedule 4 at 7 and 153 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A and Attachment B) ("Coincident peak demands are based upon three years of data consisting of 18 months of actual and 18 months of projected peak demands.").

[199] Report at Finding 521 ("The only difference between the demand allocator filed with FERC on March 14, 2025 (which was accepted on May 6, 2025) and the 2025 demand allocator presented in the Company's supplemental direct testimony was the use of updated transmission loss multipliers based on an updated system loss study included in the FERC filing.") (citing Ex. DOC-1, Schedule 4 at 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A)).

transmission loss multiplier—reflecting the most current FERC-accepted data—would increase the 2025 revenue deficiency by $272,723.[200] While the Company does not dispute that the demand allocator accepted by FERC incorporates more recent transmission loss data, these updates were not incorporated due to timing.[201]

For the 2026 plan year, the Company applied the same methodology in accordance with the Interchange Agreement but updated the demand allocator to include forecasted monthly coincident peak demands through December 2026, while relying on the same actual demand data through June 2024.[202] This approach aligns the allocation of interchange costs with the forecasted demand in 2026, ensuring that costs are assigned based on expected system usage in the plan year.

In response, the Department urged use of the most recent FERC-accepted demand allocator for both 2025 and 2026, citing a single concern—that the Company's proposed "Interchange Demand allocators are based on forecasted data that includes older transmission loss allocators."[203] While the straightforward response would have been to apply the updated transmission loss multipliers accepted by FERC, the Department instead

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[200] Ex. DOC-1 at 29-33 (Johnson Direct); Ex. DOC-2 at 7 (Johnson Surrebuttal).

[201] The Company used the older transmission loss multipliers because its supplemental direct was prepared before the FERC filing was finalized. However, use of the older transmission loss multipliers is not a "detriment to customers" as the Department claims; instead, it results in slight reductions to both the 2025 and 2026 revenue requirements.

[202] *See* Ex. Xcel-18 at Schedule 17 (Halama Supplemental Direct) (Interchange Demand Allocator). While Mr. Johnson criticized the Company's proposed 2026 demand allocator because it "still used forecasted demand allocators for the months of July 2024 through December 2026 in its calculations," the 2025 demand allocator as accepted by FERC similarly uses forecasted data beginning July 2024. *See* Ex. DOC-1 at 31 (Johnson Direct).

[203] Ex. DOC-2 at 6 (Johnson Surrebuttal).

proposed discarding the 2026 demand allocator in its entirety and allocating 2026 interchange costs using 2025 demand data—proposing a reduction to the 2026 revenue deficiency of $2,940,237.[204]

The ALJ Report recommends adopting the Department's position on the grounds that use of the most recently accepted FERC demand allocator is consistent with the Commission's decision in Docket No. E002/GR-21-630 and that the record does not support offsetting updates to other Interchange Agreement components.[205] Xcel Energy respectfully takes exception to both the ALJ's recommendation and the Findings on which it is based.

The facts underlying the Commission's decision in Docket No. E002/GR-21-630 are materially different from those presented in this case. In the prior case, the Interchange Agreement accepted by FERC after the case was filed allocated a *lower* share of costs to Minnesota, and the Commission relied on that reduced allocation to support the Department's recommended rate reductions for the 2022 test year and the 2023 and 2024 plan years.[206] Here, by contrast, the 2025 demand allocator accepted by FERC in May 2025

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[204] Ex. DOC-1 at 33 (Johnson Direct); Ex. DOC-2 at 7 (Johnson Surrebuttal).
[205] Report at Findings 525-528.
[206] *See In the Matter of the Application by Northern States Power Co., d/b/a Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 108-109 (July 17, 2023); *see also* Direct Testimony of Nancy Campbell at 23 (Oct. 3, 2022) (eDocket No. 202210-189497-04) (noting the update from the as-filed Minnesota demand allocation of 83.7474 percent to the FERC accepted interchange agreement filing rate of 84.6779 percent resulted in a $149,983 increase to revenue and a $1,332,358 decrease to expense in 2022); Surrebuttal Testimony of Nancy Campbell at 14 (eDocket No. 202212-191140-02) (Dec. 6, 2022) ("[I]f the actual demand allocator FERC approved for 2022 was 83.6779%, which

reflects a *higher* allocation of costs to Minnesota compared to the Company's proposed 2025 allocator.[207] As a result, Minnesota customers are held harmless from the increase in costs that are properly allocable to Minnesota in 2025, and the upward trend accepted by FERC in 2025 demonstrates the reasonableness of the Company's 2026 forecasted demand allocations. The ALJ's Report accurately concludes that "[r]ecent trends in the Interchange Agreement demand allocators filed with and accepted by FERC reflect an upward trend in the allocation of costs to NSPM over recent years."[208] The Report does not, however, reconcile that trend with the recommendation to apply a lower demand allocation in the 2026 plan year.[209]

Further, as the Company explained in this case, updating the 2026 demand allocator to reflect the revised transmission loss multipliers accepted by FERC—the only data element the Department identified as requiring update[210]—would increase the 2026

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is lower than the Company forecasted of 83.7474%, it makes sense to update the other years to continue to the reflect this lower actual amount in the Company's forecasted downward trend.").

[207] Ex. DOC-1 at 31 (Johnson Direct) (As shown in Table 3, the NSPM demand allocation proposed by Xcel Energy in Supplemental Direct is 84.0551 percent and the allocation accepted by FERC in the 2025 Interchange Agreement is 84.0693 percent (an increase of 0.0142 percent), which results in an increase to the 2025 test year revenue requirement of $272,723).

[208] Report at Finding 523.

[209] The ALJ Report's recommendation to hold the demand allocator flat in 2026 and continue to apply the 2025 demand allocator not supported by recent trends in the Interchange Agreement demand allocators filed with and accepted by FERC. *See* Ex. XLI-1 at 86 (LaConte Direct) (Xcel Energy's response to DOC IR 157, Attachment A); Xcel Energy Initial Brief at 156.

[210] Ex. DOC-2 at 6 (Johnson Surrebuttal) ("Xcel's proposed 2026 Interchange Demand allocators are based on forecasted data that includes older transmission loss allocators. In contrast, the 2025 Interchange Agreement includes more current period updated demand

revenue requirement by $282,504.[211] While the ALJ noted difficulty verifying the Company's calculation,[212] the $282,504 figure was derived by applying the updated transmission loss multipliers that the Department advocated as reflecting the most current data, using demand and cost information already in the evidentiary record.[213] No new assumptions, methodologies, or data were introduced. The calculation was not offered as a proposed revenue adjustment, but to illustrate the impact of updating the sole data element the Department identified as outdated—the FERC-accepted transmission loss multipliers—while otherwise retaining the 2026 demand allocator that reflects expected demand, costs, and revenues for the 2026 plan year. The $282,504 impact therefore does not require additional testimony to contextualize it; it demonstrates that adopting the data

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allocators that include updated transmission loss allocators that have been approved by FERC."); Ex. DOC-1 at 32 (Johnson Direct) ("Xcel's proposed 2026 Interchange Demand allocators are based on forecasted data that includes older transmission loss allocators. In contrast, the 2025 Interchange Agreement includes the updated transmission loss allocators that have been approved by FERC. As a result, I conclude it is more reasonable to use the updated transmission demand allocators for 2026 rather than relying on older data.").

[211] Xcel Initial Brief at 158 (citing Ex. Xcel-101 (Xcel Energy's Response to DOC IR 1160, Attachment C)); Ex. DOC-1, Schedule 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachments A and C)).

[212] Report at Finding 522 ("The Company asserts that utilizing the updated transmission loss multiplier data to compute the 2026 demand allocator would result in an increase to the 2026 revenue requirement of $282,504.540. However, this figure appears to have been presented for the first time in the Company's Initial Brief. Not only did this preclude other parties from offering testimony analyzing and contextualizing this figure, but the Administrative Law Judge was unable to verify the calculation from the record evidence cited.").

[213] The calculation simply applied the updated transmission loss multipliers filed with FERC to the 2026 Demand Allocator percentages in Attachment C to the Company's response to DOC IR 1160. *See* Ex. Xcel-101, Attachment C (Xcel Energy Response to Department of Commerce Information Request 1160), Ex. DOC-1 at MAJ-D-4, Xcel Response to DOC IR 1160, Attachments A and C (Johnson Direct).

updates the Department identified on a targeted basis would increase, not decrease, the 2026 revenue requirement. This reinforces the Company's position that a wholesale substitution of the 2025 demand allocator for 2026 is not a reasonable or proportionate response to the Department's identified concern.

Finally, the ALJ's Finding that Xcel "did not update any other components of the allocator or present any specific offsetting adjustments"[214] appears to reflect a misunderstanding of the basis for the Company's opposition to the Department's recommendation. The Company could not update other Interchange Agreement components for 2026 because actual 2026 data necessary to do so was not yet available. More importantly, the Company's argument is not that other components should have been updated, but that use of the 2025 demand allocator for 2026 would rely on coincidence peak demand data that is not representative of the 2026 plan year. This creates a fundamental mismatch between the peak demand assumptions used to allocate costs and the forecasted costs being allocated in the 2026 plan year. Further, as discussed above, the Company did update other components of the allocator by quantifying the impact of updating the transmission loss multipliers, the only element of the demand allocation the Department identified as requiring update. For these reasons, the Commission should reject the ALJ Report's recommendation and adopt the Company's proposed 2025 and 2026 Interchange Agreement demand allocator.

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[214] Report at Finding 525.

### C. Board of Directors Expense (Findings ¶¶652-662, pp 103-104)

The Company takes exception to the ALJ's recommendation to disallow 50 percent of the requested level of Board of Director's fees and expenses in both the 2025 Test Year and 2026 Plan Year.[215]

As an initial matter, it should be noted that as a Minnesota corporation, Xcel Energy is required under Minnesota law to have a Board of Directors.[216] Further, the ALJ Report's rationale for recommending disallowance of 50 percent of this expense—that the Board of Directors advances shareholder interests[217]—fails to recognize that the Board's focus on the Company's performance and financial well-being directly benefits customers.[218] Board of Director compensation is paid to provide essential governance, risk oversight, and strategic guidance for the Company.[219] Directors ensure safe, reliable, and cost-effective service for customers; oversee compliance with regulatory requirements; and make decisions that protect long-term customer interests.[220] Board compensation supports independent oversight that helps ensure prudent decision-making and delivers tangible benefits to customers through safety, reliability and resiliency, clean energy and climate leadership, system security, innovation, and affordability.[221] Market-competitive compensation is essential to attract and retain qualified directors to perform these

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[215] Report at Finding 662.
[216] Ex. Xcel-63 at 39 (Ly Rebuttal); Minn. Stat. § 302A.201, subd. 1.
[217] Report at Finding 660.
[218] Ex. Xcel-63 at 40 (Ly Rebuttal).
[219] Ex. Xcel-63 at 42 (Ly Rebuttal).
[220] Ex. Xcel-63 at 42 (Ly Rebuttal).
[221] Ex. Xcel-63 at 42 (Ly Rebuttal).

functions.[222] Consistent with these considerations, the Commission has historically approved the Company's request for Board of Directors expense in its entirety.[223]

The ALJ Report suggests that Board of Directors expenses should be allocated between shareholders and customers based on a divergence of interests between the two groups.[224] As the ALJ elsewhere correctly notes, however, the distinction between shareholder and customer interests is not a bright line; more fundamentally, those interests are not mutually exclusive.[225] Further, this framing conflates abstract interests with the Board of Director's actual governance activities. The governance, risk oversight, financial stewardship, and long-term planning responsibilities performed by the Board of Directors help ensure that the utility safely, reliably, and prudently serves customers at reasonable cost. And while shareholders may also derive benefits from effective Board oversight, those effects in no way diminish or limit the direct and substantial benefits to customers,

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[222] Ex. Xcel-63 at 43 (Ly Rebuttal).

[223] *See, e.g., In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-21-630; *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. E002/GR-12-961. In the Company's 2012 and 2021 electric rate cases, Board of Directors expenses were not contested. The Board of Director expenses were included in Employee Expense Report ("EER") Schedule 4 to the Initial Filings and subsequently included in the revenue requirement.

[224] Report at Finding 659-660, 617-618.

[225] Report at Finding 617 ("To be sure, the divide between shareholder interests and customer interests is not a bright line. Customers derive a benefit from a financially sound utility that is able to provide safe and reliable service. Further, the financial state of a utility impacts, among other things, its cost of debt; a cost which is ultimately borne by customers. Also, efficiencies leading to reductions in utility expenses benefit shareholders in the short term and, once those reductions are incorporated into a utility's next rate case, customers in the longer term.").

nor do they provide a basis for allocating 50 percent of the Company's Board of Directors expenses as shareholder-only costs.

Accordingly, the Company's Board of Directors expense is reasonable and the Commission should allow the Company to recover these costs in full.

### D. Outside Services (FERC Account 923) (Findings 663-679, pp. 104-107)

The Company takes exception to the ALJ recommendation that the Commission should adopt the Department's proposal for expenses tracked in FERC Account 923.[226]

The ALJ Decision accurately summarizes the arguments and issues relating to FERC Account 923. As the ALJ noted, FERC Account 923 is a "catch-all" FERC Account and includes expenses arising in many business areas.[227] It is true that the Company's requested recovery for outside services tracked in FERC Account 923 represents a significant increase over the average for previous years, and that from 2022 to 2024, the Company collected more through rates than was spent in this account.[228]

The ALJ relied on this history of "over-recovery" as a basis for his recommendation.[229] But that history should not be persuasive. First, focusing solely on a single FERC Account ignores the fact that the Company manages O&M on a total-company basis, which necessarily involves offsetting increases and decreases across FERC Accounts. Second, the ALJ's reasoning relating to offsets and variances among accounts is incorrect. The ALJ correctly assumed that variances "*between* accounts" from year to

[226] Report at Finding 679.
[227] Report at Findings 665, 670.
[228] Report at Finding 667.
[229] Report at Finding 677.

year would "net out over time."[230] But the ALJ then focused on year-to-year activity *within* a single account – FERC Account 923.[231] The history *within* FERC Account 923 is not relevant to the point that lower-than-expected spending in FERC Account 923 (even for several years in a row) was offset by higher spending across other FERC accounts (across multiple years).

The ALJ also asserts that it is difficult to "fault the Department for selecting an accounting system the Company is legally obligated to use."[232] Respectfully, in this passage, the ALJ has conflated two separate concepts: accounting systems and budgeting. The Company is obligated to conform to FERC's uniform system of accounts, but that does not mean that the Company must, or does, budget by FERC Account. The Company is not faulting the Department for "selecting an accounting system," it is faulting the Department for using the FERC accounting system as a means to limit the Company's recovery in an arbitrarily chosen catch-all subset of O&M. It is inherently unsound to cherry-pick a single FERC account to analyze budgeting.

Finally, the ALJ relies on first quarter 2025 data to conclude that the Company was continuing to over-recover in FERC Account 923.[233] It is unreliable to draw any conclusion at all from this small sample of data. It is common for the Company's expenses to be booked in a non-linear fashion throughout the year. It is easy to see how this could happen within FERC Account 923—if vendors such as engineers or consultants undertake a big

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[230] Report at Finding 677 (emphasis added).
[231] Report at Finding 677.
[232] Report at Finding 676.
[233] Report at Finding 674.

project from July to September, the FERC Account 923 expenses might be lower in the first part of the year and larger in the latter part of the year.

The ALJ accurately understood that the arguments here are much like the arguments relating to FERC Account 923 in Minnesota Power's 2021 rate case.[234] As Minnesota Power did in that case, Xcel Energy provided reasonable support for its anticipated FERC Account 923 O&M.[235] In the Minnesota Power case, the ALJ found that the utility's budget process had carefully considered its system, its needs, and known impacts, and therefore the record supported the utility's forecasted expenses.[236] Here, Xcel Energy has shown that its budget process carefully considered its system, its needs, and known impacts.[237] The ALJ should reach the same conclusion as was reached in the Minnesota Power case, and should accordingly reject the Department's proposal to cut O&M in FERC Account 923.

### E. Investor Relations Expenses (Findings 715-720, pp. 112-113)

The Company takes exception to Findings 717-720, limiting the Company's recovery of Investor Relations Expenses to 50 percent. As the ALJ noted, and Company provided evidence that these are necessary costs that a company with publicly-traded equity must incur and include, but are not limited to: (i) the listing of shares of XEI on the National Association of Securities Dealers Automated Quotations (NASDAQ); (ii) stock

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[234] Report at Finding 673.
[235] Report at Findings 671, 673.
[236] *In re Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 25 (Feb. 28, 2023).
[237] Ex. Xcel-26 at 4-42 (Robinson Direct) (describing budget process and comparisons); Ex. Xcel-28 at 23, (Robinson Rebuttal).

transfer agent services associated with the issuance of new common shares to investors, providing shareholders online access to accounts, and maintaining the list of registered shareholders; and (iii) an annual shareholders meeting. The Company's Investor Relations team also works to keep the credit rating agencies fully informed regarding the Company's business and financing plans to maintain strong investor demand for its long-term debt securities, enabling the Company to LTD securities at favorable costs, benefitting customers.[238] As a necessary cost of business, these costs should be recoverable in full.

### F. Time-of-Use Rate Implementation Costs (Findings 403-424, pp. 63-66)

In this case, the Company sought to recover certain costs to comply with the Commission's order related to the implementation of Residential time-of-use ("TOU") rates.[239] The ALJ Report correctly concludes that the introduction of the costs to implement the time-of-use rate with rebuttal testimony in this proceeding "was the product of the timing of Commission action in Docket E002/M-23-524, and not the result of any misconduct or negligence by the Company."[240] The ALJ Report further concludes "[t]he Company has provided sufficient evidence, for all TOU capital costs except the Rate Comparison Tool, of the nature of the capital costs and the necessity of them to comply with Commission directives to meet Xcel's burden to prove that they are appropriate for recovery."[241] Based on these Findings, the ALJ Report recommends the Commission allow

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[238] Report at Finding 715; Ex. Xcel-20 at 37-38 (Wehner Direct); Ex. Xcel-94 (Wehner Witness Summary).
[239] Report at Findings 403-417.
[240] Report at Finding 416.
[241] Report at Finding 418.

the Company to recover costs related to its TOU rate implementation, with the exception of capital costs related to the Rate Comparison Tool.[242]

The Company respectfully takes exception to the ALJ's recommendation to disallow recovery of costs associated with the Rate Comparison Tool and the Findings underlying that recommendation. The recommendation rests in significant part on the conclusion that "the Commission has expressed an interest in consideration of shadow-billing as an alternative to the Rate Comparison Tool, and the record provides an inadequate basis to evaluate the relative merits of the two options."[243] This conclusion incorrectly assumes that the Commission viewed shadow billing as an alternative to be implemented contemporaneously with TOU rate implementation. It did not. The Commission's order did not require, or even contemplate, immediate deployment of shadow billing as a substitute to enable customers to evaluate whether to opt in to the TOU rate.[244] Instead, the Commission directed Xcel to assess the feasibility and cost of shadow

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[242] Report at Finding 424.

[243] Report at Finding 424. The ALJ Report also finds that "The Commission has ordered Xcel to explore the feasibility of 'shadow-billing,' which would serve a similar purpose as the Rate Comparison Tool. The Commission did not Order Xcel to implement the Rate Comparison Tool." Report at Finding 410.

[244] *In the Matter of the Petition of Xcel Energy for Approval of Residential Time of Use Rate Design*, Docket No. E002/M-23-524, ORDER APPROVING REVISED OPT-IN PROPOSAL AND SETTING REPORTING REQUIREMENTS at 8 (May 15, 2025) ("In its first annual report, Xcel must identify the feasibility and cost of implementing a shadow billing program."). ("Xcel's future explanation of shadow billing cost and feasibility should include an assessment of the costs and benefits of adding bill impact analysis functionality to its billing system."); *In the Matter of the Petition of Xcel Energy for Approval of Residential Time of Use Rate Design*, Docket No. E002/M-23-524, ORDER APPROVING TARIFF MODIFICATIONS, APPROVING COMPLIANCE PLAN, AND SETTING ADDITIONAL REQUIREMENTS FOR RESIDENTIAL TIME-OF-USE RATE IMPLEMENTATION at 6 (Feb. 23,

billing in a subsequent annual report, indicating that shadow billing was to be explored as a potential future enhancement—not a prerequisite to, or replacement for, providing customers with meaningful pre-enrollment information. While the Commission did not explicitly mandate deployment of the Rate Comparison Tool, it approved the residential TOU rate and the Company's TOU compliance plan with the clear expectation that customers would be provided with a means to compare rates and understand the potential bill impacts of opting into the TOU rate. Implementing an opt-in TOU rate without providing customers with a tool to compare rates and understand the potential impacts of participation is not reasonable.[245] The evidentiary record in this case provides substantial support for the Rate Comparison Tool and demonstrates that the costs associated with its development and implementation are reasonable and properly recoverable.[246] Far from conflicting with the Commission's directives, the Rate Comparison Tool effectuates the Commission's order by equipping customers with the information required to meaningfully

2026) ("Xcel's future explanation of shadow billing cost and feasibility should include an assessment of the costs and benefits of adding bill impact analysis functionality to its billing system.").

[245] Various parties filing comments in Docket No. E002/M-23-524 agreed that there needed to be some mechanism for customers to compare rates and understand the potential impacts of opting into the TOU rate.

[246] While the ALJ Report concludes that much of the Company's justification for the reasonableness and usefulness of the Rate Comparison Tool was presented in its brief, Report at Finding 422, that timing reflects the fact that the OAG's objections were raised for the first time in Surrebuttal, timing the ALJ recognizes is beyond the Company's control. The Company's briefing did not introduce new evidence, but instead synthesized and explained record evidence already in this proceeding, together with information previously filed in the TOU docket. Reliance on briefing to address late-raised concerns and to marshal existing record support is appropriate and does not diminish the adequacy of the evidentiary record supporting the Rate Comparison Tool.

evaluate and elect the TOU rate, and the record demonstrates that the costs proposed for recovery related to that tool are reasonable and appropriate.

## III. CLASS COST OF SERVICE STUDY AND RATE DESIGN ISSUES

### A. Class Cost of Service Study

Xcel Energy supports many of the ALJ's recommendations regarding the Class Cost of Service Study (CCOSS) issues discussed in this proceeding.[247] However, there are some issues where the Company disagrees with the Findings and Conclusions, and recommends that the Commission reach a different decision.

#### 1. AMI Cost Classification and Allocation

The Company respectfully takes exception to the ALJ's recommendation that meters should be classified as 1/3 customer, 1/3 demand, and 1/3 energy until the Company's next rate case because it is not supported by the factual record in this proceeding.

In Finding 1067, the ALJ correctly recognized that the OAG's recommendation to classify meters as 1/3 customer, 1/3 demand, and 1/3 energy is arbitrary and lacking any record support. Despite this conclusion, the ALJ recommended use of this classification method "for any relevant rate purpose between now and a decision in Xcel's next rate case" based on the assumption that the Company has selected AMI meters because of unspecified

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[247] For example, the Company agrees with the ALJ's findings and recommendations related to the classification of fixed production plant, the rejection of the Peak-and-Average method, the classification and allocation of other production O&M, and the allocation of economic development discounts.

"demand- and energy-related benefits of these meters."[248] This recommendation should be rejected for several reasons.

First, it is simply not reasonable to order the Company to use a classification method that the ALJ has found is arbitrary. Doing so could lead to unreasonable rates for customers. It is not entirely clear what the ALJ means by "any relevant rate purpose," but the Company currently collects most costs related to AMI through the Transmission Cost Recovery rider. In most situations, changing a classification method in a CCOSS will have little impact until the next rate case. The ALJ's language here, though, could lead to an immediate change to the TCR classification of these costs which would lead to an immediate rate impact for customers. That outcome would not be reasonable, particularly when the ALJ is also recommending that more information should be obtained, through a meter study, before classification is finalized.

Second, there is no record support for the ALJ's guess about why the Company selected AMI meters.[249] There is similarly no record support for the ALJ's statement that connecting customers to the system "could be accomplished at the reduced cost of a pre-AMI meter."[250] As the Commission is aware, the Company selected AMI meters because the previous AMR meter technology had reached the end of its life, replacement parts were no longer manufactured after 2022, and the Company's contract for meter reading services

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[248] Report at Finding 1066.
[249] Report at Finding 1066 ("Xcel is instead investing more money in AMI meters, and this premium is justified by the anticipated demand- and energy-related benefits of these meters.").
[250] Report at Finding 1066.

was expiring.[251] As such, overly simplistic comparisons to pre-AMI meters does not provide a reasonable basis to change the classification method at this time.

Third, no party has identified any AMI specific functions that are demand-related or energy-related, or demonstrated that such functions drive an increase in metering costs. In the absence of such evidence, generic arguments about the potential uses for AMI meters does not provide a sound basis to change classification methods.

In recognition of increased interest in this issue, the Company can accept the Department's recommendation to conduct a study on the appropriate classification of AMI meters and provide the results of the study and a recommendation on classification with the initial filing of its next electric rate case. This will ensure that the Commission is presented with a fully developed record in the next rate case, and it will avoid setting rates in the interim based on a classification method which the ALJ has confirmed is arbitrary.

For these reasons, the Company takes exception to ALJ Findings 1069 and 1070, and recommends the following language instead:

> "There should be no change to the classification of meters in this case. Instead, the Commission accepts the Company's agreement to conduct a study on the appropriate classification of AMI meters compared to traditional meters, and to provide the results of the study and a recommendation in its next electric rate case."

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[251] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of the Transmission Cost Recovery Rider Revenue Requirement for 2021 and 2022, Tracker True-up and Revised Adjustment Factors*, Docket No. E-002/M-21-814, Petition, Attachment 4 at 5 of 97 (Nov. 24, 2021), eDocket No. 202111-180141-01.

### 2. Allocation of Demand-Related Production - D10S Allocator

A portion of production costs are classified as demand-related and allocated using the D10S allocator. In the Company's last rate case, the Commission directed the Company to calculate the D10S allocator "based on its system peak coincident with the MISO system peak using historical data."[252] In this case, the Company and the OAG have recommended different ways to perform this calculation.

The Company respectfully takes exception to the ALJ's conclusion in Findings 1021 and 1022 that the Company and OAG recommendations should be given equal weight. The OAG's calculation is by definition inconsistent with the Commission's order. It does not calculate an allocator based on a single system peak, but 190 peaks over multiple years, 188 of which are not the hour of peak demand.[253] Many of the hours in the OAG's calculation are not even the peak on the day they were measured.[254] Because of this design error, the OAG's calculation is irreparably flawed, and CCOSS models using the Company's D10S allocator should be given greater weight when setting rates in this proceeding.

As an alternative, one way to resolve disputes about the D10S allocator would be to adjust the calculation method. MISO does not forecast system peaks, which means that precise data to calculate the system peak coincident with the MISO peak, as directed by

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[252] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Authority to Increase Rates for Elec. Serv. In Minn.*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSION, AND ORDER at 99 (July 17, 2023).
[253] Ex. OAG-8 at 12 (Scharber Direct); Tr. Vol. 2 at 362:6-22 (Scharber).
[254] *Id*.

the Commission, will never exist.[255] As a result, there will likely continue to be disputes about how to calculate the allocator. In the past, the Company calculated the D10S allocator based on the NSP system peak. It is likely that returning to this methodology would result in a more stable D10S allocator over time, with fewer disputes about data sources.

For these reasons, the Company recommends that Findings 1021 and 1022 be replaced with either or both of these alternatives:

> "The OAG's calculation of the D10S allocator is inconsistent with the Commission's direction to use Xcel Energy's system peak coincident with the MISO system peak, and as a result is not reasonable. CCOSS models using the Company's D10S calculation should be given greater weight when setting rates in this proceeding."

or

> "In future rate case proceedings, the Company should calculate the D10S allocator based on the NSP system peak."

### 3. Classification and Allocation of Shared Distribution Costs

On this record, there are three methods for classifying and allocating shared distribution costs: the Minimum System, the Basic Customer, and the Peak-and-Average. The ALJ appropriately concluded that the Peak-and-Average method is flawed and should not be relied upon.[256]

The Company does, however, take exception to the ALJ's recommendation that the Commission should give equal weight to the Minimum System and the Basic Customer method. First, the Company takes exception to Finding 1053. In that Finding, the ALJ

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[255] Ex. Xcel-74 at 19 (Barthol Direct).
[256] Report at Finding 1055.

concludes that none of the methods on this record are entirely reasonable because one key driver for distribution costs is "the size of a utilities' [sic] service territory." That is true, but it is also true that the size of the utility's service territory is related at least in part to the number of customers served by the service territory. That is an indication that at least some portion of the distribution system costs *must* vary based on the number of customers served.

This undisputable fact is at odds with the Basic Customer method. The core assumption of the Basic Customer method is that the shared costs of the distribution system do not vary based on the number of customers.[257] That assumption cannot be true because the Company does not expand its distribution system unless it is doing so to reach new customers.[258] Regardless of any perceived flaws of the Minimum System method, it is not reasonable to give equal weight to a classification method with a core assumption that is patently incorrect.

For these reasons, the Company respectfully takes exception to the ALJ's Finding 1053 and 1056 that the Basic Customer be given equal weight when setting rates, and recommends the following alternative language:

> "The size of the utility's system, and therefore the costs of its distribution system, are related at least in part to the number of customers it serves."
>
> "While reasonable analysts could disagree about the precise proportion of demand- or customer-related costs, the Basic Customer method's assumption that distribution lines are zero-percent customer related is unreasonable. For

[257] Report at Finding 1039.
[258] Ex. Xcel-74 at 25 (Barthol Rebuttal) (stating that "[t]he Company would not install a transformer in the middle of a field without any customers – it only adds conductors and transformers to the system when they are needed to reach new customers, which means that the system costs for conductors and transformers are driven in part by the number of customers.").

that reason, CCOSS analysis using the Minimum System method should be given greater weight in setting rates in this proceeding."

### 4. Allocation of Demand-Related Transmission Costs

A portion of transmission costs are classified as demand-related. The Company, the Department, and XLI each recommended that these costs should be allocated using the D10S allocator.[259] The OAG recommended the use of the 12CP allocator.[260]

At the outset, ALJ Finding 1025 is inaccurate and should not be adopted. Finding 1025 indicates that the Company calculated its D10S allocator based on the six highest Xcel system peak hours, which, as acknowledged in ALJ Finding 1012, is not correct. It appears that ALJ Finding 1025 was taken from the ALJ Report in the Company's 2021 rate case,[261] including references to witnesses from that proceeding who did not participate in this case.[262] The Company used a new design for the D10S allocator, as directed by the Commission, and it is accurately described in ALJ Finding 1012.

The Company also takes exception to the ALJ's recommendation on allocating demand-related transmission costs. The ALJ recommended use of the 12CP allocator, entirely on the basis that the Commission approved the use of the 12CP allocator in the

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[259] Ex. Xcel-73 at 23-24 (Barthol Direct); Ex. DOC-16 at 35 (Zajicek Direct); Ex. XLI-3 at 19 (Ly Direct).
[260] Ex. OAG-8 at 18 (Scharber Direct).
[261] *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. 21-630, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS OF THE ALJ at 152, Finding 851 (Mar. 31, 2023).
[262] Footnotes 1108 and 1109 of the Report refer to witnesses Twite and Peppin, but neither were involved in this proceeding.

Company's last rate case.[263] This recommendation does not recognize, though, that a new record was developed in this case which demonstrates that the D10S allocation method best reflects cost causation.

Demand-related costs, like these, are those driven by customers' maximum demand.[264] The costs should be allocated consistent with the primary drivers of the underlying investments. As noted in Finding 1027, the Company plans the transmission system to meet system peak demand, not average demand over 12 peaks across the year.[265] If the Company planned to meet 12 average peaks, it would, by definition, not be able to meet customer needs at the time of true system peak demand. The experts presented by the Department and XLI each confirmed this analysis.[266] For these reasons, the Company respectfully takes exception to the recommendations of the ALJ and recommends that demand-related transmission costs be allocated using the D10S allocator.[267]

### B. Revenue Apportionment

The Company respectfully takes exception to the ALJ's recommendation to adopt the revenue apportionment recommendation of the OAG, and recommends that the Company's proposal be adopted instead.

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[263] Report at Finding 1029.
[264] Ex. Xcel-73, Schedule 2 at 4-6 (Barthol Direct).
[265] Ex. Xcel-73 at 24 (Barthol Direct).
[266] Ex. DOC-16 at 35 (Zajicek Direct); Ex. XLI-3 at 19 (Ly Direct).
[267] The Company also recommends that Footnotes 1108 and 1109 in the ALJ Report be updated. They appear to refer to exhibits and witnesses from the Company's previous rate case, rather than this one.

The ALJ's recommendation appears to be premised on two justifications. First, Findings 1102-1104 suggest that the Company's recommendation did not appropriately consider non-cost factors. That is not correct, and it is not supported by the record in this case. The Company did use its CCOSS as a starting point, but moved only 20 percent towards that estimate of cost,[268] indicating that substantial weight was given to non-cost factors including those that the Commission has historically relied on. In fact, the Company gave *more* weight to non-cost factors than the OAG, because the OAG calculated its revenue apportionment by giving 1/3 weight to each of the CCOSS models it considered.[269] In other words, the OAG primarily considered cost, while the Company only gave 20 percent weight to cost.

Second, the ALJ concluded that, while the OAG's recommendation is flawed because it relies on the Peak-and-Average CCOSS, its overall recommendation was still sound because it "falls within the range of results of its Basic Customer and Minimum System cost estimates for both the Residential and Large General Service classes."[270] This conclusion is unreasonable because the OAG's revenue apportionment explicitly gives 1/3 weight to the Peak-and-Average method,[271] which the ALJ concluded should be given "significantly less weight . . . when setting rates in this proceeding."[272] It is not reasonable

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[268] Ex. Xcel-76 at 11 (Paluck Direct).
[269] Ex. OAG-10 at 39:6-8 (Scharber Surrebuttal) ("I therefore recommend an apportionment that reflects a simple weighted average of the cost allocations reflected in the three studies.").
[270] Report at Finding 1106.
[271] Ex. OAG-10 at 39:6-8 (Scharber Surrebuttal).
[272] Report at Finding 1055.

to adopt a recommendation giving 1/3 weight to a model where the ALJ has explicitly determined that model should be given "significantly less weight."

Further, while it is technically true that the OAG's recommendation falls between the Basic Customer and Minimum System CCOSS results, it is by a slender margin. For Residential customers in 2026, the range from the OAG Basic Customer method to the Minimum System CCOSS extends from 5.9 percent to 13.5 percent.[273] The OAG's recommended apportionment is 6.7 percent, giving *far* more weight to the Basic Customer method. That is unreasonable, particularly where the ALJ already concluded that the two methods should be given "equal weight when setting rates in this proceeding."[274] When the Basic Customer method is corrected to properly use the D10S allocator for demand-related transmission costs, as requested by the Department, the OAG's recommendation would no longer even be within the range of results.[275]

Further, the ALJ's recommendation to give no rate increase to the Small General Service class is not reasonable. While the Company agrees that Small General Service should receive a smaller rate increase, it is not reasonable for one class to receive no rate increase as a result of this proceeding. In fact, doing so would place unreasonable reliance on cost factors, while ignoring important non-cost factors that should be considered.

Finally, the ALJ does not give enough weight to the recommendations of other parties. For example, the Department evaluated revenue apportionment, and recommended

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[273] Ex. Xcel-75 at 8, Table 2 (Barthol Surrebuttal).
[274] Report at Finding 1056.
[275] Ex. Xcel-75, Schedule 2, at 3 (Barthol Surrebuttal) (noting that the 2026 Residential estimate for the DOC-corrected Basic Customer method is 9.6 percent).

the Company's proposal over that of the OAG.[276] Walmart and SRA also supported by the Company's recommendation.[277] This level of support from parties of varied viewpoints is an indication that the Company's recommendation is sound – in contrast, no other party supports the OAG's recommendation.

For all of these reasons, the Company respectfully takes exception to the ALJ's recommendation, and instead recommends that the ALJ adopt the Company's recommended revenue apportionment for both 2025 and 2026.

Further, the Company recommends that the Commission reject ALJ Findings 1102-1104 because they incorrectly state that the Company did not consider non-cost factors in its recommendation. The Company recommends that the Commission reject ALJ Findings 1106 to 1008, and 1110, and replace them with the following language:

> "The Company's recommended revenue apportionment for 2025 and 2026 are a reasonable balance of cost and non-cost factors, and should be adopted."

### C. Residential and Small Commercial Customer Charges

The Company respectfully takes exception to the ALJ's recommendation to leave the existing customer charge at $6.00 for Residential Small Commercial customers. The ALJ's recommendation has three significant flaws.

First, the ALJ Findings give unreasonable weight to the OAG's "customer-specific cost" calculation, and essentially no weight to the other methods for calculating a customer charge in the record. The ALJ does not discuss the Department's calculation which, when

[276] Ex. DOC-20 at 11 (Bahn Surrebuttal).
[277] Report at Finding 1094.

corrected to account for a data error, results in a customer-specific cost calculation of $7.26.[278] Correcting the Department's calculation to include service drops would increase the calculation further. The Department's calculation supports an increase to the customer charge. The ALJ Findings also give short shrift to the Company's estimate of customer-related costs, which suggests that a customer charge of $24.00 would be supported. Instead, the ALJ's Findings focus almost exclusively on the OAG's methodology.

That treatment is not reasonable. It is particularly unreasonable given the many other sections of the ALJ Report in which the ALJ recommends that the Commission rely on multiple analytical models in making a decision, including other rate-design topics such as the CCOSS and the revenue apportionment. On this issue alone, the ALJ suggests that the Commission should give essentially no weight to the Company or Department calculations, and rely entirely on the OAG's preferred method. Even if there were record support for giving the OAG's analysis more weight, the ALJ provides no Finding justifying the recommendation to ignore the Company and Department calculations entirely, nor would one be supported by the record.

Second, the ALJ's reasoning for giving preference to the OAG's calculation is unsound. Finding 1127 concludes that the Commission should rely on the OAG's calculation because it results in a lower customer charge, which would encourage conservation. That is results-based analysis, and is not a reasonable basis to ignore the Company's cost calculation.

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[278] Ex. Xcel-78 at 12 (Paluck Rebuttal).

Third, the ALJ's reasoning fails to properly balance other policy goals against the goal of conservation. It is true that the Legislature has directed the Commission to encourage conservation, but it has also directed the Commission to be "reasonable" in doing so.[279] The Legislature certainly did not intend the Commission to encourage conservation in a way that conflicts with other statutory goals, including the requirement to set rates that that are just and reasonable, non-discriminatory, supportive of the financial health of the utility, and which encourage electrification.[280]

The ALJ's recommendation would hold the customer charge artificially low and would conflict with these other policy goals. An artificially low customer charge will increase bills for customers with higher-than-average usage, including low income customers with older homes, large families, or on space heating. It is not reasonable to disadvantage these customer groups, nor is it necessary to do so in order to encourage conservation.

An artificially low customer charge also reduces revenue stability to the Company which, at some point, could have a negative impact on the Company's financial health. Customers rely on a financially sound utility to make the investments needed to provide safe, reliable, and increasingly clean electricity. Reducing the amount of revenue recovered through fixed charges introduces greater uncertainty into recovery which could impact financial health.

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[279] Minn. Stat. § 216B.03.
[280] *See* Minn. Stat. §§ 216B.03, .07.

Further, holding the customer charge artificially low increases the volumetric rate for electricity at a time when the Commission is encouraging customers to electrify their homes, businesses, and transportation. An artificially low customer charge means an artificially high volumetric rate, which could discourage customers from pursuing electrification adjustments.

The record demonstrates that a customer charge as high as $24.00 would be economically supported; but the Company has proposed only a moderate increase to $11.00. A customer charge of $11.00 would appropriately balance the goals of conservation against other policy goals including non-discriminatory rates, financial health for the utility, and electrification.

For these reasons, the Company respectfully takes exception to the ALJ's recommendation, and recommends that the Commission adopt the Company's recommendation to increase the customer charge to $11 for Residential and Small Commercial customers. As it relates to specific findings, the Company recommends that the Commission decline to adopt ALJ Findings 1127 through 1129, and adopt the following language instead.

> "The Company's recommendation to moderately increase the customer charge for Residential and Small Commercial customers to $11.00 is reasonable, and will be adopted."

## IV. ADDITIONAL ALJ RECOMMENDATIONS

### A. Low-Income Discount Rate

The ALJ recommends that the Commission initiate "a process" to develop a potential low-income rate.[281] At the same time, the ALJ notes that the Commission should not predetermine that such a rate would be appropriate, given the legitimate concerns that such a rate may be "unreasonably preferential, unreasonably prejudicial, or discriminatory" in violation of Minnesota Statutes § 216B.03 and due to Company and Department concerns regarding the feasibility and adequacy of such a rate.[282] Specifically, Company witness Nick Martin raised concerns regarding the data underlying Joint Intervenors witness Gabriel Chan's support for a low-income rate, whether bill credit programs similar to those already in use by the Company could provide better tailored assistance by addressing fuel costs and other charges on customers' bills, and how such a rate could effectively be implemented.[283] Department witness Michael Schmitz raised concerns regarding the lack of support in Dr. Chan's testimony regarding the costs he estimated in his testimony, the ability to identify low-income customers and accurately target and verify their qualification for a low-income rate, and the risk of leakage, i.e., serving technically ineligible households.[284]

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[281] Report at Finding 1161.
[282] Report at Findings 1154, 1155, 1159, 1161; Ex. DOC-22, entirety (Schmitz Rebuttal); Ex. Xcel-71 at 55-56, 60-61; Ex. Xcel-72 at 6-12 (Martin Surrebuttal).
[283] Ex. Xcel-71 at 55, 60-62.
[284] Ex. DOC-22, entirety.

The Company continues to recommend that affordability concerns be addressed through targeted and specific programs. As the Report noted, the Company demonstrated that nearly 120,000 customers were already enrolled in such program in 2023-2024.[285] However, should the Commission find value in a separate "process" or proceeding to further explore the legality, feasibility and effectiveness of such a rate, with the explicit recognition that depending on the result of that process or proceeding it may determine not to approve such a rate, the Company will fully participate in such a process or proceeding. Therefore, the Company respectfully requests that, if the Commission accepts the ALJ's recommendation, the Commission establish that this proceeding will evaluate whether evaluate the Company's and Department's concerns and will reject the proposal if implementation of a low-income rate is unreasonable, discriminatory, or impractical.

### B. Filing Regarding Minnesota Statutes Section 216C.05

The Company takes exception to the ALJ's recommendation that the Commission order the Company to make a filing in a new docket related to Minn. Stat. § 216C.05. In the Company's last rate case, the Commission ordered the Company to make a filing in the pending advanced rate design docket related to the Minnesota policy goal that rates should be 5 percent below the national average.[286] The Company made that filing on March 31, 2025, and the Commission has taken no action on it since that time.

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[285] Report at Finding 1147

[286] *In the Matter of the Application of Northern States Power Co., dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at Order Point No. 77 (July 17, 2026).

The ALJ properly recognized that it would be improper to make findings in this rate case about a compliance filing that the Commission ordered to be filed in an entirely different proceeding.[287] In light of that Finding, it would be unreasonable to require any further action on the issue at this time.

In addition, it would be unreasonable to proliferate regulatory requirements that do not provide value to the Commission. Given the lack of action on the compliance filing in the advanced rate design docket, it does not appear that the Commission found the analysis useful. Ordering the Company to re-create that work in the future would require resources that could be better used on other issues.

For these reasons, the Company takes exception and recommends that the Commission should not require a separate analysis related to Minn. Stat. § 216C.05.

### C. Capital Structure, Long-Term Debt And Requirements For Future Rate Cases (Findings 989-990, 1205-1212; pp. 157, 196-197)

The Company takes exception to two ALJ Findings regarding the Company's capital structure[288] and to the ALJ recommendations regarding future rate case requirements related to capital structure and long-term debt.[289]

The ALJ Report correctly discusses capital structure with the other undisputed or resolved issues in this proceeding, as no party objected to the Company's proposed capital structure for either 2025 or 2026.[290] Moreover, the Report specifically found: "The

[287] Report at Finding 1201.
[288] Report at Findings 989-990.
[289] Report at Findings 1205-1212.
[290] Report at Findings 246-250.

Company's proposed capital structure is reasonable and should be approved by the Commission for ratemaking purposes in this proceeding."[291] Nonetheless, elsewhere in the Report the ALJ states that the Company "has a high equity/debt ratio, and this ratio benefits shareholders at the expense of customers."[292] The record does not support this Finding.

The ALJ bases this Finding on Department testimony comparing the Company's equity ratio to the equity ratios of the Department's proxy group companies.[293] However, in evidence not addressed in the Report, Company witness Mr. Nowak explained this is not an appropriate comparison.[294] The Department testimony compared the Company's proposed capital structure (the capital structure of an operating company utility) to the capital structures of the holding companies in the Department's proxy group.[295] Since capital at the holding company level may finance a variety of investments, including unregulated operations, comparisons to the holding company capital structure may lead to flawed and misleading conclusions.[296] And importantly, capital structure information is available for the regulated operating utilities of the proxy companies, allowing for an "apples-to-apples" comparison of those operating companies' capital structures to the Company's proposal.[297] That analysis demonstrates the Company's proposed common equity ratio of 52.50 percent to be within the range of actual common equity ratios for the

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[291] Report at Finding 250.
[292] Report at Finding 990.
[293] Report at Finding 989.
[294] Ex. Xcel-25 at 48-49 (Nowak Rebuttal).
[295] Ex. Xcel-25 at 48-49 (Nowak Rebuttal).
[296] Ex. Xcel-25 at 48-49 (Nowak Rebuttal).
[297] Ex. Xcel-25 at 48-49 (Nowak Rebuttal).

operating companies within the proxy group.[298] The record simply does not support a finding that the Company has a high equity ratio and ALJ Findings 989 and 990 should not be adopted.

The Report also recommends adopting Department recommendations that the in future rate cases the Commission require the Company to "(1) demonstrate that its proposed capital structure is cost-minimizing or reasonably departs from the least cost capital structure . . . and (2) demonstrate that the costs of each debt issuance made since its prior rate case reasonably reflect the risks of [the Company] and are not inflated by risks associated with other entities within Xcel Energy, Inc.'s corporate structure."[299] The record demonstrates that neither proposed future requirement is well founded, both could lead to future rate case filing requirements disputes and they should not be adopted.

Regarding the Company's capital structure, neither the Report nor the Department testimony explains what sort of analysis could be performed to demonstrate the Department's theoretical "cost-minimizing" capital structure. In fact, Department witness Mr. Addonizio who provided this recommendation acknowledged that while the theoretical models he posits could provide a rough estimate of such a hypothetical optimal capital structure, "the models are not easy to implement." And while he believes such models could be helpful "the Commission can reach reasonable conclusions [regarding the Company's capital structure] without them in this proceeding."[300] Further, Company Vice

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[298] Ex. Xcel-25 at 48-49 and Schedule 12 (Nowak Rebuttal).
[299] Report at Finding 1208.
[300] Ex. DOC-12 at 14 (Addonizio Direct).

President and Treasurer Todd Wehner explained the futility of and quest to determine whether the Company's capital structure is "optimal" or "cost minimizing." Mr. Wehner noted that the concept of an "optimal" capital structure implies a single, perfect point that can be achieved and maintained.[301] He further explained that an "optimal" capital structure:

> is a theoretical ideal that does not account for the dynamic and often unpredictable nature of financial markets. Capital markets behave in non-linear ways, and the price discovery process is subject to a wide range of factors outside of a company's control, including macroeconomic events and investor sentiment.[302]

Further, prudent management of the Company's financial leverage and risk profile requires a certain amount of buffer so that the Company can weather unforeseen events.[303] This means there will always be some level of imprecision when managing the capital structure, and the more relevant analysis is not whether a proposed capital structure is "optimal" but if it is reasonable given current market conditions and a utility's long-term capital needs.[304] A utility's financial integrity and its ability to raise capital must be evaluated on a spectrum, not against a theoretical "optimal" or "cost-minimizing" standard.[305]

The Department and ALJ recommendation for a new requirement related to cost of debt issuances is similarly unwarranted and unnecessary. First, the Company already must

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[301] Ex. Xcel-21 at 3 (Wehner Rebuttal).
[302] Ex. Xcel-21 at 3-4 (Wehner Rebuttal).
[303] Ex. Xcel-21 at 4 (Wehner Rebuttal).
[304] Ex. Xcel-21 at 4 (Wehner Rebuttal).
[305] Ex. Xcel-21 at 4 (Wehner Direct).

report to the Commission within 20 days of each security issuance.[306] Any such report includes an analysis from an underwriting bank detailing the transaction's performance.[307] Second, from a theoretical standpoint, the recommendation that the Company be required to "demonstrate that the costs of each debt issuance made since its prior rate case reasonably reflect the risks of [the Company] and are not inflated by risks associated with other entities within the Xcel Energy, Inc. corporate structure" is unworkable.[308] As Mr. Wehner noted, credit markets do not operate in a vacuum; they evaluate the entire corporate family's financial health and numerous other factors, including prevailing interest rates, investor demand, and the overall economic climate.[309] Additionally, the desired requirement would force the Company to prove a negative, which is logically impossible.[310] Similar to trying to prove an "optimal" capital structure, requiring the Company to prove that outside factors did not influence its cost of debt is a fruitless errand that would rely on layers of assumptions and unprovable counterfactuals.[311] For all of these reasons, Findings 1205-1212 should not be adopted.

## CONCLUSION

The ALJ Report demonstrates a thorough review of the extensive record in this proceeding. The Report properly found that the Company met its burden of proof on many

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[306] Ex. Xcel-21 at 5 (Wehner Direct) (citing Commission requirements established in MPUC Docket Nos. E,G999/CI-08-1416 and E002/S-24-368).
[307] Ex. Xcel-21 at 5 (Wehner Rebuttal).
[308] Ex. Xcel-21 at 5 (Wehner Rebuttal).
[309] Ex. Xcel-21 at 5 (Wehner Rebuttal).
[310] Ex. Xcel-21 at 5 (Wehner Rebuttal).
[311] Ex. Xcel-21 at 5 (Wehner Rebuttal).

of the disputed issues, while on others finding the Company failed to meet its burden. As discussed above, Xcel Energy generally agrees that the majority of the ALJ's Findings provide an accurate summary of the record and an appropriate application of Minnesota law to that record. However, the Company takes exception to certain Findings as inconsistent with the weight of the evidence in the record or inconsistent with applicable law and takes exception to those Findings. And respectfully requests that the Commission modify the Report consistent with these Exceptions and with the Company's February 25, 2026 Proposed Findings of Fact, Conclusions of Law and Recommendation.

Dated: May 15, 2026

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