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

**FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION  
121 7th Place East  
Suite 350  
St. Paul, Minnesota 55101-2147**

**MPUC Docket E-002/GR-24-320; E-002/M-24-321  
CAH Docket No. 28-2500-40515**

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

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**INITIAL BRIEF  
OF THE OFFICE OF THE ATTORNEY GENERAL—  
RESIDENTIAL UTILITIES DIVISION**

**January 28, 2026**

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## INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (Xcel),<sup>1</sup> seeks to raise rates by a total of 9.98 percent over the 2025-2026 period through approval of a Multiyear Rate Plan (MYRP).<sup>2</sup> Xcel's ratepayers are struggling to pay their energy bills in the face of persistent inflation and more than a decade of Xcel's yearly rate hikes, while Xcel's shareholders enjoy annual returns that far outpace inflation. The Office of the Attorney General—Residential Utilities Division (RUD) opposes Xcel's request, demonstrating through expert testimony that many aspects of Xcel's request are unreasonable, unsupported, and would be manifestly unjust to foist upon Xcel's captive ratepayers.

The Minnesota Public Utilities Commission is charged with setting “just and reasonable rates.” Xcel must prove any rate increase it seeks by producing substantial evidence that the increase would be just and reasonable, and all doubts must be resolved in favor of Xcel's ratepayers. The evidence in this case demonstrates that the Commission should reject significant portions of Xcel's request, including the overall amount of money it claims it must extract from ratepayers (its “revenue requirement”) and which ratepayers it wishes to extract that money from (its “revenue apportionment” and “rate design”). In particular, the rate increase for residential customers must be significantly reduced, and there should be no rate increase for small businesses at all. Only with significant adjustments to Xcel's requests will its rates be just and reasonable.

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<sup>1</sup> Unless otherwise noted, this brief will use “Xcel” to refer to Northern States Power Company rather than to Xcel, Inc., the Fortune 500 holding company.

<sup>2</sup> Ex. Xcel-19 at 3 (Halama Rebuttal).

## LEGAL STANDARD

Xcel has the burden to prove by a preponderance of the evidence that its request to increase rates is just and reasonable, and all doubts must be resolved in favor of ratepayers.<sup>3</sup> The preponderance of the evidence standard is defined for ratemaking purposes as “whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission’s statutory responsibility to enforce the state’s public policy that retail consumers of utility services shall be furnished such services at reasonable rates.”<sup>4</sup> In other words, Xcel bears the burden to demonstrate both that it will actually incur the costs it claims and that it would be just and reasonable for ratepayers to bear those costs in rates.<sup>5</sup> If the Commission determines that Xcel has not met its burden to prove the existence of any of the costs that Xcel seeks to impose on ratepayers, or that any portions of the utility’s request are unreasonable, then those portions of the request should be denied.

Importantly, there is no burden-shifting in a utility rate proceeding. The burden always remains with the utility to prove that its claimed costs will result in just and reasonable rates.<sup>6</sup> It would be erroneous to conclude that the utility’s position “must prevail” simply because other parties did not produce contradicting evidence or because the utility’s proposal appears “prima facie” reasonable to the factfinder.<sup>7</sup> The Commission cannot accept Xcel’s proposals at face value. Instead, the Commission must evaluate each element of Xcel’s request to determine whether Xcel

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<sup>3</sup> Minn. Stat. § 216B.16, subd. 4; Minn. Stat. § 216B.03 (requiring that any doubt as to reasonableness be resolved in consumer’s favor).

<sup>4</sup> *In re Petition of N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).

<sup>5</sup> *Id.* at 722–23 (“[b]y merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating that it is just and reasonable that the ratepayers bear the costs of those expenses.”).

<sup>6</sup> *Id.* at 726.

<sup>7</sup> *In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 33 (Mar. 12, 2018) (eDocket No. [20183-140963-01](#)).

has persuasively demonstrated that its allegations are more likely true than not *and* that including that portion of Xcel's request would result in just and reasonable rates.

## ARGUMENT

### **I. XCEL ASKS THE COMMISSION TO SQUEEZE RATEPAYERS WITH CONTINUED YEARLY RATE HIKES, DESPITE HEALTHY PROFITS, AMIDST AN AFFORDABILITY CRISIS**

Xcel began this case with a request that the Commission sanction a rate increase of \$353.3 million beginning in 2025 and an additional \$137.5 million beginning in 2026.<sup>8</sup> By the end of 2026, that would have meant \$844.1 million from ratepayers' pockets to Xcel's coffers in just two years. While the request has since been somewhat moderated, largely due to circumstances outside Xcel's control,<sup>9</sup> Xcel still wants the Commission to condone a 2025 rate increase of \$208.4 million and an additional 2026 rate increase of \$156.9 million—a 9.98 percent increase in rates<sup>10</sup> and a cumulative increase in revenue of \$573.7 million.<sup>11</sup>

Meanwhile, Xcel has met or exceeded its Earnings Per Share guidance every year for the past two decades and has boasted dividend growth for the past 22 years straight.<sup>12</sup> In 2024, Xcel's Total Shareholder Return was 9-11 percent, up from 2023.<sup>13</sup> No doubt this annual growth in shareholder wealth owes much to the annual growth in Xcel's rates. While Xcel's ratepayers wonder how to pay their utility bills, Xcel's profits beat inflation many times over.

This rate case shows how Xcel has managed to do that: by nickel-and-diming its captive ratepayers. Xcel does not just propose to recover the reasonable costs of providing electricity service. Xcel believes it is entitled to charge its ratepayers for such costs as: its executives' lavish

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<sup>8</sup> Ex. Xcel-17 at 2 (Halama Direct).

<sup>9</sup> *E.g.*, Xcel-19 at 6-7, 12-13, 22 (Halama Rebuttal) (discussing changes in nuclear decommissioning accrual, generation capacity revenue, and nuclear plant depreciation).

<sup>10</sup> *See id.*, BCH-3, sched. 2 at 4 (Halama Rebuttal).

<sup>11</sup> Ex. Xcel-19 at 3 (Halama Rebuttal).

<sup>12</sup> Ex. DOC-26 at 7 (2024 Form 10-K).

<sup>13</sup> *Id.*; Ex. DOC-25 at PDF 7 (2023 Form 10-K).

compensation packages, including portions that the Commission has not allowed in over 30 years; all of its “investor relations” costs; further costs of repairing a plant that Xcel’s imprudent actions caused to fail catastrophically; and costs that arose after it filed its rate case, contrary to the normal operation of the regulatory construct. These are just a few of the unreasonable demands the OAG opposes in this rate case. And on top of them all, Xcel expects ratepayers to pay the for the lawyers Xcel hired to advocate to raise ratepayers’ rates.

Moreover, this case comes amidst a rising affordability crisis for Xcel’s ratepayers. Households continue to struggle against inflation on basic necessities that builds on the epochal inflation they experienced in 2021 and 2022.<sup>14</sup> In Minnesota, as many as 59 percent of households had difficulty paying for usual household expenses, and 23 percent went without necessities such as food and medical care to pay their energy bills.<sup>15</sup> Xcel’s ratepayers are no exception, with average total arrears in 2024 twice what they were before the COVID-19 pandemic<sup>16</sup> and disconnections reaching an all-time high before 2025 had even ended.<sup>17</sup> The Commission has received thousands more public comments regarding this rate case than its last case, the vast majority of them opposing the rate increase.<sup>18</sup> Clearly, this rate increase is a burden on all ratepayers, not only those with the least means.<sup>19</sup>

Xcel sits atop healthy profits while its ratepayers are crushed beneath. The Commission is one of very few entities in the Minnesota economy with the power to relieve the pressure on ratepayers. It can do so by rejecting every portion of Xcel’s rate increase that Xcel has not proven

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<sup>14</sup> Ex. OAG-1 at 27-29 (Hinderlie Direct).

<sup>15</sup> Ex. CUB-3 at 6 (Levenson-Falk Direct).

<sup>16</sup> *Id.* at 7.

<sup>17</sup> Ex. OAG-3, KH-S-3 at 4 (Hinderlie Surrebuttal).

<sup>18</sup> Ex. CUB-8 at 9-10 (Levenson-Falk Surrebuttal).

<sup>19</sup> For further discussion, see Section IV.A.3, *infra*.

is absolutely necessary for the provision of safe and reliable service. Xcel's 1.3 million ratepayers are counting on it.

## II. FINANCIAL ISSUES

In the first stage of a rate case, the Commission determines the utility's revenue requirement—or the amount of revenue the utility needs to meet the cost of providing service. The utility at all times has the burden to prove<sup>20</sup> not only the existence of these costs, but also that it is reasonable for ratepayers, as opposed to shareholders, to bear these costs.<sup>21</sup> For several costs that Xcel seeks to recover in this rate case, Xcel has failed to meet this burden.

### A. The Commission Must Use the Process It Outlined for Early Retiring Plants and Should Not Accelerate Depreciation Here.

The Commission should reject the Department's recommendation to accelerate asset depreciation for the Sherburne County Generating Station Unit 3 (Sherco 3) and the Allen S. King Coal Plant (King).<sup>22</sup> The Department did not follow the Commission's procedure for analyzing the rate treatment of early retiring fossil fuel assets, and the record does not contain the full information required for this analysis. Further, adopting the Department's recommendation would create rate shock, increasing Xcel's revenue requirement by \$58.8 million in 2025 and \$55.4 million in 2026, cause intergenerational inequities, and risk making a predetermination on the prudence of plant investments.<sup>23</sup> The Commission should also reject Xcel's request to create a regulatory asset for any remaining net book value.<sup>24</sup> Instead, the Commission should follow the process it set out for early-retiring plants.

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<sup>20</sup> Minn. Stat. § 216B.16, subd. 4.

<sup>21</sup> *Petition of N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).

<sup>22</sup> Ex. OAG-6 at 2 (Lee Rebuttal).

<sup>23</sup> *Id.*

<sup>24</sup> Ex. OAG-7 at 27 (Lee Surrebuttal).

**1. The procedural background regarding these plants shows a strong record is required to determine accounting treatment for early retirement.**

The procedural background regarding early retirement for Sherco 3 and King shows that more record development is required before accelerated depreciation can be considered for these plants. 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.<sup>25</sup> 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.<sup>26</sup> But the IRP Order did not resolve (or even address) the significant policy questions of who should pay for the stranded costs of retiring coal plants and how and when that payment should take place.<sup>27</sup>

In its last rate case, Xcel proposed in rebuttal testimony to accelerate each early-retiring plants’ depreciation schedule.<sup>28</sup> Initially, the Department and OAG objected due to lack of analysis on the issue.<sup>29</sup> Later in the case, Xcel and the Department advocated to reserve the issue for further record development and “consideration of alternative rate-treatment proposals in a new docket.”<sup>30</sup> The Commission decided that “there was broad agreement that issues of depreciation accounting

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<sup>25</sup> *In re 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Co. d/b/a Xcel Energy*, 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](#)) (19-368 IRP ORDER).

<sup>26</sup> *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](#)) (21-630 ORDER).

<sup>27</sup> 19-368 IRP ORDER at 31.

<sup>28</sup> See 21-630 ORDER at 11; *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) (21-630 MOTION TO STRIKE ORDER).

<sup>29</sup> 21-630 MOTION TO STRIKE ORDER at 3-4.

<sup>30</sup> 21-630 ORDER at 11.

for early-retiring generation facilities will have significant ratepayer impacts and involve important policy considerations that have not been fully developed in this record.”<sup>31</sup> 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.”<sup>32</sup>

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.”<sup>33</sup> Following input from the Department, the OAG, all electric utilities, and labor unions, in May 2025, the Commission established a four-tiered framework to address the ratemaking treatment for utility-owned generation facilities that retire early.<sup>34</sup>

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.

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<sup>31</sup> *Id.* at 12.

<sup>32</sup> *Id.*

<sup>33</sup> *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](#)) (EARLY RETIREMENT FRAMEWORK ORDER); *id.*, NOTICE OF COMMENT PERIOD at 1 (Aug. 22, 2023).

<sup>34</sup> EARLY RETIREMENT FRAMEWORK ORDER at 7-8.

- 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 prudence concern.)<sup>35</sup>

Notably, Tier 2 discusses criteria for accelerated depreciation, although the order does not address what those criteria are. Notable about Tier 3 is that the Department assumed that assets would remain used and useful at the time of early retirement and that there is no question that the utility retiring the asset acted prudently.<sup>36</sup> Tier 4 considers “assets requiring additional analysis to determine the appropriate return, which may include no return on investment.”<sup>37</sup>

As discussed below, the Department’s analysis did not follow the framework. Reviewing the framework, testimony, and evidentiary hearing record, the Commission should not permit accelerated depreciation at this time. It goes against the framework’s goal of helping the Commission fulfill its statutory obligation to ensure just and reasonable rates by balancing the needs of ratepayers and the utility.<sup>38</sup> Sherco 3 and King should continue on their previously approved depreciation schedules.

## **2. Accelerated depreciation is inappropriate here for both Sherco 3 and King.**

Xcel is not proposing accelerated depreciation for King and Sherco 3. The OAG also does not believe accelerated depreciation is appropriate for King and Sherco 3. However, the Department is recommending that depreciation expense for King and Sherco 3 coal plants reflect the shortened operating lives assumed in the Company’s IRP.<sup>39</sup> This increases the test year and plan year depreciation expense because the cost recovery is over a shorter period of time—adding \$58.8 million to the 2025 test year revenue requirement and \$54.4 million dollar to the 2026 plan

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<sup>35</sup> *Id.*

<sup>36</sup> *Id.* at 5.

<sup>37</sup> *Id.*

<sup>38</sup> *Id.* at 7.

<sup>39</sup> Ex. OAG-6 at 2 (Lee Rebuttal).

year revenue requirement.<sup>40</sup> As a result, the plants would be fully depreciated by the end of each plant's operating life.<sup>41</sup> In line with the IRP, Xcel plans to retire King in 2028 and Sherco 3 in 2030 instead of 2040 and 2038 respectively.<sup>42</sup>

The Department states they would prefer to match IRP operating lives with depreciation lives.<sup>43</sup> While the OAG acknowledges that is a common practice, doing so here neglects the Commission's adoption of the Department's proposed framework for early-retired fossil-fuel generating facilities.<sup>44</sup> The Department's arguments that accelerating depreciation avoids rate shock and creates intergenerational equity are also not borne out with deeper analysis.

The Department's recommendation does not follow the tiered framework that it advocated for and the Commission adopted. The Department's direct testimony did not mention the Commission's framework,<sup>45</sup> which was established in May 2025.<sup>46</sup> While the Department did recognize the existence of the framework in surrebuttal testimony, the Department's witness simply listed pros and cons and it is not clear how the framework tiers are analyzed.<sup>47</sup> Still, the Department did not provide much data that is contemplated as part of Tier 1 of the Framework, which includes "plant size, original date of retirement, impact on ratepayers" and whether "the utility prudently operated the plant."<sup>48</sup>

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<sup>40</sup> *Id.* at 2, 15.

<sup>41</sup> *Id.* at 2.

<sup>42</sup> *In re Xcel Energy's 2024-2040 Upper Midwest Integrated Res. Plan*, MPUC Docket No. E002/RP-24-67, ORDER APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS at 10 (Apr. 21, 2025) (eDockets No. [20254-217941-01](#)); 19-368 IRP ORDER at 7, 31, Ordering Para. 2.A.4.

<sup>43</sup> Ex. DOC-23 at 14 (Jones Direct).

<sup>44</sup> Ex. OAG-6 at 3 (Lee Rebuttal).

<sup>45</sup> See Ex. DOC-23 at 13-16 (Jones Direct); Tr. Vol. 2 at 439 (Jones).

<sup>46</sup> EARLY RETIREMENT FRAMEWORK ORDER at 1 (showing the issued date of May 14, 2025).

<sup>47</sup> See Ex. DOC-24 at 17-20 (Jones Surrebuttal).

<sup>48</sup> Ex. DOC-23 at 8 (Jones Direct).

Instead of applying the framework, the Department’s recommendation rests on a mechanical application of accounting principles and claims of avoided rate shock that were based on erroneous data. But, to determine the ratemaking treatment for early retiring fossil fuel plants, the Commission has already deviated from the practice of setting service lives based on IRPs.<sup>49</sup> Instead, the Commission established a flexible framework to guide its policy-laden decisions on these important issues.

Even skipping to Tiers 2 and 3 of the framework, the analysis is still incomplete. For Tier 2, the Department appears to conclude that the plants meet the criteria for accelerated depreciation,<sup>50</sup> but it is not clear what those criteria are or how they are applied. Indeed, the Department admits that matching depreciable lives to the operating lives is the traditional approach “but not always” the practice.<sup>51</sup> Moving to Tier 3, the framework prohibits accelerated depreciation if it would cause rate shock.<sup>52</sup> The Department claims that rate shock would not be present because the depreciation expense decrease for the Monticello and Prairie Island plants and increase for Sherco 3 and King would “offset each other such that they still result in an overall net reduction to the revenue requirement of \$10.9 million for 2025 and \$13.9 million for 2026 when implemented together.”<sup>53</sup> But using “offsets” does not fit with how the Commission appears to have understood the framework. In explaining the Department’s proposed framework, the Commission explained: “The Department stated that accelerated depreciation may not be appropriate when it may cause rate

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<sup>49</sup> See generally EARLY RETIREMENT FRAMEWORK ORDER.

<sup>50</sup> Ex. DOC-24 at 18 (Jones Surrebuttal).

<sup>51</sup> *Id.*

<sup>52</sup> EARLY RETIREMENT FRAMEWORK ORDER at 8 (“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.”).

<sup>53</sup> Ex. DOC-24 at 19 (Jones Surrebuttal).

shock or *significant rate impacts*.”<sup>54</sup> The Department’s accelerated depreciation adjustment alone would total \$38 million in the 2025 Test Year and \$36 million in the 2026 Plan Year for King, and \$21 million in the 2025 Test Year and \$19 million in the 2026 Plan Year for Sherco 3.<sup>55</sup> These are significant rate impacts.

Even if using offsets were appropriate, the Department’s rate shock analysis is flawed because it is based on incorrect data.<sup>56</sup> To support its argument that no rate shock would occur from accelerated depreciation, the Department included tables to show how netting the reductions from the coal units with the extensions of the nuclear units would together lead to an “overall negative net adjustment.”<sup>57</sup> To determine the revenue requirement impact of adjusting the depreciable lives for these plants, the Department’s witness relied on an informal email response from Xcel.<sup>58</sup> XLI’s witness described in rebuttal how the figures provided in the Department’s direct did not match a spreadsheet produced by Xcel that was filed in the early retirement docket.<sup>59</sup> On cross-examination, the Department’s witness admitted that if the figures Xcel produced in response to an XLI Information Request were used, there would be a net *increase* to ratepayers from accelerated depreciation for Sherco 3 and King and life extensions for the nuclear plants.<sup>60</sup> In fact, there would be a net increase of approximately \$28 million.<sup>61</sup> The Department’s analysis that no rate shock would occur, therefore, appears to be based on incorrect data provided by Xcel.

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<sup>54</sup> EARLY RETIREMENT FRAMEWORK ORDER at 5 (emphasis added).

<sup>55</sup> See Ex. OAG-6 at 5-6 (Lee Rebuttal)

<sup>56</sup> Ex. XLI-5 at 5 (LaConte Rebuttal); Tr. Vol. 2 at 427-326 (Jones).

<sup>57</sup> Ex. DOC-23 at 15-16 (Jones Direct); Ex. DOC-24 at 21 (Jones Surrebuttal).

<sup>58</sup> Ex. DOC-23, HD-D-6 (Jones Direct).

<sup>59</sup> Ex. XLI-5 at 4-5 (LaConte Rebuttal).

<sup>60</sup> Tr. Vol. 2 at 431-35 (Jones).

<sup>61</sup> Tr. Vol. 2 at 435 (Jones).

In the Department's list of pros and cons, four of the six pros are premised on there being an "overall net reduction" to the revenue requirement when the coal plant accelerated depreciation is netted against the nuclear plant extended remaining lives.<sup>62</sup> The other two pros are the traditional, "but not always," practice of updating depreciation lives following IRPs (discussed above) and that matching depreciable lives with operating lives avoids "an intergenerational subsidy issue."<sup>63</sup>

The Department's intergenerational subsidy argument views the issue of intergenerational equity too narrowly.<sup>64</sup> If looking more broadly at the benefits of early retirement of fossil fuel facilities, the Department's recommendation would actually cause intergenerational inequities. This is because part of the reason that fossil fuel plants are retired early is to benefit future ratepayers by not only reducing emissions but also reducing fuel and maintenance costs.<sup>65</sup> With accelerated depreciation, future ratepayers would receive these benefits but pay none of the costs.<sup>66</sup>

To summarize, the Department's arguments to accelerate depreciation for Sherco 3 and King do not provide sufficient data to get beyond even Tier 1 of the Commission's early retirement Framework. But even moving to Tiers 2 and 3, the Department's netting of nuclear plant life extensions ignores the very substantial rate impacts of shortening the coal plant remaining lives. Further, the Department's analysis of rate shock relied on seemingly incorrect data provided by Xcel in an email. Correcting that data removes the foundation of the Department's argument that no rate shock will occur. Accelerating depreciation is inappropriate here.

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<sup>62</sup> Ex. DOC-24 at 18-19 (Jones Surrebuttal).

<sup>63</sup> *Id.*

<sup>64</sup> *See id.* at 19.

<sup>65</sup> Ex. OAG-6 at 7 (Lee Rebuttal); *see also* Ex. XLI-5 at 7 (LaConte Rebuttal).

<sup>66</sup> Ex. OAG-6 at 7 (Lee Rebuttal).

### 3. Xcel's request to create a regulatory asset is premature.

Xcel's request to create a "regulatory asset" for Sherco 3 and King is premature both under the framework and for public policy considerations. Xcel's argument ignores the full text of Tier 3 and prematurely jumps to conclusions. Tier 3 discusses the potential assignment of a regulatory asset "with a possible return."<sup>67</sup> But to get to Tier 3, the Commission would need record development and analysis of Tier 1 and Tier 2. Tier 1 starts with gathering data on issues such as prudence and whether the plant is used and useful. As discussed above, that analysis is not here. The Company's decision to early-retire the coal plant assets, while supportive to Minnesota's energy goals does not supersede the need for development of a record on prudence and the plant's "used and useful" life.<sup>68</sup>

Tier 3 also does not guarantee a return for early-retired plants.<sup>69</sup> As one analysis explains, "When plants are in service, equity risk premiums are justified by risks that investors in company shares are taking as utilities own and operate plant and equipment."<sup>70</sup> But "[o]nce plants retire, these risks are no longer present, so at least an arguable question remains about how much equity return is justified."<sup>71</sup> Whether Xcel should be permitted to receive a return, and if so at what rate, is a decision that needs to be informed by a more complete record provided through Tier 1's data gathering phase. Again, since that has not occurred, a decision would be premature here.

If the Commission acts prematurely by creating a regulatory asset, ratepayers could pay a steep price. For example, the Department did not factor into its analysis uncertainty about the

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<sup>67</sup> EARLY RETIREMENT FRAMEWORK ORDER at 8.

<sup>68</sup> Ex. OAG-6 at 7 (Lee Rebuttal).

<sup>69</sup> EARLY RETIREMENT FRAMEWORK ORDER at 8.

<sup>70</sup> Ex. OAG-6, SL-R-1 at 6 (Lee Rebuttal).

<sup>71</sup> *Id.*

retirement date of coal plants due to federal actions.<sup>72</sup> To avoid the inherent risk of making a predetermination that there will be no prudency issues at the time the plants are retired, potentially but not certainly in 2028 and 2030, the Commission should deny Xcel's request for a regulatory asset.

**B. The Remaining Sherco 3 Restoration Costs Should be Removed in Their Entirety Because They Were Caused by Xcel's Imprudent Actions.**

In 2011, Sherco Unit 3 experienced a catastrophic explosion. After a decade of litigation and Commission proceedings, in 2024 the Commission found that the outage was due to Xcel's imprudence and required Xcel to refund all costs of additional energy purchased from the regional market to ratepayers.<sup>73</sup> In addition to the Sherco 3 explosion causing Xcel to purchase more expensive power from the market, Xcel also incurred capital costs to restore Sherco 3. While insurance proceeds covered a majority of these restoration costs, approximately \$5.5 million was included in the Company's rate base in its 2013 rate case.<sup>74</sup> Because this is Xcel's first rate case since the Commission's finding that the 2011 Sherco explosion was caused by Xcel's imprudence, the OAG recommended in direct testimony that Xcel remove the remaining balance of the restoration costs.<sup>75</sup> The Company, however, claims that because these costs for the restoration of Sherco 3 have been included in rates since 2013, ratepayers should pay off the remainder.<sup>76</sup>

The Commission should require Xcel to remove the remaining Sherco 3 restoration costs from rate base. Simply because Xcel has, for over a decade, included in rate base and earned a

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<sup>72</sup> See Tr. Vol. 2 at 441 (Jones) (stating she was unaware of any actions of the Trump administration to require coal plants to remain open beyond scheduled retirement dates).

<sup>73</sup> *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 2-4 (Dec. 24, 2024) (SHERCO PRUDENCY ORDER).

<sup>74</sup> Ex. OAG-5 at 22 (Lee Direct).

<sup>75</sup> *Id.*

<sup>76</sup> Ex. Xcel-16 at 21-22 (Liberkowski Rebuttal).

return on capital investments that were incurred because of its imprudent actions, does not mean that ratepayers should continue to fund these investments. Xcel's claim that this issue was decided in the 2013 rate case incorrectly describes that decision. And the regulatory and litigation history following the Sherco 3 explosion show that this rate case is the first opportunity that the OAG had to advocate to remove the remaining imprudently incurred restoration costs from rate base.

Witness Liberkowski claims in her testimony that "the Commission authorized the Company to include these costs in rate base in the 2013 rate case, and these costs were similarly included in rate base in the Company's two subsequent rate cases."<sup>77</sup> But when asked during the evidentiary hearing if she had reviewed the Commission's orders that would have authorized the cost, Witness Liberkowski admitted that she has not reviewed the Commission's 2013 rate case order or any Xcel rate case orders since.<sup>78</sup>

Far from what is represented by Xcel's witness, the Commission initially declined to address whether the restoration costs were appropriate. Instead, in May 2015, the Commission stated: "The remaining issue—how to account for insurance proceeds and litigation recoveries resulting from an accident at the Company's Sherburne County Generating Station Unit 3 (Sherco 3)—*is not yet ripe*, since the Company's insurance claims and related litigation are not yet concluded."<sup>79</sup> Then, in August 2015, the Commission clarified its order and required Xcel to include Sherco 3 insurance proceeds as an offset to Xcel's rate base in the 2013 rate case.<sup>80</sup> The

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<sup>77</sup> *Id.* at 22.

<sup>78</sup> Tr. Vol. 1 at 26-28 (Liberkowski).

<sup>79</sup> *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, AND ORDER at 7 (May 8, 2015) (hereafter called the 13-868 INITIAL RATE CASE ORDER) (emphasis added).

<sup>80</sup> *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) (13-868 SUPPLEMENTAL RATE CASE ORDER).

cost *not* covered by insurance, however, was not addressed in the August 2015 Order.<sup>81</sup> Nor was it addressed in the Commission’s 2015 Xcel rate case order or in the Commission’s 2021 Xcel rate case order.<sup>82</sup> The lack of discussion in these cases isn’t surprising because the Commission had delayed a decision on the prudence of the outage until Xcel’s and its insurers’ litigation with the turbine manufacturer, General Electric, had concluded.<sup>83</sup>

Once litigation with GE finally concluded, in July 2022, the Commission referred the issue of prudence and the associated fuel costs for a contested case.<sup>84</sup> In December 2024, after the contested case had concluded and Xcel had filed this rate case, the Commission issued its order finding that “Xcel failed to operate and maintain Sherco 3 Unit 3 in a reasonable and prudent manner consistent with good utility practices.”<sup>85</sup> The Commission elaborated that the record showed that “Xcel made a calculated business decision to disregard its engineering judgment and defer the 2011 major inspection to 2014 in order to perform discretionary upgrades to the high- and intermediate-pressure turbines in 2011.”<sup>86</sup> The Commission concluded that Xcel’s failure to conduct necessary inspections and maintenance on Sherco Unit 3 contributed to its catastrophic failure.<sup>87</sup>

In direct testimony in this case, the OAG recommended that because Xcel imprudently operated and maintained Sherco 3, which led to the restoration costs, these cost should not continue

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<sup>81</sup> *See id.* at 12-13.

<sup>82</sup> *See generally, In re Application of N. States Power Co. for Auth. to Incr. Rates for Elec. Serv. in the State of Minn.*, E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (June 12, 2017) (15-26 ORDER); 21-630 ORDER.

<sup>83</sup> SHERCO PRUDENCY ORDER at 3.

<sup>84</sup> *Id.* at 3.

<sup>85</sup> *Id.* at 3.

<sup>86</sup> *Id.* at 16.

<sup>87</sup> *Id.* at 4.

to be recovered from ratepayers.<sup>88</sup> Contrary to Xcel’s claims, this is not a “retroactive change”<sup>89</sup> because the OAG is not advocating that the Commission attempt to claw back the years of payments that ratepayers have made for depreciation expense and return for the Sherco 3 restoration costs.<sup>90</sup> Instead, the Commission should not allow Xcel to continue to collect the depreciation expense and return on the capital costs that were incurred due to Xcel’s imprudence.<sup>91</sup>

Ratepayers have already paid a substantial amount of these imprudent costs and should not be penalized further merely because the prudency determination was delayed due to Xcel’s and its insurers’ extended litigation with General Electric. The Commission should require that Xcel remove any remaining restoration costs from rate base by removing \$2.4 million from rate base for the 2025 test year and \$2.1 million in the 2026 plan year.<sup>92</sup>

**C. Xcel Failed to Provide Sufficient Evidence of Its TOU-Related Capital Costs and Failed to Demonstrate It Isn’t Double Counting Capital Costs.**

In its rebuttal testimony, Xcel added \$3.2 million<sup>93</sup> in capital costs for implementation of its new Residential Time of Use (TOU) rate.<sup>94</sup> Xcel did not mention any capital costs related to the TOU rate in either its initial testimony or supplemental testimony. Rather, Xcel originally suggested in supplemental testimony that it would add a request for TOU-related operations and maintenance (O&M) costs in rebuttal,<sup>95</sup> only to then allege in rebuttal that it had in fact already

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<sup>88</sup> Ex. OAG-5 at 24 (Lee Direct).

<sup>89</sup> Ex. Xcel-16 at 22 (Liberkowsky Rebuttal).

<sup>90</sup> Ex. OAG-7 at 17 (Lee Surrebuttal).

<sup>91</sup> Ex. OAG-5 at 25 (Lee Direct).

<sup>92</sup> Ex. OAG-7 at 19 (Lee Surrebuttal).

<sup>93</sup> Ex. Xcel-19 at 28 (Halama Rebuttal). According to Xcel, the total capital costs are \$3.2 million, but it asks to assign \$2.8 million of that to the Minnesota jurisdiction. Ex. OAG-3 at 28 (Hinderlie Surrebuttal).

<sup>94</sup> Ex. Xcel-19 at 27-29 (Halama Rebuttal).

<sup>95</sup> Ex. Xcel-18 at 8-9, n. 2. (Halama Supplemental Direct). The TOU-related capital costs Xcel claimed in rebuttal bear no relation to the “marketing, education, and outreach” costs that Xcel said in Supplemental Direct it would be requesting in rebuttal. Ex. OAG-3, KH-S-4 at 2-4 (Hinderlie Surrebuttal).

included those O&M costs in its original O&M budget<sup>96</sup> and instead requested previously unmentioned capital costs that it could earn a return on.

Xcel's request for recovery of TOU-related capital expenditures should be rejected for multiple reasons. First, there is a real risk that Xcel is double counting nearly \$1.4 million of capital costs for development of its Rate Comparison Tool and that the Rate Comparison Tool will not be used or useful in the provision of utility service. Second, Xcel has not provided adequate support for any of the alleged TOU-related capital expenses.

**1. “The Rate Comparison Tool” may be double counted and is a speculative venture that Xcel undertook on its own initiative.**

Discovery revealed that \$1,390,191 of the new TOU-related capital costs are for development of Xcel's new Rate Comparison Tool.<sup>97</sup> However, Xcel had previously stated that this tool was in development long before the residential TOU rate was approved,<sup>98</sup> suggesting that Xcel's characterization of these costs as new costs arising from approval of the TOU rate is inaccurate at best. Furthermore, the OAG has repeatedly raised concerns regarding the usefulness of the Rate Comparison Tool, and capital expenditures that are not used and useful cannot be recovered through rates. Therefore, the Commission should deny \$171,810 of TOU-related capital costs in the 2025 test year and \$1,218,381 in the 2026 plan year that Xcel attributes to the Rate Comparison Tool.<sup>99</sup>

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<sup>96</sup> Ex. Xcel-19 at 27 (Halama Rebuttal).

<sup>97</sup> Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal).

<sup>98</sup> Ex. OAG-3 at 34 (Hinderlie Surrebuttal).

<sup>99</sup> *Id.* at 35.

**a. There is significant risk that Xcel’s request for Rate Comparison Tool capital costs is duplicative of capital costs in its initial rate request.**

Contrary to Xcel’s implication that the Rate Comparison Tool arose from the Commission’s TOU order, Xcel decided to develop this tool on its own.<sup>100</sup> It had already announced that it was “developing” such a tool in August 2024.<sup>101</sup> This was long before the residential TOU rate was approved in May 2025<sup>102</sup> and two months before Xcel filed the instant rate request on November 1, 2024. Furthermore, the Rate Comparison Tool is not a TOU-specific tool—if it is ultimately developed, it will be available for all Xcel customers.<sup>103</sup> The capital cost of developing the tool therefore did not and could not have arisen from the Commission’s TOU order. This fact, in turn, suggests that these costs are not incremental; there is a significant possibility that they were already included in Xcel’s initial filing and adding them in rebuttal would result in double counting these capital costs.

**b. The Rate Comparison Tool is unlikely to be used and useful in providing utility service.**

Even if the newly-alleged costs of developing the Rate Comparison Tool were not duplicative, the OAG has repeatedly raised concerns that the tool may not ultimately be used and useful in providing utility service, and Xcel has failed to provide any evidence to the contrary.

To earn recovery of capital costs, utility property must be “used and useful in rendering service to the public.”<sup>104</sup> Property is “used and useful” when it is both in service and “reasonably

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<sup>100</sup> *Id.* at 36.

<sup>101</sup> *Id.* at 34.

<sup>102</sup> *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, ORDER APPROVING REVISED OPT-IN PROPOSAL AND SETTING REPORTING REQUIREMENTS (May 15, 2025) (eDockets No. [20255-218995-01](#)).

<sup>103</sup> Ex. OAG-3 at 37 (Hinderlie Surrebuttal).

<sup>104</sup> Minn. Stat. § 216B.16, subd. 6.

necessary to the efficient and reliable provision of utility service.”<sup>105</sup> This is common-sense policy that prevents utilities from investing in frivolous assets purely for the purpose of charging ratepayers for a return on those assets.

Xcel has repeatedly failed to demonstrate that the Rate Comparison Tool is likely to be used and useful in providing utility service, despite the OAG’s prompting.<sup>106</sup> During the course of the TOU docket, parties recommended that shadow billing—where a customer would see on their monthly bill a side-by-side comparison of their actual bill and what their bill would have been under an alternative rate—could improve customer outcomes.<sup>107</sup> Xcel opposed shadow billing, and instead wished to implement a “rate analysis tool”<sup>108</sup> that would “essentially do shadow billing.”<sup>109</sup> But the tool would only be available online and would estimate future bills rather than showing customers a direct side-by-side comparison of their actual usage.<sup>110</sup> When approving the TOU rate, the Commission expressed concerns that many customers do not use online tools and about the accuracy of the rate advisor tool’s customer use forecast.<sup>111</sup> The Commission then ordered that Xcel assess the feasibility of shadow billing.<sup>112</sup> In TOU compliance filings, Xcel continued to advocate for the now-titled “Rate Comparison Tool” and continued not to provide any more than vague details about its functionality despite requests from the OAG and CUB.<sup>113</sup>

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<sup>105</sup> *Senior Citizens Coal. of Ne. Minn. v. Minn. Pub. Utils. Comm’n*, 355 N.W.2d 295, 300 (Minn. 1984).

<sup>106</sup> Ex. OAG-3 at 36-38 (Hinderlie Surrebuttal).

<sup>107</sup> *Id.* at 30-31.

<sup>108</sup> *Id.* at 31.

<sup>109</sup> *Id.* at 36.

<sup>110</sup> *See id.* at 36-37.

<sup>111</sup> *Id.* at 33, 36-38.

<sup>112</sup> *Id.* at 33.

<sup>113</sup> *Id.* at 37-38.

Among the little information Xcel did provide, it admitted that the design features of the tool are still all subject to change and that it has barely begun the “design phase” for the tool.<sup>114</sup>

The Commission never asked Xcel to develop the tool. What the tool will even do, much less how many people will ever use it, remains speculative. And when the tool will be put into service remains a mystery, but at this point, 2026 appears highly doubtful given that the tool was only beginning the “design phase” in October 2025. Resolving doubts in favor of consumers requires that capital costs of \$171,810 in the 2025 test year and \$1,218,381 in the 2026 plan year for the Rate Comparison Tool be denied. Once the tool actually exists, if Xcel demonstrates its usefulness, Xcel can request recovery for it at that time.

**2. Xcel has not carried its burden to show that the alleged TOU-related capital costs will be incurred or would be reasonable.**

Xcel has also not provided sufficient explanation or support for *any* of its new TOU-related capital costs. Xcel has the burden of proof, in part due to its singular access to information about its costs. Yet it simply alleged that it will incur these costs, without providing a reliable basis upon which to evaluate when or whether they will be incurred or whether they are reasonable. Xcel vaguely mentioned in testimony that the costs were due to “capital cost activities”<sup>115</sup> and attached spreadsheets showing the revenue requirement impact if the request is granted.<sup>116</sup>

The OAG asked Xcel to provide a breakdown of the costs for each actual activity by test year and plan year and provide the actual costs incurred for each activity by month.<sup>117</sup> Xcel did not provide all of the information requested, instead providing a breakdown of forecasted costs by broad activity categories.<sup>118</sup> Xcel did not provide any explanation of the basis upon which it arrived

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<sup>114</sup> *Id.* at 38.

<sup>115</sup> Ex. Xcel-19 at 28 (Halama Rebuttal).

<sup>116</sup> *Id.*, BCH-3, scheds. 3A-3B (Halama Rebuttal).

<sup>117</sup> Ex. OAG-3, KH-S-4 at 1-2 (Hinderlie Surrebuttal).

<sup>118</sup> *Id.*, KH-S-4 at 2-3.

at these forecasted costs – no calculations or assumptions to demonstrate an objective basis for them. As for the actual costs incurred, Xcel stated that it “does not currently have a breakdown of actual capital costs by capital activity,”<sup>119</sup> alleging only that it had incurred \$129,000 in capital expenses without any indication of what that money was spent on.<sup>120</sup>

Xcel has not borne its burden to show that including TOU-related capital costs in the test year and plan year would be just and reasonable. There is significant doubt about both the amount and the purpose of the expense claimed by Xcel, and this doubt should be resolved in favor of consumers. The request for \$659,641 in 2025 and \$2,458,859 in 2026 that Xcel added in rebuttal testimony should be denied. If TOU-related capital costs do exist, Xcel can petition to recover them in its next rate case, assuming it demonstrates at that time that recovering them would be just and reasonable.

**D. Xcel Failed to Provide Sufficient or Credible Evidence to Support Its Inflated Request for Costs Related to Reconnecting Customers During Periods of Extreme Heat and Poor Air Quality.**

Xcel also introduced in rebuttal testimony a previously unannounced request for capital and O&M costs arising from its new extreme heat reconnection program. This request would increase the 2025 test year revenue deficiency by \$28,000 and the 2026 deficiency by \$2,445,000.<sup>121</sup> These claimed costs are many times greater than Xcel had represented in the docket in which this program was approved,<sup>122</sup> and yet Xcel provided no coherent explanation for the massive increase in either rebuttal testimony or discovery. Xcel has completely failed to justify

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<sup>119</sup> *Id.*, KH-S-4 at 3.

<sup>120</sup> *Id.*, KH-S-4 at 2.

<sup>121</sup> Ex. OAG-3 at 45 (Hinderlie Surrebuttal).

<sup>122</sup> *Id.*

the expense, and to the extent it has provided any information, it has contradicted itself.<sup>123</sup> Xcel's request should be denied because Xcel failed to demonstrate any reasonable basis for the costs.

The reconnection program arose from Xcel's request to extend a Commission rules variance that would allow it to continue remotely disconnecting customers using its expensive new Advanced Metering Infrastructure (AMI).<sup>124</sup> After Xcel made significant capital investments in AMI that enabled remote disconnection, the OAG supported development of a remote reconnection program to use AMI capabilities to ratepayer benefit.<sup>125</sup> After notice and comment, the Commission ordered Xcel to implement a reconnection program where Xcel will temporarily reconnect service for economically vulnerable ratepayers during extreme heat events and when the Air Quality Index is 151 or higher.<sup>126</sup>

During notice and comment, the OAG was concerned about Xcel's cost estimates for the program. Xcel estimated that the program would cost \$520,000, but provided very little support for this estimate, both in its filings and in discovery.<sup>127</sup> Xcel provided no information about the supporting assumptions underlying its cost estimates other than estimating that it would reconnect 19,000 customers, which was almost 8,000 customers more than the highest level of disconnected customers reported by Xcel in any month in 2024.<sup>128</sup>

Xcel has done no better job of supporting its alleged costs in the rate case. Except now the request is higher.<sup>129</sup> The rebuttal testimony introducing the request is less than a page long and

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<sup>123</sup> *Id.* at 42, 44-45.

<sup>124</sup> *Id.* at 40-41.

<sup>125</sup> *Id.* at 41.

<sup>126</sup> *Id.*

<sup>127</sup> *Id.* at 42.

<sup>128</sup> *Id.* at 43.

<sup>129</sup> *Id.* at 44 (showing program cost estimates of \$360,000 in one-time costs and a range of per event costs with a high-end of \$163,780).

includes no details whatsoever about the nature of the costs.<sup>130</sup> Attached schedules reveal that the alleged costs would increase the revenue requirement by nearly \$2.5 million without explanation.<sup>131</sup> The OAG sent discovery requesting an explanation for the cost increase and Xcel responded that the costs claimed in the rate case are the same as the costs Xcel claimed in the reconnection program notice and comment period, which is patently incorrect.<sup>132</sup>

Xcel's rebuttal request for alleged costs relating to its reconnection program should be denied. Xcel has failed entirely to explain where the capital costs in its rebuttal request came from, and has not provided any reliable information to evaluate its inflated rebuttal request for O&M costs.<sup>133</sup> Xcel has the ability to request deferred accounting to track any expenses it may actually and prudently incur.<sup>134</sup> But the Commission should deny Xcel's request to include these unproven and potentially unreasonable costs in this rate case.

**E. Xcel Failed to Provide Any Relevant Evidence Supporting Its Demand That Ratepayers Pay for Its Highest-Paid Executives' Salaries.**

The Commission should disallow rate recovery of compensation paid to Xcel's ten highest-paid executives. Whether Xcel's captive ratepayers or its wealthy shareholders should pay for Xcel's exorbitant executive compensation is paradigmatic of the longstanding ratemaking principle that "whether to permit the recovery of an item of expense . . . is essentially a policy question of whether the shareholders or the customers should bear the cost."<sup>135</sup> Evidence showing the amount of compensation the utility feels it must pay its executives is insufficient, both

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<sup>130</sup> Ex. Xcel-19 at 20 (Halama Rebuttal).

<sup>131</sup> *Id.*, BCH-3, scheds. 3A and 3B, column 24 (Halama Rebuttal).

<sup>132</sup> Ex. OAG-3 at 46-47 (Hinderlie Surrebuttal).

<sup>133</sup> *Id.* at 48.

<sup>134</sup> *Id.* at 49.

<sup>135</sup> *In re Request of Interstate Power Co.*, 574 N.W.2d 408, 413 (Minn. 1998); *see also In re Petition of N. States Power Co.*, 416 N.W.2d 719, 723 (Minn. 1987).

according to legal precedent<sup>136</sup> and the Commission’s decision in Xcel’s last rate case.<sup>137</sup> Rather, the Commission balances the needs of ratepayers against the needs of shareholders to determine whether inclusion of executive compensation in rates would be just and reasonable.<sup>138</sup> This inquiry includes ratepayers’ need for affordable rates – indeed, Minnesota statute requires the Commission to consider ratepayers’ ability to pay in determining just and reasonable rates.<sup>139</sup>

The Commission disallowed recovery of compensation paid to Xcel’s ten highest-paid executives in its last rate case, finding that Xcel had failed to carry its burden to prove that ratepayers should shoulder the burden.<sup>140</sup> Much of this record mirrors that one. Xcel provided more evidence of the same thing: that it pays its executives the way other corporations pay their executives, which the Commission found insufficient for rate recovery. Additionally, the structure of Xcel’s executive pay, which the Commission found demonstrated a focus on shareholder needs over ratepayer needs, has not changed. Meanwhile, for this case, the OAG and Department of Commerce attempted to determine how executives devote their efforts to shareholder interests versus ratepayer interests, and the evidence largely reinforced the findings that shareholder interests predominate. The Commission should therefore deny the request for executive compensation. In the future, it could open a performance incentive docket to tie recovery of executive compensation to affordability goals.

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<sup>136</sup> *In re Petition of N. States Power Co.*, 416 N.W.2d at 723 (“[M]erely by showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden[.]”).

<sup>137</sup> 21-630 ORDER at 22.

<sup>138</sup> *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.

<sup>139</sup> Minn. Stat. § 216B.16, subd. 15.

<sup>140</sup> 21-630 ORDER at 22.

**1. The Commission and court of appeals have already rejected Xcel's argument that market-competitive pay is ipso facto recoverable.**

Despite clear guidance from the Commission and the court of appeals, Xcel failed to present sufficient evidence to justify recovery of compensation paid to its ten highest-paid executives. The Commission previously disallowed such recovery because the record showed that forcing ratepayers to pay executive compensation would be unjust, whereas Xcel provided only evidence that it pays its executives at the “market rate.” Xcel appealed this decision and lost. Now Xcel has offered effectively the same evidence as before—that it pays its executives “competitively.” Having found substantially similar evidence insufficient to justify full recovery before, the Commission should follow its previous order and deny recovery again.

In Xcel's 2021 rate case, the Commission determined that Xcel had not met its burden to prove it was reasonable for ratepayers to pay for Xcel's full proposed levels of compensation for its ten highest-paid executives.<sup>141</sup> This was based on numerous factors, including the size of Xcel's overall rate request, the fact that Xcel increased rates nearly every year for the past decade, and the clear priority that executives' incentive compensation places on shareholder interests over ratepayer interests.<sup>142</sup> The Commission also noted the many public comments it had received in which members of the public strongly opposed paying for executive compensation while struggling to afford their lives.<sup>143</sup> The Commission therefore disallowed rate recovery of Xcel's request and then set a recovery limit equal to the governor's salary for each of Xcel's ten highest-paid executives.<sup>144</sup> Xcel appealed.<sup>145</sup>

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<sup>141</sup> *Id.* at 21.

<sup>142</sup> *Id.* at 21-22.

<sup>143</sup> *Id.* at 23.

<sup>144</sup> *Id.*

<sup>145</sup> *In re N. States Power Co.*, No. A23-1672, 2025 WL 249995 at \*10 (Jan. 21, 2025).

The court of appeals held that the Commission had authority to disallow Xcel’s request to recover executive compensation.<sup>146</sup> The court affirmed that Xcel had the burden not only to show that it would incur the expense of paying its executives, but that it would be just and reasonable to charge this expense to ratepayers.<sup>147</sup> The court explicitly rejected Xcel’s argument that it had met its burden of proof simply “because it provided evidence that it generally pays employee compensation at median market rates.”<sup>148</sup> The court also stated that the Commission has the prerogative to “closely consider” compensation levels for Xcel’s highest-paid executives, given the statutory requirement that Xcel provide information regarding executive pay.<sup>149</sup> The court therefore held that the Commission lawfully concluded that Xcel had not “satisfied its burden to prove that its requested recoverable compensation cost . . . is appropriate for ratepayers to pay.”<sup>150</sup>

In short, the Commission found and the court affirmed that a showing that Xcel’s executives are paid comparably to executives at other utilities does not make recovery of that compensation just or reasonable. And yet, Xcel’s evidence on executive compensation largely doubles down on this same rejected argument, with Xcel going so far as to pay an outside expert to make materially the same point.<sup>151</sup> True, in Xcel’s 2021 rate case, it only generally showed that its overall employee compensation was based on market comparisons,<sup>152</sup> whereas in this case Xcel procured a WTW report that specifically showed its highest-paid executives are paid

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<sup>146</sup> *Id.* at \*10. The court also held that using the governor’s salary as a proxy to limit executive compensation was arbitrary and capricious, but because no party has made such a recommendation in this case, this brief will not discuss it further.

<sup>147</sup> *Id.* at \*11 (*citing N. States Power Co.*, 416 N.W.2d at 723).

<sup>148</sup> *Id.* at \*11.

<sup>149</sup> *Id.*

<sup>150</sup> *Id.*

<sup>151</sup> *See Ex. OAG-1 at 15 (Hinderlie Direct).*

<sup>152</sup> 21-630 ORDER at 22; *In re N. States Power Co.*, No. A23-1672, 2025 WL 249995 at \*11.

“competitively” compared to other utilities of its size.<sup>153</sup> But, for all the rate case expense Xcel incurred to hire WTW,<sup>154</sup> the main takeaway is that Xcel’s “compensation programs are comparable to and competitive with market practices of other similarly sized utilities and are therefore reasonable”<sup>155</sup>—precisely the conclusion that the Commission previously rejected.<sup>156</sup> Moreover, Xcel’s witness emphasized that he was making no assertions about the benefits ratepayers receive from executives<sup>157</sup> or about executive performance.<sup>158</sup> He also did not make any claims about the appropriateness of rate recovery because, he admitted, rate recovery varies by jurisdiction according to the facts and circumstances of each case.<sup>159</sup>

Xcel did attempt to dress up this insufficient evidence with red herrings. It argued that it would be at a competitive disadvantage if it did not offer its executive compensation programs.<sup>160</sup> It argued that it would not be able to “reinforce performance expectations” without its executive compensation program.<sup>161</sup> It argued that it would have difficulty retaining executives without its executive compensation program.<sup>162</sup> These are all irrelevant points. As the Commission previously observed,<sup>163</sup> Xcel is welcome to pay its executives whatever and however it wants—the only question in this case is whether it is just and reasonable for ratepayers to bear that burden.

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<sup>153</sup> Ex. Xcel-66, RVM-1, sched. 2 at 3 (Mustich Direct). Notably, the WTW report in this case was produced for this case and is not even the basis upon which Xcel actually determines executive compensation. Ex. OAG-14 at 2 (Xcel Response to OAG IR 1054).

<sup>154</sup> Ex. OAG-14, Attach. A at 5 (Xcel Response to OAG IR 1054).

<sup>155</sup> Ex. Xcel-66 at 9 (Mustich Direct).

<sup>156</sup> 21-630 ORDER at 22.

<sup>157</sup> Ex. Xcel-67 at 5-6 (Mustich Rebuttal).

<sup>158</sup> Evidentiary Hearing Transcript Volume (Tr. Vol.) 1 at 189:1-14 (Mustich).

<sup>159</sup> Tr. Vol. 1 at 192:18-25 – 193:4-7 (Mustich).

<sup>160</sup> Ex. Xcel-66 at 10 (Mustich Direct).

<sup>161</sup> *Id.*

<sup>162</sup> *Id.* at 11.

<sup>163</sup> 21-630 ORDER at 23.

The other factors that the Commission discussed in Xcel's last rate case are present here as well. Xcel's rate request is still hundreds of millions of dollars. This request was filed as soon as its last MYRP ended, meaning Xcel's rates continue to increase every year.<sup>164</sup> Many public commenters continue to express dismay at the idea of paying for executive compensation while struggling to make ends meet. And the record still shows that Xcel's executives place far more priority on shareholder needs than on ratepayer needs, which is evident from both the structure of their incentive compensation and the record regarding executives' activities.

**a. Xcel's ratepayers are struggling to pay its rates as much as ever.**

Xcel's ratepayers were struggling when it filed its last rate case, and things are even worse now. In Xcel's last rate case, Xcel began with a request to increase rates by \$677.72 million over three years, which it later reduced to \$435.2 million over three years.<sup>165</sup> It was only the latest increase after a decade of nearly annual rate increases.<sup>166</sup> Ratepayers faced widespread inflation and other economic challenges.<sup>167</sup> The Commission received numerous public comments regarding their opposition to paying executive compensation under these circumstances.<sup>168</sup>

Now, Xcel began with a request to increase rates by \$490.8 million over two years,<sup>169</sup> which it similarly later reduced to \$365.3 million over two years.<sup>170</sup> Because Xcel filed this rate case the moment its previous MYRP was about to end, Xcel's rates continue to increase every year for more than a decade,<sup>171</sup> and its residential average electricity rate was above the national average

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<sup>164</sup> Ex. OAG-1 at 26 (Hinderlie Direct).

<sup>165</sup> 21-630 ORDER at 4.

<sup>166</sup> *Id.* at 21.

<sup>167</sup> *Id.* at 20.

<sup>168</sup> *Id.* at 21.

<sup>169</sup> Ex. Xcel-17 at 2 (Halama Direct). This is a lower total, but over only two years instead of three.

<sup>170</sup> Ex. Xcel-19 at 3 (Halama Rebuttal).

<sup>171</sup> Ex. OAG-1 at 25 (Hinderlie Direct).

in 2022 and 2024.<sup>172</sup> The inflation consumers experienced during Xcel's last rate case is still baked into prices, and inflation has continued to increase prices further.<sup>173</sup> The economic challenges faced by Xcel's customers specifically can be seen in its all-time high levels of disconnections and its stubbornly high arrearage levels.<sup>174</sup> And thousands of public commenters have expressed their opposition to this rate increase.<sup>175</sup>

All of the economic factors the Commission pointed to in limiting executive compensation in Xcel's 2021 rate case remain the same or have worsened since then.

**b. Xcel's incentive compensation is driven by shareholder interests.**

The majority of Xcel's executives' compensation is paid in the form of incentive compensation, which is divided into Annual Incentive Plan (AIP) compensation and Long-Term Incentive (LTI) compensation. AIP compensation for executives varies as a percentage of overall compensation,<sup>176</sup> but for half of Xcel's highest-paid executives it is greater than base salary and for all of them it has the potential to increase if the company is profitable enough in a given year.<sup>177</sup> LTI makes up an average of 57–75 percent of executive compensation.<sup>178</sup> Both forms of

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<sup>172</sup> Ex. JIN-2 at 14 (Chan Direct).

<sup>173</sup> Ex. OAG-1 at 27-29 (Hinderlie Direct).

<sup>174</sup> *Id.* at 29-31 (Hinderlie Direct); 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).

<sup>175</sup> Ex. CUB-8 at 9-12 (Levenson-Falk Surrebuttal).

<sup>176</sup> Ex. Xcel-6, Vol. 3.IV.2 at 1088 of 1204 (Appl. Vol. 3, Req. Info.).

<sup>177</sup> Ex. Xcel-66, RVM-1, sched. 2 at 8 of 19 (Mustich Direct); Ex. Xcel-62, YL-1, sched. 4 at 8 (Ly Direct).

<sup>178</sup> Ex. Xcel-63 at 32 (Ly Rebuttal).

compensation heavily incentivize maximizing shareholder value, as the Commission has found for decades.<sup>179</sup> In fact, the Commission has never granted recovery of LTI compensation before.<sup>180</sup>

The AIP compensation that executives receive is fundamentally predicated on maximizing shareholder value. Before any employee receives AIP compensation, the company must reach an Earnings-Per-Share (EPS) threshold that is set each year.<sup>181</sup> EPS is a measure of profitability that is equal to profits minus preferred dividends, all divided by outstanding shares.<sup>182</sup> Thus setting an annual EPS threshold requires the company to reach a certain level of profit each year to meet the threshold. If the EPS threshold is not met, no AIP is paid out at all.<sup>183</sup> If the threshold is met, the CEO, who also receives AIP, then sets the amount of AIP to pay out depending on how far past the EPS baseline threshold the company goes.<sup>184</sup> Executives can earn up to 150 percent of AIP for outperforming the EPS threshold.<sup>185</sup> In other words, the more profit for the company and its shareholders, the more profit for executives.

The 57 to 75 percent of executive compensation that is paid in the form of LTI similarly demonstrates the primacy of shareholder value over ratepayer needs. LTI is only available to employees who have a “higher level of influence on the Company’s direction, strategy, and innovation.”<sup>186</sup> There are three types of LTI awards. The first type is awarded based on relative

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<sup>179</sup> *In re Application of N. States Power Co. for Auth. to Increase Its Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-92-1185, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 25-30 (Sept. 29, 1993); *In re Application of N. States Power Co. for Auth. to Increase Its Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-92-1185, ORDER AFTER RECONSIDERATION (Jan. 14, 1994).

<sup>180</sup> Ex. DOC-3 at 16 (Kehrwald Direct).

<sup>181</sup> Ex. Xcel-62, YL-1, sched. 4 at 8 (Ly Direct).

<sup>182</sup> Tr. Vol. 1 at 147:12-15 (Yen Ly).

<sup>183</sup> Ex. Xcel-62, YL-1, sched. 4 at 8 (Ly Direct).

<sup>184</sup> Ex. Xcel-62, YL-1, sched. 4 at 8 (Ly Direct).

<sup>185</sup> *Id.*

<sup>186</sup> Ex. Xcel-62 at 22 (Ly Direct).

total shareholder return.<sup>187</sup> Xcel is not requesting recovery of this portion of LTI,<sup>188</sup> but because they receive it, it still incentivizes them to maximize total shareholder return. The second type of LTI is awarded based on Xcel achieving environmental goals that are less stringent than required by Minnesota law.<sup>189</sup> The third type is time-based, which an executive receives simply for staying at the company for a certain period of time.<sup>190</sup>

Regardless of how LTI compensation is awarded, LTI compensation itself is comprised entirely of stock awards, meaning that the value of the compensation depends on the price of Xcel, Inc.'s stock.<sup>191</sup> If the stock price increases, the value of the LTI compensation to the executive also increases.<sup>192</sup> Likewise, if the stock price decreases, the value of the LTI compensation to the executive decreases. Similarly, if Xcel pays shareholders dividends, Xcel's executives receive dividends, too. Because such large sums of executive compensation are paid in the form of LTI stock awards, the majority of executive compensation directly incentivizes executives to attempt to increase Xcel, Inc.'s stock price.<sup>193</sup> In this way, Xcel's executives' interests and shareholder interests are identical.<sup>194</sup>

Xcel's incentive compensation overwhelmingly focuses executives on maximizing profits and maximizing shareholder value. As rational actors seeking to maximize their own economic wellbeing, the size and mutually reinforcing nature of these incentives ensure that other concerns are secondary. For AIP, the incentive is in the way AIP is earned: executives focus on maximizing

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<sup>187</sup> *Id.* at 23.

<sup>188</sup> *Id.* at 23-24.

<sup>189</sup> Ex. DOC-3 at 17 (Kehrwald Direct).

<sup>190</sup> Ex. Xcel-62 at 23 (Ly Direct).

<sup>191</sup> Ex. DOC-3, MBK-D-10 (Kehrwald Direct).

<sup>192</sup> Tr. Vol. 1 at 159:20-24 (Yen Ly).

<sup>193</sup> Tr. Vol. 1 at 150:2-16 (Yen Ly).

<sup>194</sup> Tr. Vol. 1 at 160:20-15 (Yen Ly).

profits to reach the EPS threshold, with the incentive to earn even more if they exceed it. For LTI, the incentive is in the form of the compensation itself—the higher the stock price and shareholder value, the higher the compensation. The portion of LTI that is based on total shareholder return further focuses executives on shareholder needs to the exclusion of ratepayer needs.

**c. The only other evidence in the record about compensation paid to Xcel’s ten highest-paid executives also demonstrates the primacy of shareholder interests over ratepayer interests.**

Despite Commission and judicial guidance that an evaluation of the relative benefits received by ratepayers and shareholders would determine rate recovery of executive compensation, Xcel only provided evidence that its executives are paid “competitively.” Although Xcel has the burden of proof to justify its request, the OAG and Department nevertheless attempted to investigate the relative shareholder and ratepayer benefits of executive compensation to provide the Commission with a fully developed record on the issue.<sup>195</sup> This included an analysis of executive performance evaluations and executive work calendars. The analysis of the performance reviews only provided further evidence of the primacy of shareholder interests to Xcel’s executives, while the executive calendars lacked sufficient detail to support any finding of ratepayer benefit.<sup>196</sup>

Xcel produced performance reviews for only two of its executives,<sup>197</sup> and appears not to have a robust performance review process for the remaining eight.<sup>198</sup> Performance reviews are a common practice that ensure executives’ efforts align with a company’s goals.<sup>199</sup> Performance reviews therefore provide official direction to an executive regarding what the company believes

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<sup>195</sup> Ex. OAG-3 at 13 (Hinderlie Surrebuttal); *see also* Ex. DOC-4 at 46-58 (Kehrwald Surrebuttal).

<sup>196</sup> Ex. OAG-4 at 14-16 (Hinderlie Surrebuttal).

<sup>197</sup> Ex. OAG-3 at 16 (Hinderlie Surrebuttal).

<sup>198</sup> *Id.* at 22.

<sup>199</sup> *Id.*

the executive should focus on to maximize their value to the company.<sup>200</sup> If a company does not have any performance review process for executives at all, the primary measure of value for an executive to follow is their incentive compensation plan.<sup>201</sup>

The performance reviews that were provided demonstrated far more emphasis on shareholder interests than ratepayer interests.<sup>202</sup> In fact, there was very little clear concern for ratepayer interests, and on the contrary, many comments emphasized shareholder interests and encouragement for executives to provide further shareholder benefits.<sup>203</sup>

As in its 2021 rate case, Xcel failed to provide any evidence that would enable a reliable analysis of the extent to which Xcel's executive compensation furthers ratepayer interests. Xcel has therefore failed to carry its burden to prove that it would be just and reasonable for Xcel's ratepayers to pay millions of dollars in compensation to Xcel's highest-paid executives. This is because of the clear focus that Xcel's executives place on shareholder interests over ratepayer interests and the obvious injustice of charging ratepayers for executives' lavish compensation, particularly with the significant evidence in the record of energy affordability challenges.<sup>204</sup> The Commission should deny Xcel's request to recover compensation paid to Xcel's highest-paid executives.

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<sup>200</sup> *Id.*

<sup>201</sup> *Id.*; Ex. Xcel-67 at 8 (Mustich Rebuttal) (“Companies design their performance compensation programs to align with their business strategies and circumstances and focus and communicate what is important.”).

<sup>202</sup> Ex. OAG-4 at 18-22 (Hinderlie Surrebuttal).

<sup>203</sup> *Id.* at 21-22.

<sup>204</sup> *See, e.g.*, Ex. OAG-1 at 27-31 (Hinderlie Direct); Ex. CUB-3 at 7-11 (Levenson-Falk Direct); Ex. JIN-2 at 4-7 (Chan Direct).

**2. The Commission has authority to tie recovery of executive compensation to ratepayer-focused metrics.**

While there is no evidentiary basis to grant Xcel's request for executive compensation here, in the future, the Commission could create a performance incentive mechanism that would allow rate recovery of a portion of executive compensation if Xcel meets Commission-defined affordability metrics.<sup>205</sup>

A public evaluation of executive efforts to improve affordability could potentially address concerning trends in affordability that Xcel's current shareholder-focused incentive compensation has been unable to resolve. Such metrics could include reducing disconnections to pre-2019 levels, eliminating arrearages, or lowering bills. Minnesota would not be the first jurisdiction to do this. The Public Utilities Regulatory Authority of Connecticut (PURA) recently tied recovery of executive compensation to a utility's achievement of ratepayer-aligned goals.<sup>206</sup> While the OAG does not recommend simply adopting exactly what PURA did, it is notable that the goals PURA chose relate to affordability, which is a core ratepayer interest that often does not benefit utility shareholders.<sup>207</sup>

Xcel's incentive compensation structure currently provides little to no incentive to executives to improve tangible outcomes for ratepayers such as lowering rates and reducing disconnections. If the Commission wishes to explore possible incentive mechanisms that would tie executive compensation to improvements in ratepayer-centric metrics, it should open a new docket for that purpose.

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<sup>205</sup> Minn. Stat. § 216B.16, subd. 19(h); Ex. OAG-3 at 23-27 (Hinderlie Surrebuttal).

<sup>206</sup> Ex. OAG-3 at 25-26 (Hinderlie Surrebuttal) (citing *Application of Connecticut Water Company to Amend Its Rate Schedule*, Connecticut PURA Docket No. 23-08-32, DECISION at 69-74 (June 28, 2024), available at [https://www.dpuc.state.ct.us/FINALDEC.NSF/811195c865ca31ba852588e2005e7a7d/36dafc592d8e7ee885258b4a004d8d9f/\\$FILE/230832-062824.pdf](https://www.dpuc.state.ct.us/FINALDEC.NSF/811195c865ca31ba852588e2005e7a7d/36dafc592d8e7ee885258b4a004d8d9f/$FILE/230832-062824.pdf)).

<sup>207</sup> Ex. OAG-3 at 26 (Hinderlie Surrebuttal).

**F. Xcel Has Not Shown that Ratepayers Should Pay for Its Membership Dues Paid to the Edison Electric Institute.**

Xcel is requesting recovery of membership dues paid to the Edison Electric Institute (EEI) in the amount of \$677,000 for the 2025 test year and \$677,000 for the 2026 plan year.<sup>208</sup>

The Commission should deny Xcel’s request for recovery of EEI dues because Xcel has failed to carry its burden to demonstrate that ratepayers actually benefit from this membership. Xcel largely appears to believe that the benefits of membership are self-evident, but simply showing that it has spent money on an expense—such as membership in a trade organization—does not guarantee rate recovery. The Commission should therefore deny Xcel’s request, as it has denied organizational dues requests before when a utility failed to demonstrate ratepayer benefit.

**1. Xcel has failed to show how EEI benefits ratepayers.**

Xcel’s request to recover EEI’s dues is not supported by the record. The OAG made two clear requests: (1) that Xcel provide evidence demonstrating the ratepayer benefits of membership; and (2) that Xcel demonstrate what portion of dues benefits ratepayers.<sup>209</sup> Xcel failed to provide sufficient evidence for the first request, and any evidence for the second request.

In response, Xcel engaged in hand-waving about the beneficial “information” that EEI provides. For example, Xcel stated that EEI provides information to help its members provide reliable and affordable electric service, without providing any examples of what that information includes.<sup>210</sup> Similarly, Xcel stated that EEI has “policies and programs that aid members in improving the quality and reducing the cost of service.”<sup>211</sup> The most concrete example of some benefit was that EEI “develops best practices for safety” and develops trainings, without further

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<sup>208</sup> Ex. OAG-7 at 6 (Lee Surrebuttal).

<sup>209</sup> *Id.* at 4.

<sup>210</sup> Ex. Xcel-28 at 3 (Robinson Rebuttal).

<sup>211</sup> *Id.* at 3–4.

elaboration.<sup>212</sup> The remainder of the activities Xcel described related to EEI’s immense influence on policymakers, where Xcel specifically 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).”<sup>213</sup>

The OAG offered recommendations of helpful information to include in the record. This included EEI presentations, training courses, and conferences that employees attended, and specific information about the safety and industry information that Xcel receives from EEI.<sup>214</sup>

But instead of providing information about the benefits of membership in EEI, Xcel stated that the travel expenses it spent on sending employees to EEI conferences in 2023 somehow showed a benefit to ratepayers.<sup>215</sup> This is simply untrue. The fact that an employee attended an EEI conference in Miami or Denver,<sup>216</sup> EEI’s Unmanned Aircraft Services meeting,<sup>217</sup> or even an “EEI Transmission Policy meeting”<sup>218</sup> in 2023 tells the Commission nothing about whether or how any alleged benefits of these meetings from a previous timeframe would accrue to ratepayers now.

Similarly, Xcel cited to Volume 3 of its Initial Filing for “hundreds of rows of data identifying numerous instances (particularly conferences) in which Company employees engaged with EEI in 2024”<sup>219</sup> (even though the cited volume shows expenses from 2023). This volume reveals 23 instances of “EEI” in the vendor column, the descriptions for which state either “IEEE will be essential to the global technical community and to technical professionals everywhere and

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<sup>212</sup> *Id.* at 3.

<sup>213</sup> *Id.* at 4 (emphasis added).

<sup>214</sup> Ex. OAG-5 at 6–7 (Lee Direct).

<sup>215</sup> Ex. Xcel-28 at 8 (Robinson Rebuttal).

<sup>216</sup> Ex. Xcel-5, Vol. 3.IV.2 at 491 of 1204 (Appl. Vol. 3, Req. Info.) (eDockets No. [202411-211520-05](#)).

<sup>217</sup> *Id.*, Vol. 3.IV.2 at 545 of 1204 (Appl. Vol. 3, Req. Info.) (eDockets No. [202411-211520-05](#)).

<sup>218</sup> *Id.*, Vol. 3.IV.2 at 493 of 1204 (Appl. Vol. 3, Req. Info.) (eDockets No. [202411-211520-05](#)).

<sup>219</sup> Ex. Xcel-28 at 8 (Robinson Rebuttal).

be universally recognized for the contributions of technology and of technical professionals in improving global conditions”<sup>220</sup> (IEEE is a different organization from EEI), or state “an electric industry program that strengthens (sic) the sectors (sic) ability to restore the nations transmission (sic) system more quickly in the event of a terrorist attack.”<sup>221</sup> The IEEE description similarly appears repeatedly in Volume 4.<sup>222</sup>

Beyond these schedules, Xcel simply directed the OAG to the EEI website.<sup>223</sup> Sending the government agency charged with representing residential and small business ratepayers to a website does not create an appropriate record.

Even if these materials did demonstrate some ratepayer benefit of EEI membership, Xcel failed to demonstrate the portion of ratepayer dues that would be just and reasonable for ratepayers to pay. This is a common practice. For example, the California Public Utilities Commission has disallowed up to 48 percent of EEI dues after finding that EEI engages in extensive lobbying.<sup>224</sup> Here, however, Xcel failed to demonstrate any breakdown of ratepayer benefit. Lacking a reasonable basis to grant any portion of EEI dues, the entire request should be rejected.

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<sup>220</sup> Ex. Xcel-5, Vol. 3.III.3 at 12, 35-36 (Appl. Vol. 3, Req. Info.) (eDockets No. [202411-211520-03](#)).

<sup>221</sup> *Id.*, Vol. 3.III.3 at 32, 36-37, 39 (Appl. Vol. 3, Req. Info.) (eDockets No. [202411-211520-03](#)).

<sup>222</sup> Ex. Xcel-7, Vol. 4.VIII.A2 at 7, 9, 15-19, 22-24, 27, 30-37 (Appl. Vol. 4, Req. Info.) (eDockets No. [202411-211521-01](#)).

<sup>223</sup> Ex. Xcel-28 at 9 (Robinson Rebuttal).

<sup>224</sup> Ex. OAG-7 at 4 (Lee Surrebuttal); *Application of Pac. Gas and Elec. Co. for Auth., Among Other Things, to Increase Rates and Charges for Elec. and Gas Serv. Effective on Jan. 1, 2014 (U39M)*, Application No. 12-11-009, DECISION 14-08-032, 2014 WL 4248558 (Cal. P.U.C. Aug. 14, 2014); *Application of S. Cal. Edison Co. (U338E) for Auth. to, Among Other Things, Increase its Authorized Revenues for Elec. Serv. in 2015, and to Reflect that Increase in Rates*, Application No. 13-11-003, DECISION 15-11-021, 2015 WL 7351928 (Cal. P.U.C. Nov. 12, 2015).

**2. The Commission has disallowed utility-related association dues when a utility fails to demonstrate how membership in that organization benefits ratepayers.**

Xcel argues that it should be granted EEI dues because the Commission has granted them for Xcel before.<sup>225</sup> However, the Commission has made very clear that, when a utility does not show the benefit to ratepayers of membership in a utility-related association such as EEI, the utility does not get to recover the cost of membership dues.

Most recently, the Commission disallowed membership dues for the American Gas Association (AGA) that had been requested by the utility Greater Minnesota Gas. The utility had argued that the AGA provided training and industry information that were directly connected to providing gas service.<sup>226</sup> The Commission rejected the utility’s “general assertions regarding the importance of AGA training and informational resources,” finding that it had “failed to identify any specific trainings, conferences, or other educational opportunities that GMG staff has actually utilized.”<sup>227</sup> The Commission disallowed recovery of the entire AGA dues request because Greater Minnesota Gas had not made a strong showing of how the membership benefits ratepayers.<sup>228</sup>

Similar to Greater Minnesota Gas’s arguments regarding the AGA, Xcel electric has only made general statements about the benefits that it receives from EEI, without pointing to any actual proof. The Commission should therefore disallow Xcel’s request to recover \$677,000 for the 2025 test year and \$677,000 for the 2026 plan year for EEI dues expense.

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<sup>225</sup> Ex. Xcel-28 at 6-7 (Robinson Rebuttal).

<sup>226</sup> *In re Application of Greater Minnesota 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 17 (Nov. 26, 2025).

<sup>227</sup> *Id.* at 19.

<sup>228</sup> *Id.*

**G. The Commission Should Only Allow Recovery of Fifty Percent of Chamber of Commerce Dues.**

In Xcel’s last rate case, the Commission limited recovery of Xcel’s Chamber of Commerce dues to 50 percent.<sup>229</sup> Yet Xcel again requests that ratepayers pay the full cost of its membership in 67 Chambers of Commerce—\$221,936 for each year in the test year and plan year.<sup>230</sup> The OAG recommends that the Commission continue to limit recovery to 50 percent, which in this case that removes \$110,968 from the test year and plan year.<sup>231</sup>

The Commission previously found in Xcel’s last rate case that “the vast majority of the chambers of commerce identified in the record highlight furthering business and economic activity in their mission statements” and that “it is reasonable to conclude that at least some of the dues Xcel contributes to these organizations will be used for economic development.”<sup>232</sup>

The Commission has previously found that chambers of commerce contribute to economic development expenses.<sup>233</sup> Economic development expenses help increase and keep the number of customers on the utility’s system.<sup>234</sup> This generally increases revenues for the Company by helping to retain and grow the utility’s system. The general increase in revenue benefits shareholders.<sup>235</sup> In the last rate case, “the vast majority of the chambers of commerce identified in the record highlight furthering business and economic activity in their mission statements.”<sup>236</sup> The same rationale applies in this case because chambers of commerce continue to benefit local communities and business in the area.<sup>237</sup> The costs should be split by ratepayers and shareholders like other

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<sup>229</sup> 21-630 ORDER at 75-76.

<sup>230</sup> Ex. OAG-5 at 8 (Lee Direct); Ex. Xcel-28 at 11 (Robinson Rebuttal).

<sup>231</sup> Ex. OAG-5 at 9 (Lee Direct).

<sup>232</sup> 21-630 ORDER at 75.

<sup>233</sup> *Id.* at 74-75.

<sup>234</sup> Ex. OAG-5 at 9-10 (Lee Direct).

<sup>235</sup> *Id.* at 9.

<sup>236</sup> 21-630 ORDER at 75.

<sup>237</sup> *Id.*

economic development expenses. Xcel has made no additional showing in this rate case to move away from the Commission's most recent analysis of this issue.

**H. The Commission Should Follow Past Practice and Disallow Xcel's Recovery of Employee Awards and Gifts.**

Under Minnesota Statutes section 216B.16 subdivision 17(a), "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."<sup>238</sup> Xcel is requesting recovery for non-safety awards and their respective administrative fees. For the 2025 test year, Xcel claims \$722,268 for non-safety awards and \$14,876 for administrative fees, totaling \$737,144.<sup>239</sup> 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.<sup>240</sup> These expenses should be disallowed. Xcel bears the burden to prove that the expenses are reasonable and necessary for the provision of utility service, they must be denied. Xcel has failed to carry its burden and the Commission should follow its past practice of denying such expenses.

**1. Xcel has incorrectly claimed that the burden is on OAG to disprove these costs.**

Xcel argued that the OAG "does not provide any support for why this should be removed from the test year and plan year."<sup>241</sup> Xcel then alleged that the OAG made "unsupported conclusory statement that such an expense is not necessary to the provision of utility service."<sup>242</sup> Xcel's attempted burden shift misstates Minnesota's law. "The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change."<sup>243</sup>

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<sup>238</sup> Minn. Stat. § 216B.15, subd. 17(a).

<sup>239</sup> Ex. OAG-7 at 10 (Lee Surrebuttal) (citing Ex. Xcel-28 at 16 (Robinson Rebuttal)).

<sup>240</sup> *Id.*

<sup>241</sup> Ex. Xcel-63 at 25-26 (Ly Rebuttal).

<sup>242</sup> *Id.* at 26.

<sup>243</sup> Minn. Stat. §216B.16, subd. 4.

The OAG thoroughly reviews these expenses and flags what has previously been disallowed or split between ratepayers and shareholders. The OAG does not, however, do Xcel's job and go out of its way to justify the expense. The Commission has previously noted that "the OAG's analysis of each expense provides helpful perspective on the level of expense that is reasonable to incorporate into rates."<sup>244</sup> In this case, the OAG draws the Commission's attention to employee awards and gifts not related to employee safety.<sup>245</sup> Xcel must prove these expenses are reasonable and necessary for the provision of utility service, but it has not done so.

**2. Awards and gift expenses should be disallowed because Xcel did not provide meaningful analysis of the ratepayer benefit of awards and gifts.**

Xcel did not provide more than conclusory statements about the necessity of its employee awards and they should therefore be denied. Whereas Xcel argued that the awards "foster a culture where employees feel valued and appreciated," implying that there might be reduced costs due to employee retention, Xcel failed to provide any evidence or analysis of these reduced costs.<sup>246</sup> Ratepayers are already paying for Xcel's employees' compensation, and it would be unreasonable to make them pay for Xcel's gifts to its employees on top of that.

The Commission has previously rejected these sorts of awards, particularly when there is insufficient record evidence of their benefit to ratepayers. The Commission denied service and retirement awards in Minnesota Power's 2021 rate case because Minnesota Power had not demonstrated they were reasonable and necessary for utility service.<sup>247</sup> The Commission also

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<sup>244</sup> *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 26 (Feb. 1, 2022) (eDocket No. [20222-182349-01](#)) (20-719 OTP RATE CASE ORDER).

<sup>245</sup> Ex. OAG-7 at 8 (Lee Surrebuttal).

<sup>246</sup> *Id.* at 9-10.

<sup>247</sup> *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) (21-335 MP RATE CASE ORDER).

denied employee awards similar to Xcel’s request in Otter Tail’s previous rate case.<sup>248</sup> While the Commission did allow Minnesota Power “spot bonuses” in its 2016 rate case, the Commission there specifically did so to address below-market compensation for “certain key employees” – in other words, due to the particularities of that case.<sup>249</sup> Those spot bonuses also were not awarded through a point-based system administered by a third party, such as Xcel’s Xcelerate rewards program.

**I. The Commission Should Limit Recovery of Investor Relations Expenses Consistent with Past Practice.**

The OAG recommends that the Commission remove half of Xcel’s request for investor relations expenses, an adjustment equal to \$421,324 in the 2025 Test Year and \$427,196 in the 2026 Plan Year.<sup>250</sup>

Xcel states that investor relations expenses include the costs of providing “shareholder services and interactions with fixed income investors,” keeping credit rating agencies informed of Xcel’s business plans, and “support[ing] the Company’s equity program.”<sup>251</sup> Despite repeated requests that it do so,<sup>252</sup> the Company has not established that investor relations expenses benefit ratepayers. The Company only states that these expenses are “unavoidable, just, and reasonable”<sup>253</sup> and claims “these costs do not benefit investors.”<sup>254</sup> Based on these conclusory statements, Xcel

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<sup>248</sup> 20-719 OTP RATE CASE ORDER at 27.

<sup>249</sup> *In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 34 (Mar. 12, 2018) (eDocket No. [20183-140963-01](#)).

<sup>250</sup> Ex. OAG-7 at 28 (Lee Surrebuttal).

<sup>251</sup> Ex. Xcel-20 at 37 (Wehner Direct).

<sup>252</sup> Ex. OAG-5, SL-D-4 (Lee Direct); *Id.*, SL-D-5.

<sup>253</sup> Ex. Xcel-20 at 38 (Wehner Direct).

<sup>254</sup> Ex. Xcel-17 at 72 (Halama Direct).

requests the Commission depart from past practice and allow it to recover 100 percent of investor relations expenses.<sup>255</sup>

Xcel cannot support 100 percent recovery simply by incurring costs. “By merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.”<sup>256</sup> As Witness Lee explains, “Other than listing the activities that make up the investor relations costs, the Company does not attempt to determine the amount of costs that are for activities that benefit ratepayers.”<sup>257</sup> Indeed, Xcel provided even less evidence regarding the reasonableness of these costs than it said it did. While the OAG raised this issue in direct testimony, Xcel’s rebuttal appears incomplete. Xcel stated that it responded to the OAG’s concerns, but no such response exists.<sup>258</sup> Xcel Witness Hamala provided a table of issues in his rebuttal testimony<sup>259</sup> that identified Witness Wehner’s testimony as responsive to the OAG’s concerns.<sup>260</sup> Witness Wehner’s rebuttal stated on the first page that he “discussed the importance of the Company’s Investor Relations efforts.”<sup>261</sup> But on the very next page, in response to the question about what his testimony addresses, he responded solely to two arguments made by the Department.<sup>262</sup> Neither of those two arguments are about investor relations expenses. Xcel neglected to address the OAG’s

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<sup>255</sup> *Id.*

<sup>256</sup> *In re Petition of N. States Power Co.*, 416 N.W.2d 722-723 (Minn. 1987).

<sup>257</sup> Ex. OAG-5 at 14 (Lee Direct).

<sup>258</sup> See Table 3, Witness Halama’s testimony

<sup>259</sup> Ex. Xcel-19 at 63, Table 3 (Halama Rebuttal).

<sup>260</sup> *Id.* at 67.

<sup>261</sup> Ex. Xcel-21 at 1 (Wehner Rebuttal).

<sup>262</sup> See *id.* at 2 (Wehner Rebuttal) (“My Rebuttal Testimony will be limited to responding to two arguments made by Department witness Addonizio. I will also provide an update on the final pricing of the Company’s 2025 long-term debt issuances.”).

argument, and the record that would supposedly justify recovery for *any* investor relations expenses is not there.

Even if Xcel had made an argument as to the appropriate recovery of investor relations expenses, historically the Commission has disallowed fifty percent of these costs.<sup>263</sup> In Xcel's 2012 rate case, the Commission adopted the ALJ's determination that it should only recover 50 percent of its investor relations costs.<sup>264</sup> The ALJ found that some of the costs "are of no or partial benefit to ratepayers."<sup>265</sup> "Absent a more exact method of allocation," the ALJ adopted the Department's recommendation to allow 50 percent recovery.<sup>266</sup> The Commission adopted these findings.<sup>267</sup> The Company only requested recovery of 50 percent of investor relations expenses in its 2021 rate case consistent with this finding.<sup>268</sup> Fifty percent recovery remains the maximum appropriate amount of recovery for Xcel's investor relations expenses.

**J. Xcel's Shareholders Benefit from Rate Case Expenses and They Should Help Pay for Them.**

In this case, Xcel has continued to increase the amount requested for recovery of rate case expenses, requesting to recover \$4,919,912, amortized over three years.<sup>269</sup> The OAG recommends

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<sup>263</sup> See, e.g., *In re Application by CenterPoint Energy Minn. Gas, a div. of CenterPoint Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Util. Serv. in Minn.*, MPUC Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 22 (June 9, 2014) (eDocket No. [20146-100252-01](#)).

<sup>264</sup> *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 16 (Sep. 3, 2013) (eDocket No. [20139-90902-01](#)) (12-961 RATE CASE ORDER).

<sup>265</sup> *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION at 108 (July 5, 2013) (eDocket No. [20137-88857-01](#)) (ALJ Order).

<sup>266</sup> *Id.*

<sup>267</sup> 12-961 RATE CASE ORDER at 46, Order Point 2 (Sep. 3, 2013).

<sup>268</sup> Ex. OAG-5 at 14 (Lee Direct).

<sup>269</sup> Ex. Xcel-7, Vol. 4.VIII.A31 at 2 (Appl. Vol. 4, MYRP Workpapers) (eDocket No. [202411-211521-01](#)).

a fifty-fifty split between ratepayers and shareholders to recognize that shareholders benefit from rate cases and to incentivize efficiency and cost containment.

Rate case expenses include a combination of costs for outside experts, anticipated regulatory fees, anticipated legal fees, and estimated costs.<sup>270</sup> Xcel's budget in this case includes over \$2.5 million for outside legal fees, \$290,000 for consultants, \$1.5 million in regulatory fees and over \$600,000 in administrative costs, amortized over three years.<sup>271</sup> The utility has control over many of these costs. Yet, if Xcel is allowed to recover all of its rate case costs from ratepayers, Xcel has no incentive to manage them. Instead, these expenses should be split equally between shareholders and ratepayers to reflect the benefits that shareholders receive from rate increase requests and to incentivize Xcel to manage these ballooning costs.

Rate cases benefit shareholders by allowing the utility to increase its revenue requirement, which supports the utility's ability to issue consistent dividends.<sup>272</sup> In addition, specific expenses directly benefit shareholders, such as the utility's cost-of-capital and return-on-equity witnesses that benefit shareholders by arguing for a higher return.<sup>273</sup>

Xcel counters that rate cases are designed to "further a utility's right to recover prudently incurred costs necessary to provide service, including a fair return on investment."<sup>274</sup> But this merely repeats the statutory directive and does not explain why customers must pay 100 percent of Xcel's rate case expenses.<sup>275</sup>

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<sup>270</sup> Ex. OAG-5 at 15 (Lee Direct).

<sup>271</sup> *Id.* at 16.

<sup>272</sup> *Id.* at 17.

<sup>273</sup> *Id.* at 18 (Lee Direct).

<sup>274</sup> Ex. Xcel-19 at 44 (Halama Rebuttal).

<sup>275</sup> Ex. OAG-7 at 14-15 (Lee Surrebuttal).

Rate case expenses are not, as Xcel suggests, outside of the Company’s control.<sup>276</sup> 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. And Xcel has not provided evidence of how it seeks to contain rate case expenses, and instead offers generalities about how it works “across all areas of the Company to contain costs and manage [] overall reasonable budget levels.”<sup>277</sup> But these generalities stand in stark contrast to Xcel’s ballooning rate case expense since 2013.<sup>278</sup>

The inflation of Xcel’s historic rate case expenses is staggering. In Xcel 2013 rate case, the Commission approved \$2,714,433.<sup>279</sup> Rate case expense then jumped 23 percent<sup>280</sup> to \$3,339,545 in Xcel’s 2015 rate case.<sup>281</sup> The costs then swelled again in the last rate case to \$4,686,303—a 40 percent increase.<sup>282</sup> Xcel now asks to recover approximately \$230,000 more than its last rate case.<sup>283</sup> Without any incentive to contain these costs, they will likely continue to increase.

Other commissions and legislatures have reined in investor-owned utilities’ rate case expenses that are passed on to customers. For example, the New Hampshire Public Utilities Commission requires a bidding process if rate case expense is estimated to be more than \$10,000.<sup>284</sup> Both New Jersey and Missouri have ordered that only 50 percent of rate case expenses

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<sup>276</sup> Ex. Xcel-19 at 45 (Halama Rebuttal) (“[T]he drivers of rate case expenses are not wholly in the utility’s control.”).

<sup>277</sup> *Id.*

<sup>278</sup> Ex. OAG-7 at 16 (Lee Surrebuttal).

<sup>279</sup> *Id.*

<sup>280</sup>  $\frac{\$3,339,545 - \$2,714,433}{\$2,714,433} \times 100$

<sup>281</sup> Ex. OAG- at 16 (Lee Surrebuttal).

<sup>282</sup> *Id.*

<sup>283</sup> \$4,919,912 - \$4,686,303 = \$233,609. While this is a less extreme increase, Xcel’s current rate case filing comes only three years after its last rate case, and Xcel’s multi-year rate plan only included two years rather than the three years of financials and requests in 2021 and 2015.

<sup>284</sup> Ex. OAG-7 at 16 (Lee Surrebuttal) (citing N.H. Code Admin. R. PUC 1905.04 (2024)).

may be recovered from ratepayers, recognizing that shareholders benefit from rate cases.<sup>285</sup> The Missouri PUC also aptly recognized that “Awarding a utility all of its incurred rate case expenses could provide that utility with a significant financial advantage over other participants in the rate case process, who may be constrained by budgetary and other financial restrictions.”<sup>286</sup> The Missouri PUC also observed that 100 percent recovery “does not encourage reasonable levels of cost containment in the utility’s rate case expense decisions.”<sup>287</sup> The Connecticut legislature has gone further and prohibited the recovery of any rate case expenses.<sup>288</sup>

The Commission should follow these other states and recognize that splitting rate case expense between ratepayers and shareholders is both fairer and promotes efficiency. To accomplish this, the Commission should remove \$819,986 from both the 2025 test year and the 2026 plan year.<sup>289</sup>

**K. Xcel’s Proposed Targeted Undergrounding Requires Ratepayer Protections.**

A cost cap on Xcel’s proposed targeted undergrounding is a necessary and reasonable consumer protection for ratepayers. The OAG has proposed a cost cap for targeted undergrounding because of discrepancies in Xcel’s cost estimates to explore targeted undergrounding.<sup>290</sup> The proposed cost cap is \$1.5 million per mile, using the highest estimates from Xcel.<sup>291</sup> Xcel opposes capping these costs because there is a difference in cost between locations and construction types.

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<sup>285</sup> Ex. OAG-5 at 20-21, SL-D-6 – SL-D-7 (Lee Direct) (attaching orders of the New Jersey Board of Public Utilities and Missouri Public Utilities Commission).

<sup>286</sup> *Id.*, SL-D-7 at 3.

<sup>287</sup> *Id.*

<sup>288</sup> Ex. OAG-5, SL-D-9 (Lee Direct) (Conn. Gen. Stat. Ann. § 16-243p).

<sup>289</sup> Ex. OAG-7 at 13 (Lee Surrebuttal).

<sup>290</sup> *Id.* at 25.

<sup>291</sup> Ex. OAG-7 at 25 (Lee Surrebuttal) (“The cap should be the initial 7 cost estimates provided by the Company, which at the highest is \$1.5 million per mile”).

However, a lack of a cost cap would expose ratepayers to funding what could amount to rated-based exploration costs.

Xcel proposed the targeted undergrounding program in its 2024 annual Safety, Reliability, and Service Quality docket to address lengthy interruptions.<sup>292</sup> The first cost estimates were submitted in April 2025 and Xcel estimated a cost of between \$1 million and \$1.5 million per mile.<sup>293</sup> Then, when Xcel filed its rate case, it claimed costs had skyrocketed to \$2.3 million per mile in the test year and \$2.2 million in the plan year.<sup>294</sup> Yet, at the same time, Xcel claimed that it was still identifying where to conduct the targeted undergrounding and its engineering assessments had not even begun.<sup>295</sup> Xcel thus doubled its low-end estimate without even knowing where it would be implementing the program.

The Commission should cap recovery of targeted undergrounding at \$1.5 million per mile for the entire Multi-Year Rate Plan in keeping with its April 2025 budget. The Commission has found cost caps appropriate to hold regulated utilities accountable to their proposed budgets. This has occurred when looking at transmission rider recovery dockets.<sup>296</sup> Xcel stated it is “refining these projects,” but it did not update the budget forecast for 2025 to reflect actual capital expenditures and capital additions, despite the chance to do so.<sup>297</sup> Xcel could have provided the

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<sup>292</sup> Ex. OAG-5 at 31-32 (Lee Direct).

<sup>293</sup> *Id.* at 33.

<sup>294</sup> *Id.*

<sup>295</sup> *Id.*, SL-D-15 at 4 (Lee Direct).

<sup>296</sup> See *In re N. States Power Co., a Minn. Corp., d/b/a Xcel Energy, for Approval of a Modification to Its TCR Tariff, 2010 Project Eligibility, TCR Rate Factors, Continuation of Deferred Accounting and 2009 True-up Report*, MPUC Docket No. E-002/M-09-1048, ORDER APPROVING 2010 TCR TRACKER REPORT, AND TCR RATE FACTORS at 8 (Apr. 27, 2010) (eDocket No. [20104-49616-01](#)).

<sup>297</sup> Ex. OAG-7 at 25 (Lee Surrebuttal).

OAG with ten months of actual expenses for the 2025 Test Year.<sup>298</sup> Xcel failed to carry its burden, so capital expenses for targeted undergrounding over \$1.5 million per mile should be disallowed.

**L. Xcel May Be Making Minnesota Pay for Other States' Wildfire Costs.**

Xcel Energy Inc. (XEI) is the parent company of several operating companies, including its Minnesota utility, Northern States Power Minnesota (NSPM), its Colorado utility, Public Service Company of Colorado (PSCo), and its service company Xcel Energy Services (XES), among other holdings. The Company proposes allocating indirect wildfire mitigation costs using the Total Plant Ratio (TPR).<sup>299</sup> Using TPR is inappropriate here because the operating companies have different wildfire risks and do not equally cause indirect wildfire costs. Although the Company acknowledges that wildfire risks vary across different parts of the country, it continues to request an allocation that does not follow cost causation.<sup>300</sup>

Xcel has not carried its burden to show that its indirect wildfire cost allocation across jurisdictions is reasonable. Despite providing direct and indirect wildfire risk management costs, Xcel only calculated the information according to the Total Plant Ratio.<sup>301</sup> This is problematic because the total plant ratio assumes that all plants, regardless of their jurisdiction, equally cause the wildfire risk management costs.<sup>302</sup> Instead, Xcel should perform a more appropriate allocation by determining the ratio of direct wildfire costs incurred by its various jurisdictions and operating companies and use that ratio to assign indirect wildfire costs. But Xcel refused to provide this information or perform this allocation. Therefore, all of Xcel's indirect wildfire costs should be denied.

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<sup>298</sup> *Id.*

<sup>299</sup> Ex. Xcel-50 at 13 (Doyle Rebuttal).

<sup>300</sup> *Id.* at 20.

<sup>301</sup> Ex.OAG-7 at 22 (Lee Surrebuttal).

<sup>302</sup> Ex. OAG-5 at 27 (Lee Direct).

Despite wildfire risks and mitigation strategies evolving as a newer issue, Xcel claims that a decades old approach known as the Cost Assignment and Allocation Manual (CAAM) must be used.<sup>303</sup> However, wildfire mitigation costs, because they vary across different parts of the country, could be directly assigned as a common cost. This would be consistent with CAAM principles.<sup>304</sup> The CAAM states that for cost causation “all activities or jurisdictions that cause the cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred....”<sup>305</sup> The OAG’s proposal to directly assign wildfire mitigation costs at a jurisdictional level follows this principal in the CAAM.

The OAG’s recommendation also follows the principle in the CAAM which 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.”<sup>306</sup> A jurisdiction that incurs more direct wildfire risk management costs logically has a greater need for wildfire risk mitigation. Therefore, the jurisdiction should also be responsible for more indirect wildfire risk management costs.<sup>307</sup>

While the OAG’s recommendation to use the ratio of direct wildfire costs to assign indirect wildfire costs is reasonable, the OAG was not able to perform this calculation because Xcel refused to provide the total direct costs in discovery or rebuttal.<sup>308</sup> Because Xcel has not provided a reasonable alternative allocation, the full amount of indirect wildfire costs that Xcel proposes to be assigned to Minnesota should be disallowed. This adjustment would remove \$1.7 million from the 2025 Test Year and \$1.8 million from the 2026 Plan Year.<sup>309</sup>

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<sup>303</sup> Ex. Xcel-50 at 16 (Doyle Rebuttal).

<sup>304</sup> *Id.*

<sup>305</sup> Ex. OAG-7 at 17 (Lee Rebuttal) (citing part of the CAAM manual).

<sup>306</sup> *Id.* at 21 (Lee Surrebuttal).

<sup>307</sup> *Id.*

<sup>308</sup> *Id.* at 20; Ex. OAG-5 at 29, SL-D-14 (Lee Direct).

<sup>309</sup> Ex. OAG-7 at 23 (Lee Surrebuttal).

**M. The Commission Should Deny the Good Neighbor Plan (NOx) Tracker Because Denial Would Not Prejudice Xcel and the Good Neighbor Plan May Never Be Implemented.**

Xcel has requested creation of a “tracker” for costs arising from compliance with the Environmental Protection Agency’s (EPA) Good Neighbor Plan (GNP) rule. 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.<sup>310</sup> The Commission may only grant deferred accounting for “good cause shown,”<sup>311</sup> 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<sup>312</sup> or when a utility incurs unforeseen and unusual expenses that are large enough to have a significant impact on the utility’s financial condition.<sup>313</sup> Trackers are considered “highly unusual ratemaking treatment.”<sup>314</sup>

The Commission should reject Xcel’s request for a GNP tracker because the GNP is not in effect and may never go into effect. The GNP arose from a series of regulatory actions that began during the Obama administration. In 2015, the EPA set National Ambient Air Quality Standards that limited nitrogen oxide emissions from power plants.<sup>315</sup> States created State Implementation Plans (SIPs) for compliance with the NAAQS, but the EPA rejected many of these SIPs, including

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<sup>310</sup> *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](#)).

<sup>311</sup> Minn. R. 7825.0300, subp. 4.

<sup>312</sup> *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](#)).

<sup>313</sup> *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).

<sup>314</sup> *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).

<sup>315</sup> Ex. Xcel-59 at 4 (West Direct).

Minnesota's.<sup>316</sup> The EPA then issued the GNP, which imposed requirements on all states for which SIPs were denied.<sup>317</sup> However, the GNP was stayed by the Supreme Court in 2024, and the stay remains in effect.<sup>318</sup> In the meantime, the EPA has begun the process of reconsidering both the GNP and the rejected underlying SIPs.<sup>319</sup> Even if the GNP is not simply eliminated through this process, Xcel conceded that whether Xcel will need to incur any GNP-related costs at all depends on what the revised rule ends up being.<sup>320</sup>

There is thus significant doubt as to whether Xcel will ever incur any costs related to the GNP, doubt which must be resolved in favor of ratepayers.<sup>321</sup> Even if some form of revised GNP is ultimately approved, the revised GNP may not result in cost increases for Xcel.<sup>322</sup> Furthermore, Xcel could not say when any of these questions regarding the GNP might be resolved.<sup>323</sup> Indeed, with no action on the GNP as of the closing of the evidentiary record in December 2025, it is likely that no GNP-related costs will be incurred during either the test year or plan year of this rate case. Last, Xcel would not be prejudiced by denial of the tracker, because it can always request deferred accounting by filing a petition with the Commission—which is the more appropriate procedure for “out of test year” costs.<sup>324</sup>

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<sup>316</sup> *Id.*

<sup>317</sup> *Id.*

<sup>318</sup> Tr. Vol. 1 at 216 (West); *Ohio v. Environmental Protection Agency*, 603 U.S. 279 (2024).

<sup>319</sup> Tr. Vol. 1 at 216-217 (West).

<sup>320</sup> Tr. Vol. 1 at 218 (West).

<sup>321</sup> Minn. Stat. § 216B.03.

<sup>322</sup> Tr. Vol. 1 at 218 (West).

<sup>323</sup> Tr. Vol. 1 at 217 (West).

<sup>324</sup> *See* Ex. OAG-3 at 49-50 (Hinderlie Surrebutal) (stating that the appropriate mechanism for deferred accounting is a request in a non-rate case docket).

Xcel has failed to demonstrate good cause for creation of a tracker for costs that Xcel is currently not obligated to incur and may indeed never incur. The Commission should therefore deny the request to create a tracker for GNP compliance costs.

### **III. RATE DESIGN – CLASS COST OF SERVICE (CCOSS)**

In the second phase of a rate case, commonly referred to as “rate design,” the Commission determines how recovery of the utility’s revenue requirement will be apportioned among its customer classes and how rates will be structured within classes. Both interclass revenue apportionment and intraclass rate design require the Commission to “balance[e] both cost and non-cost factors and making choices among public policy alternatives” to determine just and reasonable rates.<sup>325</sup>

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. Parties often develop class-cost-of-service studies (CCOSSes) to inform their revenue-apportionment recommendations. A CCOSS has three steps: functionalization, classification, and allocation.<sup>326</sup> First, costs are “functionalized” into various categories that reflect the basic elements of the electric system, such as generation, transmission, distribution.<sup>327</sup> Then, 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.<sup>328</sup> Then costs are allocated among the various customer classes based on the class’s relative contribution to overall peak demand, energy consumption, or number of customers.<sup>329</sup>

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<sup>325</sup> *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm’n*, 251 N.W.2d 350, 358 (Minn. 1977).

<sup>326</sup> Ex. OAG-8 at 3 (Scharber Direct).

<sup>327</sup> *Id.*

<sup>328</sup> *Id.* 3–4.

<sup>329</sup> *Id.* at 4.

The main goal of the CCOSS is to estimate how a utility's costs are caused by various customer classes.<sup>330</sup> While there are conventions guiding the process, there is no one correct method for doing so and no objective class costs to rely on for revenue apportionment.<sup>331</sup> Instead, a CCOSS, like any model, is only as reasonable as its assumptions, though CCOSSes based on more reasonable assumptions should be given more weight in the Commission's consideration of revenue apportionment and rate design.<sup>332</sup> CCOSSes with unreasonable assumptions should be given less or no weight. This approach recognizes that CCOSS results are subjective but refrains from concluding that they are all equally valid.<sup>333</sup>

There is significant debate regarding both the CCOSSes that should be used in this case and which methods Xcel should be required to use in performing CCOSSes in future rate cases.

**A. In this Rate Case, the OAG's CCOSSes Are the Most Reasonable in the Record and Should be Given the Most Weight.**

In this case, the OAG's CCOSSes are the most reasonable and supported in the record, and the Commission should give them the most weight in its revenue allocation and rate design decisions. Xcel's CCOSSes include unreasonable assumptions in several areas. And the Xcel Large Industrials (XLI's) modifications to Xcel's CCOSS are likewise unreasonable. Xcel's and XLI's CCOSSes include unreasonable classifications and allocations for production plant and production O&M. Xcel, XLI, and the Department all support CCOSSes that classify an unreasonable portion of distribution plant to customer costs. Last, Xcel's proposed change to its method for allocating economic development discounts for large customers is unsupported and may create significant class cost shifts as Xcel adds large data center customers.

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<sup>330</sup> *Id.* at 2–3.

<sup>331</sup> *See id.* at 3.

<sup>332</sup> *See id.* at 5.

<sup>333</sup> *Id.*

**1. The Commission should adopt OAG’s recommendations for classification and allocation of fixed production plant.**

Fixed production plant comprises a large portion of a vertically-integrated utility’s capital costs. As such, determining a reasonable classification and allocation method for these costs is imperative. There are two main disputes regarding the classification and allocation of fixed production plant. First, the OAG agrees with Xcel—and disagrees with XLI—that the Stratification method should continue to be used to classify these costs. Second, the OAG recommends improvements to Xcel’s D10S allocator to allocate demand-related production plant costs.

**a. The Commission should continue to use the Stratification Method to classify Xcel’s fixed production plant.**

Xcel classifies fixed production plant using the Stratification Method, which Xcel has used with Commission approval since the late 1970s.<sup>334</sup> 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.<sup>335</sup> 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.<sup>336</sup>

XLI proposes to replace the Stratification method with a method called the Average and Excess Demand – Four Coincident Peak (AED-4CP).<sup>337</sup> The Commission should continue to rely on the Stratification Method.<sup>338</sup> The Commission rightly rejected XLI’s same argument in Xcel’s

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<sup>334</sup> Ex. Xcel-73 at 15 (Barthol Direct).

<sup>335</sup> Ex. OAG-9 at 2 (Scharber Rebuttal).

<sup>336</sup> *Id.*

<sup>337</sup> Ex. XLI-3 at 3, 7-8, 11 (Jonathan Ly Direct).

<sup>338</sup> *See, e.g.* 21-630 ORDER at 96-97; 13-868 INITIAL RATE CASE ORDER at 64; 12-961 RATE CASE ORDER at 15.

last rate case and found that the Stratification Method “provides a sounder rationale for distinguishing between energy-related and capacity-related costs” than the AED-4CP method.<sup>339</sup>

XLI’s arguments against the Stratification Methods continue to be misplaced. XLI argues that the Stratification Method 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.<sup>340</sup> 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. This would almost certainly overstate the contribution of wind resources to meeting peak demand.<sup>341</sup> 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.<sup>342</sup> Nor does the fact that utilities invest in capital-intensive renewable resources in part to meet environmental goals change the fact that it is appropriate to classify the great majority of these costs as energy-related simply because they also provide some demand-related benefits.<sup>343</sup>

The Commission should likewise again reject XLI’s recommendation to use the AED-4CP “average and excess demand”-type allocator.<sup>344</sup> 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-

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<sup>339</sup> See 21-630 ORDER at 96-97.

<sup>340</sup> See Ex. XLI-3 at 7–8 (Jonathan Ly Direct).

<sup>341</sup> Ex. OAG-9 at 3 (Scharber Rebuttal).

<sup>342</sup> *Id.*; Ex. DOC-18 at 4 (Zajicek Surrebuttal).

<sup>343</sup> 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 id.* at 4.

<sup>344</sup> See 21-630 ORDER at 96-97; Ex. XLI-3 at 3, 11 (Jonathan Ly Direct).

coincident peak demand and the class’s average demand.<sup>345</sup> XLI’s AED-4CP method is not reasonable. 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.”<sup>346</sup> 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.<sup>347</sup> Third, XLI’s AED-4CP method does not rely on MISO-coincident peaks,<sup>348</sup> which the Commission has required Xcel to use in its generation demand allocator.<sup>349</sup>

The Commission should continue to find that the Stratification Method “provides a sounder rationale for distinguishing between energy-related and capacity-related costs than the distinction between average and excess energy consumption.”<sup>350</sup>

**b. The Commission should use the OAG’s updated D10S allocator to allocate demand-related production plant.**

Xcel allocates demand-related production-plant costs using the “D10S” allocator, which represents each class’s share of electric demand during a single annual peak hour.<sup>351</sup> The D10S allocator, like any peak-demand allocator, requires a working definition of the “peak” time.

In Xcel’s last rate case, the Commission ordered Xcel to use its “system peak coincident with the MISO system peak using historical data.”<sup>352</sup> But Xcel’s implementation of the Commission’s order is unreasonable. First, Xcel identified the hour that MISO’s system peaked in

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<sup>345</sup> Ex. OAG-9 at 7 (Scharber Rebuttal).

<sup>346</sup> *Id.* at 9–10.

<sup>347</sup> *Id.* at 10.

<sup>348</sup> *Id.* at 10.

<sup>349</sup> See 21-630 ORDER at 98.

<sup>350</sup> *Id.* at 97.

<sup>351</sup> Ex. OAG-8 at 5 (Scharber Direct).

<sup>352</sup> 21-630 ORDER at 99.

2023, which was August 23 at 4 p.m. CST.<sup>353</sup> Xcel then determined the D10S allocators for its 2025 and 2026 CCOSSES by identifying the class load shares at 4 p.m. on August 23, 2025 and August 23, 2026 from its class load forecasts.<sup>354</sup>

There are at least three problems with Xcel’s method. First, 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. August 23 falls on a Saturday in 2025 and on a Sunday in 2026, yet over 2006–2024, the MISO peak has never occurred on a weekend day.<sup>355</sup> In other words, Xcel took a Commission directive to use a D10S allocator that represents MISO’s peak and came up with an allocator that is very unlikely to represent a peak.

Second, contrary to the Commission’s directive, Xcel’s D10S allocator is not based on historical data. While it relies on MISO’s actual peak from 2023, Xcel used forecasted, not historical, data to determine the class shares themselves.<sup>356</sup> Xcel argues that “[u]sing historical data for a future test year would create a mis-match and reduce the precision of the cost allocation process.”<sup>357</sup> But this does not make Xcel’s methodology correct. Instead, using class load data corresponding to the month, day, and year of the MISO peak—adjusted for forecasted changes to class load shares—would enhance the precision of the cost-allocation process because the allocator would represent class load shares at the time of an actual system peak.<sup>358</sup> While historical class shares may not perfectly predict class shares in the test year, they are more likely to resemble test-

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<sup>353</sup> Ex. OAG-8 at 7 (Scharber Direct).

<sup>354</sup> *Id.*

<sup>355</sup> *Id.*

<sup>356</sup> *Id.*

<sup>357</sup> *Id.*

<sup>358</sup> *Id.* at 8.

year conditions than are shares from an essentially random day that corresponds to the peak from a different year.<sup>359</sup>

Third, Xcel's D10S allocator is unduly sensitive to the choice of a single peak hour.<sup>360</sup> This can be seen by comparing the class shares that result using the MISO peaks from 2023 and 2024.<sup>361</sup> MISO's peak in 2023 occurred on August 23 at 4 p.m. In 2024, it occurred on August 26 at 4 p.m.<sup>362</sup> Applying these historical peaks to Xcel's 2025 and 2026 load forecasts, the residential class's peak-demand share changes substantially from 40.41 percent in 2025 and 41.14 percent in 2026 (using the 2023 peak) to 33.91 percent in 2025 and 33.09 percent in 2026 (using the 2024 peak).<sup>363</sup>

To avoid arbitrary shifts in class shares based on a single assumption, the OAG designed a more robust D10S allocator for use in its CCOSSes.<sup>364</sup> Since MISO does not publish forecasted peaks, the OAG reviewed MISO's peaks from 2011 to 2024 to determine the range of days and times most likely to include the MISO peak.<sup>365</sup> The OAG's review resulted in the following findings: (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.<sup>366</sup> Since Xcel does not currently have historical class-load data,<sup>367</sup> the OAG next looked at Xcel's load forecasts for

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<sup>359</sup> *Id.* at 8. Historical data, however, should be adjusted to account for forecasted load growth. To achieve this in the future, Dr. Scharber recommended that when actual hourly load data by class becomes available, Xcel should "calculate the MISO-coincident peak-demand allocator by adjusting the historical class loads coincident with recent MISO peaks to reflect projected changes in class loads for the test year." Ex. OAG-10 at 12 (Scharber Surrebuttal).

<sup>360</sup> Ex. OAG-8 at 8 (Scharber Direct).

<sup>361</sup> *Id.*

<sup>362</sup> *Id.* at 9 tbl.1.

<sup>363</sup> *Id.* at 9 tbl.1.

<sup>364</sup> *See id.* at 9–13.

<sup>365</sup> *Id.* at 11.

<sup>366</sup> *Id.* at 11–12.

<sup>367</sup> *See id.* at 11.

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.<sup>368</sup> 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.<sup>369</sup>

Xcel and XLI both object to the OAG’s Alternate D10S Allocator on the basis that it includes too many hours.<sup>370</sup> Xcel argues 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.”<sup>371</sup> XLI likewise argues that the OAG’s allocator “is overly broad and includes a significant number of hours that do not reflect peak conditions.”<sup>372</sup> Contrary to Xcel and XLI’s arguments, however, including multiple hours in the production demand allocator has 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.<sup>373</sup>

Xcel criticizes the OAG’s Alternate D10S Allocator for not reflecting a high enough percentage of the Company’s Minnesota load coincident with the 2025 NSP system peak.<sup>374</sup> There are at least two issues with this. First, the NSP system peak is the not the relevant comparison—the Commission has directed that the peak-demand allocator should reflect Xcel’s load coincident with MISO’s peak.<sup>375</sup> Second, Xcel’s single-peak-hour-based D10S allocator actually fares worse than the OAG’s allocator under Xcel’s own percent-of-NSP-coincident-peak metric, representing

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<sup>368</sup> *Id.* at 12.

<sup>369</sup> *Id.* at 12 & tbl.2 (Scharber Direct).

<sup>370</sup> *See* Ex. Xcel-74 at 17 (Barthol Rebuttal); Ex. XLI-6 at 5 (Jonathan Ly Rebuttal).

<sup>371</sup> Ex. Xcel-74 at 17 (Barthol Rebuttal).

<sup>372</sup> Ex. XLI-9 at 5 (Jonathan Ly Surrebuttal).

<sup>373</sup> *See* Ex. OAG-10 at 5–6 (Scharber Surrebuttal) (citing NARUC’s cost-allocation manual).

<sup>374</sup> Ex. Xcel-74 at 17 (Barthol Rebuttal).

<sup>375</sup> 21-630 ORDER at 99.

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.<sup>376</sup> 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.<sup>377</sup> Xcel fails to explain why it prefers an allocator that represents a lower share of Minnesota's NSP-coincident peak load, since this appears to be its main concern with the OAG's D10S allocator.

Xcel and XLI also ignore the uncertainty inherent in trying to predict class loads at future peak hours.<sup>378</sup> While load forecasting is unavoidable when using a future test year, it is equally important not to put too much stock in any one estimate of class loads at the peak hour because there is too much uncertainty baked into these estimates, and too much money at stake.<sup>379</sup> Yet Xcel and XLI put all their chips on one number by relying on Xcel's single-peak D10S allocator. When the roulette wheel of the calendar turned in 2025 and 2026, those chips all fall on weekend days, when weekend peaks have not occurred in MISO since at least 2006. The Commission should instead rely on the OAG's more robust Alternate D10S Allocator for apportioning class cost responsibility in this case. And as discussed in Section III.B.1 below, the Commission should direct Xcel to move toward an allocator that reflects a broader conception of peak demand.

## **2. The Commission should reject XLI's recommendations on classification and allocation of other production O&M costs.**

Other production O&M expenses are the nonfuel costs incurred to operate a power plant, including labor, chemicals, information technology, maintenance, and licensing.<sup>380</sup> Aside from

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<sup>376</sup> Ex. OAG-10 at 4 (Scharber Surrebuttal).

<sup>377</sup> *Id.*

<sup>378</sup> *Id.* at 7.

<sup>379</sup> *Id.* at 7.

<sup>380</sup> Ex. OAG-9 at 12 (Scharber Rebuttal).

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.<sup>381</sup> 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.<sup>382</sup>

As with fixed production plant, XLI argues that the Stratification Method should not be used to classify other production O&M expenses.<sup>383</sup> XLI also 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.<sup>384</sup> XLI instead recommends that “labor-related other production O&M expenses should be allocated on AED-4CP.”<sup>385</sup> Finally, XLI argues that regional market expenses, another component of other production O&M, are largely labor-related and should be allocated “the same as NSPM’s generation and transmission plant using AED-4CP and D10S allocators.”<sup>386</sup> The Commission should reject these proposals.

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.<sup>387</sup> This classification is no more appropriate than classifying a coal or wind plant entirely as demand on the basis that the plants’ costs do not vary directly with production.<sup>388</sup> Rather, because a significant share of the O&M costs required to support coal and wind plants are incurred

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<sup>381</sup> Ex. Xcel-73 at 30 tbl.13 (Barthol Direct).

<sup>382</sup> *Id.*

<sup>383</sup> Ex. XLI-3 at 16 (Jonathan Ly Direct).

<sup>384</sup> *Id.* at 16–17.

<sup>385</sup> *Id.* at 17.

<sup>386</sup> *Id.*

<sup>387</sup> Ex. OAG-9 at 13 (Scharber Rebuttal).

<sup>388</sup> *Id.*

to provide reliable energy throughout the year, that share is appropriately classified as energy-related.<sup>389</sup> XLI fails to explain why labor costs should be fully classified as demand-related when they do not vary directly with capacity.<sup>390</sup> Finally, XLI’s recommendation to allocate regional market expenses “the same as NSPM’s generation and transmission plant using AED-4CP and D10S allocators” represents a change in functionalization—since these expenses are currently functionalized as generation—but XLI does not explain how this change would be operationalized.<sup>391</sup>

**3. The Commission should follow its past practices to consider multiple methodologies for classifying shared distribution costs and should give the OAG’s CCOSSES the most weight.**

In Xcel’s last rate case, the Commission directed Xcel to file three CCOSSES in the next rate case using three different methods for classifying distribution-system costs:<sup>392</sup>

- The Minimum System Method, which first estimates the costs of a hypothetical system that carries little to no load,<sup>393</sup> and then classifies the costs of this hypothetical “minimum” system as customer-related and the remainder of the distribution system as demand-related.<sup>394</sup> The Minimum System Method has two main variations, the Minimum-Size Method and Zero-Intercept Method.<sup>395</sup> The Minimum-Size Method uses a minimum-size piece of relevant equipment and assumes that any larger equipment must serve demand.<sup>396</sup> 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).<sup>397</sup>

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<sup>389</sup> *Id.*

<sup>390</sup> *Id.*

<sup>391</sup> *Id.* at 13–14.

<sup>392</sup> 21-630 ORDER at 105–06.

<sup>393</sup> Ex. OAG-8 at 19 (Scharber Direct).

<sup>394</sup> *Id.*

<sup>395</sup> Ex. Xcel-73 at 36 (Barthol Direct).

<sup>396</sup> *Id.*

<sup>397</sup> *See id.* at 36-37, 39; Ex. DOC-16, sched. 1 at 19 (Zajicek Direct).

- 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).<sup>398</sup>
- 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.<sup>399</sup>

The Commission found that each classification method had merit and that considering all of them would bring an appropriately broad perspective to its class-cost-of-service analysis.<sup>400</sup>

Xcel provided all three required CCOSS variations with its initial filing in this case.<sup>401</sup> It prefers the Minimum System Method and bases its revenue apportionment on that method alone.<sup>402</sup> Xcel’s Minimum System CCOSS uses a hybrid of the Minimum-Size Method and Zero-Intercept Method.<sup>403</sup> Xcel argues that the Minimum System Method is the most reasonable because “the addition of customers is a significant determinant of distribution system costs.”<sup>404</sup> XLI also supports the Minimum System Method for the same reason.<sup>405</sup> 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.<sup>406</sup>

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<sup>398</sup> Ex. OAG-8 at 20 (Scharber Direct).

<sup>399</sup> *Id.* 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. *Id.*

<sup>400</sup> 21-630 ORDER at 105.

<sup>401</sup> Ex. Xcel-73 at 33–34 (Barthol Direct).

<sup>402</sup> *Id.* at 48; Ex. Xcel-76 at 11 & n.2 (Paluck Direct).

<sup>403</sup> Ex. Xcel-73 at 41 (Barthol Direct).

<sup>404</sup> 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).

<sup>405</sup> Ex. XLI-3 at 24–25 (Jonathan Ly Direct).

<sup>406</sup> Ex. DOC- 16 at 46 (Zajicek Direct); Ex. DOC-19 at 25 (Bahn Direct).

The Commission should continue to consider all three approaches to the classification of distribution plant, but it should not give the Minimum System Method additional weight. The Minimum System Method contains significant flaws that over-classify shared distribution system costs as customer related. Further, these parties' argument against the Peak-and-Average Method that the distribution system does not include energy-related costs is misplaced. Their argument that because some shared distribution plant is incurred to serve customers it must be primarily classified as customer related ignores common cost classification for other plant.<sup>407</sup> Last, their dismissal of the Peak-and-Average Method, and any classification of energy costs in the distribution-system, because they cannot locate the method in the 1992 NARUC manual is short-sighted and uninformed.

It is particularly important not to rely solely on the Minimum System Method, as Xcel and XLI advocate, because the Minimum System Method overstates the customer-related portion of the distribution system.<sup>408</sup> Not only is this inaccurate as a matter of cost-causation, it also harms classes with large numbers of customers, such as the residential class. Overstating the customer-related portion is inaccurate because it inaccurately assumes the main driver of minimum-size shared distribution costs is the number of customers, when the main driver of distribution costs is not number of customers but the size of a utility's service territory.<sup>409</sup> Since there is no conventional classification for costs that vary by service area size, cost analysts tend to use the customer-cost category as a "dumping ground" for costs that cannot be plausibly attributed to demand or energy.<sup>410</sup> This approach is unfair to many customers who do not expand the size of

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<sup>407</sup> Ex. Xcel-74 at 25 (Barthol Rebuttal) ("The Company would not install a transformer in the middle of a field without any customers.").

<sup>408</sup> Ex. OAG-8 at 20, 22–23 (Scharber Direct).

<sup>409</sup> *Id.* at 21–22.

<sup>410</sup> *Id.* at 21–22 (quoting James C. Bonbright, *Principles of Public Utility Rates* 349 (1st ed. 1961)).

their service territory when added to the system.<sup>411</sup> This is not a novel observation cooked up by consumer-advocates or analysts at the Regulatory Assistance Project (RAP). It is an observation that James Bonbright, arguably the father of modern public utilities scholarship, made in 1961.<sup>412</sup> The Basic Customer and Peak-and-Average Methods avoid this problem by classifying as customer-related only those incremental costs that arise from the addition of one customer.<sup>413</sup>

Further, the Minimum System Method's assumption that shared distribution system costs must be primarily customer related simply because they are incurred to serve customers is out of step with cost-allocation for generation and transmission.<sup>414</sup> Generation and transmission costs may also be driven by the addition of customers.<sup>415</sup> But these costs are not typically classified on a customer basis at all. Whether a cost is incurred to serve customers is not the relevant question. The relevant question is whether "there is a direct and proportionate relationship between the number of customers and the investment, holding other factors constant."<sup>416</sup> Holding other factors constant, Xcel does not install transformers and conductors for each new customer. Indeed, there are many customers in Xcel's densely-populated service territory that do not cause new shared distribution system costs. Allocating these costs on a customer basis will penalize residential customers who are served by utilities, like Xcel, that have residential customer classes that are relatively numerous.<sup>417</sup>

The Basic Customer and Peak-and-Average Methods are superior to the Minimum System Method and do not necessarily underestimate customer-related costs, as Xcel, XLI, and the

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<sup>411</sup> *Id.* at 22.

<sup>412</sup> *Id.* at 21-22 (quoting James C. Bonbright, *Principles of Public Utility Rates* 349 (1st ed. 1961)).

<sup>413</sup> *Id.* at 22.

<sup>414</sup> Ex. OAG-10 at 17 (Scharber Surrebuttal).

<sup>415</sup> *Id.*

<sup>416</sup> *Id.*

<sup>417</sup> *See id.*

Department claim. For some items they even overestimate customer-related costs. For example, service drops are classified under both methods on a per-customer basis, yet service drops may serve multiple customers in multi-family buildings.<sup>418</sup>

Last, Xcel, XLI, and the Department’s dismissal of the Peak-and-Average Method demonstrates an unrigorous engagement with cost-allocation theory. Xcel and XLI both attempt to undermine the legitimacy of the Peak-and-Average Method, primarily dismissing it because it is not listed as a classification method in the 1992 NARUC Manual.<sup>419</sup> But the NARUC manual itself has contradictory guidance on whether distribution costs should be calculated as partially energy related, and unquestioning reliance on a more than 30-year-old document, regardless of the entity that commissioned it, is unwise. First, the NARUC manual claims there is no energy component of distribution-related costs in one chapter, while recognizing energy-related components of distribution costs in another.<sup>420</sup> Second, the NARUC manual is over 30 years old, and its authors explicitly recognized that “an agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas.”<sup>421</sup> The 2020 RAP Manual, on the other hand, does support the Peak-and-Average Method for distribution system classification on the basis that the fundamental reason for building distribution systems is to deliver energy to customers.<sup>422</sup> The RAP Manual also provides several examples of the ways in

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<sup>418</sup> 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 includes 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).

<sup>419</sup> Ex. Xcel-74 at 25-26 (Barthol Rebuttal); Ex. XLI-6 at 15-16 (Jonathan Ly Rebuttal).

<sup>420</sup> Ex. OAG-10 at 19 (Scharber Surrebuttal).

<sup>421</sup> *Id.* at 20.

<sup>422</sup> *Id.* at 20-21.

which energy use outside of the maximum peak hour still drives the need for distribution investments and thus should be classified as energy-related.<sup>423</sup> These examples include costs for upgrading distribution lines or conductions 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.<sup>424</sup> While Xcel and XLI’s cost-allocation witnesses criticized the RAP Manual,<sup>425</sup> they both admitted that they had only read the portions of the manual cited by Dr. Scharber.<sup>426</sup>

The Commission should continue its practice of reviewing the results of CCOSSES based on the Minimum System Method, the Basic Customer Method, and the Peak-and-Average Method. However, the Commission should avoid falling into the assumption that all three methods are equally valid. The Minimum System Method contains unreasonable assumptions that result in shared distribution system costs being unreasonably classified as customer-related, which in turn penalizes customers in classes with more numerous customer counts. The Commission should recognize this flaw in the Minimum System Method in its revenue apportionment determination.

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<sup>423</sup> *Id.*

<sup>424</sup> *Id.* (citing Jim Lazar et al., Regul. Assistance Project, *Electric Cost Allocation for a New Era: A Manual* 148 (Jan. 2020) (RAP Manual)).

<sup>425</sup> Tr. Vol. 1 at 123 (Barthol) (stating that the RAP Manual “may be subjective” and “one of [the RAP manual authors] used to be a consumer advocate”); Tr. Vol. 2 at 353 (Jonathan Ly) (stating that the NARUC manual is more authoritative than the RAP manual because the RAP Manual “was prepared by a team of analysts”). The 1992 NARUC manual is not included in its entirety in the record and no details of any individuals contributing to its authorship are included in the excerpts of the manual attached to Mr. Zajicek’s testimony—the only witness to attach any portions of the manual to his testimony. *See* Ex. DOC-16, sched. 1 (Zajicek Direct).

<sup>426</sup> Tr. Vol. 1 at 120 (Barthol) (stating “I reviewed the sections that Dr. Scharber had cited” in response to a question about whether he reviewed the RAP manual); *Id.* at 124 (Barthol) (acknowledging that he had not reviewed the RAP website before concluding that the RAP manual was less objective than NARUC); Tr. Vol. 2 at 342 (Jonathan Ly) (“I have not reviewed the RAP Manual in detail. I am aware of its existence and the specific citations.”).

**4. The Commission should not allow Xcel to change its allocator for economic development discount costs in this rate case, but should improve the allocation method in Xcel’s next rate case.**

The Commission should not permit Xcel to change its allocator for economic development discount costs in this case because Xcel has not shown that its updated revenue allocator is reasonable. In this rate case, therefore, the Commission should give more weight to the CCOSSES that use the R01 allocator versus the R02 allocator. However, the allocation method should be improved in the next rate case.

Economic development discounts are provided to large customers through two riders: the Business Incentive Sustainability (BIS) Rider and the Competitive Response Rider (CRR).<sup>427</sup> Although only certain large customers are eligible for these discounts, the costs are spread across all customer classes.<sup>428</sup>

Since 2012, Xcel has used the R01 (total revenue) allocator to assign these costs to customer classes.<sup>429</sup> In this case, however, Xcel has allocated the costs based on 2025 test year base revenues—the R02 (base revenue) allocator.<sup>430</sup> Xcel argues that using the R02 allocator instead of the R01 allocator is more appropriate because the economic discounts are not related to

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<sup>427</sup> Ex. OAG-10 at 30 (Scharber Surrebuttal).

<sup>428</sup> *Id.* at 31.

<sup>429</sup> 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* 13-868 INITIAL RATE CASE ORDER *and* 12-961 RATE CASE ORDER.

<sup>430</sup> Ex. Xcel-73 at 10 (Barthol Direct).

fuel costs, and the R02 allocator does not include fuel costs.<sup>431</sup> XLI made substantially the same argument.<sup>432</sup>

Xcel and XLI's argument has no more than surface appeal because whichever revenue allocation method is used, it is not fundamentally tethered to cost causation—either through fuel costs or otherwise. 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.<sup>433</sup> Instead, the only rationale for spreading costs due to a handful of customers over all of Xcel's customer classes is based on the potential benefits received by those classes.<sup>434</sup>

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.<sup>435</sup> 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.<sup>436</sup>

In this rate case, the shift in the discounts due to the change that Xcel proposes from the R01 to R02 allocator are relatively small.<sup>437</sup> But the discount costs increase significantly between the 2025 test year and 2026 plan year as Xcel projects a near-tripling of economic development

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<sup>431</sup> Ex. Xcel-74 at 40 (Barthol Rebuttal).

<sup>432</sup> Ex. XLI-6 at 21 (Jonathan Ly Rebuttal).

<sup>433</sup> Ex. OAG-10 at 31 (Scharber Surrebuttal).

<sup>434</sup> *Id.*

<sup>435</sup> *Id.* at 32. 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).

<sup>436</sup> Ex. OAG-10 at 32 (Scharber Surrebuttal).

<sup>437</sup> Ex. OAG-8 at 32 (Scharber Direct) (showing a shift in this case of approximately \$200,000).

discounts.<sup>438</sup> Furthermore, these costs could significantly increase in the future, considering that Xcel's proposed very large customer tariff would allow new very large customers, including data centers, to be eligible for the CRR discount.<sup>439</sup> Ensuring that these costs are appropriately allocated, therefore, will be central to ensuring just and reasonable rates for all customer classes in upcoming rate cases.<sup>440</sup>

In sum, because Xcel has not provided a sufficient basis for changing the allocation method, the OAG's CCOSSES continue to use the R01 allocator.<sup>441</sup> But going forward, using a revenue allocator, whether the R01 or R02, may not be appropriate given that the benefits of economic development discounts to all ratepayers are realized primarily through the energy and demand allocators. Instead, 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.<sup>442</sup> 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.<sup>443</sup>

**B. The Commission Should Require Xcel to Use Improved Classification and Allocation Methods in Xcel's Next Rate Case.**

For Xcel's next rate case, the Commission should require improvements to Xcel's D10S allocator. The Commission should also decline Xcel's and XLI's request to change the allocation method for transmission costs. Last, the OAG requests the Commission order Xcel to use a more reasonable classification for AMI costs when it rolls these costs into base rates.

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<sup>438</sup> Ex. OAG-10 at 35 (Scharber Surrebuttal).

<sup>439</sup> *Id.*

<sup>440</sup> *See id.* at 35.

<sup>441</sup> Ex. OAG-8 at 33 (Scharber Direct).

<sup>442</sup> Ex. OAG-10 at 36 (Scharber Surrebuttal).

<sup>443</sup> *Id.*

**1. The Commission should require Xcel to improve the D10S Allocator in its next rate case.**

If the Commission wants to continue relying on a peak-demand allocator that is based on the MISO annual (summer) peak, it should require Xcel to develop a D10S allocator for its next rate case that is based on multiple historical MISO peaks. This would improve the allocator's robustness as discussed above.<sup>444</sup>

In lieu of a summer-peak-based allocator, there are also compelling reasons to move to a broader conception of "peak demand" in future cases.<sup>445</sup> In particular, 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.<sup>446</sup> 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.<sup>447</sup> Indeed, the Commission has determined since 2017 that the MISO's resource adequacy requirements are the relevant consideration.<sup>448</sup>

Requiring Xcel to move to an allocator based on either four seasonal peaks or 12 monthly peaks would better reflect MISO's broader conception of peak demand than Xcel's current approach.<sup>449</sup> However, a 12-peak (12 CP) allocator is the better choice for several reasons. 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, as discussed.<sup>450</sup> Second, a 12 CP

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<sup>444</sup> See *supra* Section III.A.1.b

<sup>445</sup> See Ex. OAG-8 at 13–15 (Scharber Direct).

<sup>446</sup> *Id.* at 14.

<sup>447</sup> *Id.* at 14–15.

<sup>448</sup> 15-826 ORDER at 46 ("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.").

<sup>449</sup> Ex. OAG-8 at 15 (Scharber Direct).

<sup>450</sup> *Id.*

allocator incorporates more data points, which makes the allocator more robust.<sup>451</sup> Third, the Commission has already directed Xcel to use a 12 CP allocator for demand-related transmission costs.<sup>452</sup> The transmission system is essentially an extension of the production system, so it makes sense to allocate them in the same manner.<sup>453</sup>

Whether a D10S or 12 CP allocator is used in the next case, the Commission should require Xcel to (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.<sup>454</sup> The second option is essentially a stop-gap measure until actual class load data are available; it would require Xcel to apply historical MISO peaks to Xcel's load forecast to justify its chosen peaks. Once historical class-load data are available, the first option would require that data to be used as a starting point and adjusted to account for anticipated changes in class loads for the test year(s). The adjustment step would better incorporate the impact of large new loads like data centers into the CCOSS.<sup>455</sup> Reflecting this new load in the data used to construct allocators is the only way to ensure that existing customers will benefit from this load.<sup>456</sup>

Xcel and XLI oppose a 12 CP allocator for similar reasons that they oppose the OAG's Alternate D10S Allocator. Xcel argues that it does not "design, build, and operate its peaking resources to meet 12 individual monthly coincident peaks."<sup>457</sup> XLI argues, primarily, that MISO is still most capacity-constrained in the summer despite the adoption of a seasonal resource-

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<sup>451</sup> *Id.* at 15–16.

<sup>452</sup> *Id.* at 16.

<sup>453</sup> *Id.*

<sup>454</sup> Ex. OAG-10 at 48 (Scharber Surrebuttal).

<sup>455</sup> *Id.* at 11–12.

<sup>456</sup> *Id.*

<sup>457</sup> Ex. Xcel-74 at 18 (Barthol Rebuttal).

adequacy construct.<sup>458</sup> As an initial matter, Xcel’s 12 CP allocator (currently used for transmission demand costs) actually represents a larger portion of Minnesota load coincident with the NSP peak than does Xcel’s D10S.<sup>459</sup> Thus, Xcel’s opposition to a 12 CP allocator on the basis that it does not represent peak conditions is puzzling. More importantly, the Commission has already decided that MISO’s resource-adequacy requirements, rather than Xcel’s own system peak, are what utilities now have to plan for.<sup>460</sup> The Commission has also stated its intent that Xcel should incorporate changes to MISO’s resource-adequacy construct into peak-demand allocators.<sup>461</sup> Either an allocator based on four seasonal peaks or a 12 CP allocator would be a reasonable way of incorporating MISO’s changes.<sup>462</sup> A 12 CP allocator, however, has the advantages already noted, and Xcel should adopt it for production demand costs in the next case.

**2. The Commission should continue to require Xcel to use the 12 CP allocator for demand-related transmission costs.**

Xcel opposes continuing to allocate demand-related transmission costs using the 12 CP allocator ordered by the Commission. The Commission should not make this change.

Xcel argues that the D10S allocator is more appropriate because “transmission costs are based on the need to meet customer demands at the single highest peak of the year.”<sup>463</sup> XLI and the Department share Xcel’s critique that a system planned to meet year-round average demand would not meet the actual peak demands of customers in the summer.<sup>464</sup>

The Commission should continue requiring Xcel to allocate demand-related transmission costs using the 12 CP allocator in this case and going forward. The Commission’s requirement in

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<sup>458</sup> Ex. XLI-6 at 9–10 (Jonathan Ly Rebuttal).

<sup>459</sup> Ex. OAG-10 at 9 (Scharber Surrebuttal).

<sup>460</sup> *Id.* (quoting 15-826 ORDER at 46).

<sup>461</sup> Ex. OAG-10 at 9 (Scharber Surrebuttal) (citing 15-826 ORDER).

<sup>462</sup> *Id.* at 10–11.

<sup>463</sup> Ex. Xcel-73 at 23 (Barthol Direct).

<sup>464</sup> Ex. XLI-3 at 19–20 (Jonathan Ly Direct); Ex. DOC-16 at 35 (Zajicek Direct).

Xcel’s most recent rate case to allocate demand-related transmission costs using a 12 CP allocator because of a “growing acceptance of relying on a broader concept of peak demand” beyond just a single peak is even more true today.<sup>465</sup> Further, Xcel’s transmission system must be designed and operated to address reliability needs in all seasons of the year, as explained in the Commission’s previous order. The Commission described how utilities tend to take generation assets offline for maintenance in the spring and fall, leaving the system vulnerable to unplanned outages.<sup>466</sup> Managing unplanned outages requires ensuring adequate transmission capacity year-round as the grid’s supply and demand levels fluctuate.<sup>467</sup> The 12 CP allocator better accounts for this year-round capacity need. In fact, a witness for an Xcel affiliate in another state agrees that the 12 CP allocator is reasonable and reflects reliability needs. NSP-Wisconsin’s CCOSS witness testified that he chose to use the 12 CP allocator for transmission costs because “all 12-monthly peak loads throughout the year are important considerations for transmission reliability.”<sup>468</sup>

Xcel’s proposed alternative allocator is unreasonable in this context. Using Xcel’s D10S allocator does not better reflect how customer classes contribute to Xcel’s peak load because the allocator reflects forecasted load shares at a single hour of the year—an hour that is unlikely to correspond to the actual MISO peak or the hour of greatest transmission stress.<sup>469</sup> In fact, Xcel’s D10S allocator corresponds to a weekend hour in both 2025 and 2026, making it uniquely unsuited

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<sup>465</sup> 21-630 ORDER at 102.

<sup>466</sup> *Id.*

<sup>467</sup> *Id.*

<sup>468</sup> 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)).

<sup>469</sup> Ex. OAG-9 at 16–17 (Scharber Rebuttal).

to address Xcel, XLI, and the Department’s stated concern that the allocator should reflect the system peak.<sup>470</sup>

The Commission should continue to require Xcel to use the 12 CP allocator for Transmission costs.

**3. The Commission should require Xcel to classify AMI meters and equipment to account for their customer, demand, and energy benefits.**

Xcel is in the process of installing AMI.<sup>471</sup> To date, Xcel has recovered AMI meter costs through the TCR rider,<sup>472</sup> but Xcel will likely roll these costs into base rates in a future rate case.<sup>473</sup> Given the many energy- and capacity-related benefits that drove Xcel’s investments in AMI, when Xcel rolls these AMI meter costs into base rates, Xcel should classify these costs as one-third each energy-, capacity-, and customer-related.<sup>474</sup> Requiring this classification at the outset in future rate cases will provide a CCOSS that better attributes the benefits of AMI. Xcel and XLI’s counter arguments, on this point, miss the mark.

AMI meters have capabilities that traditional meters lack, allowing them to “facilitate a range of benefits, 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.”<sup>475</sup> These

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<sup>470</sup> Ex. OAG-10 at 9 tbl.3, 14 (Scharber Surrebuttal).

<sup>471</sup> See Ex. Xcel-76 at 25 (Paluck Direct).

<sup>472</sup> Xcel does include internal labor costs related to AMI in this rate case. Ex. Xcel-74 at 26 (Barthol Rebuttal).

<sup>473</sup> 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).

<sup>474</sup> Ex. OAG-8 at 29–30 (Scharber Direct); Ex. OAG-10 at 29–30 (Scharber Surrebuttal).

<sup>475</sup> Ex. OAG-8 at 27 (Scharber Direct).

advanced capabilities are the reason that AMI meters are installed over cheaper and older traditional meters.<sup>476</sup>

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.<sup>477</sup> Xcel even classified AMI meter costs as both customer- and capacity-related in the TCR rider, though two months after the submission of OAG's direct testimony, Xcel proposed in its 2025 TCR to classify AMI costs as 100 percent customer-related.<sup>478</sup> Now Xcel argues that it is not appropriate to allocate AMI-meter costs on any basis other than weighted customer count.<sup>479</sup> Xcel argues that all residential customers receive the same AMI meter regardless of their peak demand or how much energy they consume, and that these meters' costs are therefore driven solely by the number of customers, and not to any degree by their advanced functionality.<sup>480</sup> Similarly, XLI objects to the OAG's proposed forward-looking cost allocation, arguing that cost causation requires classification as customer-related and the NARUC Manual supports classifying meters on a customer basis.<sup>481</sup>

Xcel and XLI's objections to the OAG's position are largely based on the false premise that costs cannot be allocated based on benefits provided, unquestioning reliance on a 35-year old cost allocation manual, and ignoring past Commission decisions.

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<sup>476</sup> 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. *Id.* at 5-6.

<sup>477</sup> XLI's witness appeared to acknowledge that there are demand-related components of AMI. 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.”).

<sup>478</sup> Ex. Xcel-74 at 26 (Barthol Rebuttal); Ex. OAG-10 at 28 n.83 (Scharber Direct).

<sup>479</sup> Ex. Xcel-74 at 28–29 (Barthol Rebuttal).

<sup>480</sup> *Id.* at 28–29.

<sup>481</sup> Ex. XLI-6 at 18 (Jonathan Ly Rebuttal).

Xcel and XLI’s argument that cost allocation must be based on cost causation and not on the benefits provided is not supported by cost-allocation theory or Xcel’s own allocation practices.<sup>482</sup> Cost-allocation theory includes two primary conceptual principles: (1) cost causation; and (2) costs follow benefits.<sup>483</sup> Xcel itself applies the second principle in its own CCOSSES, including in the Stratification Method and economic-development discounts allocation discussed above.<sup>484</sup>

While 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.<sup>485</sup> The 2020 RAP Manual provides specific and persuasive analysis of classification and allocation methods for advanced metering. The RAP manual lists a range of benefits enabled by AMI meters and smart-grid investments—and these benefits span the demand, energy, and customer classifications.<sup>486</sup> While Xcel and XLI’s cost-allocation witnesses criticized the RAP Manual,<sup>487</sup> they both admitted that they had only read limited portions of the manual cited by Dr. Scharber.<sup>488</sup> In addition to recognition by experts in the field that advanced meters serve fundamentally different purposes from traditional meters, the Commission itself has recognized these differences for many years.<sup>489</sup>

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<sup>482</sup> Ex. OAG-10 at 23-24 (Scharber Surrebuttal).

<sup>483</sup> Ex. OAG-10 at 23-24 (Scharber Surrebuttal).

<sup>484</sup> *See id.* at 24; Section III.A.4, *supra*.

<sup>485</sup> Ex. OAG-10 at 25 (Scharber Surrebuttal).

<sup>486</sup> *Id.* at 25-26 (citing RAP Manual at 156-57).

<sup>487</sup> Tr. Vol. 1 at 123 (Barthol) (stating that the RAP Manual “may be subjective” and “one of [the RAP manual authors] used to be a consumer advocate”); Tr. Vol. 2 at 353 (Jonathan Ly) (stating RAP manual is less authoritative because the RAP Manual “was prepared by a team of analysts.”).

<sup>488</sup> Tr. Vol 1 at 120 (Barthol); Tr. Vol 2 at 342 (Jonathan Ly).

<sup>489</sup> *See, e.g., In re Application of Otter Tail Power Co. for Authority to Increase Rates for Elec. Serv. in Minn.*, Docket No. E-017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 75 (May 1, 2017) (“[T]he added meter costs borne by subscribers to the Residential Controlled Demand service are more appropriately understood as demand or energy costs. These costs are

XLI also argues that a 1/3 customer, 1/3 demand, 1/3 energy classification is not based on any robust analysis and therefore does not reflect cost causation.<sup>490</sup> But the OAG’s classification recommendation has a solid foundation. As Dr. Scharber explained, Xcel’s undepreciated value of meter plant increased three-fold between 2022 and 2024, coinciding with the beginning of Xcel’s AMI meter deployment.<sup>491</sup> 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).<sup>492</sup> Further, the Commission has supported a 1/3 customer, 1/3 demand, 1/3 energy classification in other proceedings.<sup>493</sup> While the full benefits of AMI have not been realized or analyzed by Xcel, classifying the benefits equally across customer, demand, and energy is the most reasonable method currently available.<sup>494</sup>

Last, the Department recommends that Xcel provide “a study showing the costs of AMI meters compared to the costs of traditional meters and the costs of reading those meters compared to AMI meters” in its next rate case.<sup>495</sup> The Department reasons, “[t]o the extent that AMI meters cost more than the traditional meter and meter reading costs, those costs should be classified as either demand- or energy-related depending on the other uses, as those costs are specifically beyond what would be necessary to just connect the customer to service and report usage.”<sup>496</sup>

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incurred to benefit [the utility’s] system as a whole, not just the customer receiving electricity through the meter.”); 21-335 MP RATE CASE ORDER at 61.

<sup>490</sup> Ex. XLI-6 at 17 (Jonathan Ly Rebuttal).

<sup>491</sup> Ex. OAG-10 at 26-27 (Scharber Surrebuttal).

<sup>492</sup> *Id.* at 28-29.

<sup>493</sup> 21-335 MP RATE CASE ORDER at 6.

<sup>494</sup> Ex. OAG-10 at 26 (Scharber Surrebuttal).

<sup>495</sup> Ex. DOC-18 at 5-6 (Zajicek Surrebuttal).

<sup>496</sup> *Id.*

While the OAG agrees that AMI meters have other uses, the benefits of which should be classified as demand- and energy-related, the Department’s recommendation is too narrowly focused on the meters themselves.

For all the reasons above, the Commission should require Xcel’s submitted CCOSS filings to classify AMI meter costs as a 1/3 customer, 1/3 demand, 1/3 energy classification in the rate case where Xcel rolls AMI into rate base.

#### **IV. RATE DESIGN – REVENUE APPORTIONMENT AND CUSTOMER CHARGE**

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.<sup>497</sup> The Minnesota Supreme Court has found that “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.”<sup>498</sup> More recently, the Commission itself has stated that it considered “non-cost concerns such as: 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.”<sup>499</sup>

The OAG’s revenue apportionment and rate design recommendations thoroughly and clearly applied multiple cost of service studies and a wide range of non-cost factors. The Commission should adopt these sound recommendations.

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<sup>497</sup> See *St. Paul Area Chamber of Com.*, 251 N.W.2d at 358.

<sup>498</sup> *Id.* at 357.

<sup>499</sup> 21-630 ORDER at 111 (citing Minn. Stat. §§ 216B.01, .03, .2401; 216C.05; 216B.16, subd. 15).

**A. The OAG’s Revenue Apportionment Recommendation Is the Only Recommendation in the Record that Considers Multiple Cost Studies and Non-Cost Factors and Should be Adopted.**

The OAG arrived at its revenue apportionment recommendation through consideration of numerous factors, including multiple cost of service studies, the ability of each customer class generally to pass on cost increases, the impact on low-income customers and ability to pay, and avoiding rate shock.<sup>500</sup> The other parties offering a complete revenue apportionment recommendation<sup>501</sup> have more limited considerations in arriving at their apportionment. Application of these considerations are explained further in the sections below, followed by the OAG’s final revenue apportionment recommendation.

**1. The OAG was the only party to follow Commission practice and considered multiple CCOSSES in its revenue apportionment recommendation.**

Cost of service is an important factor in revenue apportionment. And because determining class contributions to shared infrastructure costs is necessarily subjective, the Commission has found it useful to consider multiple theories of cost causation. The Commission explicitly continued this practice in Xcel’s last rate case, reiterating that “[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.”<sup>502</sup>

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<sup>500</sup> Ex. OAG-8 at 25 (Scharber Direct).

<sup>501</sup> Several other parties offered perspectives on the rate impact, revenue apportionment, or rate design for specific customer classes, but did not submit a recommendation for full apportionment. *See, e.g.*, Ex. SRA-3 (Bride Surrebuttal) (lighting customers); Ex. CUB-6 (Levenson-Falk Surrebuttal) (affordability of utility service). Walmart supported Xcel’s revenue apportionment at its requested revenue requirement and recommended that any reduction in revenue requirement be used to move classes towards the cost of service. Ex. WAL-1 (Austin Direct). However, it is not clear what “cost of service” Walmart specifically refers to, as it stated that it did not take a position on Xcel’s proposed cost of service model in direct and did not submit rebuttal or surrebuttal testimony. *Id.* at 15.

<sup>502</sup> 21-630 ORDER at 95.

Despite the Commission’s clear preference for considering multiple cost studies, Xcel, XLI, and the Department relied solely on Xcel’s preferred Minimum System CCOSS in their revenue apportionment recommendations. This not only runs counter to the Commission’s recent practice, it also places a level of faith in the “objectivity” of cost attribution that does not exist.

Xcel states that it begins the rate design process “by examining and using electric service costs by customer class and rate component. From this objective cost basis, we consider and balance the remaining objectives according to circumstances to develop a proposed rate design that is reasonable and fair for all customers.”<sup>503</sup> Xcel’s examination of customer class costs, however, is limited to only its preferred CCOSS. Although the Department’s CCOSS witness recommended a range of results from the Basic Customer Method to a modified Minimum System Method,<sup>504</sup> the Department’s revenue apportionment simply agrees with Xcel’s proposed 2025 apportionment, which is based solely on the Xcel’s Minimum System CCOSS, and applies that to both years in the MYRP.<sup>505</sup>

Far from Xcel’s claim that it relies on an “objective cost basis,” CCOSS results are inherently subjective<sup>506</sup> and using only one CCOSS will exacerbate this subjectivity. While the results of a CCOSS can provide useful guidance for revenue apportionment, CCOSS results are not approximations of the “true costs” of a given customer class, as most costs are either joint or common and there are no objective standards against which to compare CCOSS results.<sup>507</sup> While a CCOSS with more reasonable assumptions should be given more weight, using only one CCOSS for revenue apportionment intensifies any subjective determinations in the preferred CCOSS.

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<sup>503</sup> Ex. Xcel-76 at 10 (Paluck Direct).

<sup>504</sup> Ex. DOC-16 at 41-42 (Zajicek Direct).

<sup>505</sup> Ex. DOC-20 at 11 (Bahn Surrebuttal).

<sup>506</sup> Ex. OAG-8 at 5 (Scharber Direct).

<sup>507</sup> *Id.* at 4.

In addition to only considering a single type of CCOSS, Xcel, XLI, and the Department did not even thoroughly consider Xcel’s Minimum System CCOSS in their revenue allocation decisions. To wit, even though every CCOSS in the record that used Xcel’s rebuttal revenue requirement showed that the small general service class should receive a decrease to move closer to “cost,”<sup>508</sup> these parties recommended increases to the small general service class while claiming “cost based” recommendations.

The small general service changes in cost from the CCOSSes that were updated in surrebuttal are shown below:

Customer Class	Xcel’s Present Rates (\$ Millions)	OAG Peak and Average Costs	OAG Basic Customer Costs	OAG Minimum System Costs <sup>509</sup>	Xcel Minimum System Costs <sup>510</sup>	DOC Minimum System Costs <sup>511</sup>	XLI* Minimum System Costs <sup>512</sup>
<b>2025</b>							
Small General <sup>513</sup>	\$119.6	-6.06%	-5.54%	-1.45%	-2.9%	-3.66%	N/A
<b>2026</b>							
Small General	\$126.9	-8.87%	-8.48%	-9.72%	-6.2%	-7.29%	-2.0%

The OAG’s surrebuttal apportionment adequately assigns no increase to the Small General Services class in 2025 or 2026. By contrast, other parties assign it various increases as shown below. Because XLI did not provide updated revenue apportionment figures based on Xcel’s

<sup>508</sup> See Ex. Xcel-75 at 8, tbl. 2 (Barthol Surrebuttal) and Ex. OAG-18 (confirming this interpretation of Table 2).

<sup>509</sup> See Ex. OAG-10 at 38, tbl. 6 (Scharber Surrebuttal) for summary of OAG CCOSS results.

<sup>510</sup> Ex. Xcel-75 at 5, 7 (Barthol Surrebuttal).

<sup>511</sup> Ex. DOC-18 at 13 (Table 1 – 2025), 14 (Table 2 – 2025) (Zajicek Surrebuttal).

<sup>512</sup> 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).

<sup>513</sup> Xcel’s CCOSS tables call this customer class “Non-Demand.” See Ex. Xcel-75 at 5, 7 (Barthol Surrebuttal).

rebuttal testimony, its recommended increase is not depicted below, but it is likely closer to the Department’s and Xcel’s recommendations than the OAG’s.

Party/Year	OAG	Xcel <sup>514</sup>	DOC <sup>515</sup>
2025 - Small General Service Class Increase	0.0%	4.11%	4.03%
2026 – Small General Service Class Increase	0.0%	6.93%	6.77%

The OAG is the only party that followed the preference of the Commission to consider multiple CCOSSES in its revenue apportionment recommendation. The Commission’s practice remains sound and multiple CCOSSES should be considered in revenue apportionment.

**2. The ability of some customer classes to pass on cost increases remains an important consideration in revenue apportionment.**

As the Commission has recognized,<sup>516</sup> and the supreme court has affirmed,<sup>517</sup> the ability to pass on costs is an important consideration in revenue apportionment.

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. As Dr. Scharber explained: “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[.]”<sup>518</sup> Residential customers, in

<sup>514</sup> Ex. OAG-17 (Xcel Response to OAG IR no. 7056 Attach. A at 2, Attach. B. at 2).

<sup>515</sup> Ex. DOC-20 at 9, tbl. 3 (Bahn Surrebuttal).

<sup>516</sup> *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).

<sup>517</sup> *St. Paul Area Chamber of Com.*, 251 N.W.2d at 357.

<sup>518</sup> 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

stark contrast, cannot pass on price increases to any degree, and options for substituting away from electricity are limited.<sup>519</sup> Residential customers are instead stuck with the full price increase, and are increasingly unable to pay, as shown by Xcel’s historic disconnection and arrange numbers discussed more below.

**3. Historically high levels of disconnections and persistent arrearages show that many residential customers are unable to pay their electric bills and harm to low-income customers should be specifically considered in apportioning Xcel’s rate increase.**

Closely related to the ability to pass on costs, the ability to pay is a central consideration in revenue allocation. Not only has it long been a guiding consideration of the Commission, Minnesota law states that “[t]he commission must consider ability to pay as a factor in setting utility rates.”<sup>520</sup>

To put it bluntly, many residential customers are not able to pay their utility bills. For many, the rates are just too high to pay on top of increasing costs for other essentials. 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.<sup>521</sup>

Dr. Scharber described how customers with lower incomes have a high “energy burden,” the portion of household income devoted to paying gas and electric bills.<sup>522</sup> An energy burden above six percent is considered high, while above ten percent is considered severe.<sup>523</sup> But for the

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whether large customers will move towards self-generation or move out of Xcel’s service territory if prices increase sharply. *Id.* at 37-38.

<sup>519</sup> *Id.* at 36-37.

<sup>520</sup> Minn. Stat. § 216B.16, subd. 15; 21-630 ORDER at 111 (citing Minn. Stat. § 216B.16, subd. 15 in the context of rate design); *St. Paul Area Chamber of Com.*, 251 N.W.2d at 357.

<sup>521</sup> *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).

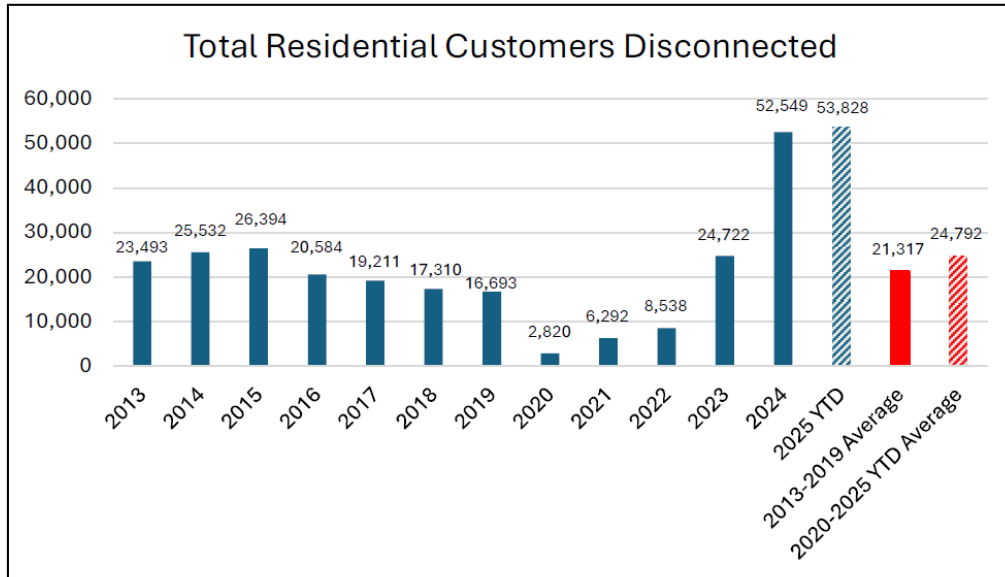
<sup>522</sup> Ex. OAG-8 at 38 (Scharber Direct).

<sup>523</sup> *Id.* at 39.

past several years, 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.<sup>524</sup> 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.<sup>525</sup> In the metro area specifically, where Xcel’s residential customers are concentrated, low-income customers<sup>526</sup> 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.<sup>527</sup>

Residential customers’ increasing inability to pay their utility bills is shown by the historic levels of disconnections and arrearages that Xcel itself is reporting. Xcel is disconnecting a historic amount of its electric and gas customers, as shown in Figure 1 from CUB Witness Levenson-Falk’s testimony below:<sup>528</sup>

**Figure 1: Total Annual Residential Disconnections, 2013 – 2025<sup>48</sup>**



<sup>524</sup> *Id.*

<sup>525</sup> *Id.* at 38.

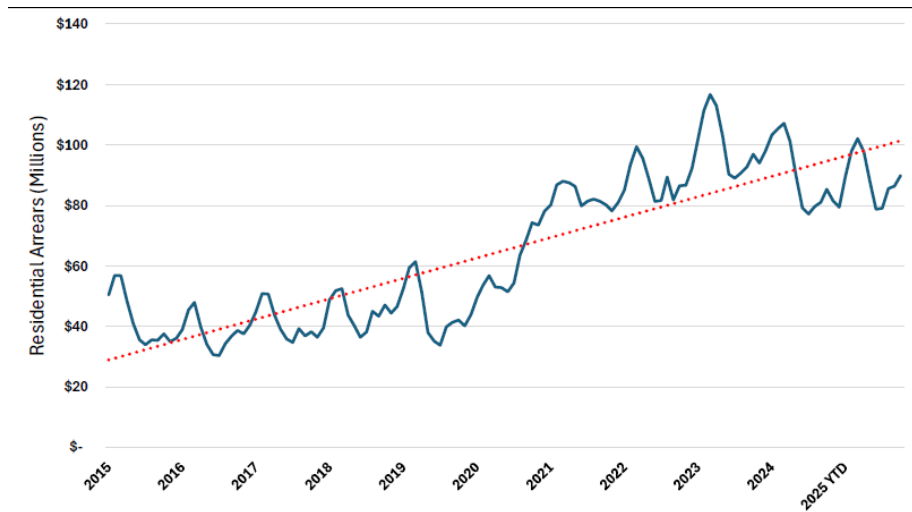
<sup>526</sup> This study defined low-income as 80 percent of median income. *See id.* at 39.

<sup>527</sup> *Id.* at 39-40 (Scharber Direct).

<sup>528</sup> Ex. CUB-8 at 8 (Levenson-Falk Surrebuttal).

Xcel’s residential arrearage levels, while coming down from all-time highs post-pandemic, have remained stubbornly high:

**Xcel Total Arrearage Levels<sup>529</sup>**



Xcel claims that these levels of arrears and disconnections are not due to its high rates but are simply due to customers building up arrearages during the disconnection moratorium in place during the height of the Covid-19 pandemic and due to customers prioritizing other household expenses.<sup>530</sup> But Xcel’s justifications don’t tell the whole story, and they are beside the point. While increasing arrears and disconnections do coincide with the end of pandemic economic assistance and the disconnection moratorium, they also coincide with Xcel’s 2021 rate case, which increased rates by net increases of \$101 million in 2022, \$193 million in 2023, and \$316 million in 2024.<sup>531</sup>

Xcel’s own analysis, reproduced in Dr. Gabe Chan’s testimony, shows that Xcel’s average residential rate is nearing or higher than at national investor-owned utilities, unless it is “adjusted.”

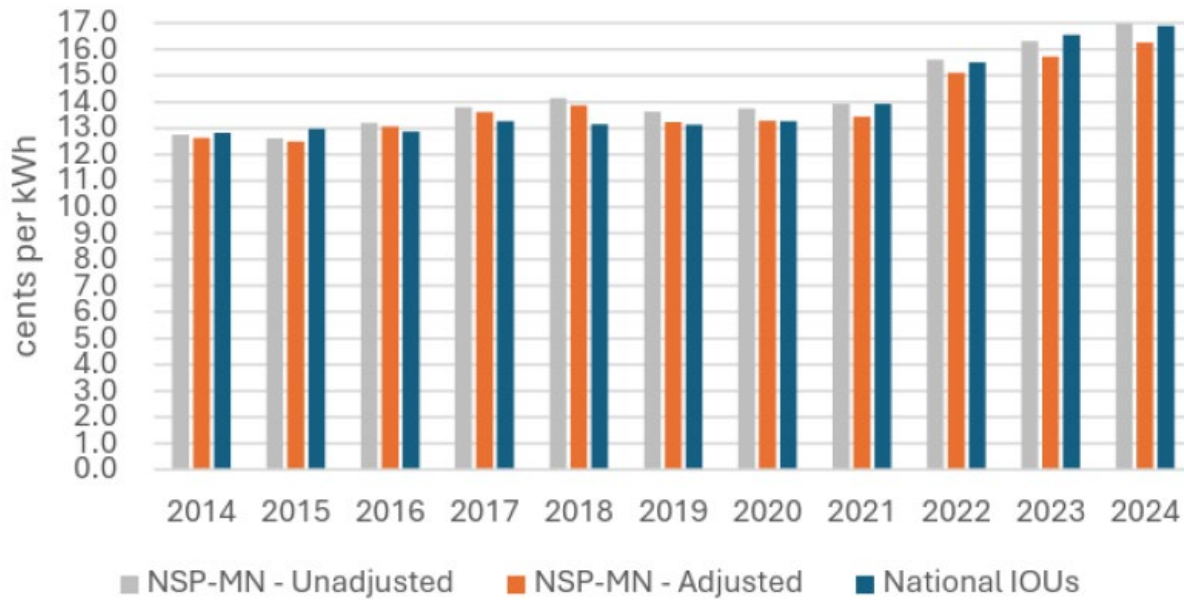
<sup>529</sup> Ex. CUB-8, ALF-SR-23 (Levenson-Falk Surrebuttal); *see also* Ex. CUB-3 at 7-9 (Levenson-Falk Direct).

<sup>530</sup> Ex. Xcel- 71 at 31 (Martin Rebuttal).

<sup>531</sup> *See* Ex. CUB-3 at 9 (Levenson-Falk Direct) (citing docket no. E002/GR-21-630 Final Rates Compliance at 1 (Oct. 17, 2023)).

The “adjusted” rate subtracts from its revenue the total cost of community solar garden bill credits and low-income programs. But as Dr. Chan notes, “many other utilities across the country are also implementing programs that collect revenue from some customers that is repaid to other customers in more or less direct fashion.”<sup>532</sup> This creates an “apples-to-oranges” comparison.<sup>533</sup> What we are left with is Xcel’s electricity rates in the grey bars meeting or exceeding the national average in 2022 and 2024:

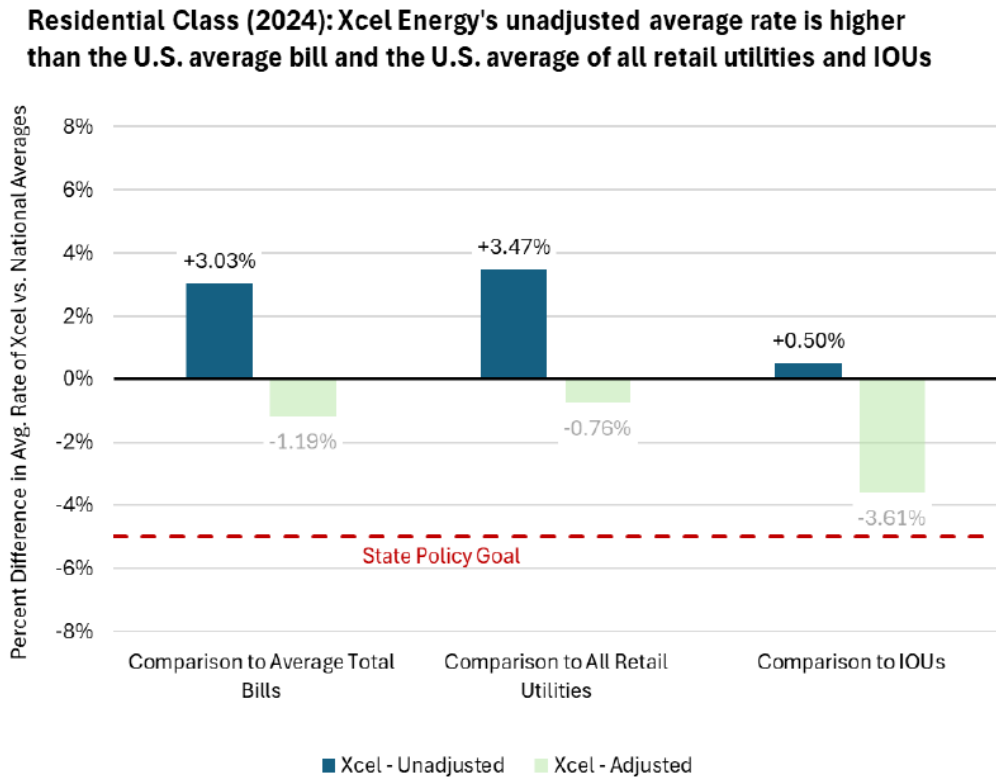
Figure A-2: Residential Average Rate



<sup>532</sup> Ex. JIN- 2 at 15-16 (Chan Direct).

<sup>533</sup> *Id.* at 16.

Dr. Chan’s own analysis shows that Xcel’s unadjusted average rate is higher than the U.S. average total bill, higher than the U.S. average of all retail utilities, and higher than IOUs:<sup>534</sup>



Regardless, ability to pay as a factor in the Commission’s rate design decision need not be tethered to *why* customers are struggling to pay their bills. The fact that residential customers are not able to afford their electric rates is enough. The Commission should give significant weight to the plethora of evidence in record showing that residential customers are struggling to pay their electric bills in its revenue apportionment considerations.

**4. The OAG’s revenue apportionment is the most reasonable in the record and should be adopted.**

In this case, the OAG is the only party whose revenue apportionment recommendation incorporates the insights of multiple cost-causation theories that the Commission has found useful

<sup>534</sup> Ex. JIN-2 at 20 (Chan Direct).

in past cases. As discussed above, the revenue apportionment of OAG witness Dr. Scharber also considers and reflects non-cost factors including ability to pass on costs, ability to pay and impact on low-income customers, and the avoidance of rate shock.

To develop her recommendation, Dr. Scharber first compared the cost-share results from the three CCOSSES to the class shares projected at present rates (“present shares”).<sup>535</sup> Table 6 of Dr. Scharber’s surrebuttal shows the results for the three CCOSSES that Dr. Scharber performed:<sup>536</sup>

**Table 6**  
**OAG CCROSS Class Cost Increases at Xcel’s Proposed Revenue Requirement**<sup>115</sup>

Customer Class	Xcel's Present Rates (\$ Millions)	OAG Peak & Average Costs		OAG Basic Customer Costs		OAG Minimum System Costs	
		Amount	Increase	Amount	Increase	Amount	Increase
<b>2025</b>							
<b>Residential</b>	\$1,428.0	\$1,428.9	0.06%	\$1,456.1	1.97%	\$1,525.3	6.81%
<b>Small General</b>	\$119.6	\$112.4	-6.06%	\$113.0	-5.54%	\$117.9	-1.45%
<b>Large General</b>	\$1,995.7	\$2,201.4	10.31%	\$2,172.9	8.88%	\$2,099.0	5.18%
<b>Lighting</b>	\$31.3	\$38.2	22.05%	\$38.9	24.24%	\$38.6	23.56%
<b>2026</b>							
<b>Residential</b>	\$1,460.5	\$1,511.2	3.47%	\$1,544.9	5.78%	\$1,623.7	11.17%
<b>Small General</b>	\$126.9	\$115.6	-8.87%	\$116.1	-8.48%	\$122.0	-3.90%
<b>Large General</b>	\$2,011.8	\$2,326.7	15.65%	\$2,291.6	13.91%	\$2,207.3	9.72%
<b>Lighting</b>	\$31.6	\$40.6	28.71%	\$41.4	31.34%	\$41.2	30.51%

As discussed above, all three of the OAG’s CCOSSES, and Xcel and the Department’s CCOSSES for that matter, suggest a decreased revenue requirement for the Small General Service Class following Xcel’s rebuttal updates to its revenue requirement.<sup>537</sup> That is, Small General Service customers are already paying more than their fair share, and Xcel’s, the Department’s, and XLI’s recommended rate increases for that class are not reasonable. Unlike Small General Service customers, Lighting customers’ present share is significantly lower than their estimated cost in all

<sup>535</sup> Ex. OAG-10 at 38 (Scharber Surrebuttal).

<sup>536</sup> *Id.* at 37.

<sup>537</sup> *Id.* at 38.

three of the OAG's CCOSSES.<sup>538</sup> This suggests Lighting customers should receive an above-average increase.<sup>539</sup>

Dr. Scharber observed that the Residential and Large General present class shares are much closer to the costs estimated by the Minimum System Method than by the other two types of studies.<sup>540</sup> But given the Commission's preference for considering a range of classification methods, Dr. Scharber explained that using an average of the three CCOSSES was appropriate.<sup>541</sup>

Dr. Scharber then made two adjustments to the average: (1) limiting the increase to the Lighting class to avoid rate shock; and (2) setting the Small General Service class's increase to zero for both 2025 and 2026. While all CCOSSES using Xcel's revised revenue requirement in rebuttal show a solely cost-based apportionment should cause the Small General Service class's rate to decrease,<sup>542</sup> keeping the increase at zero for both years balances cost factors for this class with non-cost factors for other classes, such as including inability to pass on costs for residential customers and for many low-income customers inability to pay.

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<sup>538</sup> *Id.* at 38.

<sup>539</sup> *Id.*

<sup>540</sup> *Id.* at 38-39.

<sup>541</sup> *Id.* at 39.

<sup>542</sup> *Id.* at 39-40.

The OAG’s recommended 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)	%
<b>2025: Based on Xcel’s proposed revenue requirement of \$3,780,853</b>				
<b>Residential</b>	<b>38.87%</b>	\$1,469,748	\$41,741	2.9%
<b>Small General</b>	<b>3.16%</b>	\$119,617	\$0	0.0%
<b>Large General</b>	<b>57.06%</b>	\$2,157,295	\$161,564	8.1%
<b>Lighting</b>	<b>0.90%</b>	\$34,193	\$2,918	9.3%
<b>Total</b>	<b>100.00%</b>	\$3,780,853	\$206,223	5.8%
<b>2026: Based on Xcel’s proposed revenue requirement of \$3,994,095</b>				
<b>Residential</b>	<b>39.01%</b>	\$1,558,246	\$97,783	6.7%
<b>Small General</b>	<b>3.18%</b>	\$126,894	\$0	0.0%
<b>Large General</b>	<b>56.91%</b>	\$2,272,943	\$261,167	13.0%
<b>Lighting</b>	<b>0.90%</b>	\$36,012	\$4,458	14.1%
<b>Total</b>	<b>100.00%</b>	\$3,994,095	\$363,408	10.0%

Two items should be noted about Table 7 above. First, the OAG’s revenue apportionment in surrebuttal modifies the revenue shares for the classes between 2025 and 2026.<sup>543</sup> This is reasonable where significant changes in the composition of classes can be expected during the next several years if significant data center load is added to the system, as Xcel predicts.<sup>544</sup> While it may not be absolutely necessary to use separate apportionments in this case, it is the most appropriate method. But keeping the apportionment for 2025 for both years, as has been the Commission’s practice, may also be reasonable in this case,<sup>545</sup> provided the Commission is willing to revisit the practice if significant data center load comes online in separate test years in future cases. Second, Table 7 shows the cost increases using Xcel’s entire rebuttal revenue requirement.

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<sup>543</sup> *Id.* at 39-40.

<sup>544</sup> *Id.* at 40.

<sup>545</sup> *Id.* at 43.

If the Commission adjusts Xcel's revenue requirement, it should apply the proposed class shares provided in Table 7 to the approved base revenues.<sup>546</sup>

The OAG's recommended apportionment incorporates the insights of three different CCOSS models, identifying patterns across the three models and moving customers closer to cost in a gradual manner to avoid rate shock. For all the reasons stated above, this apportionment appropriately balances cost and policy considerations and the Commission should adopt it.

**B. The Commission Should Reject Xcel's Proposal to Increase Residential and Small General Service Customer Charges.**

Xcel proposes to nearly double the customer charges for its Residential and Small General Service tariffs from \$6 to \$11 per month.<sup>547</sup> This is a sharp departure from both the amount and the method that the Commission used to set Xcel's customer charge in Xcel's most recent rate case. The Commission should reject Xcel's attempt to immediately deviate from the Commission's sound rationale in Xcel's last rate case.

There are numerous reasons for the Commission to reject Xcel's customer charge hike in this case. Just a handful of these reasons are addressed below.<sup>548</sup> Lower customer charges have a more solid cost foundation. Lower customer charges promote intra-class equity and equity generally. And lower customer charges promote conservation. Maintaining Xcel's current customer charges for Residential and Small General Service customers will be more cost-based, equitable, and in line with Minnesota law and policy goals.

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<sup>546</sup> Ex. OAG-8 at 46 (Scharber Direct).

<sup>547</sup> Ex. Xcel-76 at 14 (Paluck Direct).

<sup>548</sup> Both Dr. Scharber and Witness Bahn provide significantly more analysis than can be summarized in a post-hearing brief. That analysis remains valuable and can be located at 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). Energy Cents Coalition Witness Shardlow also raised concerns about the impacts of the customer charge increase on low-income customers. Ex. ECC-1 at 2-3 (Shardlow Direct).

Xcel's proposed customer charge increases are based on a flawed analysis of customer costs. Xcel claims that its customer charge proposal better reflects "customer-related costs."<sup>549</sup> But even Xcel's Basic Customer CCOSS includes 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."<sup>550</sup> The NARUC Manual calls these "marginal customer costs, which "include the costs of the service drops, the costs of meters and metering and the customer accounts expenses."<sup>551</sup> In line with the NARUC Manual, the Connecticut and Texas commissions limit customer charges to costs that vary by customer such as metering, billing, and customer service.<sup>552</sup>

Xcel's attempt to justify these costs with its Basic Customer Method ignores that Xcel's Basic Customer CCOSS include a variety of inappropriate costs, such as expenses related to pensions and benefits, injuries and claims, uncollectible accounts, amortization, and payroll taxes.<sup>553</sup> As Dr. Scharber explains, "Whether or not these costs should be classified as customer-related for class cost apportionment purposes, they do not belong in the customer charge."<sup>554</sup>

Instead, Dr. Scharber estimated customer-specific expenses and assets to include: costs related to meters, services, meter-reading, customer accounts, and customer assistance.<sup>555</sup> Because

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<sup>549</sup> Ex. Xcel-77 at 10 (Paluck Rebuttal).

<sup>550</sup> Ex. OAG-8 at 47-48 (Scharber Direct) (quoting Bonbright, *Principles of Public Utility Rates*, at 347)).

<sup>551</sup> Ex. OAG-8 at 48 (Scharber Direct) (quoting NARUC Manual at 144).

<sup>552</sup> See *id.* 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)).

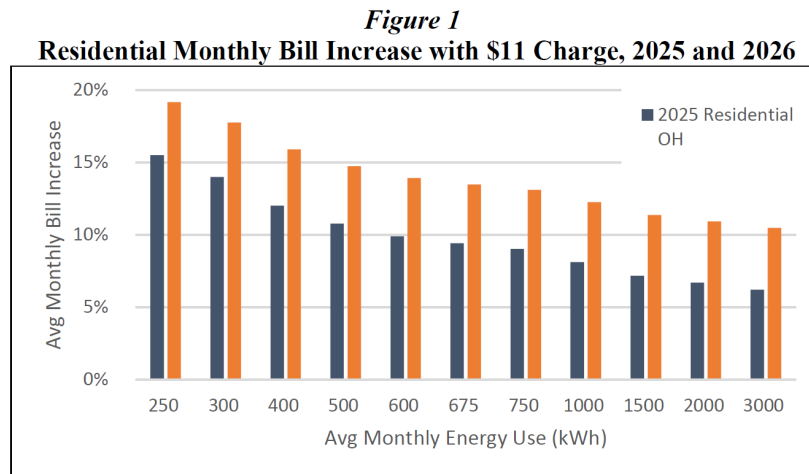
<sup>553</sup> Ex. OAG-8 at 50-51 (Scharber Direct).

<sup>554</sup> *Id.* at 51.

<sup>555</sup> *Id.*; Ex. OAG-10 at 47 (Scharber Surrebuttal).

Xcel could not provide an estimate of the percentage of service drops that are shared, Dr. Scharber conservatively included all service-drop costs in her analysis, although service-drop costs inflate the per-customer estimates due to the prevalence of shared-service drops in areas with significant multi-family dwellings.<sup>556</sup> Likewise, Dr. Scharber’s estimate includes Xcel’s proposed rate of return, which includes a 10.3% return on equity, making the estimate higher.<sup>557</sup> Even using this conservative methodology, Dr. Scharber estimated that customer-specific costs for the residential class were \$5.82 in 2025 and \$5.71 in 2026 should Xcel receive its rebuttal revenue requirement.<sup>558</sup>

A lower fixed charge promotes both intraclass equity and equity in the more traditional sense. Increases in customer charges will raise a low-usage customer’s bill by a greater percentage than a high-usage customer’s.<sup>559</sup> With such a steep customer charge increase, as 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:<sup>560</sup>



<sup>556</sup> Ex. OAG-8 at 22-23, 48 (Scharber Direct); Ex. OAG-10 at 46-47 (Scharber Surrebuttal).

<sup>557</sup> Ex. OAG-8 at 51 (Scharber Direct); Ex. Xcel-25 at 6 (Nowak Rebuttal).

<sup>558</sup> Ex. OAG-12 (Scharber Amended Witness Statement) (providing corrected figures following receipt of Xcel corrected information request response).

<sup>559</sup> Ex. OAG-10 at 54 (Scharber Surrebuttal).

<sup>560</sup> 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).

As shown above, 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.<sup>561</sup> A residential customer using 1000 kWh per month, however, would experience an increase of only 8 percent in 2025 and 12 percent in 2026.<sup>562</sup>

As the Commission has recognized, preventing intra-class inequity, such as the examples illustrated above, is particularly important for utilities that serve many multi-family dwellings and more reasonably reflects the fixed costs attributable to the many different types of customers in the residential class.<sup>563</sup> The fixed costs to serve an exurban lake home at the end of a long driveway are likely to be significantly higher than serving a one-bedroom apartment in a four-plex in East Saint Paul. Yet under Xcel’s proposal both these customers would pay \$11 dollars a month regardless of energy usage. That’s simply not fair. And the Commission has recognized that this lack of fairness associated with high customer charges tends to “confuse and alienate customers by impairing customer understanding of their energy bills.”<sup>564</sup>

A lower customer charge also protects low-income customers. Income and electricity use are correlated. 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.<sup>565</sup> An increase

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<sup>561</sup> Ex. OAG-8 at 55 (Scharber Direct).

<sup>562</sup> *Id.*

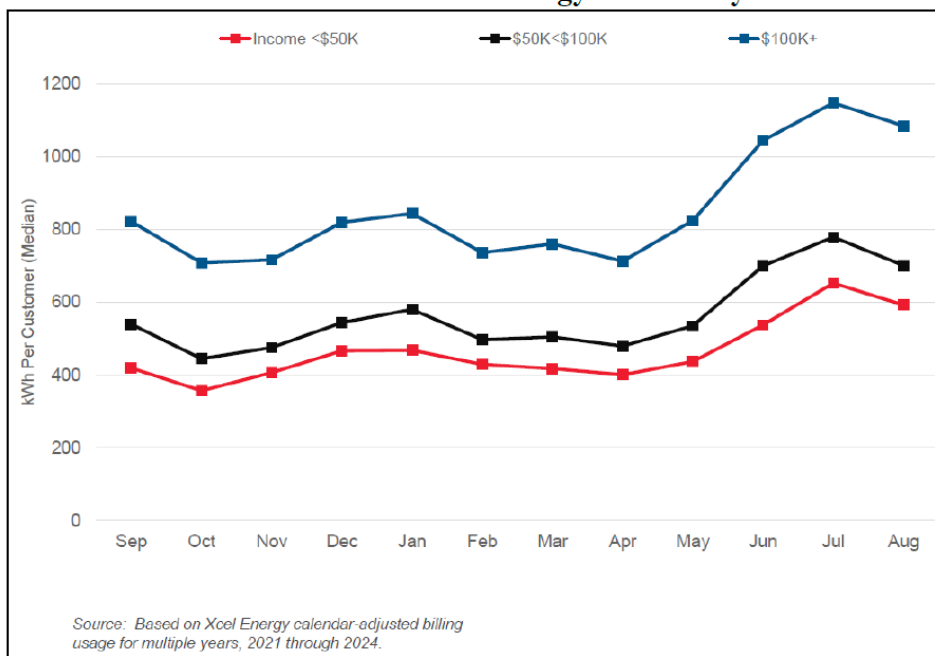
<sup>563</sup> See 21-630 ORDER at 117 (“In setting the customer charge in this case, alignment with the Basic Customer method is particularly important in light of the wide variety of residential customers within Xcel’s service territory. Many Residential customers are in single family dwellings, but according to the Department, more than 200,000 customers live in multi-unit dwellings of various sizes.”).

<sup>564</sup> 21-630 ORDER at 116-117.

<sup>565</sup> Ex. OAG-8 at 58-59, sched. HS-D-19 (Scharber Direct) (citing Xcel’s Residential Energy Use Study – Minnesota Market).

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.

**Figure 4**  
**Electric Use by Household Income from**  
**Xcel’s 2024 Residential Energy Use Survey<sup>135</sup>**



Last, lower customer charges encourage conservation. Minnesota statutes mandate that the Commission “set rates to encourage energy conservation” “[t]o the maximum reasonable extent.”<sup>566</sup> The Commission has taken its statutory directive seriously and lowered the monthly customer charge for Xcel’s residential electric customers in its last rate case.<sup>567</sup> The Commission should not increase the customer charges again now. Dr. Scharber estimated the potential energy savings from a lower customer charge using EIA data on price elasticity of demand for Residential electricity.<sup>568</sup> While the individual savings were not large, due to Xcel’s large Residential customer

<sup>566</sup> Minn. Stat. § 216B.03 (2024).

<sup>567</sup> 21-630 ORDER at 117.

<sup>568</sup> Ex. OAG-8 at 60 (Scharber Direct).

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.<sup>569</sup>

The Residential and Small General Service customer charges should therefore remain unchanged.

## CONCLUSION

Xcel's rate increase request would result in rates that are unjust and unreasonable, and that would add to the energy burdens faced by Xcel's captive ratepayers. For the foregoing reasons, the Commission should adopt the OAG's recommendations.

Dated: January 28, 2026

Respectfully submitted,

KEITH ELLISON  
Attorney General  
State of Minnesota

/s/ Joey Cherney

JOEY CHERNEY  
Assistant Attorney General  
Atty. Reg. No. 0403219

WENDY RAYMOND  
Assistant Attorney General  
Atty. Reg. No. 0402802

PETER SCHOLTZ  
Assistant Attorney General  
Atty. Reg. No. 0389936

445 Minnesota Street, Suite 600  
St. Paul, Minnesota 55101-2125  
(651) 300-7569 (Voice)  
(651) 296-9663 (Fax)  
Joey.cherney@ag.state.mn.us

ATTORNEYS FOR MINNESOTA  
OFFICE OF THE ATTORNEY GENERAL—  
RESIDENTIAL UTILITIES DIVISION

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<sup>569</sup> *Id.*