BEFORE THE MINNESOTA COURT OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
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MPUC Docket E-002/GR-24-320; E-002/M-24-321
CAH Docket No. 28-2500-40515

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

PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF THE OFFICE OF THE ATTORNEY GENERAL— RESIDENTIAL UTILITIES DIVISION

February 25, 2026

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STATE OF MINNESOTA
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FINDINGS OF FACT AND CONCLUSIONS

This matter came on for an Evidentiary Hearing before Administrative Law Judge ("ALJ") Joseph Meyer on December 17 and 18, 2025. Pursuant to the ALJ's First Prehearing Order of January 31, 2025, the Office of the Attorney General – Residential Utilities Division ("OAG") files its Proposed Findings of Fact and Conclusions of Law. The OAG submits proposed findings only for issues on which it has taken a position. That the OAG has remained silent on an issue on which it has not taken a position should not be interpreted as an endorsement of Xcel's or any other party's position.

I. FINANCIAL ISSUES

A. Early Retirement of the Allen S. King and Sherburne County Coal Plants

1. The parties dispute in this case how to set the remaining lives for two coal plants that are retiring prior to the end of their potential operating lives—Allen S. King (King) and Sherburne County Unit 3 (Sherco 3). The procedural history of this dispute is lengthy, but necessary to understand the issue and provide the Commission with a recommendation.

2. In Xcel's 2020-2034 integrated resource plan (IRP), the Commission approved Xcel's proposal to early-retire two of Xcel's coal-fired electric generating plants, Sherco 3 and King.[1] The IRP Order approved Xcel's request to change the Sherco 3 retirement year from 2040 to 2030 and change the King retirement year from 2037 to 2028.[2] The IRP Order did not resolve the significant policy questions of who should

[1] *In re 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Co. d/b/a Xcel Energy*, MPUC Docket No. E-002/RP-19-368, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS at 7, 31 (April 15, 2022) (eDockets No. 20224-184828-01).
[2] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 10 (Jul. 17, 2023) (eDockets No. 20237-197559-01).

pay for the stranded costs of retiring coal plants and how and when that payment should take place.[3]

3. Following the IRP Order, in Xcel's last rate case, Xcel proposed in rebuttal testimony to accelerate each early-retiring plants' depreciation schedule.[4] Xcel and the Department advocated to reserve the issue for further record development and "consideration of alternative rate-treatment proposals in a new docket."[5]

4. The Commission decided that "there was broad agreement that issues of depreciation accounting for early-retiring generation facilities will have significant ratepayer impacts and involve important policy considerations that have not been fully developed in this record."[6] So the Commission decided "because the issue was introduced relatively late in the proceeding, a new docket will provide opportunities to develop a full record, including exploration of the potential mitigations and any other potentially reasonable solutions."[7]

5. In line with this decision, the Commission opened docket number 23-375 to investigate depreciation accounting and other ratemaking issues and "inform consideration of potentially standardizing the ratemaking treatment applicable to utility-owned generation facilities that retire early."[8] Following input from the Department, the OAG, all electric utilities, and labor unions, in May 2025, the

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[3] *In re 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Co. d/b/a Xcel Energy*, MPUC Docket No. E-002/RP-19-368, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS at 31 (April 15, 2022) (20224-184828-01).

[4] *See In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 11 (Jul. 17, 2023) (eDockets No. 20237-197559-01); *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, ORDER PARTIALLY GRANTING MOTION TO STRIKE at 3-4 (Nov. 30, 2022) (eDockets No. 202211-190981-01).

[5] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 11 (Jul. 17, 2023) (eDockets No. 20237-197559-01).

[6] *See In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 12 (Jul. 17, 2023) (eDockets No. 20237-197559-01).

[7] *See In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 12 (Jul. 17, 2023) (eDockets No. 20237-197559-01).

[8] *In re Comm'n Inquiry into the Ratemaking Treatment for Early Ret. Generating Facilities Owned by Regul. Elec. Util.*, MPUC Docket No. E002, E015, E017/CI-23-375, ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY RETIRING GENERATING FACILITIES at 2 (May 14, 2025) (eDockets No. 20255-218956-01); *id.*, NOTICE OF COMMENT PERIOD at 1 (Aug. 22, 2023).

Commission established a four-tiered framework to address the ratemaking treatment for utility-owned generation facilities that retire early.[9]

6. The framework establishes a process for Commission decision making, which the Commission emphasized was flexible:

    - Tier 1: Data Gathering Phase: Is plant used and useful, plant size, original date of retirement, impact on ratepayers and has the utility prudently operated the plant will also be considered. Move to Tier 2.
    - Tier 2: Does the early-retiring asset meet the criteria established for accelerated depreciation? If yes, stop. Assign accelerated depreciation. If no, move to Tier 3.
    - Tier 3: Does the early-retiring asset meet the Tier 2 standards, except that accelerated depreciation would cause rate shock? If yes, assign regulatory asset with a possible return. If no, move to Tier 4.
    - Tier 4: Further investigation is required to determine appropriate ratemaking treatment. (Tier 4 assumes the asset is of unique nature or the plant was not used and useful at the time of early-retirement or possible prudency concern.)[10]

7. In its initial filing, Xcel did not request to make any adjustments to the remaining lives of Sherco 3 and King. Xcel requested, however, that "when the facilities are retired, any remaining net book value should be transferred to a regulatory asset and coupled with the Commission-approved weighted average cost of capital (WACC)."[11] Xcel stated that this proposal was consistent with the proposal in docket no. 23-375.[12] As described above, the Commission did not adopt Xcel's proposal in that proceeding and instituted the four-tiered framework instead.

8. In intervenor direct testimony, the Department proposed to accelerate the remaining lives of Sherco 3 and King to their 2030 and 2028 respective retirement dates. In direct testimony, the Department did not address the Commission's four-tiered framework. Instead, the Department stated "we prefer to match the IRP operation

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[9] *In re Comm'n Inquiry into the Ratemaking Treatment for Early Ret. Generating Facilities Owned by Regul. Elec. Util.*, MPUC Docket No. E002, E015, E017/CI-23-375, ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY RETIRING GENERATING FACILITIES at 7-8 (May 14, 2025) (eDockets No. 20255-218956-01).

[10] *In re Comm'n Inquiry into the Ratemaking Treatment for Early Ret. Generating Facilities Owned by Regul. Elec. Util.*, MPUC Docket No. E002, E015, E017/CI-23-375, ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY RETIRING GENERATING FACILITIES at 7-8 (May 14, 2025) (eDockets No. 20255-218956-01).

[11] Ex. Xcel-17 at 76 (Halama Direct).

[12] Ex. Xcel-17 at 76 (Halama Direct).

lives with depreciation lives, whenever possible, unless there is a significant concern with rate shock."[13]

9. To support its recommendation, the Department provided a table, based on figures that it received from Xcel in a Microsoft Excel document attached to an email.[14] Xcel represented in the email that "the coal increase partially offsets the nuclear decrease and the net result would be a decrease in both 2025 and 2026."[15] The Department asserted that extending the remaining lives for Xcel's nuclear plants (Monticello and Prairie Island) and accelerating depreciation for Sherco 3 and King would result in a combined revenue requirement decrease of $10.89 million in the 2025 test year and $13.56 million in the 2026 plan year.[16]

10. In surrebuttal testimony, the Department clarified that it viewed the "pros" of its approach as 1) following the traditional but not mandatory approach to update depreciable lives to match the operating lives under an IRP; 2) avoiding an intergenerational subsidy issue "where future ratepayers would have to pay for coal plant costs after the plants are no longer operating and customers who did not benefit from the plants may be paying for them"; 3) the "offset" provided by extending the nuclear plants' remaining lives "such that they still result in an overall net reduction to revenue requirement[]"; 4) lack of rate shock to customers because of the aforementioned overall reduction to the revenue requirement; 5) the Commission's direction to address early retirements in rate cases, which the Department interpreted "to mean it should be addressed in the current rate case and not a potential future rate case;" and 6) the long term rate impacts of extending depreciation due to paying Xcel's return if a regulatory asset is created—calculated at $63 million.[17]

11. Also in surrebuttal testimony, however, the Department acknowledged that there were at least two "cons" to accelerating depreciation in this case: 1) it would not provide potentially needed rate mitigation; and 2) "Xcel may not be able to fully recover costs incurred for these plants due to accelerated depreciation not being included in interim rates."[18]

12. Xcel opposed the Department's recommendation to accelerate depreciation for Sherco 3 and King.[19] Xcel opposed the Department's recommendation based on the size of the increase to its revenue requirement of approximately $58.8 million in 2025 and $55.4 million in 2026.[20] Xcel reasoned that accelerating depreciation would result in significant rate impacts, a consideration under tier two of the Commission's

[13] Ex. DOC-23 at 14 (Jones Direct).
[14] Ex. DOC-23 at 15, HDL-D-6 (Jones Direct).
[15] Ex. DOC-23, HDL-D-6 (Jones Direct).
[16] Ex. DOC-23, HDL-D-6 (Jones Direct).
[17] Ex. DOC-24 at 18-20 (Jones Surrebuttal).
[18] Ex. DOC-24 at 20 (Jones Surrebuttal).
[19] Ex. Xcel-86 at 3-4 (Moeller Rebuttal).
[20] Ex. Xcel-19 at 50 (Halama Rebuttal).

Framework Order.[21] Xcel did agree to lengthen the remaining lives for Monticello and Prairie Island.[22] Xcel continued to request a regulatory asset for any remaining balance for Sherco 3 and King after retirement.

13. The OAG and XLI opposed the Department's recommendation to accelerate depreciation and also opposed Xcel's request for creation of a regulatory asset because that issue is not yet ripe.[23]

14. The OAG agreed that matching an asset's depreciable life for ratemaking purposes to the IRP operating life set in an IRP is a common practice and may be reasonable in many cases, but described how the Commission had moved away from this practice for early retiring fossil fuel plants.[24] The OAG noted how the Department's analysis appears to have skipped Tier 1 of the Framework and moved to Tier 2, but focused solely on rate shock.[25] The OAG also described intergenerational equity issues if current ratepayers are made to pay for accelerated depreciation.[26] Part of the reason fossil fuel generators are retired early is to benefit future ratepayers by reducing emissions and fuel and maintenance costs.[27] Under accelerated depreciation, however, future ratepayers receive these benefits but pay none of the costs.[28]

15. Going forward, the OAG recommended that the Commission should consider a broader range of benefits to both current and future ratepayers that flow from the decision to retire fossil-fuel generators early. Additionally, the Commission will need to balance the risk of rate shock with the appropriate capital recovery for the Company given that shareholders have already been compensated for risks associated with early retirements. These considerations cannot be made if recovery of early retired assets is accelerated as a matter of course.[29]

16. XLI also raised concerns that the spreadsheet provided by Xcel, on which the Department based its conclusion that the nuclear plant life extension would offset the coal plant accelerated depreciation, could not be substantiated. XLI sent an information request to Xcel requesting the "live Excel format with all formulas intact" for both the "accelerated depreciation method" and the "securitization method."[30] Xcel responded by directing XLI to the Department's testimony but also provided spreadsheet models prepared for Docket No. CI-23-375, the early retirement docket, that used the accelerated depreciation method.[31] The figures from

[21] Ex. Xcel-19 at 52 (Halama Rebuttal).
[22] Ex. Xcel-86 at 3-4 (Moeller Rebuttal); Ex. Xcel-19 at 22 (Halama Rebuttal).
[23] Ex. OAG-6 (Lee Rebuttal); Ex. XLI-5 (LaConte Rebuttal).
[24] Ex. OAG-6 at 3-8 (Lee Rebuttal).
[25] Ex. OAG-6 at 5 (Lee Rebuttal).
[26] Ex. OAG-6 at 7 (Lee Rebuttal).
[27] Ex. OAG-6 at 7 (Lee Rebuttal).
[28] Ex. OAG-6 at 5, 7 (Lee Rebuttal).
[29] Ex. OAG-6 at 8 (Lee Rebuttal).
[30] Ex. XLI- 5, Appx. E (LaConte Rebuttal) (Xcel response to XLI-90)
[31] Ex. XLI- 5, Appx. E (LaConte Rebuttal) (Xcel response to XLI-90)

Docket No. CI-23-375 provided to XLI do not match the figures Xcel provided to the Department.[32] If the figures provided by Xcel in response to XLI are used, there would be a net increase to the revenue requirement of approximately $28 million, applying the full slate of the Department's power-plant depreciable life recommendations.[33]

17. In opposing Xcel's request to create a regulatory asset, the OAG pointed out that the Framework appears to contemplate regulatory asset creation at the time of the plant's retirement.[34] Tier 3 contemplates potential regulatory-asset treatment for generating facilities that "remain used and useful at the time of their early retirements and [where] the utility has acted prudently.[35] These two requirements can only be assessed at the time of retirement.[36] By waiting until the end of the operating life, the Commission will have a full record of the facts needed to assess all factors contemplated in the Commission's four tier structure to decide how to treat any undepreciated plant balance.[37] The OAG recommended the Commission take no action now and reevaluate at the end of each facility's operating life.

18. The ALJ agrees with Xcel, XLI, and the OAG that application of the Commission's four-tiered framework was created to resolve issues like this one. However, because of how the record developed in this case, with the Department raising the issue in direct testimony with little analysis, it is difficult to apply the Commission's four-tiered framework on this record. Particularly, the record has not been developed regarding the data gathering phase contemplated by Tier 1 of the Framework, and it is unclear how the Commission would assess "whether the utility prudently operated the plant" while the plant is still in operation.[38] The limited evidence in the record regarding prudent plant operation relates to another litigated issue, the remaining rate base for repairs following the Sherco 3 explosion over a decade ago that the Commission has determined was caused by Xcel's imprudent plant maintenance.[39] While this issue was not raised vis-a-vis Sherco's early retirement nor were the

[32] *Compare* Ex. XLI-5 at 5, Appx. E (LaConte Rebuttal) (Xcel response to XLI-90) *with* Ex. DOC-23 at 15, HDL-D-6 (Jones Direct).
[33] Tr. Vol. 2 at 435 (Jones).
[34] Ex. OAG-6 at 10 (Lee Rebuttal).
[35] *In re Comm'n Inquiry into the Ratemaking Treatment for Early Ret. Generating Facilities Owned by Regul. Elec. Util.*, MPUC Docket No. E002, E015, E017/CI-23-375, ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY RETIRING GENERATING FACILITIES at 5 (May 14, 2025) (eDockets No. 20255-218956-01).
[36] Ex. OAG-6 at 10 (Lee Rebuttal).
[37] Ex. OAG-6 at 10 (Lee Rebuttal).
[38] *In re Comm'n Inquiry into the Ratemaking Treatment for Early Ret. Generating Facilities Owned by Regul. Elec. Util.*, MPUC Docket No. E002, E015, E017/CI-23-375, ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY RETIRING GENERATING FACILITIES at 7-8 (May 14, 2025) (eDockets No. 20255-218956-01).
[39] *See, e.g.* Ex. OAG-5 at 22-25 (Lee Direct).

impacts of Xcel's imprudence analyzed by the parties, it shows the limitations of proceeding with the four-tiered Framework on this record.

19. In addition, XLI has raised significant doubt as to whether the figures upon which the Department based its analysis are correct. If the figures that Xcel provided to XLI are used, then the Department's central claim—that extending the nuclear facilities depreciable lives offsets the coal plant accelerated depreciation—fails. Determining which set of numbers is correct is not necessary to resolve this issue, however, for the reasons below.

20. The ALJ also agrees with the OAG and XLI that considering offsetting life extensions as part of the rate shock analysis creates a problematic precedent, where utilities could seek accelerated depreciation by finding other assets on which to extend depreciation on their books.

21. Given the outstanding questions, the ALJ believes maintaining the current depreciation schedule is the most appropriate. The Department has not provided the necessary evidence to complete the analysis the Commission contemplated in its framework, and even if it had, rate shock appears to be a very substantial concern cutting against accelerated depreciation.

22. The ALJ also finds that Xcel's request to create a regulatory asset is premature. Because the plant is still in service, whether it will be prudently operated at the end of its useful life is unknown. Xcel would not be prevented from requesting a regulatory asset in the future, provided that it can show that it prudently operated the plant and incurred these remaining costs as the framework appears to contemplate.

B. Sherco Unit 3 Restoration Costs

23. The OAG argued that Xcel should remove capital costs of $2.375 million in the 2025 Test Year and $2.125 million in the 2026 Plan Year for plant restoration costs resulting from the explosion of Sherco Unit 3's turbine on November 19, 2011.[40]

24. Xcel does not deny that these costs were imprudently incurred but argues that these restoration costs have previously been included in rates since 2013, and ratepayers should pay off the remainder.[41]

25. The Commission has not, however, resolved this issue in previous rate cases. In 2015, the Commission stated that "The remaining issue—how to account for insurance proceeds and litigation recoveries resulting from an accident at the Company's

[40] Ex. OAG-5, SL-D-10 at 2 (Lee Direct).
[41] Ex. Xcel-16 at 21-22 (Liberkowski Rebuttal).

Sherburne County Generating Station Unit 3 (Sherco 3)—is not yet ripe, since the Company's insurance claims and related litigation are not yet concluded."[42]

26. Then, in August 2015, the Commission clarified its order by requiring Xcel to include Sherco 3 insurance proceeds as an offset to Xcel's rate base in the 2013 rate case.[43] In doing so, the Commission did not comment on the treatment of any remaining rate base that was not offset by these insurance proceeds.[44] The Commission also did not address these costs in its 2015 or 2021 Xcel rate case order.[45]

27. Instead, the Commission waited to determine the prudency of Xcel's actions leading up to the outage in Xcel's fuel clause dockets after Xcel's litigation with General Electric (GE) had concluded.[46] Following a contested case, in December 2024, the Commission issued its order finding that "Xcel failed to operate and maintain Sherco Unit 3 in a reasonable and prudent manner consistent with good utility practices."[47] Notably, this decision was issued after Xcel filed this rate case.[48]

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[42] *In re Application of N. States Power Co. for Auth. to Incr. Rates for Elec. Serv. in the State of Minn*., MPUC Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 7 (May 8, 2015) (eDockets No. 20155-110264-01).

[43] *In re Application of N. States Power Co. for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-13-868, ORDER REOPENING, CLARIFYING, AND SUPPLEMENTING MAY 8, 2015 ORDER at 12 (August 31, 2015) (eDockets No. 20158-113661-01).

[44] *In re Application of N. States Power Co. for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-13-868, ORDER REOPENING, CLARIFYING, AND SUPPLEMENTING MAY 8, 2015 ORDER at 12 (August 31, 2015) (eDockets No. 20158-113661-01).

[45] *In re Application of N. States Power Co. for Auth. to Incr. Rates for Elec. Serv. in the State of Minn*., MPUC Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (June 12, 2017) (eDockets No. 20176-132748-01.) *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Jul. 17, 2023) (eDockets No. 20237-197559-01).

[46] *In re Sherco Prudency Review*, MPUC Docket Nos. E-002/GR-12-961, 13-868, 13-599, 14-579, 16-523, 17,492, 18-373, ORDER ADOPTING ADMINISTRATIVE LAW JUDGE REPORT AS MODIFIED, REQUIRING REFUND OR CERTAIN DISALLOWED REPLACEMENT POWER COSTS, AND REQUIRING FURTHER ACTION at 3 (Dec. 24, 2024) (eDockets No. 202412-213317-01).

[47] *In re Sherco Prudency Review*, MPUC Docket Nos. E-002/GR-12-961, 13-868, 13-599, 14-579, 16-523, 17,492, 18-373, ORDER ADOPTING ADMINISTRATIVE LAW JUDGE REPORT AS MODIFIED, REQUIRING REFUND OR CERTAIN DISALLOWED REPLACEMENT POWER COSTS, AND REQUIRING FURTHER ACTION at 3 (Dec. 24, 2024) (eDockets No. 202412-213317-01).

[48] *In re Sherco Prudency Review*, MPUC Docket Nos. E-002/GR-12-961, 13-868, 13-599, 14-579, 16-523, 17,492, 18-373, ORDER ADOPTING ADMINISTRATIVE LAW JUDGE REPORT AS MODIFIED, REQUIRING REFUND OR CERTAIN DISALLOWED REPLACEMENT POWER COSTS, AND REQUIRING FURTHER ACTION at 3 (Dec. 24, 2024) (eDockets No. 202412-213317-01) (citing the Commission's Order date of December 24, 2024); *See* Ex. Xcel-3 (Notice of Change in Rates);

28. Xcel argued that denying recovery of Sherco 3 restoration costs would be a "retroactive change,"[49] because the costs had been included in the 2013 rate case and "in every rate case since then."[50]

29. The OAG argued that this is the first rate case after the Commission's prudency determination was made and that a decision about the inclusion of these costs had not been previously made. The OAG argued that because the Commission found that the Company imprudently operated and maintained Sherco 3, which led to the explosion, plant restoration costs should not continue to be recovered from ratepayers.[51]

30. The ALJ finds that the OAG's recommendation to remove imprudently incurred capital costs from Xcel's rate base is not retroactive. This is the first rate case following the Commission's determination that Xcel's imprudent actions caused the Sherco 3 outage. It appears that ratepayers have already paid a substantial amount of these imprudent costs. Per Xcel, a portion of the restoration costs' plant balance has been depreciated, as it was included and approved for recovery in the Company's 2013 rate case.[52] The Company has benefited from these imprudently incurred costs but should not benefit anymore.

31. The ALJ finds that Xcel has not met its burden to show that including costs flowing from the Company's imprudent actions leading to Sherco 3's catastrophic failure is just and reasonable.

32. The Commission should exclude the balance of $5.5 million that has not yet been recovered from ratepayers from rate base for the plant restoration costs not covered by insurance, as well as the associated depreciation expense and taxes,[53] that have been included in the 2025 Test Year and 2026 Plan Year.

C. Residential Time of Use Rate Capital Costs

33. Xcel Energy added a request in rebuttal testimony to increase its rate base by $659,641 in the 2025 test year and by $2,458,859 in the 2026 plan year for capital costs associated with implementing the new residential Time of Use (TOU) rate.[54]

Ex. Xcel-19 at 34 (Halama Rebuttal) (stating what Xcel included in Xcel's initial filing relating to Sherco 3 restoration costs).

[49] Ex. Xcel-16 at 22 (Liberkowski Rebuttal).

[50] Ex. Xcel-16 at 22 (Liberkowski Rebuttal); Xcel Initial Br. at 164.

[51] Ex. OAG-5 at 24 (Lee Direct); Ex. OAG-7 at 17 (Lee Surrebuttal).

[52] Ex. OAG-5 at 22 (Lee Direct) (citing *In re Application of N. States Power Co. for Auth. to Incr. Rates for Elec. Serv. in the State of Minn*, MPUC Docket No. E-002/GR-13-868, COMPLIANCE FILING FINAL RATES COMPLIANCE TARIFFS at Schedule 1D, Schedule 1I at Column 10 (Sep. 2, 2015) (eDockets No. 20159-113737-01).

[53] Ex. OAG-5, SL-D-10 at 4 (Lee Direct).

[54] Ex. Xcel-19 at 27 (Halama Rebuttal); Ex. OAG-3, KH-S-4 at 2 (Hinderlie Surrebuttal).

Xcel stated that this would increase the 2025 test year revenue deficiency by $20,000[55] and the 2026 plan year revenue deficiency by $329,000.[56]

34. Xcel stated in its supplemental testimony filed on March 17, 2025 that it would add a rebuttal testimony request for costs "related to marketing, education, and outreach" arising from the March 6 hearing where the TOU rate was approved.[57] Xcel did not mention capital costs in that filing.[58]

35. In rebuttal testimony, Xcel stated that it had already included the O&M costs of the TOU rate in its initial filing, but it introduced the capital costs of the TOU rate in rebuttal testimony because the Commission's May 15, 2025 order approving a residential TOU rate was issued after the initial rate case filing.[59] Xcel stated that the capital costs were for the capital cost activities of the technical implementation of the rate. This would include setting up new rates in its customer information system and other integrated systems, developing programs to support customers that elect to opt-in to the rate, transitioning customers from the current TOU pilot rate to the new TOU rate, automation of meter exchanges for customers on a TOU rate, implementing changes to allow participation by customers in particular programs, and unit and user testing of all new programs.[60] Xcel also stated that it would need to purchase software licenses and develop a new Rate Comparison Tool.[61]

36. Xcel did not provide information demonstrating a basis for its claimed costs in testimony.[62] The OAG submitted discovery requesting more detailed information about the capital cost activities and a cost breakdown for each.[63] The OAG requested that costs be broken down by activity and by the month in which they were incurred in the 2025 test year and month in which they were forecasted to be incurred in the 2026 plan year.[64] Xcel responded with a short description of broad categories of capital cost activities and a table listing the cost of each broad category.[65] Xcel did not provide a breakdown of costs by month.[66]

37. The OAG also requested a breakdown of the capital costs of the Rate Comparison Tool by month.[67] Xcel provided a table listing Rate Comparison Tool costs according

[55] Ex. Xcel-19, sched. 3A at 4, column 34 (Halama Rebuttal).
[56] Ex. Xcel-19, sched. 3B at 4, column 34 (Halama Rebuttal).
[57] Ex. Xcel-18 at 9, n. 2 (Halama Supplemental Direct).
[58] *See* Ex. Xcel-18 at 9, n. 2 (Halama Supplemental Direct).
[59] Ex. Xcel-19 at 27-28 (Halama Rebuttal).
[60] Ex. Xcel-19 at 28 (Halama Rebuttal).
[61] Ex. Xcel-19 at 28 (Halama Rebuttal).
[62] *See* Xcel-19 at 27-29 (Halama Rebuttal).
[63] Ex. OAG-3, KH-S-4 at 1 (Hinderlie Surrebuttal).
[64] Ex. OAG-3, KH-S-4 at 1 (Hinderlie Surrebuttal).
[65] Ex. OAG-3, KH-S-4 at 2-3 (Hinderlie Surrebuttal).
[66] Ex. OAG-3, KH-S-4 at 3 (Hinderlie Surrebuttal).
[67] Ex. OAG-3, KH-S-4 at 1 (Hinderlie Surrebuttal).

to the same broad categories as it listed for the overall TOU-related capital costs.[68] Xcel did not break down these costs by month. The capital costs of the Rate Comparison Tool accounted for $171,810 in the test year and $1,218,381 in the plan year.[69]

38. The OAG argued that Xcel's request to add TOU-related capital costs to rate base should be denied because Xcel had failed to carry its burden to show that Xcel would incur the costs it claimed and that the costs were reasonable.[70] The OAG also argued that the costs of Rate Comparison Tool in particular should be denied because there is a risk the TOU costs introduced in rebuttal testimony are not incremental to Xcel's initial or supplemental filing and there is no evidence that the Tool will actually be used and useful in providing utility service.[71]

1. Total TOU-related Capital Costs.

39. The OAG argued that Xcel had not carried its burden to show that it would incur any of the capital costs of the TOU rate because the evidence Xcel provided was insufficient.[72] The OAG argued that Xcel had simply alleged that it would incur its costs, but had failed to provide a reliable evidentiary basis upon which to evaluate when and whether the costs would actually be incurred, even after the OAG requested further information in discovery.[73] The OAG further argued that Xcel did not provide any explanation for the basis of the costs it claimed, such as the calculations or assumptions underlying the costs.[74] Additionally, the OAG observed that Xcel stated in supplemental direct testimony that Xcel would add in rebuttal a request for the costs of "education, marketing, and outreach," but that the actual rebuttal request was for previously-unmentioned capital costs and the descriptions of the capital costs were not related to education, marketing, or outreach.[75]

40. Because Xcel introduced the capital costs in rebuttal with limited information, arguments supporting inclusion of these costs were made in its initial brief rather than in testimony. Xcel argued that it should recover the TOU-related capital costs because the Commission ordered Xcel to implement the TOU rate and the claimed costs reflect the necessary costs of compliance.[76] According to Xcel, the descriptions of the capital cost activities that it provided in its rebuttal testimony was sufficient to justify the request.[77] It also argued that the costs were approved by the Commission

[68] Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal).
[69] Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal).
[70] OAG Initial Br. at 21-22.
[71] Ex. OAG-3 at 33 (Hinderlie Surrebuttal).
[72] OAG Initial Br. at 21.
[73] OAG Initial Br. at 21.
[74] OAG Initial Br. at 21-22.
[75] OAG Initial Br. at 17; Ex. OAG-3 at 29 (Hinderlie Surrebuttal).
[76] Xcel Initial Br. at 177.
[77] Xcel Initial Br. at 182.

at a January 8, 2026 hearing.[78] Finally, Xcel argued that the capital true-up mechanism it proposed in this rate case would protect customers if the actual TOU-related capital costs end up being lower than claimed in the rate case.[79]

41. The ALJ finds that Xcel has not carried its burden to prove that including the TOU-related capital costs in rate base would be just and reasonable. In its rebuttal testimony, Xcel did not provide any more cost information than the aggregate capital cost.[80] When the OAG requested descriptions and breakdowns of the capital cost activities in discovery, Xcel provided only vague descriptions and only partially complied with the breakdown request.[81] Additionally, these costs were only provided in rebuttal testimony, and were not the same costs that Xcel had claimed in its supplemental direct testimony that it would add in rebuttal testimony.[82] Contrary to Xcel's assertion, the Commission did not approve the budget Xcel included in its August compliance filing; the Commission chose not to adopt the decision option that would have approved the budget[83] and the Commission clarified in its order that it was not making a prudency determination regarding the "as-yet-unseen Rate Comparison Tool."[84] And finally, the proposed capital true-up mechanism does not relieve Xcel of its burden to prove including the alleged TOU-related capital costs in Xcel's rate base would be just and reasonable.

42. The ALJ finds that Xcel has failed to provide substantial evidence demonstrating that it will indeed incur the claimed TOU-related capital costs. The utility bears the burden of proof at all times, and doubts must be resolved in favor of the consumer. In this case, the lack of detail about the claimed TOU-related capital costs raises significant doubt about both the timing and the actual amount of capital costs Xcel will incur to implement the TOU rate. The fact that Xcel added the request so late in the contested case process and the request was different from Xcel's prior representation raises further doubt about the veracity of the request. The capital true-up is also insufficiently protective against the risk that Xcel overestimated these capital costs because it would only refund customers if its aggregate actual capital-related revenue

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[78] Xcel Initial Br. at 181.
[79] Xcel Initial Br. at 182.
[80] Ex. Xcel-19 at 29 (Halama Rebuttal).
[81] Ex. OAG-3, KH-S-4 at 2-3 (Hinderlie Surrebuttal).
[82] *Compare* Ex. Xcel-18 at 9, n. 2 (Halama Supplemental Direct) *to* Xcel-19 at 27-29 (Halama Rebuttal).
[83] Minnesota Public Utilities Commission Agenda Meeting of January 8, 2026 at 1:49:00 – 1:50:18, *available at* https://minnesotapuc.granicus.com/player/clip/2620?view_id=2&redirect=true (Jan. 8, 2026); *In re Petition of N. States Power Co., d/b/a Xcel Energy, for Approval of a Residential Time of Use Rate Design,* Docket No. E-002/M-23-524, STAFF BRIEFING PAPERS at 15-17 (Dec. 30, 2025).
[84] *In re Petition of N. States Power Co., d/b/a Xcel Energy, for Approval of a Residential Time of Use Rate Design*, Docket E-002/M-23-524, ORDER APPROVING TARIFF MODIFICATIONS, APPROVING COMPLIANCE PLAN, AND SETTING ADDITIONAL REQUIREMENTS FOR RESIDENTIAL TIME-OF-USE RATE IMPLEMENTATION at 6, Order Point 12 (Feb. 23, 2026).

requirement falls below the approved revenue requirements in this rate case.[85] Thus if Xcel's actual TOU-related capital expenditures are lower than budgeted, ratepayers would not receive a refund if other actual capital expenditures are higher than budgeted.

43. The ALJ therefore recommends that the Commission disallow Xcel's request to include TOU-related capital costs in Xcel's rate base in the amount of $659,641 in the 2025 test year and by $2,458,859 in the 2026 plan year.

2. Rate Comparison Tool Capital Costs.

44. The OAG also recommended that, even if the Commission allowed some TOU-related capital costs, the Commission should still disallow the portion of TOU-related capital costs that Xcel attributed to the Rate Comparison Tool, equal to $171,810 in the 2025 test year and $1,218,381 in the 2026 plan year.[86] The OAG argued that there was a significant risk that the costs attributed to the Rate Comparison Tool were already included in Xcel's initial request, making the rebuttal request for that portion of the TOU-related capital costs duplicative, and that the Rate Comparison Tool would not result in utility plant that is used and useful in the provision of utility service.[87]

45. Xcel had announced that it was in the process of developing the tool in August 2024, two months before Xcel filed its rate case in November 2024.[88] Additionally, the Rate Comparison Tool will be available to all Xcel ratepayers, not only ratepayers interested in or on the TOU rate.[89] And although Xcel stated that the Rate Comparison Tool was a significant portion of the capital costs of implementing the TOU rate,[90] the Commission did not order Xcel to develop the Tool.[91] The OAG argued that these facts raised doubts about Xcel's claim that the Rate Comparison Tool was an incremental cost to the initial filing, and that the costs of the Tool may instead have already been included in Xcel's initial request.[92]

46. The OAG also argued that there were significant doubts about whether the Tool would be used and useful in the provision of utility service. In the TOU docket, parties had recommended that "shadow billing" could improve customer outcomes.[93] Xcel had argued that its Rate Comparison Tool would "essentially do[] shadow billing," but the Commission expressed concern that an online tool may not be as widely used as information on a customer's bill and concerns with how Xcel would accurately

[85] Ex. Xcel-15 at 29 (Liberkowski Direct).
[86] OAG Initial Br. at 18.
[87] OAG Initial Br. at 19-21.
[88] Ex. OAG-3 at 34 (Hinderlie Surrebuttal).
[89] Ex. OAG-3 at 37 (Hinderlie Surrebuttal).
[90] Ex. Xcel-19 at 28; Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal).
[91] Ex. OAG-3 at 36 (Hinderlie Surrebuttal).
[92] OAG Initial Br. at 19.
[93] Ex. OAG-3 at 30-31 (Hinderlie Surrebuttal).

forecast customer usage.[94] The Commission ordered Xcel to identify the feasibility and cost of implementing "shadow billing" in its first annual report on the new rate.[95]

47. When Xcel filed its first compliance filing for the TOU rate, it stated that it would continue to develop its Rate Comparison Tool.[96] The OAG and CUB expressed concern that the Rate Comparison Tool would not be useful to Xcel's customers because it appeared to provide only estimates rather than actual bills based on actual usage information.[97] They also were concerned that the Tool might require customers to input their own data, which would result in fewer customers using it.[98] Xcel responded with a description that did not make clear whether the comparison would be an estimate or whether customers would need to input their own data, and that stated that all design choices "are subject to change as development progresses."[99] As of September 2025, Xcel had not made any capital expenditures on development of the Tool and it had only begun the design phase in October 2025.[100]

48. Because Xcel introduced the capital costs in rebuttal with limited information, arguments supporting inclusion of these costs were made in its initial brief rather than in testimony. Xcel argued that the Rate Comparison Tool is a necessary capital cost of technical implementation of the TOU rate.[101] According to Xcel, it would be unreasonable to offer the TOU rate without the Rate Comparison Tool because customers will need a way to understand how the TOU rate will affect their bills.[102] Xcel also argued that its TOU-related capital costs were incremental costs, pointing to a statement in rebuttal testimony that the initial filing did not include technical implementation costs[103] and a statement in discovery that Electric-Vehicle-related TOU costs were incremental to other EV costs.[104] Finally, Xcel argued that its forecasted 2026 launch of the Tool means that the Tool will be used and useful.[105]

49. The ALJ finds that Xcel has not carried its burden to prove that the Rate Comparison Tool is an incremental cost to Xcel's initial filing. The record shows that Xcel has been in the process of developing the Tool since at least August 2024[106] and the Tool will be available to all Xcel ratepayers.[107] While Xcel stated that TOU-related technical implementation costs were not included in the initial request, Xcel's

[94] Ex. OAG-3 at 36-37 (Hinderlie Surrebuttal).
[95] Ex. OAG-3 at 36 (Hinderlie Surrebuttal).
[96] Ex. OAG-3 at 37 (Hinderlie Surrebuttal).
[97] Ex. OAG-3 at 37 (Hinderlie Surrebuttal).
[98] Ex. OAG-3 at 37 (Hinderlie Surrebuttal).
[99] Ex. OAG-3 at 37-38 (Hinderlie Surrebuttal).
[100] Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal).
[101] Xcel Initial Br. at 179.
[102] Xcel Initial Br. at 180.
[103] Ex. Xcel-19 at 27 (Halama Rebuttal).
[104] Xcel Initial Br. at 177-178; Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal).
[105] Xcel Initial Br. at 180.
[106] Ex. OAG-3 at 34 (Hinderlie Surrebuttal).
[107] Ex. OAG-3 at 37 (Hinderlie Surrebuttal).

testimony differentiated between technical implementation costs and the Rate Comparison Tool.[108] Similarly, Xcel only stated in discovery that the costs of "necessary programs to support EV programs" were not duplicative of other EV-related capital costs,[109] which says nothing of the Rate Comparison Tool. There is therefore significant doubt that costs of development of the Rate Comparison Tool were not already included in Xcel's initial rate request, and if they were not, they should have been included there or in Xcel's supplemental testimony.

50. The ALJ also finds that Xcel has not carried its burden to prove that the Rate Comparison Tool will be used and useful in the provision of utility service during the MYRP. There is no evidence in the record that the concerns raised by the Commission and by the OAG regarding the usefulness of the Tool have been addressed by Xcel.[110] At the same time, although Xcel began developing the Tool back in August 2024,[111] it admitted that it had only begun the design phase of the Tool by October 2025 and that it had not yet made capital expenditures on the Tool.[112] It further admitted that all design features of the Rate Comparison Tool remained subject to change.[113] Taken together, there is significant doubt whether the Tool will be finished in time for a 2026 launch and whether customers will use the Tool when it is eventually launched.

51. All doubts must be resolved in favor of ratepayers.[114]

52. The ALJ therefore recommends that, if the Commission allows Xcel to include TOU-related capital costs in rate base, the Commission should disallow the portion of capital costs that Xcel attributed to the Rate Comparison Tool. This would reduce the TOU-related capital costs by $171,810 in the 2025 test year and $1,218,381 in the 2026 plan year.[115]

D. Hot Weather Reconnection Costs

53. Xcel Energy added a request in rebuttal testimony to recover costs relating to a new program in which Xcel must temporarily reconnect service for disconnected residential customers during periods of extreme heat or poor air quality.[116] Xcel claimed that this program would add $404,000 to Xcel's rate base in the 2025 test year[117] and $1,600,000 to rate base in the 2026 plan year.[118] Xcel also claimed

[108] Ex. Xcel-19 at 28 (Halama Rebuttal).
[109] Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal).
[110] Ex. OAG-3 at 36-37 (Hinderlie Surrebuttal).
[111] Ex. OAG-3 at 34 (Hinderlie Surrebuttal).
[112] Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal).
[113] Ex. OAG-3 at 38 (Hinderlie Surrebuttal).
[114] Minn. Stat. § 216B.03 (2024).
[115] Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal).
[116] Ex. Xcel-19 at 20 (Halama Rebuttal).
[117] Ex. Xcel-19, sched. 3A at 4 (Halama Rebuttal).
[118] Ex. Xcel-19, sched. 3B at 3 (Halama Rebuttal).

$1,893,000 in operating expenses in the 2026 plan year.[119] Overall, they would increase the 2025 test year revenue deficiency of $28,000[120] and increase the 2026 plan year revenue deficiency by $2,445,000.[121]

54. The Commission ordered Xcel to propose a reconnection program in Xcel's annual service quality docket.[122] The program protects economically vulnerable utility consumers by temporarily reconnecting their service during extreme heat events and when the Air Quality Index (AQI) reaches 151 or higher.[123] The Commission approved a modified version of Xcel's proposal and ordered the program be implemented by May 1, 2026.[124]

55. During the notice and comment period, Xcel estimated that the cost of the program would include a one-time set-up cost of $360,000 and variable costs of between $38,608 and $163,780 per event.[125] The OAG had served discovery requesting more detailed cost information and had requested that Xcel provide more information about the assumptions underlying its cost estimates.[126] In comments, the OAG stated that Xcel's cost estimates were unsupported.[127] When the Commission ordered Xcel to implement the program, it did not state whether it found Xcel's cost estimates to be reasonable, but it did require Xcel to provide a summary of the costs of the program in future annual Service Quality reports.[128]

56. The OAG argued that Xcel has not carried its burden to support the costs it claims. Before rebuttal testimony, the program was briefly mentioned by three witnesses, but costs were not mentioned until rebuttal testimony.[129] Because the costs Xcel estimated during the comment period did not include capital costs and were lower than Xcel claimed in rebuttal testimony, the OAG requested more information about the rebuttal costs in discovery and an explanation for the difference in cost between the comment period and rebuttal testimony.[130] Xcel responded that the costs in the rate case were derived from the mid-range of the costs claimed in the comment

[119] Ex. Xcel-19, sched. 3B at 4 (Halama Rebuttal).
[120] Ex. Xcel-19, sched. 3A at 4 (Halama Rebuttal).
[121] Ex. Xcel-19, sched. 3B at 4 (Halama Rebuttal).
[122] Ex. OAG-3 at 40-41 (Hinderlie Surrebuttal).
[123] Ex. OAG-3 at 41 (Hinderlie Surrebuttal).
[124] *In re N. States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability, and Service Quality Report*, Docket No. E-002/M-25-27, ORDER (July 25, 2025) (eDockets No. 20257-221406-01).
[125] Ex. OAG-3 at 44 (Hinderlie Surrebuttal).
[126] Ex. OAG-3 at 43 (Hinderlie Surrebuttal).
[127] Ex. OAG-3 at 43 (Hinderlie Surrebuttal).
[128] *In re N. States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability, and Service Quality Report*, Docket No. E-002/M-25-27, ORDER at 2 (July 25, 2025) (eDockets No. 20257-221406-01).
[129] Ex. OAG-3 at 45-46 (Hinderlie Surrebuttal).
[130] Ex. OAG-3 at 46-47 (Hinderlie Surrebuttal).

period.[131] The OAG observed that the costs were very different and could not be tied to the mid-range, and it was unable to reconcile Xcel's conflicting claims.[132] The OAG further observed that Xcel acknowledged a high degree of uncertainty regarding costs, including "[t]he frequency of heat events and AQI events in the future," "the duration and type of event," "the extent to which heat event days and AQI event days will coincide, determining to what extent the two types of events are additive."[133]

57. Because of Xcel's conflicting statements and the uncertainty regarding costs, the OAG concluded that Xcel failed to explain the basis for the program's capital costs and why they are reasonable, and that there is no reasonable basis to estimate the program's O&M costs.[134] The OAG recommended disallowing the costs of the program in the rate case and allowing Xcel to request deferred accounting in the program's original docket, with the deferred expenses reviewed in Xcel's next rate case.[135]

58. Because Xcel introduced these costs in rebuttal testimony with limited information, arguments supporting inclusion of these costs were made in its initial brief rather than in testimony. Xcel argued that it should be allowed to recover the costs of the program claimed in its rebuttal testimony because the Commission ordered the creation of the program and implementing the program by May 1, 2026 was the reason for increased costs.[136] Xcel stated that the Commission acknowledged that implementing the program by May 1, 2026 would result in higher costs and ordered the program be implemented by that date anyway.[137] Xcel also argued that the fact that the program itself is reasonable and in the public interest justified recovery of the costs it claimed in rebuttal testimony.[138] Finally, Xcel argued that if the costs are not granted in this rate case, then instead of deferred accounting, a tracker should be established in this rate case.[139]

59. The ALJ finds that Xcel has failed to support its request for the costs of the reconnection program. Xcel introduced these costs in rebuttal testimony with only a statement that it was ordered to implement the program and no explanation of the basis for the claimed costs.[140] The costs are far greater than the cost estimate from the notice and comment period.[141] Xcel provided no evidence to explain the large increase from this initial cost estimate, and its statement that the claimed costs are the

[131] Ex. OAG-3 at 47 (Hinderlie Surrebuttal).
[132] Ex. OAG-3 at 47 (Hinderlie Surrebuttal).
[133] Ex. OAG-3 at 48 (Hinderlie Surrebuttal).
[134] Ex. OAG-3 at 48 (Hinderlie Surrebuttal).
[135] Ex. OAG-3 at 49-50 (Hinderlie Surrebuttal).
[136] Xcel Initial Br. at 185.
[137] Xcel Initial Br. at 186.
[138] Xcel Initial Br. at 188.
[139] Xcel Initial Br. at 190.
[140] Ex. Xcel-19 at 20, sched. 3A at 3-4, sched. 3B at 3-4 (Halama Rebuttal).
[141] Ex. OAG-3 at 44 (Hinderlie Surrebuttal).

same as the mid-range of its comment period cost estimates is incorrect.[142] Xcel stated in its brief that the faster timeline is the reason for the higher costs, but there is no record support for this allegation, and this statement does not establish the veracity of the costs.[143] Additionally, Xcel itself admitted that reconnection program costs would remain highly uncertain until the program has been in operation.[144] There is therefore no reasonable record basis for the costs claimed by Xcel.

60. The ALJ therefore recommends that the Commission deny Xcel's request for the costs related to the reconnection program.

61. The ALJ also recommends that the Commission deny Xcel's request for a cost tracker and instead allow Xcel to petition for deferred accounting for the reconnection program. A tracker is a form of deferred accounting.[145] Deferred accounting may be granted for good cause shown.[146] There is no record evidence in this rate case to support a determination of good cause for a tracker for reconnection program costs, as these costs were only introduced in rebuttal testimony and no witness testified regarding the propriety of establishing a tracker for these costs. It would therefore be more appropriate for the Commission to evaluate the propriety of deferred accounting for these costs in the original docket if Xcel makes a deferred accounting request there.

E. Executive Compensation

62. Xcel requested recovery of $7,301,541 in the 2025 test year and $7,573,008 in the 2026 plan year for compensation paid to its ten highest-paid executives.[147] This request includes base pay, Annual Incentive Plan compensation (AIP) capped at 20 percent of employee salary, and Long-Term Incentive compensation (LTI) that is granted based on environmental and time-based metrics.[148]

63. In Xcel's previous rate case, the Commission disallowed Xcel's request for recovery of executive compensation and instead allowed recovery of $150,000 per executive.[149] The Commission found in that case that Xcel had not carried its burden to prove that it was reasonable for Xcel's ratepayers to pay Xcel's full proposed level of compensation for its ten highest-paid executives.[150] This was based on the size of

[142] Ex. OAG-3 at 46-47 (Hinderlie Surrebuttal).
[143] Xcel Initial Br. at 185.
[144] Ex. OAG-3 at 48 (Hinderlie Surrebuttal).
[145] Minn. R. 7825.0300, subp. 4.
[146] Minn. R. 7825.0300, subp. 4.
[147] Ex. Xcel-6, Vol. 3.IV.2 at 1089-1090 (Appl. Vol. 3, Req. Info.).
[148] Ex. Xcel-63 at 29 (Yen Ly Rebuttal).
[149] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 23 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[150] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec.*

Xcel's overall rate request, the fact that Xcel had increased rates nearly every year for the preceding decade, the priority on shareholder interests that the highest-paid executives' compensation structure incentivized, and the many public comments in opposition to paying for executive compensation while ratepayers struggled with affordability.[151]

64. Xcel appealed this order, but the court of appeals upheld the Commission's authority to disallow recovery of executive compensation.[152] The court affirmed that Xcel has the burden to demonstrate not only that it would incur the expense of paying its executives, but that it would be just and reasonable to charge this expense to ratepayers.[153] In doing so, the court rejected Xcel's argument that it met its burden of proof simply "because it provided evidence that it generally pays employee compensation at median market rates."[154] The court also stated that the Commission has the prerogative to closely consider compensation levels for Xcel's ten highest-paid executives because Minnesota Statute section 216B.16, subd. 17 requires Xcel to file information regarding executive pay.[155] The court did reject the Commission's grant of recovery of $150,000 per executive, holding that using the governor's salary to set the proper level of recovery, without more, was arbitrary and capricious.[156]

65. In this case, Xcel argued that it should recover executive compensation because it needed to pay market-competitive compensation to attract its executives.[157] It presented evidence that its compensation philosophy and compensation paid to its executives align with the compensation philosophy and compensation paid to executives at other large corporations and large utilities.[158] Xcel targets its total direct compensation at the 50th percentile of a representative group of comparable utilities and a group of comparably-sized corporations, which is the same philosophy held by many of its utility peer corporations.[159] Xcel pays its executives 2.6 percent above the market median of companies selected by Xcel's witness for inclusion in his compensation report.[160] Similarly, Xcel's witness found that Xcel's AIP and LTI compensation were comparable to and competitive with the other utility corporations selected by Xcel's witness for comparison.[161]

Serv. in the State of Minn., MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 22 (Jul. 17, 2023) (eDockets No. 20237-197559-01).

[151] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 21-22 (Jul. 17, 2023) (eDockets No. 20237-197559-01).

[152] *In re N. States Power Co.*, No. A23-1672, 2025 WL 249995 at *10 (Jan. 21, 2025).

[153] *In re N. States Power Co.*, No. A23-1672, 2025 WL 249995 at *11 (Jan. 21, 2025).

[154] *In re N. States Power Co.*, No. A23-1672, 2025 WL 249995 at *11 (Jan. 21, 2025).

[155] *In re N. States Power Co.*, No. A23-1672, 2025 WL 249995 at *11 (Jan. 21, 2025).

[156] *In re N. States Power Co.*, No. A23-1672, 2025 WL 249995 at *12 (Jan. 21, 2025).

[157] Ex. Xcel-62 at 35 (Yen Ly Direct).

[158] Ex. Xcel-66 at 3 (Mustich Direct).

[159] Ex. Xcel-66 at 4 (Mustich Direct).

[160] Ex. Xcel-66 at 7 (Mustich Direct).

[161] Ex. Xcel-66 at 9 (Mustich Direct).

66. Many of the factors upon which the Commission denied executive compensation in Xcel's previous case are still present. Xcel has requested to recover $365.3 million over two years,[162] comparable to its 2021 rate case request for $435.2 million over three years.[163] Xcel has continued to raise its rates nearly every year for over a decade.[164] Xcel's residential average electricity rate was above the national average in 2022 and 2024.[165] Consumers are still struggling with inflation.[166] Xcel has had a historical level of disconnections and its arrearages remain stubbornly high.[167] Thousands of public commenters have expressed opposition to this rate increase.[168]

67. The OAG and the Department argued that, in addition to these background facts, the structure of compensation paid to Xcel's ten highest-paid executives creates an overwhelming incentive to prioritize shareholder interests over ratepayer interests.[169]

68. AIP compensation is greater than base salary for half of Xcel's ten highest-paid executives.[170] It is only paid out if Xcel meets an Earnings Per Share goal.[171] Earnings Per Share is a measure of profitability, so AIP is not paid if Xcel does not reach a certain level of profitability.[172] In 2024, the EPS threshold was equal to the EPS guidance Xcel provided to shareholders in its Form 10-K.[173] The AIP payout can also be increased if Xcel exceeds its Earnings Per Share goal.[174] Xcel must also meet other metrics called Key Performance Indicators (KPIs) to achieve the full AIP payout, but failure to meet each metric only reduces a portion of AIP and the KPIs are not difficult to achieve.[175] Xcel's customer satisfaction KPI only requires the company to be in the 30th percentile of JD Power's Customer Satisfaction Survey of

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[162] Ex. Xcel-19 at 3 (Halama Rebuttal).
[163] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 4 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[164] Ex. OAG-1 at 25 (Hinderlie Direct).
[165] Ex. JIN-2 at 14 (Chan Direct).
[166] Ex. OAG-1 at 27-29 (Hinderlie Direct).
[167] Ex. OAG-3, KH-S-3 (Hinderlie Surrebuttal); Ex. CUB-3 at 7-11 (Levenson-Falk Direct); Ex. JIN-2 at 4-7 (Chan Direct).
[168] Ex. CUB-8 at 9-12 (Levenson-Falk Surrebuttal).
[169] OAG Initial Br. at 32-33; Ex. OAG-1 at 24-25 (Hinderlie Direct); Ex. DOC-3 at 39-41 (Kehrwald Direct).
[170] Ex. Xcel-6, Vol. 3.IV.2 at 1088 of 1204 (Appl. Vol. 3, Req. Info.).
[171] Ex. Xcel-66, sched. 2 at 8 of 19 (Mustich Direct); Ex. Xcel-62, YL-1, sched. 4 at 8 (Ly Direct).
[172] Ex. DOC-3 at 40 (Kehrwald Direct); Tr.Vol. 1 at 147:10–148:6 (Yen Ly).
[173] Ex. Xcel-62, sched. 4 at 8 (Ly Direct); Ex. DOC-26 at 25 (Xcel Energy Inc.'s 2024 Form 10-K).
[174] Ex. Xcel-66, sched. 2 at 8 of 19 (Mustich Direct); Ex. Xcel-62, YL-1, sched. 4 at 8 (Ly Direct); Ex. DOC-3 at 40 (Kehrwald Direct).
[175] Ex. Xcel-62, sched. 4 at 6 (Ly Direct).

residential utility customers.[176] Xcel's employee safety KPI allows one employee workplace death per year before executives do not receive that portion of AIP.[177]

69. LTI compensation constitutes an average of 57–75 percent of the total compensation paid to Xcel's highest-paid executives.[178] LTI compensation is paid entirely in stocks.[179] Portions of LTI are awarded on three separate bases. Approximately 40 percent of overall LTI is awarded based on Xcel's total shareholder return.[180] Xcel is not requesting rate recovery of this portion, but its executives still receive it.[181] Another portion of LTI is awarded based on meeting certain environmental metrics.[182] The last portion is awarded based on how long an executive has stayed at the company.[183]

70. The OAG argued that AIP incentivizes executives to focus on shareholder interests because executives will not receive AIP if Xcel does not meet its EPS guidance, and at the same time, executives will receive extra AIP if Xcel exceeds its Earnings Per Share guidance.[184] This demonstrates that executives' personal financial incentive is to increase Xcel's profits by as much as possible to meet or exceed the AIP Earnings Per Share metric. The OAG argued that the KPI thresholds are too easy to meet to motivate performance.[185] Additionally, a failure to meet each individual KPI metric only reduces a portion of AIP compensation, whereas meeting or exceeding the Earnings Per Share threshold affects the entire AIP payout.[186] The OAG concluded that AIP therefore overwhelmingly incentivizes executives to focus on shareholder interests over ratepayer interests.[187]

71. The OAG also argued that the nature of LTI compensation incentivizes executives to place an overwhelming focus on shareholder interests instead of ratepayer interests.[188] LTI compensation is paid entirely in the form of stocks, meaning that executives are also shareholders.[189] As such, their compensation increases if they make business decisions that increase the stock price.[190] It also means executives receive dividends if they pay out dividends. In this way, executive interests and

[176] Ex. Xcel-62, sched. 4 at 6 (Ly Direct).
[177] Ex. Xcel-62, sched. 4 at 6 (Ly Direct).
[178] Ex. Xcel-63 at 32 (Ly Rebuttal).
[179] Ex. DOC-3 at 40 (Kehrwald Direct); *Id.*, MBK-D-10 (Kehrwald Direct).
[180] Ex. Xcel-62 at 23 (Ly Direct).
[181] Ex. Xcel-62 at 23-24 (Ly Direct).
[182] Ex. Xcel-62 at 22 (Ly Direct).
[183] Ex. DOC-3 at 17 (Kehrwald Direct).
[184] Ex. Xcel-62 at 23 (Ly Direct).
[185] OAG Reply Br. at 15-17.
[186] Ex. Xcel-62, sched. 4 at 6, 8 (Ly Direct).
[187] OAG Initial Br. at 32.
[188] OAG Initial Br. at 32.
[189] Ex. DOC-3, MBK-D-10 (Kehrwald Direct).
[190] Tr. Vol. 1 at 159:20-24 (Yen Ly).

shareholder interests are identical.[191] And even though Xcel is not asking for rate recovery of the 40 percent of LTI that is paid out based on total shareholder return, executives are still held to that metric, which further incentivizes executive focus on shareholder interests.[192]

72. The Department and OAG also submitted discovery to try to assess the extent to which executive activities benefitted ratepayers.[193] These parties requested the work calendars of Xcel's ten highest-paid executives and performance evaluations for these executives.[194] Xcel refused to provide the requested information until the ALJ issued an order compelling production.[195] The OAG reviewed the calendars and concluded that there was insufficient information to determine whether executives engaged in activities that benefit ratepayers.[196] The calendar entries were attached to the testimony of Department witness Kehrwald.[197] The OAG explained that many calendar entries remained redacted even in the Not Public version because, according to Xcel, they did not include work-related information.[198] Of the entries viewable to the OAG's witness, many still lacked the specificity that would be needed to determine whether the activity related to ratepayer or shareholder benefits.[199] The OAG also reviewed the performance evaluations, but noted that Xcel only provided them for two of its executives.[200] The OAG concluded that the majority of the discussion of one executive's performance focused on activities that further shareholder interests.[201] The OAG expressed concern that more executives do not receive performance evaluations and argued that without performance evaluations, the primary feedback employees receive regarding their performance is whether they meet compensation incentive metrics.[202]

73. Xcel argued that it should recover executive compensation because it pays market-competitive compensation rates.[203] It also argued that ratepayer interests and shareholder interests are not distinguishable.[204] According to Xcel, its executives work to efficiently run an enterprise that provides safe, reliable, sustainable, and cost-effective power, and that work benefits both customers and investors.[205] Xcel argued that these responsibilities require balancing financial stewardship with operational

[191] Tr. Vol. 1 at 160:20-15 (Yen Ly).
[192] Ex. Xcel-62 at 23 (Ly Direct).
[193] Ex. OAG-3 at 13 (Hinderlie Surrebuttal); *see also* Ex. DOC-4 at 46-58 (Kehrwald Surrebuttal).
[194] JOINT MOTION TO COMPEL DISCOVERY, Cherney Declaration, Ex. A-C (Jul. 25, 2025).
[195] ORDER GRANTING IN PART AND DENYING IN PART MOTION TO COMPEL (Aug. 29, 2025).
[196] Ex. OAG-4 at 14-16 (Hinderlie Surrebuttal).
[197] Ex. DOC-4, MBK-S-12 (Kehrwald Surrebuttal).
[198] Ex. OAG-3 at 14 (Hinderlie Surrebuttal).
[199] Ex. OAG-3 at 15 (Hinderlie Surrebuttal).
[200] Ex. OAG-3 at 16 (Hinderlie Surrebuttal).
[201] Ex. OAG-4 at 18-22 (Hinderlie Surrebuttal).
[202] Ex. OAG-3 at 22 (Hinderlie Surrebuttal).
[203] Ex. Xcel-63 at 15-16, 29-30 (Yen Ly Rebuttal).
[204] Ex. Xcel-63 at 30 (Yen Ly Rebuttal).
[205] Ex. Xcel-63 at 28 (Yen Ly Rebuttal).

performance.[206] However, Xcel also acknowledged that it would be reasonable for shareholders to bear at least some portion of executive compensation.[207]

74. Xcel also argued that the structure of incentive compensation focuses executives on ratepayer interests. According to Xcel, incentive compensation exists to ensure that executives have "skin in the game."[208] Xcel pointed to the KPI metrics of AIP compensation,[209] as well as the environmental portion of LTI compensation.[210] Xcel also argued that time-based LTI compensation benefits ratepayers because it incentivizes continuity in leadership.[211]

75. The ALJ finds that Xcel has not carried its burden to demonstrate that it would be just and reasonable for ratepayers to pay the compensation of Xcel's ten highest-paid executives. Xcel has the burden to prove both that it will reasonably incur an expense and that it would be just and reasonable for ratepayers to bear that expense. Xcel has not made the requisite showing to recover top-ten executive compensation.

76. Shareholder interests and ratepayer interests are not identical. Shareholders' interest is in the return they receive on their investment. Ratepayer interests include affordable rates, and safe and reliable service. The pursuit of some ratepayer interests can also meet shareholder interests – for example, making new capital expenditures to increase reliability will result in shareholders receiving increased return due to those capital expenditures.[212] However, the pursuit of shareholder interests does not meet ratepayer interests – for example, increasing profits by reducing O&M expenditures, prioritizing new capital expenditures upon which the company can earn a return instead of repairing existing plant, or paying out dividends instead of using the money to reduce the need to raise rates.[213]

77. The ALJ finds that many of the ratepayer interests that the Commission previously found necessitated disallowing executive compensation continue to apply in this case. The size of Xcel's MYRP request is comparable to the size of its previous request.[214] Xcel has continued to raise rates nearly every year for a decade.[215] Inflation has

[206] Ex. Xcel-63 at 28 (Yen Ly Rebuttal).
[207] Ex. Xcel-63 at 29 (Yen Ly Rebuttal).
[208] Ex. Xcel-63 at 33 (Yen Ly Rebuttal).
[209] Tr. Vol. 1 at 148:2-8; Ex. Xcel-62, sched. 4 at 6-7 (Ly Direct).
[210] Ex. Xcel-63 at 22 (Yen Ly Rebuttal).
[211] Ex. Xcel-63 at 24 (Yen Ly Rebuttal).
[212] Ex. OAG-3 at 4 (Hinderlie Surrebuttal).
[213] *See* Ex. OAG-3 at 4-5 (Hinderlie Surrebuttal).
[214] Ex. Xcel-19 at 3 (Halama Rebuttal); *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 4 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[215] Ex. OAG-1 at 25 (Hinderlie Direct).

continued to climb.[216] Xcel's ratepayers are struggling to pay for utility service, as demonstrated by disconnections, arrearages, and public comments.[217]

78. The ALJ also finds that the structure of Xcel's executive compensation strongly incentivizes a focus on shareholder interests over ratepayer interests. This is true for both AIP compensation and LTI compensation. Before any AIP can be paid out, Xcel must meet an Earnings Per Share threshold equal to its Earnings Per Share guidance provided to shareholders.[218] AIP is increased if Xcel exceeds this Earnings Per Share threshold.[219] This focuses employees who receive AIP on increasing profits in order to increase Earnings Per Share. While AIP can be reduced if the company does not meet KPIs,[220] the threshold for meeting each KPI is too low and the payout reduction for missing a KPI threshold is too low to meaningfully incentivize executives.

79. Similarly, LTI compensation is paid out in stocks and comprises the majority of compensation paid to Xcel's ten highest-paid executives.[221] Because it is paid in the form of stocks, executive compensation increases if the stock price increases and executives receive dividends if dividends are paid out. Executives therefore have a direct incentive to increase stock price and pay out dividends. In this way, executives' interests are identical to shareholders' interests. Additionally, approximately 40 percent of LTI is awarded based on total shareholder returns, further focusing executives on prioritizing shareholder interests over ratepayer interests.

80. The ALJ finds Xcel's arguments unavailing. Xcel argues that it must pay its executives at a level competitive with other large corporations in order to keep and attract its executives, but Xcel's desired conclusion that *ratepayers* therefore must pay its executives' compensation does not follow. The relevant inquiry requires balancing the interests of ratepayers and shareholders,[222] and the Commission has long found that utility expenses that further shareholder interests over ratepayer interests should be borne by shareholders.[223] Because executive compensation

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[216] Ex. OAG-1 at 27-29 (Hinderlie Direct).
[217] Ex. OAG-3, KH-S-3 (Hinderlie Surrebuttal); Ex. CUB-3 at 7-11 (Levenson-Falk Direct); Ex. JIN-2 at 4-7 (Chan Direct); Ex. CUB-8 at 9-12 (Levenson-Falk Surrebuttal).
[218] The EPS threshold was $3.50 for 2024. Ex. Xcel-62, sched. 4 at 8 (Ly Direct). Xcel stated that it met its initial ongoing earnings guidance. Ex. DOC-26 at 7 (Xcel Energy Inc.'s 2024 Form 10-K). Its diluted EPS in 2024 was $3.50. *Id*. at 26 (Xcel Energy Inc.'s 2024 Form 10-K).
[219] Ex. Xcel-62, sched. 4 at 8 (Yen Ly Direct).
[220] Ex. Xcel-62, sched. 4 at 6 (Yen Ly Direct).
[221] Ex. Xcel-63 at 32 (Yen Ly Rebuttal); Ex. DOC-3, MBK-D-10 (Kehrwald Direct).
[222] *In re Request of Interstate Power Co.*, 574 N.W.2d at 413 ("[T]he MPUC's responsibility was to balance the needs of the customers and the shareholders."); Minn. Stat. § 216B.16, subd. 6.
[223] *See In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 15 (Jul. 17, 2023) (eDockets No. 20237-197559-01); *see, e.g., In re Application of Minn. Power for Auth. to Increase Rates for Elec. Service in Minn.*, Docket No. E-015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 36 (Nov. 2, 2010) (eDockets No. 201011-56128-01).

prioritizes shareholder interests, shareholders should bear that expense. Xcel remains free to pay its executives as much as it wishes.

81. The ALJ finds that AIP and LTI overwhelmingly incentivize a focus on profits and shareholder returns, which are direct shareholder interests rather than ratepayer interests. Because of the strength of this incentive, and Xcel's lack of evidence demonstrating any executive activities directly benefitting ratepayers, the ALJ also finds that Xcel has not met its burden to demonstrate that it would be just and reasonable to include executive base pay in rates.

82. The ALJ also finds that recovery of executive compensation is not necessary for Xcel to meet the cost of providing service. In Xcel's last rate case, the Commission limited recovery of compensation paid to Xcel's ten highest-paid executives to $150,000 per executive.[224] Even with this limitation on recovery, Xcel met its initial ongoing earnings guidance from 2022 to 2024, as it has for over 20 years,[225] and enjoyed profits of $1.736 billion in 2022, $1.771 billion in 2023, and $1.936 billion in 2024.[226] Recovery of executive compensation is therefore not necessary for Xcel to recover its cost of providing service.

83. The ALJ therefore recommends that the Commission disallow Xcel's request to recover compensation paid to Xcel's ten highest-paid executives.

84. While the OAG recommended disallowing executive compensation in this docket, the OAG suggested that, in a separate docket, the Commission should explore creation of a Performance Incentive Mechanism that would allow Xcel to recover a portion of executive compensation if it met certain ratepayer-focused metrics.[227] The OAG argued, "If the utility's executives are being openly evaluated as to how they are achieving well-designed ratepayer centered metrics…this could incentivize Xcel's executives to exercise leadership and provide more ratepayer benefits to Minnesotans."[228] The OAG pointed out that the Public Utilities Rates Authority of Connecticut tied the total executive compensation that a utility can recover to the utility's performance according to affordability metrics.[229] The OAG emphasized the importance of affordability metrics as the primary focus of such an incentive structure

[224] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 23 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[225] Ex. DOC-26 at 7 (Xcel Energy Inc.'s 2024 Form 10-K).
[226] Ex. DOC-25 at 26 (PDF page 31) (Xcel Energy Inc.'s 2023 Form 10-K); Ex. DOC-26 at 25 (Xcel Energy Inc.'s 2024 Form 10-K). These citations also show Xcel's ongoing earnings were even higher than its profits.
[227] Ex. OAG-3 at 24-25 (Hinderlie Surrebuttal).
[228] Ex. OAG-3 at 25 (Hinderlie Surrebuttal).
[229] Ex. OAG-3 at 25-26 (Hinderlie Surrebuttal).

because the utility's return on equity incentivizes achievement of goals that rely on capital outlays.[230]

85. The ALJ recommends that the Commission consider opening a docket to determine metrics for recovery of portions of executive compensation that will incentivize improved affordability.

F. EEI Membership Dues

86. Xcel requests recovery of $677,000 in dues expenses in both the 2025 test year and 2026 plan year related to its membership in Edison Electric Institute.[231] This is based "in large part on the 2024 actuals," after being funneled down to the Minnesota electric jurisdiction.[232] Xcel states that the above total does not contain lobbying-related expenses.[233]

87. Under Minnesota law, the Commission must not permit recovery of a utility's travel, entertainment, and related employee expenses, including "dues and expenses for memberships in organizations or clubs" if the Commission finds the expenses are unreasonable and unnecessary for the provision of utility services.[234]

88. The Commission has also found that utilities need to show "how the membership dues connect to the provision or improvement of utility services" and that an itemized accounting of activities and costs allocated to each activity may be necessary for recovery in some instances.[235]

89. The Commission has previously rejected requests for membership dues when a utility has provided "general assertions regarding the importance of [trade organization] training and informational resources." The Commission has also rejected recovery when a utility has "not made a stronger showing that the membership is used and useful" by the utility "in a manner that benefits ratepayers."[236]

90. Xcel stated "EEI will be essential to the global technical community and to technical professionals everywhere, and be universally recognized for the contributions of technology and of technical professionals in improving global conditions."[237] Xcel

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[230] Ex. OAG-3 at 26 (Hinderlie Surrebuttal).
[231] Ex. Xcel-28 at 5 (Robinson Rebuttal).
[232] Ex. Xcel-28 at 5 (Robinson Rebuttal).
[233] Ex. Xcel-28 at 5-6 (Robinson Rebuttal).
[234] Minn. Stat. § 216B.16, subd. 17.
[235] *In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. G-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 24-25 (Feb. 2, 2022) (eDockets No. 20222-182349-01).
[236] *In re Application of Greater Minn. Gas, Inc. for Auth. to Increase Rates for Nat. Gas Util. Serv. in Minn.*, MPUC Docket No. G-022/GR-24-350, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 19 (Nov. 26, 2025) (eDockets No. 202511-225331-01).
[237] Ex. Xcel-7, Vol. 4.VIII.A2 at 4-48 (Appl. Vol. 4, MYRP Workpapers).

also made a broad statement that "the Company's membership in the EEI allows the Company to have access to information, conferences, and trainings that provide great value to the Company and its customers."[238]

91. The OAG maintained that Xcel did not provide evidence demonstrating the ratepayer benefits of membership nor demonstrate what portion of dues benefit ratepayers.[239] The OAG requested that Xcel substantiate its claimed benefits by providing information such as a listing of EEI presentations, trainings, and conferences its employees attended with an explanation of the ratepayer benefits for these activities.[240]

92. Xcel did not supply the requested information and instead responded by generally repeating that EEI provides information to help members provide reliable and affordable electric service.[241] Xcel also noted that EEI develops safety best practices and other trainings.[242] Xcel explicitly stated that the Company "benefits from EEI's extensive work related to transmission, the clean energy transition and coordination with the National Association of Regulatory Utility Commissioners (NARUC)."[243] However, Xcel stated that it cannot quantify the benefits ratepayers receive from membership in EEI because the involvement of Xcel with EEI is so varied and extensive.[244] Xcel pointed to the list it provided of 2023 conferences.[245]

93. The ALJ finds that Xcel has not sufficiently articulated the benefit to ratepayers for EEI dues and has instead provided general assertions regarding the importance of trainings and resources. Xcel failed to meet its burden and as a result cannot recover the cost for EEI dues. The ALJ recommends disallowance of Xcel's request to recover $677,000 for the 2025 test year and $677,000 for the 2026 plan year.[246]

G. Chamber of Commerce Dues

94. Xcel requests recovery of $221,936 of its Chamber of Commerce dues in the test year and plan year.[247] Xcel is requesting 100 percent recovery of its Chamber of Commerce dues.[248]

95. Under Minnesota law, the Commission must not permit recovery of the utility's travel, entertainment, and related employee expenses including "dues and expenses

[238] Ex. Xcel-28 at 9 (Robinson Rebuttal).
[239] Ex. OAG-7 at 4, 6 (Lee Surrebuttal).
[240] Ex. OAG-5 at 6-7 (Lee Direct).
[241] Ex. Xcel-28 at 3 (Robinson Rebuttal).
[242] Ex. Xcel-28 at 3 (Robinson Rebuttal).
[243] Ex. Xcel-28 at 4 (Robinson Rebuttal).
[244] Ex. Xcel-28 at 9 (Robinson Rebuttal).
[245] *E.g.,* Ex. Xcel-5, Vol. 3.IV.2 at 8 (Appl. Vol. 3, Req. Info.).
[246] Ex. OAG-7 at 7 (Lee Surrebuttal).
[247] Ex. Xcel-6, Vol. 4.VIII.A4 at 1 (Appl. Vol. 4, MYRP Workpapers).
[248] Ex. Xcel-17 at 72 (Halama Direct).

for memberships in organizations or clubs" if the Commission finds these expenses unreasonable and unnecessary for the provision of utility service.[249] The Commission may "allow a public utility to recover from ratepayers the expenses incurred for economic and community development."[250] The burden to establish reasonableness is on the utility.[251]

96. The Commission has found that utilities need to show "how the membership dues connect to the provision of or improvement of utility services" and that an itemized accounting of activities and costs allocated to each activity may be necessary for recovery in some instances.[252]

97. The Commission has previously found that "Shareholders as well as customers benefit from economic development activities, because increased economic activity in the Company's service territory is likely to result in increased energy usage to fuel these activities. Because only a portion of the activity's benefit accrues to customers, it is appropriate for the Company to only recover a portion of the total economic development cost."[253]

98. The Commission previously found that chambers of commerce further business and economic activity and portions of chamber dues are used for economic development, but that economic development benefits could not be attributed to the full amount of chamber of commerce dues.[254] This is as recent as Xcel's last rate case.[255]

99. The OAG argued that the Commission should treat chamber of commerce dues like economic development expenses and split the costs between ratepayers and shareholders.[256]

100. The OAG argued that the economic development expenses help increase and keep the number of customers on the utilities system.[257] This generally increases revenue

[249] Minn. Stat. § 216B.16, subd. 17.
[250] Minn. Stat. § 216B.16, subd. 13.
[251] Minn. Stat. § 216B.16, subd. 4.
[252] *In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. G-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 24-25 (Feb. 2, 2022) (eDockets No. 20222-182349-01).
[253] See *In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 21 (Feb. 1, 2022) (eDockets No. 20222-182349-01).
[254] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-001/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 75-76 (July 17, 2023) (eDockets No. 20237-197559-01).
[255] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-001/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 75-76 (July 17, 2023) (eDockets No. 20237-197559-01).
[256] Ex. OAG-5 at 9 (Lee Direct).
[257] Ex. OAG-5 at 8 (Lee Direct).

for the Company by helping to sustain and grow the utility's system and thus its rate base. The increase in revenue benefits shareholders.[258] The OAG argued the Commission's rationale from the last Xcel rate case should apply because the economic development activities of chambers of commerce continue to benefit both ratepayers and shareholders.[259]

101. Xcel states that chambers of commerce are an indirect means for the Company to increase the number of its customers.[260] However the Company does not provide evidence that chambers of commerce do not benefit and support local communities and businesses in the area. Xcel instead tried to shift the burden onto the OAG to prove the OAG's case instead of providing information as to why the Commission should move away from prior orders.[261]

102. The ALJ finds that Xcel has not carried its burden to show it should recover 100 percent of chambers of commerce dues. Chamber of commerce dues benefit shareholders by increasing economic development, which, in turn, increases revenues for Xcel. The ALJ finds it proper to continue to treat these dues like economic development expenses and split the cost between ratepayers and shareholders.

103. For these reasons, the ALJ recommends that the Commission should reduce the chamber of commerce dues expense by $110,968 in both the test year and plan year.

H. Employee Awards and Gifts Expense

104. Minnesota Statute § 216B.16, subdivision 17(a) states that "the Commission may not allow as operating expenses a public utility's travel, entertainment, and related employee expense that the commission deems unreasonable and unnecessary for the provision of utility service."[262]

105. The burden remains on the utility to show that the rate change is just and reasonable.[263]

106. The Commission has previously rejected awards and gift expenses when there is insufficient evidence of their benefit to ratepayers.[264] The Commission has

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[258] Ex. OAG-5 at 9-10 (Lee Direct).
[259] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-001/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 75 (July 17, 2023) (eDockets No. 20237-197559-01).
[260] Xcel-28 at 12 (Robinson Rebuttal).
[261] Xcel Initial Br. at 205.
[262] Minn. Stat. § 216B.15, subd. 17(a).
[263] Minn. Stat. § 216B.16, subd. 4.
[264] *In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 30 (Feb. 28, 2023) (eDockets No. 20232-193486-01); *In re Application of Otter Tail Power Co. for Auth. to*

previously denied service and retirement awards in Minnesota Power's 2021 rate case due to the utility's failure to build a record on the expenses.[265]

107. The Commission has also denied employee awards in a prior rate case.[266]

108. Xcel requests recovery of $722,268 for non-safety awards and $14,876 for administrative fees, totaling $737,144 for the 2025 test year.[267] For the 2026 plan year, Xcel claims $752,749 for non-safety awards and $15,503 for administrative fees, for a total of $768,252.[268]

109. Xcel states these awards are for two types of costs: 1) performance-based and safety recognition and 2) the Xcelebrate program that focuses on work performance, accomplishments, years of contribution and retirements.[269] Xcel provides most of its awards and gifts through its Xcelebrate program.[270] Xcel states that this program helps to foster a culture of appreciation.[271] The awards and gifts, according to Xcel, assist in driving employee engagement, productivity, and retention.[272] Xcel also states, "these awards are an essential part of the Company's overall approach to employee compensation."[273]

110. The OAG argues that the Commission should remove $737,144 from the 2025 test year and $768,242 from the 2026 plan year for non-safety related awards and gifts.[274]

111. The OAG maintained that the Commission should disallow awards and gifts not related to Xcel's safety recognition program due to lack of support in the record showing these expenses are reasonable and necessary for the provision of utility service.[275]

Increase Rates for Elec. Serv. in Minn., MPUC Docket No. E-017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 47-48 (May 1, 2017) (eDockets No. 20175-131511-01).

[265] *In re Application of Minn. Power for Authority to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 30 (Feb. 28, 2023) (eDockets No. 20232-193486-01).

[266] *In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 47 (May 1,2017) (eDockets No. 20175-131511-01).

[267] Ex. OAG-7 at 10 (Lee Surrebuttal) (citing Ex. Xcel-28 at 16 (Robinson Rebuttal)).

[268] Ex. Xcel-28 at 16 (Robinson Rebuttal).

[269] Ex. Xcel-28 at 14-15 (Robinson Rebuttal).

[270] Ex. Xcel-28 at 14 (Robinson Rebuttal).

[271] Ex. Xcel-62 at 28 (Yen Ly Direct).

[272] Ex. Xcel-62 at 28 (Yen Ly Direct).

[273] Xcel Initial Br. at 208 (citing Xcel-28 at 14-16 (Robinson Rebuttal).

[274] Ex. OAG-7 at 10 (Lee Surrebuttal).

[275] Ex. OAG-7 at 8 (Lee Surrebuttal).

112. The OAG argued that Xcel had only provided conclusory statements regarding the necessity of its employee awards and the request should therefore be denied.[276]

113. Although Xcel made statements "implying there might be reduced costs," Xcel did not provide evidence or analysis of reduced costs.[277] Xcel responds to the OAG's argument that it is unaware of "any methodology by which this issue could be 'analyzed.'"[278]

114. Xcel has the burden to introduce evidence supporting how these gifts and awards relate to the provision of utility service. Xcel's decision to rely on generalized statements and not provide analysis to prove its case is not persuasive because Xcel does not show how ratepayers are benefited by the goals and benchmarks of the awards.[279] The ALJ recommends that Xcel's gifts and awards that are not related to safety recognition be disallowed.

I. Investor Relations Expense

115. The Commission has previously decided that "some level of investor relations expense is necessary for the provision of utility service; equally clearly, the Company has the burden of proof to establish the nature, amount, and necessity of each expense claimed."[280]

116. Xcel asserted that these costs include the cost of providing "shareholder services and interactions with fixed income investors," keeping credit rating agencies informed of Xcel's business and supporting the Company's equity program.[281] Xcel argued that 100 percent of investor relations expenses are "a necessary cost of doing business for a regulated utility and thus are included in the cost service and recoverable from customers."[282] Xcel argues that 100 percent of these costs are "unavoidable" and "do not benefit investors."[283]

117. The OAG responded that the costs should be shared between ratepayers and shareholders because investor relations costs also benefit shareholder interests.[284] The OAG explained "Other than listing the activities that make up the investor

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[276] OAG Initial Br. at 41-42.
[277] Ex. OAG-7 at 8 (Lee Surrebuttal).
[278] Xcel Initial Br. at 210.
[279] *See In re Application of Minn. Power for Authority to Increase Rates for Elec. Serv. in Minn.*, Docket No. E-015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 30 (Feb. 28, 2023) (eDockets No. 20232-193486-01).
[280] *In re Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minn. Gas for Auth. To Increase Natural Gas Rates in Minn.*, G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 22 (June, 9, 2014) (eDockets No. 20146-100252-01).
[281] Ex. Xcel-20 at 37 (Wehner Direct).
[282] Ex. Xcel-19 at 43 (Halama Rebuttal).
[283] Ex. Xcel 20 at 38 (Wehner Direct).
[284] Ex. OAG-7 at 12 (Lee Surrebuttal).

relations costs, the Company does not attempt to determine the amount of costs that are for activities that benefit ratepayers."[285] Some costs are of no or only partial benefit to ratepayers.[286]

118. Xcel provided no substantive rebuttal to the OAG's positions on this issue.[287]

119. The ALJ finds that Xcel has only provided information showing that both shareholders and ratepayers create investor relations costs. The ALJ finds limiting recovery to 50 percent of the investor relations costs is reasonable.

J. Rate Case Expense

120. Xcel is requesting $4.9 million for rate case expenses amortized over three years, from 2025 to 2027.[288]

121. Xcel calculated rate case expenses using a two-part method.[289] First, Xcel used actual historical rate case expenses. Then, Xcel "anticipated costs to be incurred for outside experts, regulatory and legal fees, and administrative costs such as required notices."[290]

122. Rate case expenses include a combination of costs for outside experts, anticipated legal fees, consultants, anticipated regulatory fees, administrative costs, and estimated costs.[291] Xcel argues that it has demonstrated the reasonableness of the forecasted expense and showed that the rate case expenses proposed for recovery are a necessary cost of regulated utility operations.[292]

123. For this rate case, Xcel has 24 company witnesses, including two external consultants testifying on return on equity, rate of return, capital structure, cost of debt, and executive compensation.[293] Xcel also retained the service of three external law firms.[294]

124. The OAG recommended that rate case expenses be equally borne by Xcel's shareholders and ratepayers, reflected in a 50 percent reduction in Xcel's request. The

[285] Ex. OAG-5 at 14 (Lee Direct).
[286] Ex. OAG-5, SL-D-5 at 1 (Lee Direct).
[287] Although Xcel witness Halama indicated that witness Wehner provided rebuttal testimony regarding the investor relations expenses, there is no rebuttal testimony on investor relations expenses. Ex. Xcel-19 at 63 (Halama Rebuttal) (citing Table 3).
[288] Ex. Xcel-17 at 84-85 (Halama Direct).
[289] Xcel Initial Br. at 169.
[290] Xcel Initial Br. at 169.
[291] Ex. OAG-5 at 16-17 (Lee Direct).
[292] Xcel Initial Br. at 170.
[293] Ex. OAG-5 at 17 (Lee Direct).
[294] Ex. OAG-5 at 17 (Lee Direct).

OAG illustrated how Xcel has continued to increase the amount it recovers for rate case expenses, as shown in the table below:[295]

Rate Case Expenses Recovered from Ratepayers

	13-868 Approved Amount	15-826 Approved Amount	21-630 Approved Amount
Total	$2,714,433[42]	$3,339,545[43]	$4,686,303[44]

125. The OAG's table shows that rate cases expense jumped 23 percent[296] from the 2013 to 2015 rate case, then increased another 40 percent between the 2015 to 2021 rate case.[297] The increase between the 2021 rate case and the current rate case appears to be less extreme, around $230,000. However, Xcel's current rate case filing comes only three years after its last rate case, and Xcel's current multi-year rate plan only includes two years rather than the three years of financials and requests in 2021 and 2015.[298]

126. The OAG's primary argument is that it is unreasonable for ratepayers to pay 100 percent of rate case expenses when the Company's shareholders receive benefits from Xcel's efforts to increase its rates.[299] The OAG argues that rate cases benefit shareholders by allowing the utility to increase its revenue requirement. Further, the OAG argues that specific rate case expenses benefit shareholders, such as the utility's cost-of-capital and return-on-equity witnesses, who benefit shareholders by arguing for a higher return.[300]

127. Xcel responds by citing the Commission's prior rate case proceedings, but does not cite to a decision rejecting the OAG's argument.[301] Reviewing those decisions, the ALJ notes that the Commission has found that "reasonable, prudently incurred rate case expenses are properly included in test year costs" and amortized.[302] Xcel seems to only respond that the Company does not have full control of the rate case expenses it incurs.[303]

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[295] Ex. OAG-5 at 17 (Lee Direct).
[296] (($3,339,545 – $2,714,433)/$2,714,433) x100
[297] OAG Initial Br. at 47.
[298] OAG Initial Br. at 47.
[299] Ex. OAG-5 at 17 (Lee Direct).
[300] Ex. OAG-5 at 18 (Lee Direct).
[301] Xcel Initial Br. at 173-174.
[302] *In re Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minn. Gas for Auth. to Increase Natural Gas Rates in Minn.*, Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 25, 27 (June, 9, 2014) (eDockets No. 20146-100252-01).
[303] Ex. Xcel-19 at 45 (Halama Rebuttal).

128. The OAG refutes that Xcel does not have control over rate case expenses.[304] The OAG points out that Xcel chooses when the rate case is filed, which experts or lawyers to hire, and how to manage its internal staff, retained counsel, and retained experts to manage costs.[305]

129. Further, the OAG argues that Xcel does not have an incentive to keep its rate case expenses low if it can simply pass them on to ratepayers.[306]

130. Xcel responds by stating that the "Company maintains a focus on keeping rates low, working across all areas of the Company to contain costs and manage to overall reasonable budget levels, recognizing that controlling our costs and maintaining efficient operations is beneficial to our customers."[307]

131. Finally, the OAG discussed a variety of examples where commissions and legislatures have "reined in" investor owned utilities' rate case expenses that are passed onto ratepayers.[308] The New Hampshire Public Utilities Commission requires a bidding process if rate case expenses are estimated to be over $10,000 dollars.[309] New Jersey and Missouri both recognize that shareholders benefit from rate cases and order that only 50 percent of rate case expenses may be recovered from ratepayers.[310] Missouri's Public Utilities Commission further recognizes that 100 percent recovery "does not encourage reasonable levels of cost containment in the utility's rate case expense decisions."[311] Connecticut legislature has prohibited the recovery of any rate case expenses.[312] Colorado has a statute directing the Public Utilities Commission to "limit the amount of rate case expenses that an investor-owned electric or gas utility may recover from the utility's customers."[313]

132. Xcel has not carried its burden to show it is just and reasonable for ratepayers to pay for 100 percent of rate case expenses. While Xcel is required to go through a full ratemaking proceeding when requesting a change in rates,[314] Xcel's ratepayers are not the only beneficiaries of a rate case. Xcel argues that the purpose of a rate case is to further a utility's right to recover prudently incurred costs necessary to provide service. But Xcel acknowledges that rate cases include an impact on the return on

[304] Ex. OAG-5 at 16-17 (Lee Direct).
[305] OAG Initial Br. at 47.
[306] Ex. OAG-7 at 15 (Lee Surrebuttal).
[307] Ex. Xcel-19 at 45 (Halama Rebuttal).
[308] Ex. OAG-7 at 16 (Lee Surrebuttal) (citing N.H. Code Admin. R. PUC 1905.04 (2024)).
[309] Ex. OAG-7 at 16 (Lee Surrebuttal) (citing N.H. Code Admin. R. PUC 1905.04 (2024)).
[310] Ex. OAG-5 at 20-21, SL-D-6 – SL-D-7 (Lee Direct).
[311] Ex. OAG-5, SL-D-7 at 3 (Lee Direct).
[312] Ex. OAG-5, SL-D-7 at 3 (Lee Direct).
[313] Ex. OAG-5, SL-D-8 at 1 (Lee Direct) (COLO. REV. STAT. ANN. § 40-3-102.5 (WEST 2025)).
[314] Ex. Xcel-19 at 43 (Halama Rebuttal).

equity (ROE).[315] The ALJ finds that shareholders do benefit from rate case expenses like ratepayers do, and these expenses should be shared.

133. Further, the ALJ finds that equal assignment of rate case expense to ratepayers and shareholders creates an appropriate cost containment mechanism for these expenses, as Xcel's significantly increased costs in its past three rate cases have shown that it otherwise lacks an incentive to contain costs.

134. The ALJ recommends that the Commission remove $819,986 from both the 2025 test year and the 2026 plan year, equal to 50 percent of Xcel's requested rate case expense.[316]

K. Targeted Undergrounding

135. Xcel identified its request for targeted undergrounding capital costs in supplemental testimony, equal to $2.3 million of capital additions in the 2025 test year and another $6.7 million of capital additions in the 2026 plan year,[317] for a total of $9 million combined.[318] Xcel stated "Targeted undergrounding will address elevated rates of lengthy interruptions (over 12 hours) identified in an equity analysis filed in docket E002/M-24-27."[319] Xcel stated that the objective of the targeted undergrounding program is to improve reliability for customers by undergrounding overhead line.[320] The program identified 171 feeders containing 1,157 miles of overhead distribution lines with over 300,000 customer interruptions per year.[321] Xcel stated it was going to underground approximately one mile of overhead distribution system in 2025 and three miles in 2026.[322]

136. The OAG disputed the project's cost.[323] As a result, the OAG recommends that the Commission order a cost cap of $1.5 million per mile to protect ratepayers, equal to an $800,000 reduction in the 2025 test year and a reduction of $2.2 million to the 2026 plan year capital additions.[324]

137. The OAG based this cost cap on Xcel's original proposal for this program in the 2024 Safety, Reliability, and Service Quality docket[325]—the same docket cited by Xcel in the Company's supplemental testimony as the genesis of the capital additions.[326]

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[315] Ex. Xcel-19 at 44 (Halama Rebuttal).
[316] Ex. OAG-7 at 13 (Lee Surrebuttal).
[317] Ex. Xcel-37 at 2-3 (Mensen Supplemental Direct).
[318] Ex. Xcel-37 at 4 (Mensen Supplemental Direct).
[319] Ex. Xcel-37 at 3 (Mensen Supplemental Direct).
[320] Ex. Xcel-37 at 3 (Mensen Supplemental Direct).
[321] Ex. Xcel-37 at 3-4 (Mensen Supplemental Direct).
[322] Ex. Xcel-37 at 4 (Mensen Supplemental Direct).
[323] Ex. OAG-5 at 32-34 (Lee Direct).
[324] Ex. OAG-5 at 34 (Lee Direct); Ex. OAG-7 at 25 (Lee Surrebuttal).
[325] Ex. OAG-5 at 31-32 (Lee Direct).
[326] Ex. Xcel-37 at 3 (Mensen Supplemental Direct).

Xcel's first cost estimates submitted in April 2025 were between $1 million and $1.5 million per mile.[327] But in the rate case filing, Xcel's estimates doubled to a per mile cost of $2.3 million in the 2025 test year and $2.2 million in the 2026 plan year.[328]

138. The OAG raised concerns that the costs proposed for the 2025 test year and 2026 plan year are higher than what Xcel proposed in its original proposal and that Xcel indicated costs could increase further.[329] Xcel stated that it "expects to refine Targeted Undergrounding cost estimates as we gain further experience and complete more of these projects."[330] Further, Xcel did not provide updated costs for the 2025 test year to support its request despite having ten months of actual costs incurred in the 2025 test year.[331]

139. Only in its initial brief did Xcel begin to argue that the targeted undergrounding program in the rate case consists of different projects not included in the proposal in docket no. 24-27.[332] Xcel argued that these different projects require different costs.[333]

140. Xcel also responded that the cost cap is not necessary given that the target undergrounding program is a capital program and subject to the Company's true-up mechanism.[334] Xcel argued that any refund of costs would protect ratepayers.[335]

141. The OAG argued that the capital true-up does not relieve Xcel of its burden to prove that including targeted undergrounding capital costs in rates is just and reasonable.[336] Second, that the purported refund that might issue does not protect ratepayers from Xcel's wide range of cost estimates for the project, as a refund would only issue if Xcel's aggregate actual capital-related costs falls below the approved revenue requirement in this rate case.[337]

142. The ALJ recommends that to ensure that the costs of this project remain reasonable, the Commission should order a cost cap on the program of $1.5 million per mile of targeted undergrounding, which is equal to the higher end of Xcel's initial cost estimate. It is not reasonable to permit Xcel to manipulate program costs between dockets and ratepayers should be protected at the program's onset, not retroactively

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[327] *In re N. States Power Co.'s Ann. Rep. on Safety, Reliability, and Service Quality for 2024 and Pet. for Approval of Elec. Reliability Standards for 2025*, MPUC Docket No. E-002/M-25-27, Part 3 of 3 Order Compliance at 124-25 (Apr. 1, 2025) (eDockets No. 20254-217138-05).
[328] *See* Ex. Xcel-37 at 2, 4 (Mensen Supplemental Direct).
[329] Ex. OAG-7 at 24 (Lee Surrebuttal).
[330] Ex. Xcel-35 at 5 (Mensen Rebuttal).
[331] Ex. OAG-7 at 24-25 (Lee Surrebuttal).
[332] Xcel Initial Br. at 214-215.
[333] Xcel Initial Br. at 215.
[334] Xcel Initial Br. at 215.
[335] Xcel Initial Br. at 215.
[336] OAG Reply Br. at 3.
[337] OAG Reply Br. at 3.

through a true-up mechanism that considers aggregate capital costs rather than specific factors of individual capital projects.

L. Wildfire Costs

143. Xcel Energy Inc. (XEI) is the parent company of several operating companies in several states including Minnesota (Northern States Power Minnesota), Colorado (Public Service of Colorado), New Mexico and Texas (Southwestern Public Service Company), and its service company, Xcel Energy Services (XES).[338] Xcel is proposing to amend the NSPM Service Agreement[339] to allocate wildfire mitigation costs using the Total Plant Ratio (TPR).[340] Xcel has the burden to show this proposal is reasonable.[341]

144. According to Xcel, the Total Plant Ratio "serves as a proxy for the geographic footprint of our system that may be subject to potential wildfire risk."[342]

145. The Department and OAG argue against using the Total Plant Ratio because it does not follow cost causation and is therefore unreasonable.[343] Using the Total Plant Ratio assumes that wildfire risk is the same across all plants and jurisdictions.[344] The OAG and Department argue that the indirect wildfire costs instead should be allocated based on NSPM's share of direct wildfire costs.[345]

146. The OAG makes multiple arguments as to why Xcel's proposal is unreasonable. Xcel's proposal ignores that wildfire risk factors differ across jurisdictions.[346] These risks include the size of wildfire, weather conditions, and the likelihood that a wildfire might be ignited from various sources.[347] But Xcel's proposal assumes all facilities across all operating companies equally cause wildfire risk management costs.[348]

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[338] Ex. DOC-1 at 19 (Johnson Direct).
[339] Ex. Xcel-49 at 5 (Doyle Direct); *In re N. States Power Co. 2025 Annual Filing Regarding Its Service Agreement with Xcel Energy Ser. Inc*., MPUC Docket No. E,G-002/AI-25-245, ANNUAL REPORT (May 30, 2025) (eDockets No. 20255-219394-01) ; Ex. OAG-5 at 27 (Lee Direct).
[340] Ex. Xcel-49, NLD-1 Schedule 2(b) at 10 (Doyle Direct).
[341] Minn. Stat. § 216B.16 subd. 4; Ex. Xcel-50 at 2 (Doyle Rebuttal).
[342] Ex. OAG-5, SL-D-11 at 1 (Lee Direct).
[343] Ex. OAG-5 at 27 (Lee Direct); Ex. DOC-1 at 43 (Johnson Direct).
[344] Ex. OAG-5 at 27 (Lee Direct) (citing Ex. OAG-5, SL-D-11 at 1 (Lee Direct)).
[345] Ex. OAG-5 at 27-28 (Lee Direct); Ex. DOC-1 at 44-45 (Johnson Direct).
[346] Ex. OAG-5 at 27 (Lee Direct); OAG-7 at 20 (Lee Surrebuttal).
[347] Ex. OAG-5 at 28 (Lee Direct).
[348] Ex. OAG-5 at 28 (Lee Direct).

147. Xcel responds that it is not "clear how indirect costs could be allocated on a direct basis."[349] Xcel then argues the section would not fit into the historical framework,[350] although this is a newly emerging issue.

148. The OAG refutes Xcel's argument that its recommendation violates the Xcel's Administrative Service Agreement because Xcel's cost allocation manual states "a cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that cause the cost to be incurred."[351] In discovery, the Department requested Xcel to "provide the impact of the 2025 and 2026 test years using NSPM's share of direct wildfire costs from XES (instead of Total Plant Ratio) to allocate indirect wildfire costs."[352]

149. Xcel failed to comply, only providing a breakout of indirect wildfire costs allocated using the disputed Total Plant Ratio.[353] The OAG explained that it could not identify the costs that should be allocated to NSPM without the total XES direct and indirect costs for both 2025 and 2026.[354] The OAG stated that if Xcel had provided the amount, the ratio of XES direct costs allocated to NSPM of the total XES direct costs could have been calculated.[355] This would have then allowed the XES indirect costs to be properly allocated because the calculated ratio could be applied to the XES total indirect costs.[356] The result would have been the amount of indirect costs that should be allocated to NSPM.[357]

150. The Department and OAG argue that all indirect wildfire costs should be removed due to Xcel's decision not to provide information needed to properly allocate them.[358] Xcel stated that the $3.3 million in the 2025 test year and $4.3 million in the 2026 plan year represent total wildfire mitigation costs for NSPM Minnesota, including both direct and allocated indirect costs.[359] However, Xcel did not provide the amount of indirect wildfire costs calculated without the total plant ratio in the record. As a result, the ALJ finds that Xcel has not met its burden to prove its request for wildfire mitigation costs is correct.

151. The ALJ is persuaded that it is not reasonable to approve the use of the total plant ratio for allocation without letting the investigating parties, the Department and OAG, have the ability to understand if the proposal is reasonable. It is unclear what totals are being charged to the Minnesota jurisdiction. Minnesotans should not be paying

[349] Ex. Xcel-50 at 16 (Doyle Rebuttal).
[350] Ex. Xcel-50 at 20 (Doyle Rebuttal).
[351] Ex. OAG-7 at 21 (Lee Surrebuttal) (quoting Ex. Xcel-50 at 16-17 (Doyle Rebuttal)).
[352] Ex. OAG-5, SL-D-14 (Lee Direct); *See also* Ex. DOC-1 at 45 (Johnson Direct).
[353] Ex. OAG-7 at 23 (Lee Surrebuttal).
[354] Ex. OAG-7 at 23 (Lee Surrebuttal).
[355] Ex. OAG-7 at 23 (Lee Surrebuttal).
[356] Ex. OAG-7 at 23 (Lee Surrebuttal).
[357] Ex. OAG-7 at 23 (Lee Surrebuttal).
[358] Ex. OAG-7 at 23 (Lee Surrebuttal).
[359] Ex. Xcel-50 at 15 (Doyle Rebuttal).

for other states' costs. Paying for costs attributable to other jurisdictions outside of Minnesota is unreasonable.

152. The ALJ is additionally persuaded that Xcel has not met its burden to demonstrate that Xcel should deviate from standard cost causation principles. As a result, the ALJ recommends the disallowance of $1.7 million in the 2025 test year and $1.8 million in the 2026 plan year.

M. NOx Tracker

153. Xcel requested that the Commission create a tracker for costs it may incur to comply with the United States Environmental Protection Agency's (EPA) final rule for the Federal Implementation Plan for the 2015 8-hour Ozone National Ambient Air Quality Standards, Docket ID No. EPA-HQ-OAR-2021-0668, also referred to as the "Good Neighbor Plan" (GNP).[360] The GNP established limits on nitrogen oxide (NOx) emissions from power plants through an allowance-based trading program.[361] Because Xcel anticipated being unable to keep its emissions below its allowance budget, it anticipated either needing to upgrade its facilities or to purchase additional allowances.[362] Xcel requested establishment of a tracker because the costs of compliance were difficult to predict.[363]

154. The GNP arose from a series of EPA actions that began with National Ambient Air Quality Standards (NAAQS) that were set in 2015.[364] States were required to create State Implementation Plans (SIP) to comply with the 2015 NAAQS, but the EPA rejected 23 SIPs, including Minnesota's.[365] The EPA issued the GNP in 2023, a Federal Implementation Plan for all states whose SIPs had been rejected.[366]

155. The OAG argued that the Commission should not create a tracker for the costs of compliance with the GNP because the GNP is not currently in effect and it is unlikely that the GNP will go into effect during the MYRP.[367] The GNP was challenged by litigation in the U.S. Court of Appeals for the Eighth Circuit and separate litigation in the District of Columbia Circuit.[368] A stay of the GNP was issued in both cases, including a stay by the U.S. Supreme Court in 2024.[369] The Supreme Court stay remains in effect.[370] The EPA has also begun the process of reconsidering both the

[360] Ex. Xcel-59 at 1-2 (West Direct).
[361] Ex. Xcel-59 at 4 (West Direct).
[362] Ex. Xcel-59 at 4 (West Direct).
[363] Ex. Xcel-59 at 9-10 (West Direct).
[364] Ex. Xcel-59 at 4 (West Direct).
[365] Ex. Xcel-59 at 3-4 (West Direct).
[366] Ex. Xcel-59 at 3-4 (West Direct).
[367] OAG Initial Br. at 52.
[368] Ex. Xcel-59 at 7 (West Direct).
[369] Ex. Xcel-59 at 7 (West Direct); Tr. Vol. 1 at 216 (West); *Ohio v. Environmental Protection Agency*, 603 U.S. 279 (2024).
[370] Tr. Vol. 1 at 216 (West); *Ohio v. Environmental Protection Agency*, 603 U.S. 279 (2024).

GNP and the rejected underlying SIPs.[371] The OAG argued that the GNP may be eliminated through this process, and if it is not, Xcel conceded that whether it will need to incur GNP-related costs depends on the outcome of the EPA's reconsideration process.[372]

156. Xcel argued that, although the GNP is stayed and the current administration is reconsidering the GNP, the GNP is still a final rule, and the tracker should therefore be established.[373]

157. For a utility to use a tracker, it must petition the Commission for deferred accounting—an exception to standard ratemaking procedures that allows utilities to record, or "track," out-of-test-year expenses.[374] The Commission may only grant deferred accounting for "good cause shown,"[375] such as situations where it is exceptionally difficult to develop a reliable test year expense amount for costs that will be incurred during a test year or when a utility incurs unforeseen and unusual expenses that are large enough to have a significant impact on the utility's financial condition.[376] Trackers are considered "highly unusual ratemaking treatment."[377]

158. In this case, the ALJ finds that Xcel has not established good cause for creation of a tracker. While Xcel has shown that it would be difficult to develop a reliable test year expense amount for costs of compliance with the GNP, the GNP was not in effect for the entirety of the test year and is still not in effect. Because the EPA has announced that it will reconsider both the GNP and the underlying denial of Minnesota's SIP, it appears doubtful that the GNP will ever come into effect, meaning that Xcel will never incur any costs to comply with the GNP. Because Xcel has not shown that these expenses are unforeseen and unusual and has not even shown it is likely to incur costs to comply with the GNP, much less that they will have a significant impact if deferred accounting is not granted in this rate case, the ALJ concludes that good cause does not exist to establish a tracker for such costs.

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[371] Tr. Vol. 1 at 216-217 (West).
[372] OAG Initial Br. at 53.
[373] Xcel Initial Br. at 232-233.
[374] *In re Petition by N. States Power Co. d/b/a Xcel Energy for Approval of Deferrals Related to Depreciation O&M and Property Tax for 2022*, MPUC Docket No. G002/M-21-750, ORDER DENYING PETITION at 3 (Feb. 9, 2022) (eDockets No. 20222-182600-01).
[375] Minn. R. 7825.0300, subp. 4.
[376] *In re Application of CenterPoint Energy for Auth. To Increase Nat. Gas Rates in Minn.*, MPUC Docket No. G-008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 39 (Jan. 11, 2010) (eDockets No. 20101-45867-01); *In re Petition by N. States Power Co. d/b/a Xcel Energy for Approval of Deferrals Related to Depreciation O&M and Property Tax for 2022*, MPUC Docket No. G002/M-21-750, ORDER DENYING PETITION at 3 (Feb. 9, 2022) (eDockets No. 20222-182600-01).
[377] *In re Application of CenterPoint Energy for Auth. To Increase Nat. Gas Rates in Minn.*, MPUC Docket No. G-008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 39 (Jan. 11, 2010) (eDockets No. 20101-45867-01).

II. RATE DESIGN

159. Once the Commission has determined the utility's revenue requirement, it must determine which customer classes should pay for the costs reflected in the revenue deficiency, and how rates should be designed to recover those costs from customers.

160. Revenue apportionment describes the assignment of the utility's approved revenue requirement to the various customer classes. Put differently, if setting the revenue requirement is like determining the size of the pie, then revenue apportionment is akin to cutting the slices.[378]

161. Rate design, in contrast to the determination of the revenue requirement, is a quasi-legislative function. This step of the ratemaking process largely involves policy decisions to be made by the Commission.[379] Rate design requires the application of judgment to synthesize a range of objective and subjective factors.[380]

162. Rate design is not a formulaic process, but involves balancing many factors.[381]

A. CCOSS

163. An important consideration in apportioning revenue responsibility among customer classes is "class cost of service," or how much it costs the utility to serve each customer class.[382] Utilities and other rate-case parties develop class-cost-of-service studies ("CCOSSes") to inform their revenue-apportionment and rate design recommendations.

164. As the Commission has recognized, "Estimating the cost to serve any given customer is challenging because a utility will incur different costs to serve different types of customers, and will incur many costs that benefit multiple types of customers."[383] The latter type of costs can be complicated by the occurrence of "joint" and "common" costs. Joint costs occur when the provision of one service is a byproduct

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[378] Ex. DOC-1 at 14 (Johnson Direct).
[379] *St. Paul Area Chamber of Com. v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977).
[380] Ex. OAG-8 at 4-5 (Scharber Direct) (describing how even class cost of service studies, arguably the most objective part of rate design, remain inherently subjective "due to the jointness or commonness of most costs and the lack of an objective standard against which to compare the CCOSS results").
[381] *See St. Paul Area Chamber of Com. v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977) (stating that after the revenue requirement is established "many countervailing considerations come into play.").
[382] Ex. OAG-8 at 2 (Scharber Direct).
[383] *See In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 95 (Jul. 17, 2023).

of the production of another service.[384] Common costs arise when an entity produces several services using the same facilities or inputs.[385] CCOSSes can be helpful in allocating joint and common costs, but there is no one correct method for doing so.[386]

165. A CCOSS provides guidance for revenue apportionment decisions. But it is important to keep in mind that CCOSS results are not approximations of "true costs" for a customer class, as the presence of joint and common cost and lack of an objective standard prevent the creation of a truly objective CCOSS.[387] Similarly, there can be no objective "movement toward class costs" in revenue apportionment.[388] The focus in this report is therefore on how reasonable the CCOSSes assumptions are or how closely they align with the understandings or priorities stated by the Commission in past orders.

166. A CCOSS has three steps: functionalization, classification, and allocation. First, costs are "functionalized" into various categories that reflect the basic elements of the electric system, such as generation (or "production"), transmission, distribution. Second, costs are classified according to three factors that drive the need to incur them: meeting customers' peak demand, providing reliable year-round energy, and connecting customers to the system regardless of their demand and energy requirements. Finally, in a step closely tied to classification, costs are allocated among the various customer classes based on their relative contribution to overall peak demand, energy consumption, or number of customers.[389]

167. In this rate case, there are disputes among several parties regarding (1) which classification and allocation methods should be used to produce CCOSSes in this proceeding and (2) which classification and allocation methods Xcel should be required to use in its CCOSSes in its next rate case. This report will address both of these issues below:

1. Classification and Allocation of Production Costs

168. Fixed production plant—the fixed costs of the Company's owned-generation resources—comprises a large portion of a vertically-integrated utility's capital costs.[390] Parties disagree on both the appropriate classification of these costs as energy or demand related and the allocation of the demand-related portions of these costs.

[384] Ex. OAG-8 at 2 (Scharber Direct).
[385] Ex. OAG-8 at 3 (Scharber Direct).
[386] Ex. OAG-8 at 3 (Scharber Direct).
[387] Ex. OAG-8 at 4 (Scharber Direct).
[388] Ex. OAG-8 at 5 (Scharber Direct).
[389] Ex. OAG-8 at 3-4 (Scharber Direct).
[390] *See* Xcel-17, sched. 7 at 1 (Halama Direct).

a. Classification of Fixed Production Costs – Stratification

169. Xcel classifies fixed production plant using the Stratification Method, which Xcel has used with Commission approval since the late 1970s.[391] The Stratification Method assumes that utilities invest in baseload resources, which have higher capital costs and lower operating costs relative to peaking plants, mainly to reduce the overall cost of producing energy.[392] The share of energy-related costs for a given plant type can then be estimated as the portion of its generation costs per kilowatt that exceed the comparable costs for a peaking plant.[393]

170. Xcel, the OAG, and the Department all support continuing to use the Stratification Method to classify fixed production plant.[394]

171. XLI argues that the Stratification Method is flawed and overclassifies wind and solar production plant as energy-related because these resources do not produce energy all the time and are constructed to meet Minnesota's carbon-free by 2040 law.[395]

172. XLI recommends the Commission instead use a different method to classify and allocate fixed production costs, the Average and Excess Demand–Four Coincident Peak (AED-4CP) method.[396] An "average and excess demand" allocator assumes production costs are caused by classes in proportion to both their average demand across all hours of the year and their "excess" demand, defined as the difference between a class's system-coincident peak demand and the class's average demand.[397]

173. As the OAG's witness testified, while it is true that wind and solar resources are not available every hour of the year, it does not follow that their costs should be classified primarily as demand-related.[398] Since CCOSS convention dictates that generation costs be classified as demand- and/or energy-related, it makes the most sense to classify both wind and solar as predominantly energy-related as there is no dispute that these resources are not dispatchable to respond to a demand increase.[399] That utilities invest in capital-intensive renewable resources in part to meet environmental

[391] Ex. Xcel-73 at 15 (Barthol Direct).
[392] Ex. OAG-9 at 2 (Scharber Rebuttal).
[393] Ex. OAG-9 at 2 (Scharber Rebuttal).
[394] Ex. Xcel-74 at 11-15 (Barthol Rebuttal); Ex. OAG-9 at 1-12 (Scharber Rebuttal); Ex. DOC-18 at 2-4 (Zajicek Surrebuttal). As discussed below, however, these parties do not all agree on how production costs should be allocated.
[395] *See* Ex. XLI-3 at 7-8 (Jonathan Ly Direct).
[396] Ex. XLI-3 at 3, 11 (Jonathan Ly Direct).
[397] Ex. OAG-9 at 7 (Scharber Rebuttal); Ex. XLI-3 at 11-12 (Jonathan Ly Direct).
[398] Ex. OAG-9 at 3 (Scharber Rebuttal).
[399] Ex. OAG-9 at 3 (Scharber Rebuttal); Ex. DOC-18 at 4 (Zajicek Surrebuttal).

goals does not change the fact that it is appropriate to classify the majority of these costs as energy-related.[400]

174. While there may be more appropriate methods of classifying production plant that could be explored in the future,[401] the AED-4CP method has several flaws. First, its reliance on "excess demand" fails to recognize that utility systems are largely planned to provide capacity during times of peak demand, not "excess demand."[402] Second, XLI's AED-4CP method allocates all types of generation to average or excess demand in the same proportion, meaning that it would classify and allocate the costs of a system made mostly of gas turbines in the same way as a system made mostly of coal or wind plants, an illogical outcome.[403] Third, XLI's AED-4CP method does not rely on MISO-coincident peaks,[404] which the Commission has required Xcel to use in its generation demand allocator.[405]

175. In Xcel's last electric multi-year rate plan, the Commission determined that the Stratification Method "provides a sounder rationale for distinguishing between energy-related and capacity-related costs" than the AED-4CP method.[406]

176. The ALJ finds that the Commission's determination remains sound. In fact, the Commission considered many of XLI's arguments in Xcel's last rate case, and XLI has not provided persuasive new evidence that makes this record distinguishable.[407] As a result, the CCOSSes in the record using the stratification method should be given greater weight than XLI's CCOSS using the AED-4CP method.

b. Allocation of Production Costs – D10S Allocator

177. After classifying production costs, Xcel allocates demand-related production costs using a peak demand allocator, which Xcel calls the D10S allocator.[408] Xcel states that its D10S allocator estimates the percentage of overall demand that is caused by

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[400] Ex. OAG-9 at 3-4 (Scharber Rebuttal). A time-based allocation method would be a more appropriate solution to the problem that XLI raises, but no party, including XLI, has performed a time-based allocation study in this docket. *See* Ex. OAG-9 at 4 (Scharber Rebuttal).
[401] Ex. OAG-9 at 4, 7 (Scharber Rebuttal).
[402] Ex. OAG-9 at 9-10 (Scharber Rebuttal).
[403] Ex. OAG-9 at 10 (Scharber Rebuttal).
[404] Ex. OAG-9 at 10 (Scharber Rebuttal).
[405] *See In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 98 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[406] *See In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 96-97 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[407] *See In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 96-97 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[408] Ex. Xcel-73 at 17 (Barthol Direct).

each customer class for a specific time period and then allocates fixed production plant cost based on these percentages.[409] The selection of the specific time period that is used, therefore, matters greatly for determining how fixed production costs are allocated.[410]

178. In Xcel's last rate case, the Commission ordered Xcel to use the time period that represents Xcel's "system peak coincident with the MISO system peak using historical data."[411] The Commission chose the period of Xcel's system peak coincident with the MISO system peak "because MISO's coincident peak now identifies the period when the electrical system has the least spare resources to manage additional load or a loss of capacity."[412] The Commission directed Xcel to use historical data because MISO had not provided data necessary for Xcel to forecast the periods of peak demand on MISO's system in future years.[413]

179. To calculate the D10S allocator in this case, Xcel identified the hour that MISO's system peaked in 2023, which was Wednesday, August 23 at 4 p.m. CST.[414] Xcel then determined the D10S allocators for its 2025 and 2026 CCOSSes by identifying the class load shares at 4 p.m. on Saturday, August 23, 2025 and Sunday, August 23, 2026 from its class load forecasts.[415]

180. The OAG agrees that the Commission's order in the last rate case should be followed, but believes that Xcel's implementation of this method was unreasonably arbitrary.[416] The OAG points to three primary problems. First, the OAG points out that the hours Xcel chose to represent "peak" load are not coincident with MISO's system peak or even Xcel's own system peak because they fall on weekends in 2025 and 2026.[417] Yet over 2006–2024, the MISO peak has never occurred on a weekend day.[418] Second, the OAG observes that Xcel used forecasted, not historical, data to determine the class shares themselves.[419] Third, the OAG explains that Xcel's

[409] Ex. Xcel-73 at 17 (Barthol Direct).
[410] *See* Ex. OAG-8 at 8 (Scharber Direct) (explaining that because Xcel's demand allocator is based on a single hour, it is very sensitive to the choice of that hour).
[411] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order at 99 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[412] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order at 98 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[413] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order at 99 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[414] Ex. OAG-8 at 7 (Scharber Direct).
[415] Ex. OAG-8 at 7 (Scharber Direct).
[416] Ex. OAG-8 at 5-16 (Scharber Direct); Ex. OAG-10 at 1-13 (Scharber Surrebuttal).
[417] Ex. OAG-8 at 7 (Scharber Direct).
[418] Ex. OAG-8 at 7 (Scharber Direct).
[419] Ex. OAG-8 at 7 (Scharber Direct).

methodology is extremely sensitive to the choice of a single peak hour.[420] The OAG showed that Xcel's results would change drastically if MISO's 2024 peak was used instead of the 2023 peak.[421]

181. To avoid these pitfalls, the OAG's expert designed an alternative D10S allocator to use in its CCOSSes in this case. The OAG's expert reviewed MISO's peaks from 2011 to 2024 to determine the range of days and times most likely to include the MISO peak.[422] The OAG's expert determined that (1) all peaks occurred between June 21 and August 26; (2) they always occurred during the hours ending at 3 or 4 p.m. CST; and (3) they never occurred on a weekend.[423] Because Xcel does not currently have historical class-load data,[424] the OAG next looked at Xcel's load forecasts for 2025 and 2026 and, for each class, summed its loads at the hours of 3 and 4 p.m. on weekdays between June 21 and August 26.[425] The OAG then divided those class load totals by the sum of the system loads for the same hours to yield the OAG's Alternate D10S Allocator.[426]

182. Xcel, XLI, and the Department objected to the OAG's alternative allocator, arguing that it used too many hours to reflect peak conditions.[427]

183. XLI argues that the OAG's allocator "is overly broad and includes a significant number of hours that do not reflect peak conditions."[428] Xcel argued that by reflecting the average of 94 high-demand hours, the OAG's allocator "represents only 84 percent of the Company's 2025 Minnesota load coincident with the NSP system peak."[429] While the Department agreed with the OAG that reliance on a single data point to create the allocator could result in large swings, the Department believed that using a smaller data set might be more reasonable.[430] Nevertheless, the Department used Xcel's single peak D10S allocator in its CCOSSes.[431]

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[420] Ex. OAG-8 at 8 (Scharber Direct).
[421] Ex. OAG-8 at 8-9 (Scharber Direct).
[422] Ex. OAG-8 at 11 (Scharber Direct).
[423] Ex. OAG-8 at 11-12 (Scharber Direct).
[424] Ex. OAG-8 at 11 (Scharber Direct). For future cases, the OAG suggests using class load data corresponding to the month, day, and year of the MISO peak—adjusted for forecasted changes to class load shares—to enhance the precision of the cost-allocation process because the allocator would represent class load shares at the time of an actual system peak. Ex. OAG-8 at 8 (Scharber Direct).
[425] Ex. OAG-8 at 12 (Scharber Direct).
[426] Ex. OAG-8 at 12 & tbl.2 (Scharber Direct).
[427] *See* Ex. Xcel-74 at 17 (Barthol Rebuttal); Ex. XLI-6 at 5 (Jonathan Ly Rebuttal); Ex. DOC-18 at 9-12 (Zajicek Surrebuttal).
[428] Ex. XLI-9 at 5 (Jonathan Ly Surrebuttal).
[429] Ex. Xcel-74 at 17 (Barthol Rebuttal).
[430] Ex. DOC-18 at 11 (Zajicek Surrebuttal).
[431] Ex. DOC-18 at 12 (Zajicek Surrebuttal).

184. The OAG's expert performed quantitative analysis which proved the superiority of the OAG's D10S allocator to Xcel's D10S allocator. While disputing that comparing the percentage of the Company's Minnesota load coincident with the 2025 NSP system peak was relevant due to the Commission's preference for using the MISO peak, the OAG's expert showed that OAG's D10S allocator performed better in this regard.[432] Xcel's single peak allocator represents only 67 percent of the Minnesota load that Xcel forecasts will occur at the time of NSP's 2025 peak and 72 percent of the Minnesota load Xcel forecasts will occur at the time of the NSP's 2026 peak.[433] By contrast, the OAG's Alternate D10S Allocator reflects 84 percent and 89 percent, respectively, of the Minnesota load that Xcel forecasts will occur at the time of the 2025 and 2026 NSP peaks.[434]

185. Using multiple hours in the production demand allocator has also been common practice for many years and is recommended by the National Association of Regulatory Utility Commissioners (NARUC) where, as here, a utility bases its generation-planning decisions on reliability criteria.[435]

186. As discussed further below, there are likely improvements that can be made to the D10S allocator in future rate cases to fully realize the intent of the Commission's order in Xcel's 2021 rate case to base fixed production plant demand allocation on the Company's system peak coincident with MISO's system peak. For the current case, however, the ALJ finds that Xcel's implementation of the Commission's order is unreasonable because it uses class load shares from two weekend days in Xcel's 2025 and 2026 test years, which are unlikely to reasonably represent any system peak, much less the MISO coincident peak. As the OAG's expert showed, a MISO peak has not occurred on a weekend at least in the past 15 years.[436]

187. Xcel's choice to use weekend days results in an unreasonable picture of class cost causation and unfairly penalizes classes that generally use more energy during the weekend hours. Because fixed production demand costs are such a significant portion of Xcel's capital costs, the Commission should give Xcel's, XLI's, and the Department's CCOSSes significantly less weight in its consideration as they are materially tainted by the unreasonable choice of using weekend hours as peak hours.

188. To avoid this unreasonable result, the OAG's alternative D10S allocator should be used in this case and Xcel should be required to further improve its D10S allocator in future rate cases.

[432] Ex. OAG-10 at 4 (Scharber Surrebuttal).
[433] Ex. OAG-10 at 4 (Scharber Surrebuttal).
[434] Ex. OAG-10 at 4 (Scharber Surrebuttal).
[435] *See* Ex. OAG-10 at 5-6 (Scharber Surrebuttal) (citing NARUC's cost-allocation manual).
[436] Ex. OAG-8 at 11-12 (Scharber Direct).

c. Production Cost Allocation – Improvements to Fixed Production Plant Demand Cost Allocation for Future Rate Cases

189. The OAG maintained that Xcel should be required to make improvements to its allocation of production plant demand costs and offered various alternatives for the Commission's consideration.[437] Particularly, the OAG recommended that the Commission move towards an allocator based on multiple historical MISO peaks to improve the allocator's robustness and to reflect MISO's seasonal resource adequacy construct.[438]

190. The Commission has found since 2017 that the MISO's resource adequacy requirements are the relevant consideration for Xcel's investments.[439] MISO has shifted from planning for resource adequacy based on a single summer peak to a "seasonal resource adequacy construct" based on its system peaks in four seasons, and Xcel must now meet MISO's reserve requirement in each season.[440] MISO predicts that resource adequacy will increasingly become a year-round concern, as a result of both changing customer load shapes and a generation mix that is shifting toward intermittent resources.[441]

191. The OAG's primary preference was for the Commission to order Xcel to use a 12 CP allocator. The OAG provided three reasons for the superiority of the 12 CP allocator. First, an allocator that incorporates demands for all peak and non-peak months of the year is more consistent with recent MISO capacity-planning guidelines.[442] Second, a 12 CP allocator incorporates more data points, which makes the allocator more robust.[443] Third, the Commission has already directed Xcel to use a 12 CP allocator for demand-related transmission costs.[444] The transmission system is essentially an extension of the production system, in that it transmits the energy that is being produced, so it makes sense to allocate them in the same manner.[445]

192. The OAG also made multiple recommendations to incorporate regardless of whether the Commission sticks with the D10S allocator or moves to a 12 CP allocator for allocation of demand-related production costs. The OAG recommended that Xcel

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[437] Ex. OAG-8 at 9-11 (Sharber Direct); Ex. OAG-11 at 8-12 (Scharber Surrebuttal).
[438] Ex. OAG-8 at 13–15 (Scharber Direct).
[439] *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Service in Minn.*, Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46 (Jun. 12, 2017) ("While Xcel and other parties persuaded the ALJ that Xcel designs its system to meet its own system peak, the Commission notes that MISO prescribes the formula for calculating the amount of capacity that any given member is to maintain.").
[440] Ex. OAG-8 at 14 (Scharber Direct).
[441] Ex. OAG-8 at 14-15 (Scharber Direct).
[442] Ex. OAG-8 at 14-15 (Scharber Direct).
[443] Ex. OAG-8 at 15-16 (Scharber Direct).
[444] Ex. OAG-8 at 16 (Scharber Direct).
[445] Ex. OAG-8 at 14-15 (Scharber Direct).

either: 1) use actual class load data from the years of the MISO peaks that were used to construct the allocator, adjusted to account for forecasted load changes, or 2) if historical class load data are not available, use forecasted load data corresponding to likely MISO peaks with a clear explanation of how the likely MISO peak hours were selected.[446] Requiring Xcel to adjust historical class load data would allow the allocators to better incorporate the impact of large new loads like data centers, ensuring that these customers bear their full cost of service and that other customers benefit from spreading out fixed costs.[447]

193. Xcel and XLI opposed the use of a 12 CP allocator, again arguing that it includes too many data points for a demand allocator.[448] XLI also argued that MISO is still most capacity-constrained in the summer despite the adoption of a seasonal resource-adequacy construct.[449]

194. In the ALJ's view, the Commission's determination in Xcel's past two rate cases remains sound that MISO's resource-adequacy requirements, rather than Xcel's own system peak, are what utilities now have to plan for.[450] The Commission's determination that Xcel should incorporate changes to MISO's resource-adequacy construct into peak-demand allocators continues to be persuasive.[451]

195. The OAG's recommended improvements to Xcel's fixed production plant allocators should be adopted. If the Commission does not wish to choose between an allocator based on four seasonal peaks or a 12 CP allocator, it could order Xcel to produce CCOSSes using both. While CCOSSes are difficult to perform, production costs are a large enough portion of Xcel's revenue requirement that producing two methods is not overly burdensome in proportion to the value it would provide to the record.

196. If the Commission chooses to only require a single method, the 12 CP allocator is straightforward and is already being used for Xcel's demand-related transmission costs. In either case, Xcel should 1) use actual class load data from the years of the MISO peaks used, adjusted to account for forecasted load changes, or 2) if historical class load data are not available, use forecasted load data corresponding to likely MISO peaks with a clear explanation of how the likely MISO peak hours were selected.[452]

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[446] Ex. OAG-10 at 48 (Scharber Surrebuttal).
[447] Ex. OAG-10 at 11-12 (Scharber Surrebuttal).
[448] Ex. Xcel-74 at 18 (Barthol Rebuttal); Ex. XLI-6 at 9–10 (Jonathan Ly Rebuttal).
[449] Ex. XLI-6 at 9-10 (Jonathan Ly Rebuttal).
[450] Ex. XLI-6 at 9-10 (Jonathan Ly Rebuttal) (quoting *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Service in Minn.*, Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46 (Jun. 12, 2017) (eDockets No. 20176-132748-01)).
[451] Ex. OAG-10 at 9 (Scharber Surrebuttal) (citing *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Service in Minn.*, Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46 (Jun. 12, 2017) (eDockets No. 20176-132748-01)).
[452] Ex. OAG-10 at 48 (Scharber Surrebuttal).

d. Allocation of Other Production O&M

197. Other production O&M expenses are the nonfuel costs incurred to operate a power plant, including labor, chemicals, information technology, maintenance, and licensing.[453] Aside from chemical and water-use costs, which are classified as energy-related, Xcel uses the results of the Stratification Method to classify these expenses as demand- or energy-related.[454] Expenses associated with a specific generator type are classified the same as the underlying plant, and for expenses not related to a generator type, Xcel uses the energy- and demand-related shares of the total plant-specific expenses.[455]

198. XLI argues that the Stratification Method should not be used to classify other production O&M expenses and instead recommends various alternative classification and allocation methods be used for subcomponents of other production O&M.[456] XLI contends that a significant portion of other production O&M expenses are labor-related, do not vary with energy production, and should not be classified as energy-related to any degree.[457] XLI instead recommends that "labor-related other production O&M expenses should be allocated on AED-4CP." XLI also recommends that regional market expenses, another component of other production O&M which are largely labor-related, should be allocated "the same as NSPM's generation and transmission plant using AED-4CP and D10S allocators."[458]

199. Xcel, the OAG, and the Department opposed XLI's recommendations.[459]

200. The OAG argued that XLI's labor-expense recommendation reflects an outdated idea that costs that do not vary directly with production (i.e., fixed costs), such as labor, are appropriately classified as demand-related.[460] This classification is no more appropriate than classifying a coal or wind plant entirely as demand-related on the basis that the plant's costs do not vary directly with production.[461] It is equally unreasonable to classify labor costs as demand-related when they do not vary directly with capacity.[462] Rather, because a significant share of the O&M costs required to support coal and wind plants are incurred to provide reliable energy throughout the year, that share is appropriately classified as energy-related.[463]

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[453] Ex. OAG-9 at 12 (Scharber Rebuttal).
[454] Ex. Xcel-73 at 30 tbl.13 (Barthol Direct).
[455] Ex. Xcel-73 at 30 tbl.13 (Barthol Direct).
[456] Ex. XLI-3 at 16 (Jonathan Ly Direct).
[457] Ex. XLI-3 at 16 (Jonathan Ly Direct).
[458] Ex. XLI-3 at 17 (Jonathan Ly Direct).
[459] Ex. Xcel-74 at 12-16 (Barthol Rebuttal); Ex. OAG-9 at 1-12 (Scharber Rebuttal); Ex. DOC-18 at 2-4 (Zajicek Surrebuttal).
[460] Ex. OAG-9 at 13 (Scharber Rebuttal).
[461] Ex. OAG-9 at 13 (Scharber Rebuttal).
[462] Ex. OAG-9 at 13 (Scharber Rebuttal).
[463] Ex. OAG-9 at 13 (Scharber Rebuttal).

201. The ALJ finds that XLI's recommendation related to the classification of other production O&M is not reasonable. XLI's arguments against classifying labor as energy-related do not make it more reasonable to classify labor costs as demand-related. As the OAG noted, labor costs do not vary directly with capacity.[464] Instead, classifying O&M costs in the same way that the underlying capital costs are classified is a reasonable proxy and the Commission should continue to pair capital and O&M production costs in this way.

2. Transmission Cost Allocation – Demand

202. In Xcel's most recent rate case, the Commission required that, going forward, Xcel should allocate demand-related transmission costs using a 12 CP allocator.[465] Xcel now asks to be relieved of the requirement to use a 12 CP allocator and argues that using its single coincident peak (1 CP) D10S allocator is more appropriate.[466] Xcel argues that because "transmission costs are based on the need to meet customer demands at the single highest peak of the year" its 1 CP allocator is reasonable.[467]

203. XLI and the Department both supported Xcel's request to depart from the Commission's 2023 decision and use a 1 CP allocator.[468]

204. The OAG recommended that the Commission continue to require a 12 CP allocator for transmission costs. The OAG supported the Commission's rationale from its most recent Xcel rate case and noted that Xcel's Wisconsin affiliate supports a 12 CP allocator on the basis that 12 peaks are important considerations for transmission reliability.[469]

205. The ALJ agrees with the OAG that the 12 CP allocator continues to best reflect transmission demand cost causation and how Xcel is compensated for its transmission assets. In Xcel's last rate case, the Commission cited "growing acceptance of relying on a broader concept of peak demand" beyond just a single peak.[470] The Commission also described the importance of transmission system reliability in all seasons of the year, not just on a single peak day. As the Commission explained, utilities tend to take generation assets offline for maintenance in the spring

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[464] Ex. OAG-9 at 13 (Scharber Rebuttal).
[465] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 102 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[466] Ex. Xcel-73 at 23 (Barthol Direct).
[467] Ex. Xcel-73 at 23 (Barthol Direct).
[468] Ex. XLI-3 at 19–20 (Jonathan Ly Direct); Ex. DOC-16 at 35 (Zajicek Direct).
[469] Ex. OAG-8 at 17 (Scharber Direct) (quoting *Application of N. States Power Co. for Authority to Adjust Electric and Natural Gas Rates*, PSCW Docket No. 4220-UR-127, Direct Test. of Ryan Moldenhauer at 13 (Mar. 31, 2025)).
[470] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 102 (Jul. 17, 2023) (eDockets No. 20237-197559-01).

and fall, leaving the system vulnerable to unplanned outages.[471] Managing unplanned outages requires ensuring adequate transmission capacity year-round as the grid's supply and demand levels fluctuate.[472]

206. As discussed above, Xcel's D10S allocator has fundamental flaws, and while these flaws could be corrected in Xcel's next rate case, the use of a 12 CP allocator for both transmission and production-related demand costs is a simpler path forward and more reasonable in this case.

207. For these reasons, the Commission should continue to require that Xcel use a 12 CP allocator to allocate the demand-related portion of transmission costs.

3. Distribution Cost Classification

a. Distribution Cost Classification – General Classification Methods

208. In Xcel's last rate case, the Commission directed Xcel to file three CCOSSes in this rate case using three different methods for classifying distribution-system costs.[473] The Commission determined that each classification method described below had merit and that considering all of them would bring an appropriately broad perspective to its class-cost-of-service analysis.[474] They are:

- The Minimum System Method, which first estimates the costs of a hypothetical system that carries little to no load,[475] and then classifies the costs of this hypothetical "minimum" system as customer-related and the remainder of the distribution system as demand-related.[476] The Minimum System Method has two main variations, the Minimum-Size Method and Zero-Intercept Method.[477] The Minimum-Size Method uses a minimum-size piece of relevant equipment and assumes that any larger equipment

[471] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 102 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[472] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 102 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[473] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order at 105-06 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[474] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order at 105 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[475] Ex. OAG-8 at 19 (Scharber Direct).
[476] Ex. OAG-8 at 19 (Scharber Direct).
[477] Ex. Xcel-73 at 36 (Barthol Direct).

must serve demand.[478] The Zero-Intercept Method uses statistical analysis to estimate the cost curve for all currently installed equipment of different demand ratings and then estimate the cost of a piece of equipment with zero-capacity (based on where the curve "intercepts" the y axis).[479]

- The Basic Customer Method, which classifies distribution equipment that serves a single customer as customer-related (e.g., meters and non-shared service drops) and all shared distribution components as demand-related (e.g., primary and secondary lines and line transformers).[480]
- The Peak-and Average Method, which first classifies distribution equipment that serves a single customer as customer-related (e.g., meters and non-shared service drops), and then classifies shared distribution equipment as both energy- and demand related.[481]

209. Xcel provided all three required CCOSS variations with its initial filing in this case.[482] It prefers the Minimum System Method and bases its revenue apportionment on that method alone.[483] Xcel's Minimum System CCOSS uses a hybrid of the Minimum-Size Method and Zero-Intercept Method.[484]

210. Xcel argues that the Minimum System Method is the most reasonable because "the addition of customers is a significant determinant of distribution system costs."[485] XLI also supports the Minimum System Method for the same reason.[486] The Department supports the use of the both Minimum System and Basic Customer Methods to inform rate design, but not the Peak-and-Average Method.[487]

211. The OAG recommended the Commission continue to consider all three approaches to the classification of distribution plant, but it should not give the Minimum System Method more weight than other methods.[488]

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[478] Ex. Xcel-73 at 36 (Barthol Direct).
[479] *See* Ex. Xcel-73 at 36-37, 39 (Barthol Direct).; Ex. DOC-16, sched. 1 at 19 (Zajicek Direct).
[480] Ex. OAG-8 at 20 (Scharber Direct).
[481] Ex. OAG-8 at 20 (Scharber Direct). The theory behind the Peak-and-Average method is that a portion of the shared distribution system is needed to serve a base amount of energy at all times, while the remaining costs reflect the "upsizing" of the system that is needed to serve peak demand. Ex. OAG-8 at 20 (Scharber Direct).
[482] Ex. Xcel-73 at 33–34 (Barthol Direct).
[483] *Id.* at 48; Ex. Xcel-76 at 11 & n.2 (Paluck Direct).
[484] Ex. Xcel-73 at 41 (Barthol Direct).
[485] Ex. Xcel-73 at 48 (Barthol Direct); *see also* Ex. OAG-8, sched. HS-D-7 (Scharber Direct) (providing *NARUC Manual* page references supporting the idea that the addition of customers is a significant determinant of distribution system costs).
[486] Ex. XLI-3 at 24–25 (Jonathan Ly Direct).
[487] Ex. DOC-16 at 46 (Zajicek Direct); Ex. DOC-19 at 25 (Bahn Direct).
[488] Ex. OAG-8 at 26 (Scharber Direct); Ex. OAG-10 at 16 (Scharber Surrebuttal); Tr. Vol. 2 at 367 (Scharber).

212. The OAG pointed out several flaws with the Minimum System Method that cause it to overstate customer costs. First, the Minimum System Method overstates the customer-related portion of the distribution system by assuming the main driver of minimum-size shared distribution costs is the number of customers, when the main driver of distribution costs is the size of a utility's service territory.[489] This approach is unfair to the many customers who do not expand the size of Xcel's service territory when added to the system.[490] Second, the relevant question for customer-related costs is whether "there is a direct and proportionate relationship between the number of customers and the investment, holding other factors constant," not simply whether the costs are related to the addition of customers.[491] Holding other factors constant, Xcel does not install shared distribution system equipment such as transformers and conductors for each new customer.[492]

213. Xcel, XLI, and the Department maintained that the Basic Customer and Peak and Average Methods underestimate customer-related costs.[493] The OAG responded that the Basic Customer and Peak and Average methods do not necessarily underestimate customer-related costs, and even overestimate them in some cases.[494] The OAG pointed out that service drops may serve multiple customers in multi-family buildings even though they are classified under both methods on a per-customer basis.[495]

214. Xcel and XLI also opposed consideration of the Peak and Average Method because it includes an energy component in distribution system costs, leaning on the fact that it is not included in the 1992 NARUC manual as a distribution classification method.[496]

215. The OAG pointed out that the NARUC manual itself contains contradictory statements on whether there is an energy component of distribution costs.[497] The OAG noted that a newer cost allocation manual published by the Regulatory Assistance Project (RAP) supports the Peak-and-Average Method for distribution system classification on the basis that the fundamental reason for building

[489] Ex. OAG-8 at 21-22 (Scharber Direct).
[490] Ex. OAG-8 at 21-22 (Scharber Direct) (quoting James C. Bonbright, *Principles of Public Utility Rates* 349 (1st ed. 1961)).
[491] Ex. OAG-8 at 21-22 (Scharber Direct).
[492] *See* Ex. OAG-8 at 21-22 (Scharber Direct).
[493] Ex. Xcel-74 at 24-26 (Barthol Rebuttal); Ex. XLI-3 at 24 (Jonathan Ly Direct); Ex. DOC-16 at 29 (Zajicek Direct).
[494] Ex. OAG-8 at 22-23 (Scharber Direct).
[495] Ex. OAG-8 at 23 (Scharber Direct). To be clear, Dr. Scharber used this as an example of how even the Basic Customer method may overclassify some costs as customer-related, but Dr. Scharber's CCOSSes *do in fact* classify service-drops as customer costs and include service drops in her customer-cost calculation for the customer charge because Xcel did not have data on shared versus non-shared service drops. *See* Ex. OAG-10 at 46-47 (Scharber Surrebuttal) (customer-cost calculation for customer charge).
[496] Ex. Xcel-74 at 25-26 (Barthol Rebuttal); Ex. XLI-6 at 15-16 (Jonathan Ly Rebuttal).
[497] Ex. OAG-10 at 19 (Scharber Surrebuttal).

distribution systems is to deliver energy to customers.[498] The RAP Manual also provides several examples of the ways in which energy use outside of the maximum peak hour still drives the need for distribution investments and thus should be classified as energy-related.[499] These examples include costs for upgrading distribution lines or conductors to reduce line losses, which depend on load in every hour, and costs for replacing transformers that wear out due not only to overloading on peak hours but also due to high loads in hours that are not class peaks.[500]

216. The ALJ is persuaded that the Commission should not abandon its practice of reviewing the results of CCOSSes based on the Minimum System Method, the Basic Customer Method, and the Peak-and-Average Method. The ALJ also finds persuasive many of the critiques of the Minimum System Method leveled by the OAG, and agrees that it should not be given any additional weight over the other two methods. Instead, the Commission should continue its practice of "considering multiple perspectives on the classification and allocation of distribution costs"[501] as it weighs its quasi-legislative decision on how to allocate Xcel's revenue requirement to the various customer classes.

b. Distribution Cost Allocation – AMI Meters

217. Xcel is in the process of installing Advanced Metering Infrastructure (AMI).[502] To date, Xcel has recovered AMI meter costs through the Transmission Cost Recovery (TCR) rider,[503] but Xcel will likely roll these costs into base rates in a future rate case.[504]

218. Xcel currently classifies these costs in its TCR rider as both customer- and demand-related.[505] However, two months after intervenor direct was submitted in this case, Xcel proposed to change that classification to be 100 percent customer-related.[506]

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[498] Ex. OAG-10 at 20-21 (Scharber Surrebuttal).
[499] Ex. OAG-10 at 20-21 (Scharber Surrebuttal).
[500] Ex. OAG-10 at 20-21 (Scharber Surrebuttal). (citing Jim Lazar et al., Regul. Assistance Project, *Electric Cost Allocation for a New Era: A Manual* at 148 (Jan. 2020) (RAP Manual)).
[501] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 105 (Jul. 17, 2023) (eDockets No. 20237-197559-01).
[502] *See* Ex. Xcel-76 at 25 (Paluck Direct).
[503] Xcel does include internal labor costs related to AMI in this rate case. Ex. Xcel-74 at 26 (Barthol Rebuttal).
[504] *See* Ex. Xcel-15 at 33-37 (Liberkowski Direct) (discussing projects in riders that are, and are not, being rolled into base rates in this MYRP).
[505] Ex. Xcel-74 at 26 (Barthol Rebuttal).
[506] Ex. Xcel-74 at 26 (Barthol Rebuttal). Xcel's TCR filing was made in its 2025 AMI Annual Report filed on October 31, 2025. *See* Ex. OAG-10 at 28 n.83 (Scharber Surrebuttal) (Citing MPUC Docket Nos. E-002/M-21-814 and E-002/M-25-386, Xcel's 2025 AMI Annual Report at 16 (Oct. 31, 2025) (eDocket No. 202510-224502-02)).

219. The OAG argued that when Xcel rolls these costs into base rates, it should classify these costs as one-third each energy-, demand-, and customer-related because energy- and demand-related benefits drove Xcel's investment in AMI.[507] AMI meters have potential benefits that traditional meters lack, "including more effective load management, reduced line losses, automated power outage detection, restoration capabilities, the ability to implement time-of-use rates, reduced meter reading costs, and more efficient integration of electric vehicles and renewables."[508] These advanced capabilities are the reason that AMI meters are installed over cheaper and older traditional meters.[509]

220. The OAG supported its 1/3 energy-related, 1/3 demand-related, 1/3 customer-related classification with Xcel's cost data. Xcel's undepreciated value of meter plant increased three-fold between 2022 and 2024, coinciding with the beginning of Xcel's AMI meter deployment.[510] In aggregate, therefore, the value of the pre-AMI meters with traditional customer benefits, is roughly 1/3 of the post-AMI meter cost. AMI also presents demand and energy benefits through, for example, enabling load-management programs (demand) and potentially reducing investments in baseload and transmission plants (which are partially classified as energy-related in Xcel's CCOSSes).[511] The OAG maintained that splitting the remaining costs between demand and energy was reasonable based on data that is currently available and has been previously supported by the Commission for other utilities.[512]

221. Xcel and XLI opposed the OAG's recommendation. Xcel's and XLI's primary argument is that meters have traditionally been classified as 100 percent customer-related, relying on the NARUC cost allocation manual, and that because adding an extra customer adds an extra meter, AMI costs directly vary with the number of customers.[513]

222. The OAG responded that while an additional customer may add an additional AMI meter, the benefits of AMI meters are both demand- and customer-related.[514] In addition, classifying AMI infrastructure as 100 percent customer-related ignores the additional cost of AMI meters above traditional meters.[515] While the OAG agreed

[507] Ex. OAG-8 at 29–30 (Scharber Direct); Ex. OAG-10 at 29–30 (Scharber Surrebuttal).
[508] Ex. OAG-8 at 27 (Scharber Direct).
[509] *See* Ex. DOC-16 at 5-6 (Zajicek Direct). Witness Zajicek acknowledges there are some reduced costs to reading AMI meters and requested Xcel provides a study showing the costs of meter reading and the meters themselves for AMI meters compared and traditional meters. Ex. DOC-16 at 5-6 (Zajicek Direct).
[510] Ex. OAG-10 at 26-27 (Scharber Surrebuttal).
[511] Ex. OAG-10 at 28-29 (Scharber Surrebuttal).
[512] Ex. OAG-10 at 26 (Scharber Surrebuttal); *In re Application of Minn. Power for Authority to Increase Rates for Elec. Serv. in Minn.*, Docket No.E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 61 (Feb. 28, 2023).
[513] Ex. XLI-6 at 18 (Jonathan Ly Rebuttal).
[514] Ex. OAG-8 at 27 (Scharber Direct).
[515] Ex. OAG-10 at 26-27 (Scharber Surrebuttal).

that the NARUC manual is a persuasive authority on cost-allocation for traditional utility plant, the NARUC manual was published in 1992—years before AMI technology existed.[516] Unlike the NARUC manual's lack of discussion of AMI, a newer cost allocation manual, published in 2020 by Regulatory Assistance Project, discusses classification and analysis for advanced metering extensively.[517] RAP lists a range of benefits enabled by AMI meters and smart-grid investments—and these benefits span the demand, energy, and customer classifications.[518]

223. The Commission itself has recognized the demand and energy benefits of AMI infrastructure. In its 2022 decision in an Otter Tail Power rate case, the Commission ordered Otter Tail to perform an analysis to guide future cost classification for advanced meters in either its next rate case or a subsequent AMI proposal.[519] In a 2023 decision in Minnesota Power's 2021 rate case, the Commission required Minnesota Power to modify the traditional treatment of allocating metering costs as 100 percent customer-related in its subsequent rate case.[520] To do so, the Commission gave Minnesota Power a choice of either analyzing how AMI meters are associated with customer costs as well as energy and demand costs, or allocating AMI costs equally to customer, demand, and energy factors.[521]

224. Xcel does not appear to dispute that AMI meters' energy and capacity benefits were the reason they were chosen over meters with more limited functionality. In fact, until the OAG raised this issue in the rate case, Xcel classified its AMI costs as partially demand-related in the TCR rider.[522] Similarly, XLI's witness appears to acknowledge that there are some demand-related components of AMI.[523]

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[516] Ex. OAG-10 at 25 (Scharber Surrebuttal).
[517] Ex. OAG-10 at 25-26 (Scharber Surrebuttal) (citing Jim Lazar et al., Regul. Assistance Project, *Electric Cost Allocation for a New Era: A Manual* at 156-57 (Jan. 2020) (RAP Manual)).
[518] Ex. OAG-10 at 25-26 (Scharber Surrebuttal) (citing Jim Lazar et al., Regul. Assistance Project, *Electric Cost Allocation for a New Era: A Manual* at 156-57 (Jan. 2020) (RAP Manual)).
[519] *See In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 49-50, 70 (Feb. 2, 2022) (eDockets No. 20222-182349-01).
[520] *In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 61 (Feb. 28, 2023) (eDockets No. 20232-193486-01).
[521] *In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 61 (Feb. 28, 2023) (eDockets No. 20232-193486-01).
[522] Ex. Xcel-74 at 26 (Barthol Rebuttal). Xcel's TCR filing was made in its 2025 AMI Annual Report filed on October 31, 2025. *See* Ex. OAG-10 at 28 n.83 (Scharber Surrebuttal) (Citing MPUC Docket Nos. E-002/M-21-814 and E-002/M-25-386, Xcel's 2025 AMI Annual Report at 16 (Oct. 31, 2025) (eDocket No. 202510-224502-02)).
[523] *See* Ex. XLI-6 at 19 (Ly Rebuttal) ("[I]f the Commission deems it appropriate to alter the classification of meters as a result of AMI deployment, it should classify these costs in a manner similar to other distribution plant components, which are either demand or customer-related.").

225. Because AMI infrastructure would not have been installed if it only provided traditional customer benefits, the ALJ finds classifying AMI costs as 100 percent customer-related to be unreasonable. Until a more exacting method of allocation between AMI's energy-, demand-, and customer-components can be determined, the Commission should require Xcel to classify these costs as 1/3 energy-related, 1/3 demand-related, and 1/3 customer-related when Xcel rolls these costs into its rate base.

4. Economic Development Discounts Allocation

226. The parties dispute the allocation of two types of costs arising from discounts offered to large customers through two separate riders. Xcel's Business Incentive and Sustainability (BIS) Rider provides reductions in demand charges and off-peak energy charges for the first five to six years for new customers meeting billing-demand minimums.[524] The Competitive Response Rider (CRR) provides a discount on base rates for certain large demand-metered customers who can provide evidence that their service is subject to "effective competition."[525] The CRR rate recovers at least the customer's "incremental" cost of service, estimated by Xcel, and the discount cannot exceed the difference between the standard tariff and the customer's lowest-cost alternative.[526]

227. Since 2012, Xcel has been using its R01 (total revenue) allocator to assign these costs to customer classes.[527] In this case, however, Xcel has allocated the costs based on 2025 test year base revenues—the R02 (base revenue) allocator.[528] Xcel argues that using the R02 allocator instead of the R01 allocator is more appropriate because the

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[524] Ex. OAG-11 at 30 (Scharber Surrebuttal) (citing N. States. Power Co., Minnesota Electric Rate Book at 5-139).
[525] Ex. OAG-11 at 30 (Scharber Surrebuttal) (citing N. States. Power Co., Minnesota Electric Rate Book at 5-122).
[526] Ex. OAG-11 at 30 (Scharber Surrebuttal) (citing N. States. Power Co., Minnesota Electric Rate Book at 5-122).
[527] Ex. Xcel-73 at 10 (Barthol Direct). While Xcel claimed that using "a total revenue allocator" was "ordered by the Commission" in Xcel's 2013 rate case, there is no evidence of the Commission ordering Xcel to use any particular allocation method in either Xcel's 2012 or 2013 rate case. Instead, it appears that Xcel proposed this allocation in 2013, and it was not addressed in the Commission's order. *See* Ex. OAG-10 at 33-35 (Scharber Surrebuttal). Therefore, while the allocator has been in use for some time, stating that it was "ordered" by the Commission is somewhat inaccurate. *Compare* Ex. Xcel-73 at 10 (Barthol Direct) *with In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Service in the State of Minn.*, Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 62-70 (May 8, 2015) (eDockets No. 20155-110264-01); *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Service in the State of Minn.*, Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 55 (Sep. 3, 2013) (eDockets No. 20139-90902-01).
[528] Ex. Xcel-73 at 10 (Barthol Direct).

economic discounts are not related to fuel costs, and the R02 allocator does not include fuel costs.[529] XLI supports Xcel's change.[530]

228. The OAG argued that Xcel should continue to use the R01 allocator in this rate case but improve the allocator in the next rate case.[531]

229. The OAG pointed out that Xcel's argument for changing from an allocator that includes fuel costs to one that does not was a red herring because neither is fundamentally tethered to cost causation. Instead, the R01 allocator is designed to allocate costs on the basis of potential benefits provided by economic development rates.[532] If cost causation was determinative, these costs would be allocated to the C&I Demand class alone, since members of this class alone "cause" the costs.[533] Instead, the fact that these costs that arise from a handful of customers are allocated across all of Xcel's customer classes is based on the potential benefits received by those classes.[534]

230. The OAG reasoned that the rationale for allocating the costs of economic development discounts, therefore, must be based on the benefits that all customer classes may receive from a broader sharing of fixed system costs.[535] This broader sharing, beyond sharing the actual revenues, would be due to the addition of the discount recipients' peak load and energy requirements to the demand and energy allocators, not through the revenue they provide.[536]

231. The OAG pointed out that in this case, the difference between using the currently-required R01 or Xcel's proposed R02 allocator is not significant. But these costs are rapidly increasing and stand to increase more in the future if Xcel adds more data center customers[537]—between the 2025 test year and 2026 plan year, Xcel projects a near-tripling of economic development discounts.[538]

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[529] Ex. Xcel-74 at 40 (Barthol Rebuttal).
[530] Ex. XLI-6 at 21 (Jonathan Ly Rebuttal).
[531] Ex. OAG-10 at 31-32 (Scharber Surrebuttal).
[532] Ex. OAG-10 at 32 (Scharber Surrebuttal).
[533] Ex. OAG-10 at 31 (Scharber Surrebuttal).
[534] Ex. OAG-10 at 32 (Scharber Surrebuttal).
[535] Ex. OAG-10 at 32 (Scharber Surrebuttal). XLI claims that the benefits of the economic discounts are through BIS and CRR rider-customers' "incremental revenues which offset a portion for fixed system costs." Ex. XLI-6 at 3 (Jonathan Ly Rebuttal). But the revenues do not, in fact, flow to all customer classes. Instead, the net revenues paid by the BIS and CRR rider-customers only offset the C&I Demand class revenue obligation in the CCOSS. Ex. OAG-10 at 32 (Scharber Surrebuttal).
[536] Ex. OAG-10 at 32-33 (Scharber Surrebuttal).
[537] Ex. OAG-8 at 32 (Scharber Direct) (showing a shift in this case of approximately $200,000); Ex. OAG-10 at 35 (Scharber Surrebuttal).
[538] Ex. OAG-10 at 35 (Scharber Surrebuttal).

232. The ALJ finds that because Xcel had not provided a sound basis for changing from the R01 to the R02 allocator, the Commission should more heavily endorse CCOSSes that use the R01 method. That being said, the difference between the two methods in this case is not substantial, and the real impacts of what allocator is used will likely be felt in Xcel's next rate case.[539] For that reason, the Commission should give significant consideration to the discussion below regarding requirements for Xcel's treatment of economic development discount costs in its CCOSS in its next electric rate case filing.

233. The ALJ agrees with the OAG that, to more appropriately allocate these costs, the Commission should require Xcel to allocate economic development costs based on an average of the energy and peak-demand allocators in the next rate case.[540] This is appropriate because the purported benefits of the addition of large customers (i.e. spreading out fixed system costs over more sales) will come to fruition through changes in energy and demand allocators.[541] If Xcel can provide evidence that the benefits of economic development discounts to each class exceed the amounts allocated on that basis, Xcel can propose another allocation method in its next rate case.[542]

5. CCOSS Conclusions

234. The ALJ recommends that the CCOSSes in the record that include more reasonable assumptions should be given more weight in revenue apportionment.

235. A representative table of the CCOSSes in the record for the 2026 Plan Year is provided below for illustration. Because Xcel agreed that SRA's relatively minor proposed changes to its CCOSS were reasonable but did not have time for a full update,[543] Xcel's minimum-system CCOSS with those changes is presented as the Xcel/SRA CCOSS. The order of the CCOSSes below, however, should not be an indication of their relative weight nor should the Commission assume that a CCOSS that falls in the middle of the table is inherently more reasonable. Instead, as it has in the past, the Commission should weigh the strengths and weaknesses of the various CCOSSes methods to inform its revenue requirement decision. In line with the analysis above, the ALJ agrees that the OAG's CCOSSes are the most reasonable in the record and should accordingly be given the most weight.

[539] Ex. OAG-10 at 35 (Scharber Surrebuttal).
[540] Ex. OAG-10 at 36 (Scharber Surrebuttal).
[541] Ex. OAG-10 at 33 (Scharber Surrebuttal).
[542] Ex. OAG-10 at 33 (Scharber Surrebuttal).
[543] Ex. Xcel-75 at 8 (Barthol Surrebuttal).

Table 1 – 2026 CCOSSes in the Record

Party	Method	Residential	SCI Non-Demand	Demand	Lighting
OAG[544]	Peak & Avg	3.47%	-8.87%	15.65%	28.71%
OAG[545]	Basic Customer	5.78%	-8.48%	13.91%	31.34%
DOC[546]	Basic Customer	9.44%	-11.88%	11.54%	26.92%
OAG[547]	Hybrid	11.17%	-3.90%	9.72%	30.51%
Xcel/SRA[548]	Hybrid	13.5%	-6.1%	8.3%	29.3%
DOC[549]	Hybrid	14.84%	-7.29%	7.34%	26.09%
XLI[550]	Hybrid	16.1%	-2.0%	6.3%	19.9%

B. Revenue Apportionment

236. The CCOSS helps the Commission analyze the cost factors in rate design, but the Commission must also balance non-cost factors to make its policy-based decisions about who should bear any cost increases.[551]

237. "In order to achieve a fair and reasonable allocation of the increase among consumer classes," the Commission may balance a range of factors in this determination, including but not limited to "cost of service, ability to pay, tax consequences, and ability to pass on increases."[552]

[544] *See* Ex. OAG-10 at 38 (Scharber Surrebuttal). Note that the figures in Dr. Scharber's surrebuttal are different from the figures that Mr. Barthol represented as the OAG's position in his surrebuttal testimony, which Xcel appears to have not updated for its initial brief. *Compare id. with* Ex. Xcel-75 at 8 (Barthol Surrebuttal).
[545] Ex. OAG-10 at 38 (Scharber Surrebuttal).
[546] Due to the unexplained discrepancies in Xcel's table. The OAG uses the figures from the Department's surrebuttal tables, not Xcel's brief. *See* Ex. DOC-18 at 14 (Zajicek Surrebuttal).
[547] Ex. OAG-10 at 38 (Scharber Surrebuttal).
[548] Ex. Xcel-75 at 8 (Barthol Surrebuttal). As discussed above, because the OAG understands that Xcel agrees with SRA's proposed change, the line in Mr. Barthol's surrebuttal testimony for SRA is used. However, the differences between SRA's and Xcel's lines appear to only impact the Lighting and SCI Non-Demand classes at the level of granularity that Xcel presents in Table 2. Ex. Xcel-75 at 8 (Barthol Surrebuttal).
[549] Ex. DOC-18 at 14 (Zajicek Surrebuttal).
[550] Because XLI witness Johnathan Ly did not update his CCOSS to incorporate Xcel's rebuttal revenue requirement, the OAG relies on Xcel's depiction of XLI's position in Mr. Barthol's surrebuttal. *See* Ex. Xcel-75 at 8 (Barthol Surrebuttal).
[551] *See St. Paul Area Chamber of Com. v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 358 (Minn. 1977).
[552] *St. Paul Area Chamber of Com. v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977); Minn. Stat. § 216B.16, subd. 15.

238. The Commission has also emphasized recently that it considers multiple cost studies to inform its revenue allocation decisions in addition to non-cost concerns.[553] As the Commission stated in Xcel's most recent electric rate case, "[n]o single cost-study method can be judged superior to all others in all contexts, and the choice among methods involves disputes over assumptions, applications, and data."[554] "Evaluating multiple cost studies aids the Commission in weighing cost and non-cost factors when setting rates, as each analysis provides a perspective from which to evaluate the other analyses."[555]

239. For "non-cost concerns" the Commission has recently stated that its consideration includes the following factors: "equity, justice, and reasonableness; the avoidance of discrimination, unreasonable preference, and unreasonable prejudice; continuity with prior rates to avoid rate shock; revenue stability; economic efficiency; encouragement of energy conservation; customers' ability to pay; and ease of understanding and administration."[556]

1. Test Year and Plan Year Revenue Allocation

240. The parties dispute whether revenue allocation should stay the same throughout the MYRP or be updated for the 2026 plan year. Xcel proposes to update the revenue allocation between the test year and plan year because C&I demand class sales were projected to increase materially.[557]

241. The Department recommends that the Commission use Xcel's 2025 test year revenue apportionment shares for both the test year and the plan year.[558] The Department correctly notes that this is consistent with past commission practice in Xcel's MYRPs.[559]

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[553] *See, e.g.*, *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 95 (Jul. 17, 2023) (eDockets No. 20237-197559-01); *In re Application of Greater Minn. Gas, Inc. for Authority to Increase Rates for Nat. Gas Serv. in Minn.*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 36 (Nov. 26, 2025)

[554] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 95 (Jul. 17, 2023) (eDockets No. 20237-197559-01).

[555] *In re Application of Greater Minn. Gas, Inc. for Authority to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G-022/GR-24-350, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 36 (Nov. 26, 2025)

[556] *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 111 (Jul. 17, 2023) (eDockets No. 20237-197559-01) (citing Minn. Stat. §§ 216B.01, .03, .2401; 216C.05; 216B.16, subd. 15).

[557] Ex. Xcel- 77 at 5-6 (Paluck Rebuttal).

[558] Ex. DOC-19 at 29-30 (Bahn Direct).

[559] Ex. DOC-19 at 29-30 (Bahn Direct) (citing *In re Appl. of N. States Power Co. for Auth. to Increase Elec. Serv. Rates in Minn.,* Docket No. E-002/GR-15-826, FINDING OF FACT,

242. While the OAG recognized that the Commission has previously kept the allocation the same for the MYRP's duration, the OAG recommended the Commission use separate apportionments in this case.[560] The OAG's witness explained that because "significant changes in the composition of classes are expected between the years in a MYRP, the disadvantages of using uncertain forecast data may be outweighed by the benefits of changing the apportionments."[561] As an example, the OAG explained that "if significant data-center load is added to the system in coming years, as Xcel predicts, there could be large changes in load, costs, and revenues from year to year."[562] For the 2025 and 2026 years, the OAG agreed with Xcel that "material changes between 2025 and 2026 make separate apportionments most appropriate."[563] The ALJ agrees with Xcel and the OAG that it is most appropriate to update the class shares in the 2026 revenue allocation due to material changes from increased C&I demand class sales.

2. Cost Study Basis of Revenue Allocation Recommendations

243. Xcel's revenue allocation is based on a single cost study—its minimum-system CCOSS or hybrid CCOSS.[564]

244. Although the Department of Commerce introduced two CCOSSes in the record and its rate design witness described those CCOSSes in testimony, the Department agreed with Xcel's 2025 revenue apportionment based on Xcel's minimum-system CCOSS.[565] While the Department recommended that the 2025 revenue apportionment be used for both years of the MYRP, this recommendation was based on past commission orders rather than consideration of any cost factors.[566]

245. XLI's revenue allocation is also based on a single cost study—XLI's minimum-system CCOSS.[567]

246. The OAG's revenue allocation analysis began by using an average of the cost-share results from the OAG's three CCOSSes (Basic Customer CCOSS, Peak and Average CCOSS, and the OAG's Minimum-System or Hybrid CCOSS).[568] While the OAG disputed that the minimum-system study was as robust as Basic Customer and Peak

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CONCLUSIONS, AND ORDER at 56 (June 12, 2017) (eDocket No. 20176-132748-01) *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 114 (Jul. 17, 2023) (eDockets No. 20237-197559-01)).

[560] Ex. OAG-10 at 40 (Scharber Surrebuttal).
[561] Ex. OAG-10 at 41 (Scharber Surrebuttal).
[562] Ex. OAG-10 at 41 (Scharber Surrebuttal).
[563] Ex. OAG-10 at 43 (Scharber Surrebuttal).
[564] Ex. Xcel-76 at 10 (Paluck Direct).
[565] *See* Ex. DOC-19 at 18-30 (Bahn Direct); Ex. DOC-20 at 11 (Bahn Surrebuttal).
[566] Ex. DOC-19 at 29-30 (Bahn Direct).
[567] Ex. XLI-3 at 28-34 (Johnathan Ly Direct).
[568] Ex. OAG-10 at 38-39 (Scharber Surrebuttal).

& Average CCOSS, the OAG used an equally weighted average given the Commission's preference for considering a range of classification methods.[569]

247. The ALJ recommends that the Commission consider a range of CCOSSes in line with its past practice. Given that several parties did not show, or did not explain, how multiple CCOSSes were used in their analysis, the ALJ gives greater weight to the OAG's revenue apportionment recommendation, as it is most clearly in line with the Commission's past practice and based on well-developed CCOSSes, as determined above.

248. Given the large disputes in rate cases regarding CCOSS methodologies, it is rare that all CCOSSes in a record point to a common cost-based outcome. In this case, however, all CCOSSes show that even if Xcel's full rebuttal increase is authorized, a purely cost-based allocation would assign a rate decrease to the small general service class (or Non-demand C&I in Xcel's figures).[570] The table below, compiled from the various recommendations in the record, shows the available 2025 and 2026 CCOSS increases/decreases at Xcel's currently requested revenue requirement:

[569] Ex. OAG-10 at 38-39 (Scharber Surrebuttal).

[570] See Ex. OAG-10 at 38, tbl. 6 (Scharber Surrebuttal) for summary of OAG CCOSS results; Ex. Xcel-75 at 5, 7 (Barthol Surrebuttal); Ex. DOC-18 at 13 (Table 1 – 2025), 14 (Table 2 – 2026) (Zajicek Surrebuttal). XLI did not update its CCOSS in surrebuttal using Xcel's rebuttal revenue requirement. However, Xcel's CCOSS witness provided a table showing an estimate of XLI's 2026 increase in Surrebuttal. Ex. Xcel-75 at 8 (Barthol Surrebuttal).

Customer Class	Xcel's Present Rates ($ Millions)	OAG Peak and Average Costs	OAG Basic Customer Costs	OAG Minimum System Costs[571]	Xcel Minimum System Costs[572]	DOC Minimum System Costs[573]	DOC Basic Customer Costs[574]	XLI* Minimum System Costs[575]
	2025							
Small General[576]	$119.6	-6.06%	-5.54%	-1.45%	-2.9%	-3.66%	-7.74%	N/A
	2026							
Small General	$126.9	-8.87%	-8.48%	-9.72%	-6.2%	-7.29%	-11.88%	-2.0%

249. However, with this unique convergence, only the OAG explained how this uniform cost outcome influenced its revenue apportionment decision. The OAG explained that it was appropriate to have no rate increase for Small General service in both 2025 and 2026 under Xcel's currently requested revenue requirement.[577]

250. Other parties continued to request substantial increases for the small general service class. For example, Xcel seeks to assign an over 6 percent increase to the Small General Service class in 2026.[578]

251. The ALJ finds persuasive the consensus of all CCOSSes in the record showing that the small general service class should receive a decrease of at least 2% and up to

[571] See Ex. OAG-10 at 38, tbl. 6 (Scharber Surrebuttal) for summary of OAG CCOSS results.
[572] Ex. Xcel-75 at 5, 7 (Barthol Surrebuttal).
[573] Ex. DOC-18 at 13 (Table 1 – 2025), 14 (Table 2 – 2026) (Zajicek Surrebuttal).
[574] Ex. DOC-18 at 13 (Table 1 – 2025), 14 (Table 2 – 2026) (Zajicek Surrebuttal).
[575] XLI did not update its CCOSS in surrebuttal using Xcel's rebuttal revenue requirement. However, Xcel's CCOSS witness provided a table of what that estimates XLI's 2026 increase in Surrebuttal. Ex. Xcel-75 at 8 (Barthol Surrebuttal).
[576] Xcel's CCOSS tables call this customer class "Non-Demand." *See* Ex. Xcel-75 at 5, 7 (Barthol Surrebuttal).
[577] Ex. OAG-10 at 38-39 (Scharber Surrebuttal).
[578] Ex. Xcel-76 at 10 (Paluck Rebuttal). Xcel updated its revenue apportionment class shares in surrebuttal testimony after adopting a minor change to its CCOSS recommended by the SRA. *See* Ex. Xcel-78 at 3 (Paluck Surrebuttal). While these changes in terms of increases are not in the record, Xcel's recommended 6.77% increase to Small General service in rebuttal is unlikely to drop below 6 percent due to this minor change. Ex. Xcel-77 at 10 (Paluck Rebuttal).

11.88%.[579] As discussed further below, the ALJ believes holding rates flat, or potentially decreasing rates, for this class is reasonable.

3. Non-cost Factors

252. Numerous parties introduced evidence regarding non-cost factors that should be considered in the Commission's revenue apportionment determination. Notably, parties introducing evidence on this point did not necessarily submit full revenue apportionment recommendations. Nevertheless, the Commission should consider this evidence as it weighs its revenue apportionment decision.

253. There is a particularly well-developed record in this case regarding certain non-cost factors, particularly ability to pass on costs and ability to pay, which are discussed below.

a. Ability to Pass On Costs

254. The Commission has long recognized that the ability of customers to pass on costs is an important consideration in revenue apportionment.[580]

255. Customer classes have varying abilities to pass on costs. Commercial and industrial customers are generally able to pass on the costs of an input, like electricity, to their own customers to some degree. "Larger firms with more monopoly power, facing a less elastic demand curve, may be able to pass along costs to a higher degree. Smaller businesses in a more competitive market, on the other hand, will generally be less able to pass along costs, if their customers can substitute away from their product or service[.]"[581]

256. Residential customers, on the other hand, cannot pass on price increases to any degree, and options for substituting away from electricity are limited.[582]

257. The ALJ finds that the ability to pass on costs between the customer classes favors limiting increases to the residential class, and to a lesser extent, the small general service class.

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[579] Ex. DOC-18 at 14 (Zajicek Surrebuttal) (providing a -11.88% change under the Department's Basic Customer CCOSS); Ex. Xcel-75 at 5, 7 (Barthol Surrebuttal) (showing an estimated -2% change for Ly's revenue allocation class shares).

[580] *In re Application of Minn. Power for Authority to Increase Elec. Serv. Rates in Minn.*, MPUC Docket No. E-001/GR-08-415, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 63 (May 4, 2009) (eDockets No. 20095-37158-01); *See also St. Paul Area Chamber of Com. v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977)

[581] Ex. OAG-8 at 36 (Scharber Direct). Dr. Scharber agreed, however, that the ability of large industrial customers to pass on price increases should be balanced against considerations of whether large customers will move towards self-generation or move out of Xcel's service territory if prices increase sharply. Ex. OAG-8 at 37-38 (Scharber Direct).

[582] Ex. OAG-8 at 36-37 (Scharber Direct).

b. Ability to Pay

258. The Commission is required to consider ability to pay as a factor in setting utility rates.[583] The Commission has incorporated this consideration into its revenue allocation decisions.[584]

259. There is a plethora of information in the record regarding the current inability of many residential customers to pay their bills. This is shown by energy burden, historic disconnection levels, historic levels of arrears, and persistent inflation. Several witnesses, from multiple parties, testified on these points.[585]

260. The OAG provided analysis showing that customers with lower incomes have a high "energy burden," the portion of household income devoted to paying gas and electric bills.[586] An energy burden above six percent is considered high, while above ten percent is considered severe.[587] The total energy burden for Minnesota households below the federal poverty level is about 22 percent, with an electricity-specific energy burden of 12 percent.[588] Even for the 19 percent of Minnesota households with incomes below 200 percent of the federal poverty level, a significant number of Minnesotans live with a high or severe energy burden.[589] In the metro area specifically, where Xcel's residential customers are concentrated, low-income customers[590] struggle with significant energy burdens at a median of 7.2 percent, while a quarter of low-income households in the metro area were found to have "severe" energy burdens, above 14 percent.[591]

261. CUB and the OAG both introduced evidence on the high level of disconnections that Xcel is reporting.[592] As shown in Figure 1 from CUB Witness Levenson-Falk's

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[583] Minn. Stat. § 216B.16, subd. 15.

[584] *See, e.g.*, *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 111 (Jul. 17, 2023) (eDockets No. 20237-197559-01). (citing Minn. Stat. § 216B.16, subd. 15 in the context of rate design); *see also St. Paul Area Chamber of Com. v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977).

[585] *See generally, e.g.*, Ex. OAG-8 at 38-41 (Scharber Direct); Ex. OAG-1 at 27-32 (Hinderlie Direct); Ex. CUB-3 (Levenson-Falk Direct); Ex. CUB-8 (Levenson-Falk Surrebuttal); Ex. JIN-2 (Chan Direct); Ex. JIN-5 (Chan Surrebuttal); Ex. DOC-22 at 3 (Schmitz Rebuttal).

[586] Ex. OAG-8 at 38-39 (Scharber Direct).

[587] Ex. OAG-8 at 39 (Scharber Direct).

[588] Ex. OAG-8 at 39 (Scharber Direct).

[589] Ex. OAG-8 at 39 (Scharber Direct).

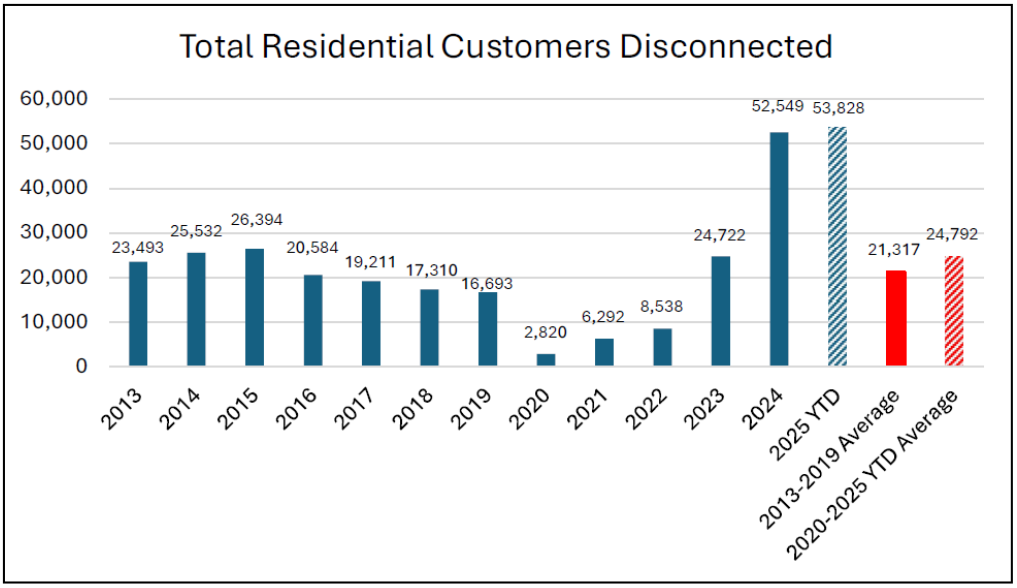
[590] This study defined low-income as 80 percent of median income. *See* Ex. OAG-8 at 39 (Scharber Direct).

[591] Ex. OAG-8 at 39-40 (Scharber Direct).

[592] Ex. CUB-8 at 8 (Levenson-Falk Surrebuttal); Ex. OAG-1 at 29-32, KH-D-11 (Hinderlie Direct); Ex. OAG-3, KH-S-3 (Hinderlie Surrebuttal).

testimony, Xcel is disconnecting a historic amount of its electric and gas customers:[593]

Figure 1: Total Annual Residential Disconnections, 2013 – 2025[48]

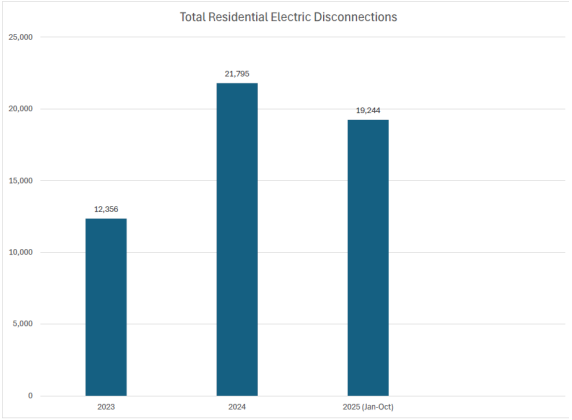


262. Even using the more conservative figures that the OAG relies on, which is limited to electric disconnections and does not include disconnections of less than 24 hours, shows an alarming trend in increased electric disconnections since Xcel's last rate case:[594]

[593] Ex. CUB-8 at 8 (Levenson-Falk Surrebuttal).

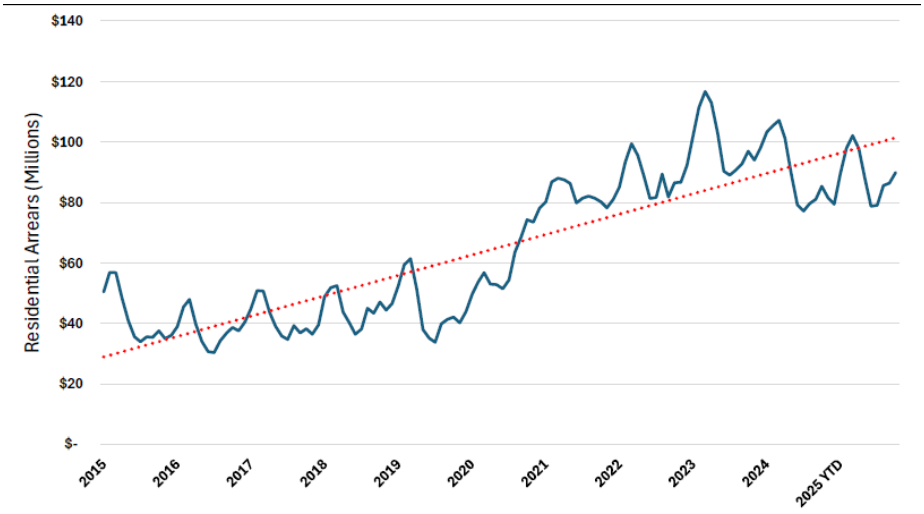
[594] Explanation for the methodology is included in Ms. Hinderlie's direct testimony. *See* Ex. OAG-1 at 30-31 & n.105, KH-D-11 (Hinderlie Direct). Ms. Hinderlie updated the analysis with more recent data in surrebuttal testimony. *See* Ex. OAG-3, KH-S-3 (Hinderlie Surrebuttal).

Figure 1 – Total Residential Electric Disconnections[595]



263. In addition to disconnections, CUB introduced evidence showing that Xcel's residential arrearage levels while coming down from all-time highs post-pandemic, have remained stubbornly high:

Figure 2 – Xcel Total Arrearage Levels[596]



264. While Xcel claims that these levels of arrears and disconnections are due to broader economic pressures and not its rate increases,[597] the ability-to-pay analysis does not require assigning blame to the utility for the Commission to consider certain customer classes' relative abilities to pay. The evidence showing that customers, in this case residential customers, are struggling to pay their bills is sufficient.

[595] Ex. OAG-3, KH-S-3 at 2 (Hinderlie Surrebuttal).
[596] Ex. CUB-8, ALF-SR-23 (Levenson-Falk Surrebuttal); *see also* Ex. CUB-3 at 7-9 (Levenson-Falk Direct).
[597] Ex. Xcel-71 at 31 (Martin Rebuttal).

265. The ALJ finds that the record contains substantial evidence that residential customers in Minnesota are facing high energy burdens. Further, the record contains substantial evidence that many of Xcel's residential customers specifically are unable to pay their bills, to the point of racking up substantial arrearages and even having their service disconnected. Given the magnitude of these concerns, the ALJ recommends that the Commission weigh heavily the evidence in the record regarding the inability of many residential customers to pay their utility bills in its revenue allocation considerations.

4. Revenue Allocation Recommendation

266. Based on the cost and non-cost factors in the record, the ALJ finds the OAG's revenue apportionment to be the most reasonable in the record. The OAG's apportionment uses multiple CCOSSes, accounts for the consensus across all CCOSSes in the record that the Small General Service class is paying more than its fair share, reduces the cost-based increase to the Lighting class to account for rate shock, considers non-cost factors affecting the residential class, and modifies the 2026 revenue allocation to account for material changes in C&I demand sales.[598]

267. This revenue apportionment is shown below:

Table 7
OAG Recommended Apportionment at Xcel's Proposed Revenue Requirement

Customer Class	OAG Proposed Class Shares	Class Revenues at Xcel's Proposed Revenue Requirement ($000s)	Class Increases at Xcel's Proposed Revenue Requirement Under OAG Apportionment	
			($000s)	%
2025: Based on Xcel's proposed revenue requirement of $3,780,853				
Residential	**38.87%**	$1,469,748	$41,741	2.9%
Small General	**3.16%**	$119,617	$0	0.0%
Large General	**57.06%**	$2,157,295	$161,564	8.1%
Lighting	**0.90%**	$34,193	$2,918	9.3%
Total	**100.00%**	$3,780,853	$206,223	5.8%
2026: Based on Xcel's proposed revenue requirement of $3,994,095				
Residential	**39.01%**	$1,558,246	$97,783	6.7%
Small General	**3.18%**	$126,894	$0	0.0%
Large General	**56.91%**	$2,272,943	$261,167	13.0%
Lighting	**0.90%**	$36,012	$4,458	14.1%
Total	**100.00%**	$3,994,095	$363,408	10.0%

268. If the Commission reduces Xcel's revenue requirement, the ALJ believes that, consistent with past Commission practice, the most straightforward modification to revenue apportionment is to apply the proposed class shares to the total revenue approved by the Commission.[599]

[598] Ex. OAG-10 at 37-40 (Scharber Surrebuttal).
[599] *See* Ex. OAG-10 at 49 (Scharber Surrebuttal).

C. Customer Charge

269. After revenues are apportioned to classes, rates must still be designed for each class. Rate design for the Residential and Small General customer classes has historically been based on a two-part tariff, which includes 1) a fixed customer charge intended to recover customer-specific costs that do not vary with the amount of energy used and 2) a per-kWh volumetric charge.[600]

270. Rate design theorists generally agree that customer-specific costs are appropriate for potential inclusion in the customer charge. James Bonbright wrote that customer costs include "the costs of metering and billing along with whatever other expenses the company must incur in taking on another consumer."[601] The NARUC Manual calls these costs "marginal customer costs," or the costs specific to individual customers, and says they 'include costs of the service drops, the costs of meters and metering and the customer accounts expenses."[602] The Regulatory Assistance Project (RAP) recommends that these costs should be limited to the cost of connecting to the grid, and the balance of the grid costs should be recovered in the per unit or energy price.[603]

271. In addition to cost factors, the Commission has found that the promotion of energy conservation is an important consideration in setting a customer charge.[604] Minnesota statutes mandate that the Commission "set rates to encourage energy conservation" "[t]o the maximum reasonable extent."[605]

272. The Commission has also considered other non-cost factors in setting the customer charge such as preventing intra-class inequity, particularly in ensuring customers that live within multi-family dwellings do not subsidize those in single-family dwellings with a higher cost of service.[606]

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[600] Ex. OAG-8 at 46 (Scharber Direct).
[601] Ex. OAG-8 at 48 (Scharber Direct) (quoting James C. Bonbright, *Principles of Public Utility Rates* 347 (1st ed. 1961)).
[602] Ex. OAG-8 at 48 (Scharber Direct).
[603] Ex. OAG-8 at 47 (Scharber Direct).
[604] *See, e.g.*, *In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 117 (Jul. 17, 2023) (eDockets No. 20237-197559-01)
[605] Minn. Stat. § 216B.03 (2024).
[606] *See In re Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.,* MPUC Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 117 (Jul. 17, 2023) (eDockets No. 20237-197559-01) ("In setting the customer charge in this case, alignment with the Basic Customer method is particularly important in light of the wide variety of residential customers within Xcel's service territory. Many Residential customers are in single family dwellings, but according to the Department, more than 200,000 customers live in multi-unit dwellings of various sizes.").

273. Xcel proposes to raise its customer charge for its Residential and Small General Service tariffs from $6 to $11 per month.[607] Xcel claimed that this change better reflects "customer-related costs" as shown by its Minimum-System and Basic Customer CCOSS.[608]

274. The OAG, the Department, and the Energy Cents Coalition all opposed Xcel's proposed increase.[609]

275. The OAG pointed out that the "customer-related costs" that Xcel points to for its proposed increase include a variety of costs beyond those recommended by rate design theorists, who generally agree that customer charges should be set as the costs of metering and billing along with costs associated with "taking on another customer."[610] The OAG also described how including only marginal costs aligns with the NARUC Manual and is the established methodology in other jurisdictions including Connecticut and Texas.[611]

276. The OAG's expert estimated customer-specific expenses and assets to include: costs related to meters, services, meter-reading, customer accounts, and customer assistance.[612] Even using Xcel's proposed rate of return in this analysis, the OAG estimated that customer-specific costs for the residential class were $5.82 in 2025 and $5.71 in 2026, if Xcel receives its rebuttal revenue requirement.[613]

277. Xcel's Basic Customer Method CCOSS included several additional cost categories as customer costs, such as expenses related to pensions and benefits, injuries and claims, uncollectible accounts, amortization, and payroll taxes.[614]

278. The ALJ finds that the cost basis provided by the OAG is more in line with rate design theory, the NARUC Manual, and has precedent in other jurisdictions.

279. The OAG also provided extensive analysis showing how a lower customer charge promotes both intraclass equity and protects low-income customers. Increases in customer charges will raise a low-usage customer's bill by a greater percentage than

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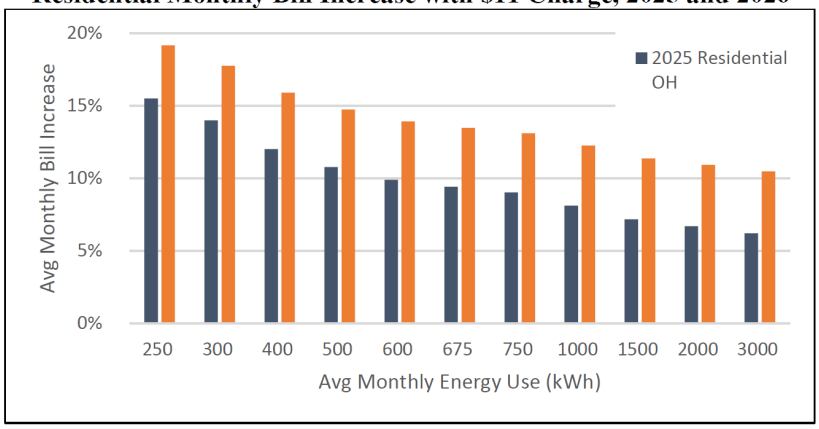
[607] Ex. Xcel-76 at 14 (Paluck Direct).
[608] Ex. Xcel-77 at 10 (Paluck Rebuttal).
[609] *See* Ex. OAG-8 at 46-63, Ex. OAG-10 at 44-48 (Scharber Surrebuttal); Ex. DOC-19 at 30-44 (Bahn Direct), Ex. DOC-20 at 11-14 (Bahn Surrebuttal); Ex. ECC-1 at 2-3 (Shardlow Direct).
[610] Ex. OAG-8 at 47-48 (Scharber Direct).
[611] *See* Ex. OAG-8 at 50 (Scharber Direct) (quoting Conn. Gen. Stat. § 16-243bb and *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Subst. R. § 25.344*, Docket No. 22344, Interim Order Establishing Generic Customer Classification and Rate Design at 6 (Tex. Pub. Util. Comm'n Nov. 22, 2000)).
[612]Ex. OAG-8 at 51 (Scharber Direct); Ex, OAG-10 at 47 (Scharber Surrebuttal).
[613] Ex. OAG-12 (Scharber Amended Witness Statement) (providing corrected figures following receipt of Xcel corrected information request response).
[614] Ex. OAG-8 at 50-51 (Scharber Direct).

a high-usage customer's.[615] With the customer charge increase Xcel is proposing, a low-usage customer will experience a much greater bill increase than a high-usage customer, as shown by the chart below:[616]

Figure 1
Residential Monthly Bill Increase with $11 Charge, 2025 and 2026

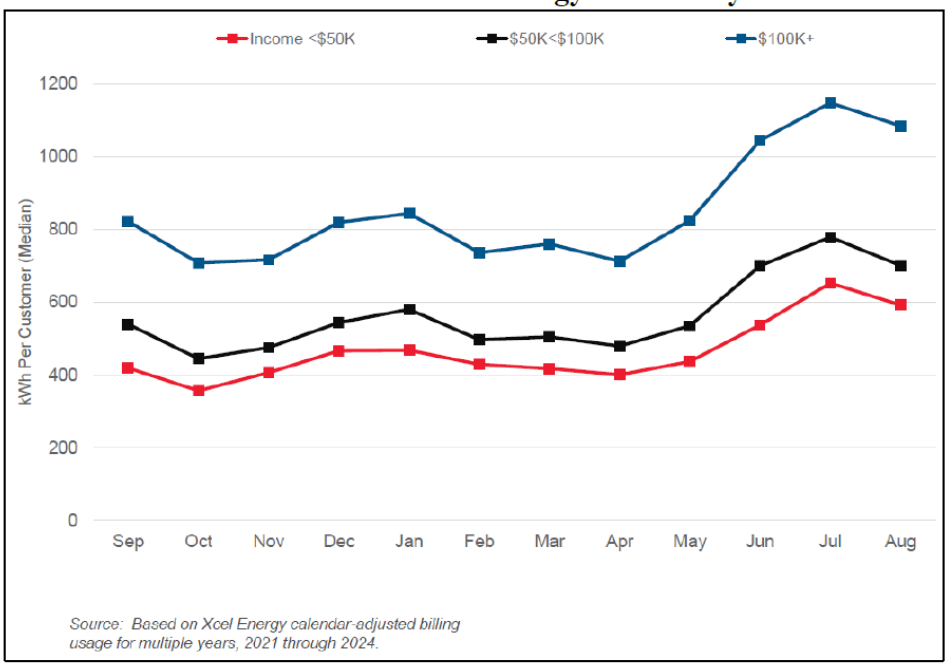


280. As the chart shows, for a residential customer using 250 kWh per month, Xcel's proposal would lead to average monthly bill increases of almost 16 percent in 2025 and 20 percent in 2026.[617] A residential customer using 1000 kWh per month, however, would experience an increase of only 8 percent in 2025 and 12 percent in 2026.[618]

281. The OAG explained how avoiding the disparities shown in the above chart are particularly important to protect low-income customers. Income and electricity use are correlated.[619] Customers with lower incomes tend to use less energy overall, as shown by Xcel's own data, showing the median monthly electricity usage for households making more than $100,000 was 1.5 to 2 times higher than households with incomes under $50,000.[620] An increase in the customer charge would likely result in a greater percentage increase in the monthly bills of low-income households than those of higher-income households.

[615] Ex. OAG-8 at 54-56 (Scharber Direct).
[616] The orange part of the key represents 2026 but the key was inadvertently removed during the filing process. *See* Ex. OAG-10 at 55 (Scharber Direct); OAG Initial Br. at 96.
[617] Ex. OAG-8 at 55 (Scharber Direct).
[618] Ex. OAG-8 at 55 (Scharber Direct).
[619] Ex. OAG-8 at 59 (Scharber Direct).
[620] Ex. OAG-8 at 58-59, sched. HS-D-19 (Scharber Direct) (citing Xcel's Residential Energy Use Study – Minnesota Market).

Figure 4
Electric Use by Household Income from Xcel's 2024 Residential Energy Use Survey[135]



282. The OAG also estimated the impact of Xcel's proposed customer charge on energy conservation. To do this, the OAG estimated the potential energy savings from a lower customer charge using EIA data on price elasticity of demand for Residential electricity.[621] While the individual savings were not large, due to Xcel's large Residential customer sales, a customer charge of $6 versus $11 dollars would have potential savings of 50,000 to 100,000 MWh for the Residential class alone.[622]

283. The ALJ recommends that the Commission not increase the residential and small general service customer charge. Keeping the customer charge flat has a cost basis supported by rate design theory that is also used in other jurisdictions. It would also protect low-income customers and avoid intra-class cost shifting from customers in single family homes to those in multi-family units. Last, the OAG's estimate for the potential energy savings from keeping the customer charge unchanged shows that maintaining the existing customer charge is necessary to comport with the statutory requirement to encourage energy conservation to the maximum reasonable extent.[623]

[621] Ex. OAG-8 at 60 (Scharber Direct).
[622] Ex. OAG-8 at 60 (Scharber Direct).
[623] Minn. Stat. § 216B.03 (2024).

Dated: February 25, 2026

Respectfully submitted,

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