414 Nicollet Mall
Minneapolis, MN 55401

October 23, 2023

—Via Electronic Filing—

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

RE: INITIAL COMMENTS
IN THE MATTER OF COMMISSION REVIEW OF UTILITY PERFORMANCE INCENTIVES FOR ENERGY CONSERVATION
DOCKET NO. E,G999/CI-08-133

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Comments in response to the Minnesota Public Utilities Commission's Notice of Comment issued on September 13, 2023 and the Notice of Extension issued on October 6, 2023 in reference to the Department of Commerce's Proposed Modification of the Shared Savings Financial Incentive Mechanism.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Angela Smelser at 612-370-3447 or Angela.R.Smelser@xcelenergy.com or contact me at 612-342-9027 or Nick.C.Mark@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

NICK MARK
MANAGER, DSM STRATEGY & POLICY

Enclosures
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF COMMISSION REVIEW OF UTILITY PERFORMANCE INCENTIVES FOR ENERGY CONSERVATION

DOCKET NO. E,G999/CI-08-133

COMMENTS

INTRODUCTION AND SUMMARY

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Comments in response to the Minnesota Public Utilities Commission's Notice of Comment issued on September 13, 2023 and the Notice of Extension issued on October 6, 2023. These Comments are in reference to the Department of Commerce's (Department) Proposed Modification of the Shared Savings Financial Incentive Mechanism (*Recommendations*).

At the highest level, the changes proposed by the Department would:

(1) Base the incentive on net benefits calculated using the new Minnesota Cost Test (Minnesota Test or MCT), rather than the current Utility Cost Test (UCT);
(2) Set a Net Benefit Cap of 3.4% of net benefits; and
(3) Set an expenditure cap of 15%, or 20% if a certain savings threshold is reached.

Additionally, the Department recommends that for electric utilities, both the minimum savings needed to earn an incentive and the point at which the Net Benefit Cap is reached should be increased to reflect changes to the statutory minimum electric savings goal. The Department also makes various recommendations regarding the treatment of efficient fuel-switching, load management, and low-income programs. The result of the Department's *Recommendations* is a reduced financial incentive particularly for electric utilities.

Xcel Energy agrees with the recommendation to base the incentive on the Minnesota Test. The Company also supports the Department's recommendations relating to efficient fuel-switching, load management, and low-income programs, as it understands them and as discussed below. However, for a variety of reasons, we believe the incentive caps as a percent of net benefits and as a percent of expenditures should be adjusted from those proposed in the *Recommendations* for both electric and natural gas incentives. By adjusting these caps and the thresholds at which they apply, as discussed in more detail below, the Commission can ensure that the incentive continues to effectively reflect the importance of energy efficiency (and related programs) in the state's policy framework.

The Department's *Recommendation*s imply, but do not explicitly state, that the Demand-Side Management (or CIP/ECO) financial incentive should be reduced. In particular, the Department suggests that Minnesota utilities are receiving more from the financial incentive mechanism than is justified by their results. For example, the Department recommends a revised cap on the incentive as a percent of net benefits. The proposed cap is lower than the Department's estimate of the cap that would be justified simply by the shift from the Utility Cost Test to the Minnesota Test. While not explicitly recognized in the *Recommendations*, it is clear that the Department's intent is to reduce the incentive, though it asserts that the reduction in the electric incentives would be "only nominal."[1]

Significant state policy goals counsel against reducing the financial incentive at this time. Not only would such action contradict long-standing provisions emphasizing the centrality of energy efficiency to the state's energy policy, it would work at cross-purposes to more recent policies (both state and federal) encouraging electrification of various energy end uses. This is not the time to reduce the focus on energy efficiency.

The Department supports its *Recommendations* by comparing Minnesota to other states. The Company believes that the Department's analysis shows not that Minnesota utilities are receiving excessive incentives, but rather that they are dramatically out-performing utilities in other states. The cost of energy efficiency in Minnesota compares very favorably to the cost of energy efficiency in other states, even when considering the cost of Minnesota's incentive. If Minnesota utilities are earning more in incentives for energy efficiency than their peers elsewhere, it is because Minnesota utilities are delivering better programs at lower cost.

There is thus no reason to make changes to the mechanism that are intended to reduce the value of the incentive. The Department's *Recommendations* not only would

[1] Department *Recommendations*, p. 25.

do this but would reduce the electric incentive much more than the "nominal" amount suggested by the Department's predictions. Rather, the Company's analysis suggests that the actual effect on its electric incentive would be a considerable reduction, on the order of 20 to 40 percent.

Such an outcome would be counter to the state's policy objectives and would risk sending a signal to utilities that they are being punished for previous over-achievement delivering highly effective and cost-effective energy efficiency programs. To ensure instead that the mechanism continues to encourage utilities to pursue savings "systematically and aggressively"[2] and to reward them based on their "skill, efforts, and success,"[3] the Company proposes the following modifications to the Department's recommendations:

- The incentive should be calibrated such that each electric utility starts earning an incentive at energy savings of 1.5 percent of sales and achieves the maximum percent of net benefits at energy savings of 2.2 percent of sales;
- The maximum net benefits awarded (the Net Benefits Cap) should be 5.5 percent of Minnesota Test net benefits for electric utilities and 4.0 percent of Minnesota Test net benefits for gas utilities; and
- The Spending Cap should be set at 20 percent of expenditures, or 25 percent of expenditures if the utility exceeds the designated high-achievement threshold (2.0 percent of sales for electric and 1.2 percent for gas).

In the remainder of these Comments, the Company focuses on the differences between the Department's *Recommendations* and the Company's own analysis of the potential impact of those recommendations, including why it believes the *Recommendations* understate the impact of the proposed changes, and elaborates on why the incentive should not be reduced at this time. The Company also explains the rationale for the specific alternative recommendations offered above.

COMMENTS

I. BACKGROUND

The Commission's most recent Order on the Shared Savings Financial Incentive Mechanism was on December 9, 2020, where the Commission extended the incentive for the 2021-2023 triennium and established next steps for the Department. These steps included conducting a stakeholder process to evaluate ways of improving the

[2] MN Stat. 216B.2401 (a).
[3] MN Stat. 216B.16, subd. 6c(c)(2).

shared-savings mechanism for potential adoption in the 2024-2026 triennium, including: the incorporation of lifetime energy savings, an incentive for utilities that achieve permanent peak reductions, comparison of alternative mechanisms (including a comparison of incentive mechanism for energy efficiency with "how a similar-sized … supply-side investment would be rewarded financially through the cost-of-service model"), and energy efficiency opportunities to support increased load flexibility.

On May 25, 2021, Governor Tim Walz signed the Minnesota Energy Conservation Act (ECO) of 2021 as part of the revised Minn. Stat. §216B.241. The ECO Act extended financial incentives to public natural gas utilities for fuel-switching measures and to all public utilities for load management efforts.

On March 31, 2023, the Department adopted a new primary test, dubbed the Minnesota Test, for measuring cost-effectiveness of utility ECO portfolios.[4]

On September 1, 2023, the Department filed comments recommending that the Commission approve a 2024-2026 Shared Savings Financial Incentive Mechanism as summarized below:

All Utilities:

- Base the incentive on a percentage of net benefits, calculated using the Minnesota Cost Test
- Set a net benefits cap of a 3.4%
- Set an expenditure cap of 15%
- Expenditures for efficient fuel switching (EFS) can be used towards the expenditure cap.
- If the utility exceeds energy savings above 1% of retail sales, excluding load management are allowed to count the increased net benefits for load management towards the financial calculation (if the program was approved on or after May 25, 2021).
- Non-cost-effective low-income programs may be excluded from the calculation of net benefits for the financial incentive but may be applied towards the calculation of overall portfolio of determining progress toward the financial incentive. In other words, the utility can remove them from the net benefit calculation but include them in the calculation towards retail sales achievement.

[4] *Decision In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities*, Department of Commerce, March 31, 2023.

Electric Utilities: The incentive begins when the utility achieves savings of at least 1.3% of retail sales. The incentive awarded begins at 1.3 percent of Minnesota Test net benefits and increases to a maximum of 3.4 percent of net benefits at savings achievement of 2 percent of sales or greater. If the utility achieves savings above 2 percent of sales, the expenditure cap increases to 20%. Savings and net benefits resulting from EFS cannot be used towards the financial incentive, though spending for EFS can be included in the calculation of the expenditure cap.

Natural Gas Utilities: The incentive begins when the utility achieves savings of at least 0.7% of retail sales. The incentive awarded begins at 1.3 percent of Minnesota Test net benefits and increases to a maximum of 3.4 percent of net benefits at savings achievement of 1.2 percent of sales or greater. If the utility achieves savings above 1.2 percent of sales, the expenditure cap increases to 20%. Savings and net benefits resulting from EFS can be used towards the financial incentive if 1% retail sales is reached through non-EFS achievement. Spending for EFS can be included in the calculation of the spending cap.

II. AGREEMENT WITH VARIOUS RECOMMENDATIONS

The Company supports the *Recommendation's* interpretation of changes resulting from the ECO Act, specifically as it addresses EFS and low income. With regard to load management, our interpretation of the *Recommendation* is as follows.

- Load management programs that also achieve annual energy savings will be treated the same as any other energy efficiency resource – that is, such programs will be included in the overall savings and net benefits achieved by the utility's portfolio when calculating the incentive, consistent with how such programs have historically been treated.
- For load management programs that do not result in annual energy savings, the net benefits may be included in the calculation of the incentive if:
  - The program was approved after May 25, 2021; and
  - The utility has achieved energy efficiency savings of at least 1 percent of sales).

The Company supports the incentive calculation details for load management as described above.

The Company also supports both the underlying structure of the Department's recommended incentive mechanism (that is, awarding an increasing share of net benefits as energy savings achievements increase) and the change from using UCT net benefits to the new Minnesota Test net benefits. However, as discussed below, the Company does not support changes intended to reduce the value of the incentive at this time, and the Company proposes changes to the calibration of the mechanism that are intended to avoid that result.

III. THE INCENTIVE FOR ENERGY EFFICIENCY SHOULD NOT BE REDUCED

A. Minnesota Policies Support a Robust Incentive for Energy Efficiency

Minnesota statute is clear – indeed, explicit – in prioritizing both energy efficiency and the alignment of utilities' financial interests with energy efficiency. Cost-effective energy savings "are preferred over all other energy resources" in the state's energy savings and optimization policy goal and, along with load management programs, "should be procured systematically and aggressively."[5] In the language authorizing the incentive, the Commission is given broad latitude in the design of the mechanism and may adopt any incentive mechanism "such that implementation of cost-effective conservation is a preferred resource choice for the public utility[.]"[6] Clearly, the legislature intended for its policy preference for energy efficiency to be translated to an earnings signal for utilities that would cause them, whenever possible, to prioritize saving energy above generating and delivering it.

Moreover, recent state and federal legislation has clearly signaled a policy interest in electrification of a number of energy end uses currently met predominantly with fossil fuels. Space heating, water heating, and transportation are the largest of these end uses. Through the federal Inflation Reduction Act and recent Minnesota legislation, to name only two, policymakers have sought to find ways to encourage customers to embrace electrification, in pursuit of both cost and emissions savings. As these new loads come onto the grid, the importance of energy efficiency (and load management) will become greater than ever if electric utilities are to avoid costly upgrades to their systems – to say nothing of the cost to customers of installing and operating over-sized heating and cooling systems.

Given the critical role of energy efficiency, both as the state's preferred resource and as an essential tool for the achievement of other goals, the Company recommends avoiding any changes intended to reduce the value of the incentive mechanism. The

[5] MN Stat. 216B.2401(a).
[6] MN Stat. 216B.16, subd. 6c(c)(3)

incentive is a critical tool that translates the state's policy objectives into utility business objectives. The success of the mechanism in motivating utilities to achieve far more than mere compliance with the state's minimum targets is evident in the fact that most utilities have proposed energy savings goals in their 2024-2026 ECO Triennial filings that are well above the minimum.

B. Adopting the *Recommendations* Would Result in an Incentive Reduction

The Department's *Recommendations* include a proposal to move from the utility cost test (UCT) to the new Minnesota Test (MCT), consistent with the adoption of the MCT by the Department as the primary test by which utility programs are assessed for cost-effectiveness. The Company supports this change, both for consistency and because, with the inclusion of the value of avoided greenhouse gas emissions in the MCT, it encourages utilities to pursue not merely high levels of energy savings, but specifically those savings which maximize value to customers and the climate.

Simultaneous with the move from an incentive based on the UCT to one based on the MCT, the Department recommends reducing the extent to which net benefits from utility achievements are shared with utilities. Notably, the Department's recommended maximum incentive as a percent of net benefits (the "Net Benefits cap") is lower than the percentage the Department calculates as corresponding to the current mechanism. Specifically, the Department calculates that 4 percent of MCT net benefits would roughly equate to the current Net Benefits cap of 10 percent of UCT net benefits. Nevertheless, its proposed Net Benefits cap for 2024-2026 is less than 4 percent; it is 3.4 percent of MCT net benefits.

The Department's *Recommendations* do not explicitly provide a rationale for the recommendation of reducing the Net Benefits cap from 4 percent to 3.4 percent (other than to acknowledge that it would roughly equate to 8.5 percent of UCT net benefits). In response to an Information Request, however, the Department confirmed that the reduction is intentional and stated that "the Department is continuing the trend of marginally ratcheting down the performance incentive and expects energy savings to continue to grow for gas and electric utilities[.]"[7] The Department also stated that it believes its proposal is "reasonable and still comparatively generous" "based on the comparison with other states."[8]

---

[7] Department response to Information Request XE-007.
[8] *Ibid.*

C. The Comparison with Other States Does Not Support a Reduced Incentive

As discussed above, state policy places great emphasis on energy efficiency and the incentive mechanism is the tool by which it communicates that emphasis to utilities. As also discussed, energy efficiency is likely to become only more important, and the Commission should therefore not make changes to the mechanism intended to reduce the value of the incentive. Because the Department has recommended reducing the incentive based on a comparison to other states—who are not operating within the Minnesota policy framework—the Company has looked closely at those comparisons. Based on its analysis, the Company does not agree that the Department's comparison supports the proposed incentive reduction.

Previously in this docket, parties have discussed shortcomings in comparisons between Minnesota's incentives for energy efficiency and those in other states. For example, parties noted that while previous comparisons discussed incentives per unit of energy saved and as a percent of net benefits, they "fail[ed] to consider the cost of the efficiency programs themselves."[9] The *Recommendations* for 2024-2026 do consider program costs briefly, but mainly in the context of incentives as a percent of expenditures, which the Department acknowledges "can be misleading when comparing states."[10]

The Company's review of the state comparisons in the *Recommendations* here similarly demonstrates that they are incomplete because such comparisons ignore the difference in program costs between states. As an example, the *Recommendations* state that "Between 2019 and 2021, electric utilities in Massachusetts were predicted to receive a performance incentive of 5.7 percent of their energy efficiency budgets, while gas utilities in Massachusetts were expected to receive an even lower amount of 2.9 percent of their budgets."[11] What is not stated is that over the same period, the budget for programs in Massachusetts were nearly $800 million for natural gas and nearly $2 *billion* for electric programs.[12] Of note, the savings goals in Massachusetts, while respectable at 2.7 percent of sales for electricity and 1.25 percent of sales for gas[13], are not dramatically different from those proposed by Minnesota utilities, even as the program budgets are an order of magnitude higher in Massachusetts.

[9] *Comments* of CenterPoint Energy in the current docket, August 17, 2015.
[10] Department of Commerce, *A Report on the Impacts of the 2010-2014 Shared Savings Demand-Side Management (DSM) Financial Incentive on Investor-Owned Utility Conservation Achievements and Customer Costs* in the current docket, July 14, 2015, p. 38.
[11] Department *Recommendations,* p. 39.
[12] https://ma-eeac.org/wp-content/uploads/Term-Sheet-10-19-18-Final.pdf
[13] *Ibid.*

A similar dynamic exists for most of the other states to which Minnesota is compared: utilities in other states are spending vastly more to achieve similar or even lower energy savings. Using information provided by the Department in response to Information Request 4, the Company prepared the following tables showing a comparison of the full cost of energy efficiency – including both program costs and incentives – between Minnesota and the other states identified in the *Recommendations*.[14]

Table 1: Total Cost of Electric Energy Efficiency Programs per first-year kWh Saved

State	Average Cost	Average Incentive	Average Savings	Average Total Cost per kWh
Rhode Island	$116,833,333	$5,351,483	190,264,936	$0.64
Massachusetts	$1,995,000,000	$114,000,000	4,278,484,549	$0.49
Connecticut	$183,884,809	$9,305,686	330,345,282	$0.58
Colorado (Xcel Energy)	$94,677,915	$15,312,500	598,449,423	$0.18
Xcel Energy Minnesota	$104,601,657	$26,389,812	650,988,831	$0.20

Table 2: Total Cost of Gas Energy Efficiency Programs per first-year Dth Saved

State	Average Cost	Average Incentive	Average Savings	Average Total Cost per Dth
Rhode Island	$35,333,333	$1,659,534	440,123	$84.05
Massachusetts	$799,500,000	$23,000,000	10,583,467	$77.72
Connecticut	$49,878,559	$2,566,736	646,655	$81.10
Colorado (Xcel Energy)	$16,237,058	$5,140,738	928,396	$23.03
Xcel Energy Minnesota	$15,976,861	$3,800,226	876,155	$22.57

Additionally, the Department's IR response did not include Xcel Energy Colorado's gas program spending. The Company accessed this information from the annual reports found on the Company's website[15].

[14] California is omitted from Tables 1 and 2 because the information provided by the Department indicated that only two utilities (Southern California Edison and SoCal Gas) were included in its comparison and because the data provided did not include spending for either utility.
[15] https://www.xcelenergy.com/company/rates_and_regulations/filings/colorado_demand-side_management

The figures below present the same information graphically, making clear the gulf in cost-effectiveness between Minnesota and other states.

Figure 1: Total Cost of Electric Energy Efficiency Programs per first-year kWh saved

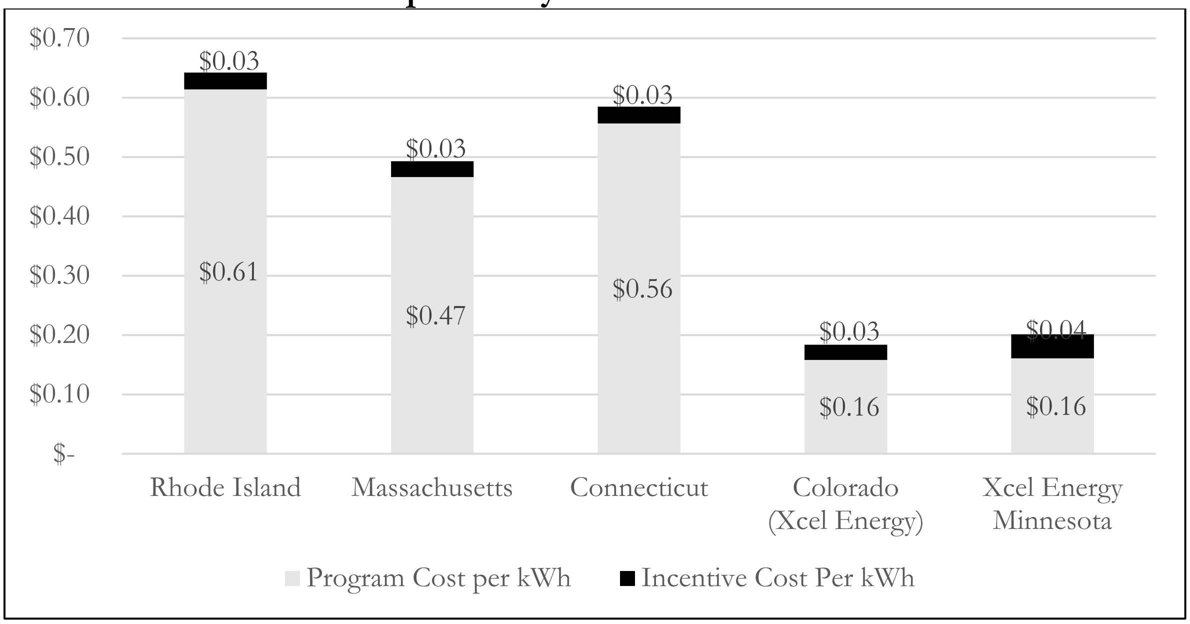
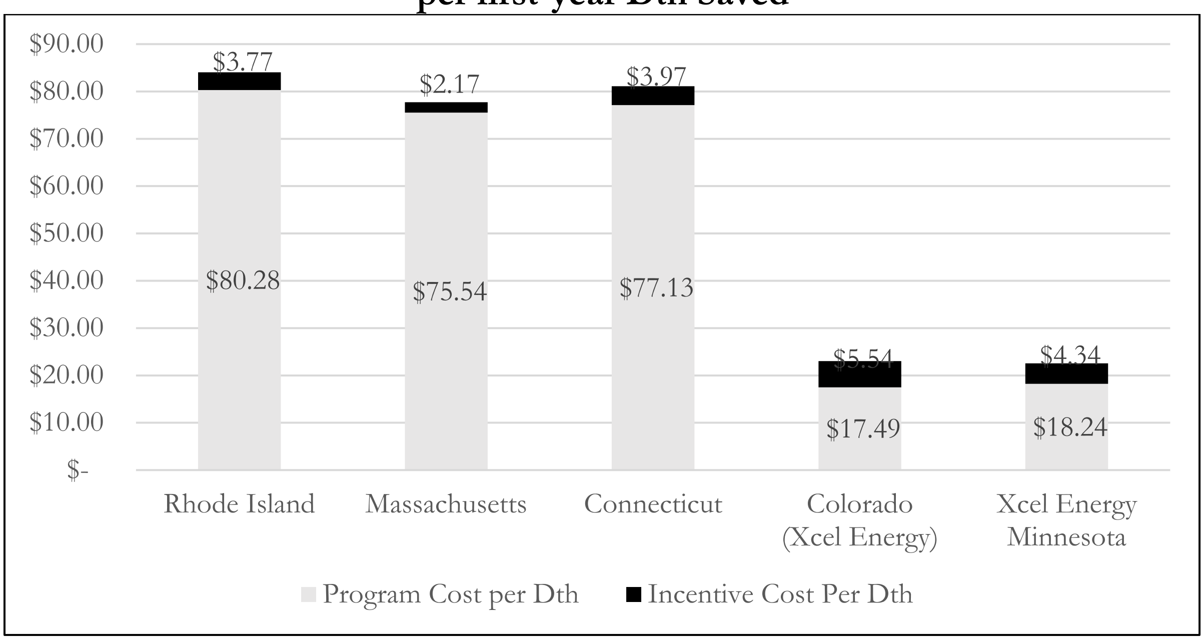


Figure 2: Total Cost of Gas Energy Efficiency Programs per first-year Dth Saved



As is clear from the foregoing, Minnesota's incentive mechanism is not excessive in comparison to other states, nor is it creating a "burden to rate payers"[16] in Minnesota. To the contrary, the full cost of efficiency in Minnesota is well below both the cost of energy and the cost of efficiency in states to which the Department has made comparisons.[17] If the mechanism is rewarding utilities in Minnesota at a higher level than is seen in other states, there is a simple and obvious explanation: Minnesota's utilities are doing a better job at saving energy at a low cost to customers than are utilities in other states. In other words, it is "justified by the utilit[ies'] skill, efforts, and success in conserving energy," precisely as intended by Minnesota Statute.[18]

IV. THE DEPARTMENT'S PROPOSAL WOULD CONSIDERABLY REDUCE INCENTIVES

The Department's *Recommendations* include estimates of average utility incentive awards that would result from its proposed changes to the mechanism, and conclude that "electric utilities' average incentives decrease only nominally." Importantly, these estimates were not developed by applying the *Recommendations'* proposed incentive mechanism to the utilities' filed Triennial Plans. Instead, the *Recommendations* modified those Plans by an "adjustment factor" intended to reflect the fact that many utilities have historically over-achieved relative to the goals proposed in their Triennials (Proposed Adjustment Factor).

Based on the Company's analysis, the impact would be considerably more than "nominal" and in fact would likely reduce its electric incentive by as much as 40 percent. A detailed discussion of why the Company's analysis arrives at such a different result from the Department's is provided in Attachment A. In summary, though, Company's analysis shows that:

- The *Recommendations* err in the data used to calculate the Department's Proposed Adjustment Factors, and the use of the Company's adjustment factors based on corrected data (Corrected Adjustment Factors) would improve the incentive projections;
- The Department's approach of applying the Proposed Adjustment Factors based on average achievement from 2017 to 2022 masks substantive underlying trends in both savings and net benefits. Consideration of recent trends indicates that it is not accurate to assume that a simple average of the period is a good predictor of future savings achievement because the early

[16] Department response to IR XE 007

[17] Indeed, the only state in which the full cost of energy efficiency is comparable to Minnesota is Colorado – and the Department's comparison to Colorado used only data for Xcel Energy's programs. The fact that highly-cost-effective programs in both states are being delivered by the same utility is hardly a coincidence.

[18] MN Stat. 216B.16, subd 6c.(c)(2).

years inflate the average considerably and result in savings predictions that run contrary to the most recent trends;

- The Department's approach assumes that the relationship between the UCT and the MCT would be constant over time and does not appear to recognize that, as electric utilities have made and continue to make progress in reducing emissions from electricity generation, the emissions avoided through energy efficiency have and will continue to decline, reducing the difference between the UCT and MCT net benefits; and
- Based on a complete view of data and historical trends in both savings and net benefits, it is reasonable to expect actual results in 2024-2026 to align more closely with the Company's Triennial filing even than suggested by the use of Corrected Adjustment Factors.

The importance of the adjustment factor on the estimated impact of the proposed changes to the incentive mechanism is substantial. Indeed, the *Recommendations* arrive at their estimation of a "nominal" reduction only by effectively assuming that the Company will be able to achieve an average of 810 GWh in savings over 2024-2026. The Company has never reached savings levels at this level, and indeed has only exceeded 700 GWh once.

The result can be seen in the figures below, which compare the average incentives earned by the Company in 2020-2022 to the calculated incentive results as shown in Figures 11 and 12 of the *Recommendations*. The first two columns in each figure reproduce the values shown for Xcel Energy in the Department's Figures 11 and 12. The third column shows the result of using the Corrected Adjustment Factors (as shown in Attachment A), and the fourth column shows the result of applying the Department's proposed revised mechanism to the Company's Triennial Plan as filed, with no adjustment factor. Based on this information, the Company believes that the *Recommendations* over-estimate the likely financial incentive for its electric programs by something like \$5-\$10 million, representing a roughly 20 to 40 percent reduction in the incentive compared to recent years.

Figure 3: Predicted Average Incentives under Various Scenarios (Xcel Energy Electric)

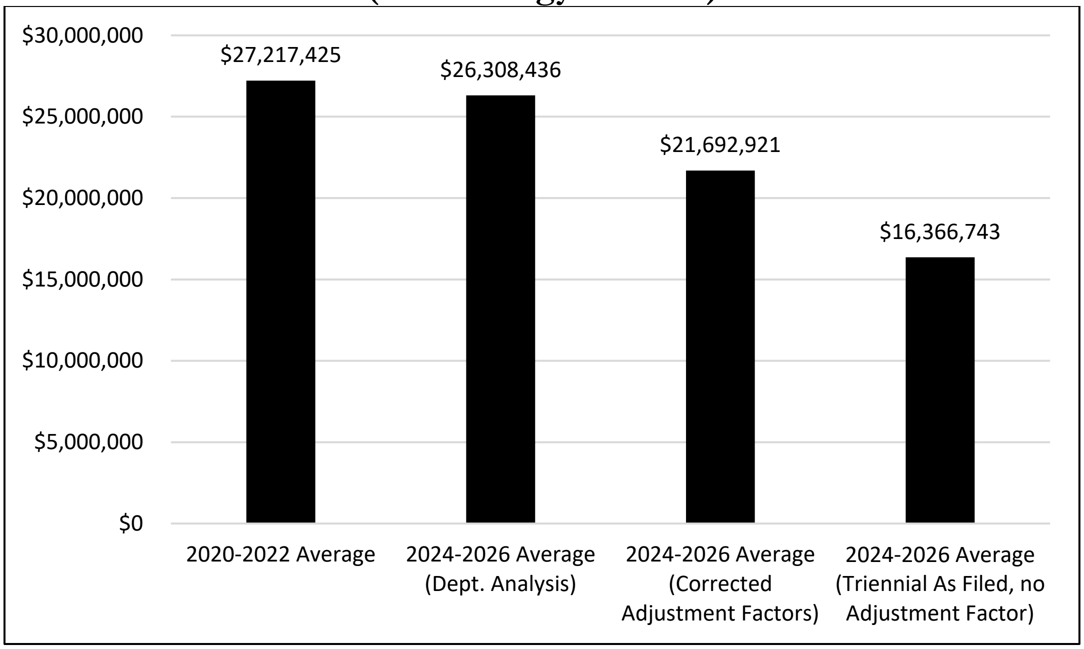
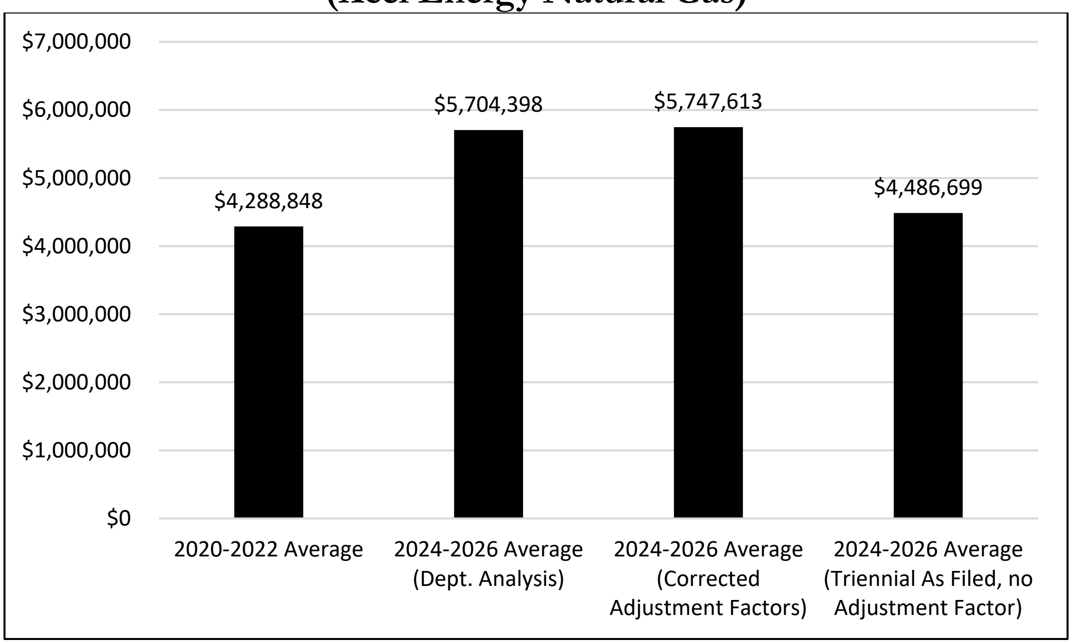


Figure 4: Predicted Average Incentives under Various Scenarios (Xcel Energy Natural Gas)



In sum, the Company believes that its 2024-2026 Triennial filing represents a better predictor of actual results than has historically been the case and the Triennial data should therefore be used to develop estimates of the incentives that might result from a given mechanism. At a minimum, the correct data should be used to develop any adjustment factors that are applied, and the results should be considered in context with the Triennial filing.

V. ENERGY EFFICIENCY IS UNDER-VALUED RELATIVE TO SUPPLY-SIDE INVESTMENTS

Setting aside for a moment the ultimate impact of the *Recommendations* on the financial incentive, the Company will address the Department's discussion comparing the shared-savings incentive design to the results of treating CIP/ECO expenses as if they were traditional supply-side investments. This section of the *Recommendations* is intended to be responsive to the Commission's request that the Department compare alternative incentive mechanism designs "to each other and to how a similar-sized (in terms of cost) supply-side investment would be rewarded financially through the cost-of-service model."[19]

In its *Recommendations,* the Department compared the nominal and net present value (NPV) of the revenue requirements (RR) of a hypothetical $80 million investment to the 2022 DSM program costs, with incentives. The comparison was presented in terms of the cost per first-year unit of energy saved, scaling 2022 energy savings achievements to the $80 million hypothetical investment for purposes of comparison. For most utilities, the Department found that the cost of CIP/ECO per first-year energy savings is between the nominal RR and NPV RR, and concluded from that fact that the current incentive mechanism "is extremely generous and lucrative for the utilities."

The implication of the Department's assertion is that utilities are earning as much or more on CIP/ECO as they would from "similar-sized (in terms of cost)" investments in supply-side resources. However, estimating revenue requirements per unit of energy saved does not address the question of how a supply-side investment would be rewarded financially. If it shows anything, it shows simply how much customers would need to pay per unit of energy saved if CIP were recovered under a long-term investment model. This is not the same as a comparison of the financial reward of different potential investments. In other words, it is not clear that the conclusion drawn by the Department follows from the revenue requirement data presented.

[19] Ordering Point 4.c from the Commission's December 9, 2020 *Order* in the current docket.

The revenue requirements necessary to support a given investment can be affected by a number of factors which may or may not change the attractiveness of the investment. As an example, the federal wind production tax credit provides a revenue stream to investments in wind generation that reduces the amount of revenue that must be recovered from customers to pay for the investment (*i.e.*, the revenue requirement), but does not affect the utility's return on investment.

Considering the current incentive mechanism in comparison to a supply-side investment is a matter of balancing both the rates of return and the length of the investments. The purpose, ultimately, is to make a short-term investment in energy efficiency more attractive than a long-term investment in supply-side options. Intuitively, a long-lived investment with a modest annual rate of return will generally provide a much larger total return than a single-year investment even with a high percentage return.

As an example, the table below compares two hypothetical investments of $80 million, one over 20 years at an 8 percent return and one for a single year at a 20 percent return. While the NPV of revenue requirements for the short-term investment is higher than the long-term investment, the NPV of the return on the long-term investment is dramatically higher – nearly three times higher.

Table 3: Hypothetical Investment Comparison

	Long-Term Investment	**Short-Term Investment**
Rate of Return	8%	20%
Discount Rate	8%	8%
Initial Investment	$80,000,000	$80,000,000
Lifetime	20 years	1 year
Nominal Return on Investment	$67,200,000	$16,000,000
NPV of Return	$40,727,410	$14,814,815
Nominal Revenue Requirement	$116,480,000	$96,000,000
NPV of Revenue Requirement	$80,000,000	$88,888,889

Here, as in the analysis presented in the *Recommendations*, the cost of the short-term investment including the incentive ($96 million) is between the NPV RR and the nominal RR of the long-term investment. This does not mean that short-term investment earns more than the long-term investment. Rather, it is simply a function of the fact that the rate of return exceeds the discount rate used for the short-term investment.[20]

It would be possible to identify a rate of return for the single-year investment that would result in the same return as the longer investment, but the Company has not undertaken that exercise because its purpose here is not to argue that a cost-of-service model is the right approach to incentivizing energy efficiency in Minnesota at this time.

Rather, it is simply to illustrate that first, comparison of investments on the basis of revenue requirements is misleading; and second, that even under the current design of the shared-savings incentive mechanism, the return on energy efficiency is not "extremely generous and lucrative" compared to the return on supply-side investments. This does not mean that energy efficiency must generate returns equal to the returns of supply-side investments to be attractive. The current mechanism has been successful in driving effective investments in energy efficiency, suggesting that the return on efficiency is reasonably balanced against the return from supply-side investments. However, modifications intended to reduce the total incentive would potentially disrupt this balance, making supply-side investments more attractive. This would move further away from treating energy efficiency as the state's preferred energy resource, and from making cost-effective energy savings the preferred resource choice for the utility.

VI. XCEL ENERGY'S PROPOSED INCENTIVE MECHANISM

Based on the information above, the Company proposes a revised calibration of the incentive mechanism. Starting with the common characteristics of the electric and gas mechanism, the Company proposes a more nominal reduction to the spend cap. The Cap should be set at 20 percent of expenditures or 25 percent of expenditures if the utility exceeds the designated high achievement threshold (2.0 percent of sales for electric and 1.2 percent for gas). This would retain the dynamic in the existing mechanism (and the mechanism proposed by the Department) which recognizes that high levels of achievement will likely require higher levels of both effort and spending. The Company's proposed expenditures cap is a reduction from the current level, but not as dramatic a reduction as that proposed by the Department.

As noted above, the Company agrees with the proposal to base the incentive on the percent of Minnesota test net benefits, but disagrees with the proposed net benefits

[20] The rate of return for an incentivized investment should always exceed the discount rate if the purpose is to make one investment more attractive than another; the question is by how much.

caps. The Company also believes it is reasonable to set different net benefit caps for electric and for gas utilities.

For electric utilities, the Company proposes a net benefits cap of 5.5 percent. The Department has estimated that to account for the change from using the UCT to the MCT, a net benefits cap of 4 percent of MCT net benefits would give results comparable to the existing mechanism. However, as discussed in Attachment A this does not account for ongoing trends in emissions, and thus effectively penalizes utilities that have already worked to add more clean energy to their system. To account for this, the Company proposes a nominal increase to the net benefit cap from 4 percent to 5.5 percent.

Additionally, for electric utilities the Company proposes changes to the earnings threshold. In recognition of statute's indication that the incentive should encourage "vigorous and effective" performance, the Company proposes raising the earnings threshold for electric utilities from 1.3 percent of sales to 1.5 percent of sales as well as raising the point at which utilities achieve the maximum percent of net benefits from 2.0 percent of sales to 2.2 percent of sales. This both encourages utilities to continue to pursue energy efficiency and aligns the incentive calibration more closely with historic achievement, rather than the less-aggressive statutory minimum. With these two changes, the incentive mechanism would continue to reward and encourage high achievement, while also sending a signal to electric utilities that this is not a time to reduce their efforts.

For gas utilities the Company proposes a 4.0 percent cap on net benefits. The Department's analysis suggests that this would account for the shift from the UCT to the Minnesota Test, without seeking to reduce the incentive. Because the carbon intensity of gas is likely to remain relatively constant, the point above (and in Attachment A) regarding ongoing emission trends is less applicable. Therefore, no further adjustments are needed to achieve parity with the old incentive mechanism, which has been successful at motivating highly effective and highly cost-effective programs.

With these calibrations the Company estimates it would receive an average incentive of $25,948,610 over 2024-2026 for its electric programs and $5,248,016 for its gas programs. These figures are comparable to the estimates of $26,308,436 and $5,704,398 that the Department estimated would result from its proposal.

CONCLUSION

The Company appreciates the opportunity to provide these comments on the Department's *Recommendations*. Based on our analysis and the discussion above, the Company recommends the following:

- The Commission should not take action intended to reduce the amount of utility incentives for energy efficiency achievement at this time; and
- In order to account for the change from the UCT to the Minnesota test while ensuring the mechanism continues to provide a reasonable reward for utilities' "skills, efforts, and success in conserving energy":
    - The incentive should be calibrated such that each electric utility qualifies for an incentive when it achieves energy savings of 1.5 percent of sales, and earns the maximum percent of net benefits when it achieves energy savings of 2.2 percent of sales, encouraging higher levels of energy savings;
    - The maximum net benefits awarded (the Net Benefits Cap) should be 5.5 percent of Minnesota Test net benefits for electric utilities, reflecting that the Minnesota Test results in higher net benefits than the utility test but that continued reductions in electric-sector emissions mean a slightly higher percentage is necessary to maintain incentive levels;
    - The maximum net benefits awarded (the Net Benefits Cap) should be 4.0 percent of Minnesota Test net benefits for the gas utility, reflecting the change from the UCT; and
    - The Spending Cap should be set at 20 percent of expenditures, or 25 percent of expenditures if the utility exceeds the designated high-achievement threshold (2.0 percent of sales for electric and 1.2 percent for gas).

Dated: October 23, 2023

Northern States Power Company

"Adjustment Factors" Applied to Triennial Filings

To help explain how the Department's *Recommendations* arrive at its estimated award values[1], and ultimately the significant reduction to the financial incentive, the Company is providing this more detailed analysis and discussion of the "adjustment factors" utilized in the Department's energy savings, budgets, and expected net benefit analysis (found on page 24 of the *Recommendations*) and how they were applied in the *Recommendations.*

Noting that utilities have historically over-achieved in the delivery of their CIP/ECO portfolios relative to their Triennial filings, the Department's *Recommendations* included "adjustment factors" to the energy savings, budgets, and expected net benefits in utilities' 2024-2026 Triennials based on historic achievement relative to Triennial proposals over the six years 2017-2022 (Proposed Adjustment Factors). These Proposed Adjustment Factors were then applied to "scale up" (or in a few cases, down) achievements from the figures provided by the utilities in their Triennials and to develop the Department's "prediction" of what utilities will achieve in 2024-2026.[2]

After reviewing and analyzing the Proposed Adjustment Factors and the data on which they are based, the Company identified two primary concerns with the adjustment factors and how they were applied in the *Recommendations.* First, and most importantly, the calculation of the Proposed Adjustment Factors was based on inaccurate historic data. Second, application of the Proposed Adjustment Factors relies on an implicit assumption that historic overachievement will persist at the same rate in the future, though there are good reasons to think this will not be the case (which may have been evident had the correct historic data been used).

The Company discusses each of these concerns below. In addition, the Company elaborates on possible drivers for the utilities' over-achievement in the past, which does not appear to have been considered in the *Recommendations.*

A. The Proposed Adjustment Factors Should be Calculated Differently

Setting aside for the moment the question of whether the use of "adjustment factors" is reasonable and appropriate, the Proposed Adjustment Factors were calculated from inaccurate data. In the *Recommendations,* Table 7 summarized the Proposed Adjustment Factors; those for Xcel Energy are reproduced below.

[1] Department *Recommendations*, pp. 23-24.
[2] Department *Recommendations*, pp. 23-24.

Table A1: Adjustment Factors Calculated by the Department for Xcel Energy[3]

	Energy Savings	Budget	Net Benefits
Xcel Energy Electric	30%	4%	71%
Xcel Energy Natural Gas	3%	-10%	32%

The Company sent an Information Request to the Department requesting the data and calculations used to derive Table 7.[4] In reviewing the data provided, it appears that the Proposed Adjustment Factors were developed comparing the savings and budget goals as proposed in utilities' initial Triennial filings (Proposed Targets) with actual results from implementation found in the utilities' Annual Status Reports (Actual Results). For purposes of considering the relationship of actual results to the Proposed Targets, this approach could be reasonable (particularly given that for 2024-2026, only initial proposals are available). The Company notes that beyond that limited purpose, however, this approach could be problematic, as it ignores the impact of changes during the initial review and approval of Triennials and subsequently through modifications.

However, in comparing the Proposed Targets to Actual Results, the data included several errors. The most consequential of these errors was the use of Proposed Targets that did not include the savings, spending, or net benefits of Alternative CIP filings, while the Actual Results *did* include the impact of Alternative CIPs. Specifically, the data relied on by the Department excludes The Center for Energy and the Environment's One Stop Efficiency Shop (One Stop Efficiency Shop) in 2021 and 2022 plan values. One Stop Efficiency Shop was filed with a goal of 80 GWh, which covers the gap between the Proposed Target and Actual Results.[5]

Had the Alternative CIPs been treated consistently as to both the Proposed Targets and the Actual Results, the Company believes the calculated adjustment factors would have been those shown in Table 2 below. The data used by the Company to calculate these corrected adjustment factors is provided in Attachment B to these Comments (Corrected Adjustment Factors) and includes the Alternative CIPs in both the Proposed Target and Actual Results. The impact of these Corrected Adjustment Factors is significant, as shown in Figure 3 of the Company's Comments.

[3] Table A1 is a partial reproduction of Table 7 in the Department's *Recommendations* (page 24) showing only information for Xcel Energy. The Company has not assessed the accuracy of the Department's calculated adjustment factors with regard to any other utility.
[4] Attachment 1, Department Response to Information Request XE-2.
[5] The Company notes that the erroneous treatment of One Stop Efficiency Shop may have resulted from its uniqueness; it is the Company's understanding that it is the only Alternative CIP that has been included in utility incentive calculations in the past.

Table A2: Corrected Adjustment Factors Calculated by Xcel Energy[6]

	Energy Savings	Budget	Net Benefits
Xcel Energy Electric	23%	-2%	41%
Xcel Energy Natural Gas	2%	-9%	33%

B. Adjustment Factors Obscure Recent Achievement Trends

While using the correct data to calculate adjustment factors is critical, the Company's analysis also found that the approach used to derive the Proposed Adjustment Factors (which approach the Company reproduced to develop the Corrected Adjustment Factors in Table A2) elides important trends in recent performance.

First, the extent to which the Company has been able to exceed its goals has been decreasing. This is not because achievement has been declining. To the contrary, both energy savings and net benefits results have been strong. Rather, the Company has regularly pursued more ambitious goals[7], and exceeding those ever-increasing goals is becoming more difficult. In 2022 the Company fell nearly 11 percent short of its own energy savings target, despite achieving savings more than 55 percent greater than the statutory goal.

[6] See Attachment B for the data and calculations that underlie Table A2, which are taken from the Company's Status Report filings found here: https://www.xcelenergy.com/company/rates_and_regulations/filings/minnesota_demand-side_management

[7] Indeed, the Company's proposed energy savings goals in its Triennial plans are consistently well above the statutory minimum.

Figure A1: Comparison of electric savings goals to actuals with percent overachievement

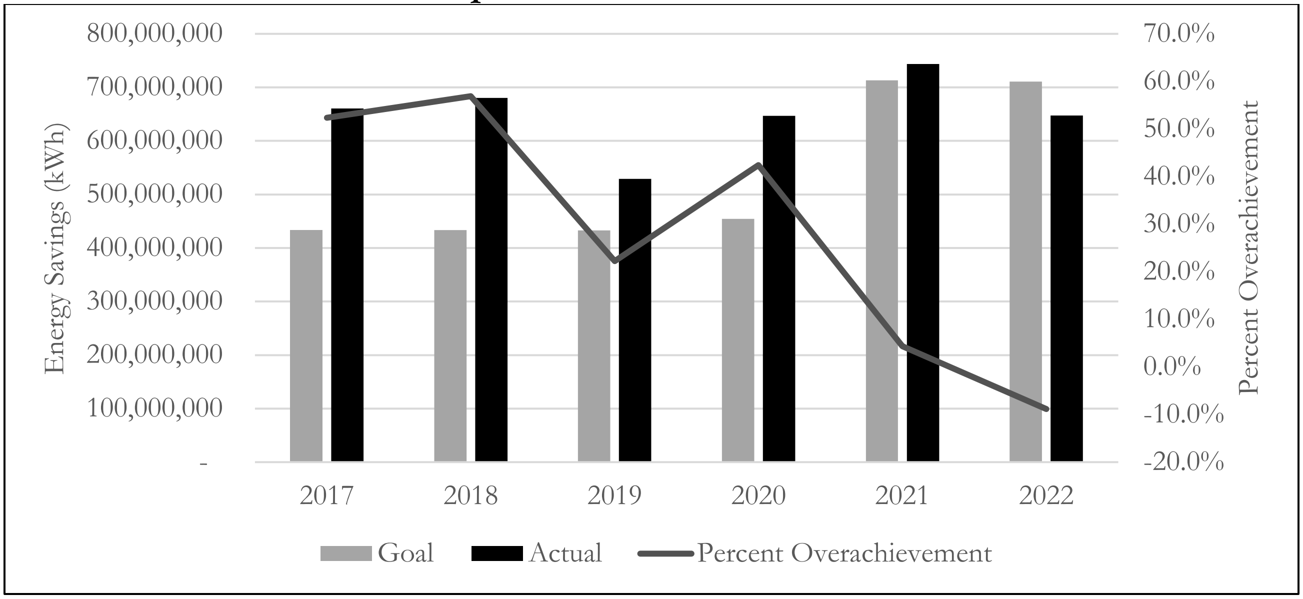
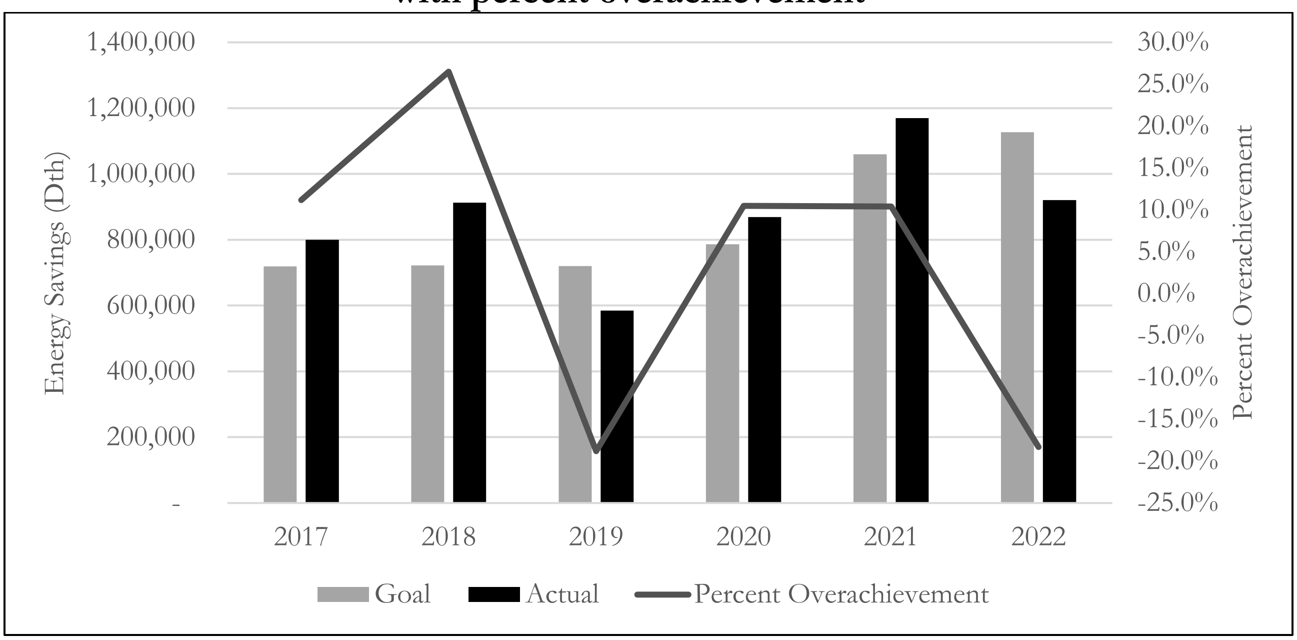


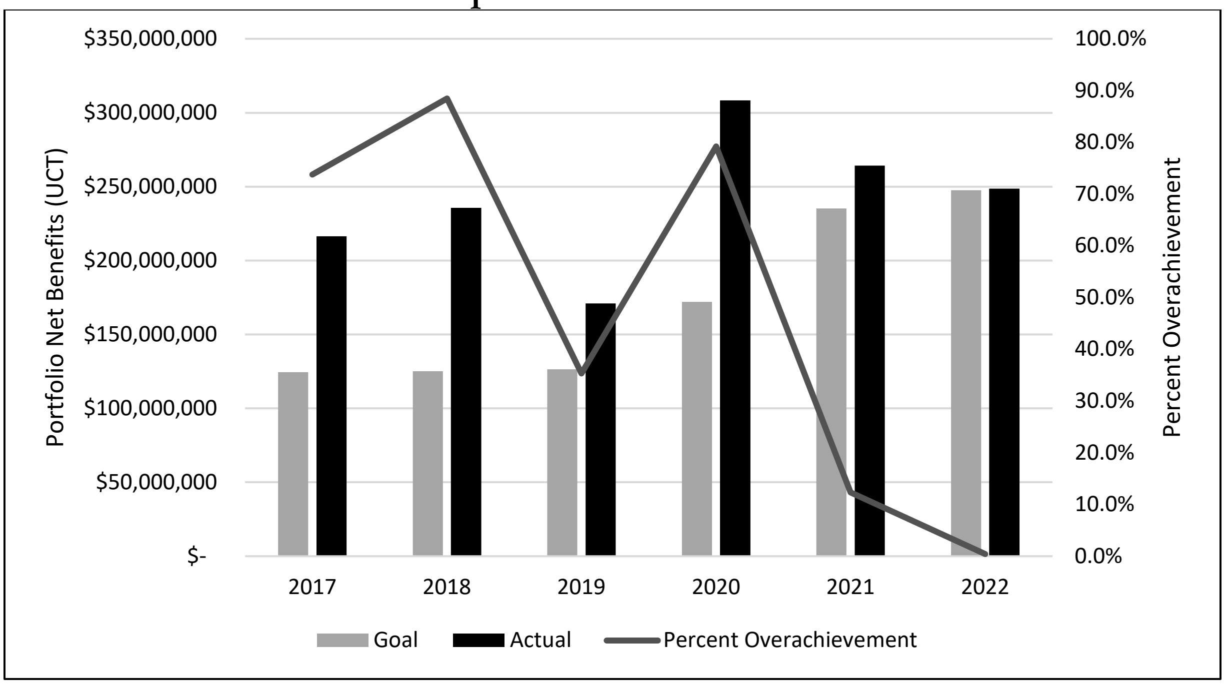
Figure A2: Comparison of gas savings goals to actuals with percent overachievement



The Company's Proposed Targets for the 2024-2026 Triennium are around 50 percent higher than the goals for 2017-2020 and are fairly close to the average savings achieved in 2017-2022. It is thus a mistake to assume that the considerable over-achievement of goals in the early part of that period will persist in 2024-2026, or to assume that a simple average of the period is a good predictor of future savings achievement given that the early years inflate the average considerably and result in savings predictions that run contrary to the most recent trends. This is particularly true for the Company's electric programs, but it is also worth noting that the Company has proposed an aggressive expansion of its gas programs over 2024-2026 and dramatically exceeding those higher goals is unlikely.

The complications with applying the Proposed Adjustment Factors extend beyond energy savings, affecting the predictions of net benefits as well. As shown in Table A2 above, the Company believes that, when using accurate data, the electric net benefits Corrected Adjustment Factor is considerably lower than the Proposed Adjustment Factor.[8] As with energy savings, the use of a simple average obscures recent trends in net benefit achievement relative to goal; this trend is illustrated in Figure A3 below.

Figure A3: Comparison of electric net benefit goals to actuals with percent overachievement



One driver of this declining trend is the same as that seen with energy savings – i.e., that the Company's targets have increased and over-achievement relative to target is thus more difficult.

Another factor driving the declining trend relates to the change from the Utility Cost

[8] It is worth noting that because the incentive mechanism is based on both energy savings and net benefits, the inaccuracy of an incentive projection based on flawed savings assumptions is compounded if the net benefits assumptions are similarly flawed.

Test (UCT) to the MN Test (MCT). The Department undertook a regression analysis to understand the relationship of the UCT to the MCT, as summarized in the *Recommendations* and detailed in its Attachment C. Based on this analysis, which used data from program years 2019-2021, the Department concluded that, "*Minnesota Test Net Benefits are on average about 2.5 times higher than Utility Cost Test Net Benefits*" and, as a result, a financial incentive equal to ten percent of UCT net benefits would be roughly equal to four percent of MCT net benefits.[9] Based on the ratios of UCT to MCT summarized in the Department's Table 6, this result seems intuitively reasonable.

However, the Department assumed that the relationship between the UCT and the MCT would be constant over time – that is, that MCT net benefits in 2024-2026 would continue to be about 2.5 times the UCT benefits in 2024-2026.[10] This assumption is unsupported in the *Recommendations*. Further, at least for Xcel Energy's electric programs, it is inconsistent both with ratio of estimated net benefits estimates for the two tests provided in the Company's Triennial filing and with intuitive expectation that results from considering the differences between the UCT and the MCT.

The Department correctly identifies that net benefits under the MCT are "significantly higher" than under the UCT, and one driver of the increase is the inclusion of the value of avoided carbon emissions in the MCT.[11] The impact of carbon emissions on net benefits for gas utilities is likely to be constant between one year and another, because the overall carbon content of delivered gas is unlikely to change considerably. For electric utilities, however, it is crucial to recognize that a given kWh of savings will result in considerably different carbon emission savings in different years. In other words, as electric utilities have made and continue to make progress in reducing emissions from electricity generation, the emissions avoided through energy efficiency have and will continue decline, reducing the difference between the UCT and MCT net benefits.

This decline in the difference between UCT and MCT net benefits over time does not appear to be accounted for in the Department's analysis. Moreover, the importance of carbon emissions in the MCT means that electric utilities such as Xcel Energy that have already moved to significantly reduce emissions become victims of their own success in the context of the financial incentive mechanism in both absolute terms

[9] Department *Recommendations*, Attachment C, p.2 and subsequent discussion.
[10] "[W]e assume that MN Test Net Benefits are a constant factor times Utility Cost Test Net Benefits," Department *Recommendations*, p. 24.
[11] Department *Recommendations*, p. 19. The Department also notes that the use of a lower discount rate in the MCT results in higher net benefits relative to the UCT; in the Company's view this is true but by far the dominant factor is the inclusion of carbon.

(because there is less net benefit from savings) and in terms of the comparison to other utilities (because utilities with higher emissions will generate more net benefit from the same amount of savings, resulting in a higher incentive).

In summary, the Company believes that recent trends in the Company's achievements are obscured by the use of adjustment factors based on historic data to develop incentive projections. Instead, the Company believes that its 2024-2026 Triennial filing represents a better predictor of actual results than has historically been the case and the Triennial data should therefore be used to develop estimates of the incentives that might result from a given mechanism. At a minimum, the correct data should be used to develop any adjustment factors that are applied, and the results should be considered in context with the Triennial filing.

Electric Energy Efficiency				
	Savings Goal			Actual Savings
	Department	Xcel	Difference	
2017	434,000,000	433,513,457	486,543	660,435,156
2018	433,000,000	433,694,480	(694,480)	680,448,447
2019	433,000,000	432,766,260	233,740	528,899,459
2020	454,000,000	454,160,800	(160,800)	646,796,991
2021	632,915,358	712,950,947	(80,035,589)	743,837,488
2022	630,456,680	710,492,269	(80,035,589)	647,675,810

	Budget Goal			Actual Spending
	Department	Xcel	Difference	
2017	$ 96,007,201	$ 96,225,301	$ (218,100)	$ 109,109,805
2018	$ 94,110,123	$ 94,257,723	$ (147,600)	$ 107,451,885
2019	$ 97,308,531	$ 95,881,968	$ 1,426,563	$ 92,816,075
2020	$ 102,371,401	$ 102,371,401	$ -	$ 104,461,579
2021	$ 105,789,166	$ 125,604,411	$ (19,815,245)	$ 109,504,882
2022	$ 108,482,773	$ 128,333,716	$ (19,850,943)	$ 104,265,717

	Net Benefits Goal			Actual Net Benefits
	Department	Xcel	Difference	
2017	$ 110,420,662	$ 124,588,000	$ (14,167,338)	$ 224,008,869
2018	$ 117,038,908	$ 125,035,146	$ (7,996,238)	$ 238,855,791
2019	$ 117,882,545	$ 126,433,463	$ (8,550,918)	$ 175,891,796
2020	$ 143,846,735	$ 172,011,014	$ (28,164,279)	$ 308,239,130
2021	$ 176,295,040	$ 235,282,432	$ (58,987,392)	$ 268,810,002
2022	$ 185,547,122	$ 247,529,191	$ (61,982,069)	$ 242,712,020

Electric Adjustment Factors		
Savings	Spend	UCT Net Benefits
23%	-2%	41%

Natural Gas Energy Efficency				
	Savings Goal			Actual Savings
	Department	Xcel	Difference	
2017	719,365	719,360	5	799,597
2018	721,929	721,929	-	913,240
2019	720,223	720,223	-	584,761
2020	786,334	786,334	-	868,599
2021	1,052,032	1,059,783	(7,751)	1,170,229
2022	1,119,274	1,127,024	(7,750)	920,504

	Budget Goal			Actual Spending
	Department	Xcel	Difference	
2017	$ 16,829,590	$ 16,547,440	$ 282,150	$ 14,181,339
2018	$ 17,169,355	$ 16,803,354	$ 366,001	$ 15,506,839
2019	$ 17,546,319	$ 17,180,479	$ 365,840	$ 13,929,520
2020	$ 18,730,192	$ 18,730,192	$ -	$ 14,587,983
2021	$ 17,740,491	$ 17,928,663	$ (188,172)	$ 18,291,279
2022	$ 18,457,932	$ 18,648,205	$ (190,273)	$ 19,857,191

	Net Benefits Goal			Actual Net Benefits
	Department	Xcel	Difference	
2017	$ 19,245,891	$ 17,638,744	$ 1,607,147	$ 29,231,281
2018	$ 19,245,891	$ 18,736,542	$ 509,349	$ 36,593,467
2019	$ 19,245,891	$ 19,938,929	$ (693,038)	$ 25,211,491
2020	$ 23,983,131	$ 23,553,131	$ 430,000	$ 46,802,220
2021	$ 41,704,156	$ 41,498,140	$ 206,017	$ 50,201,464
2022	$ 46,615,214	$ 46,407,097	$ 208,117	$ 35,780,290

Gas Adjustment Factors		
Savings	Spend	UCT Net Benefits
2%	-9%	33%

Certificate of Service

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

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

xx electronic filing

Docket No. E,G999/CI-08-133

Dated this 23rd day of October 2023

/s/

____

Ella Giefer
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_8-133_Official
Anjali	Bains	bains@fresh-energy.org	Fresh Energy	408 Saint Peter Ste 220 Saint Paul, MN 55102	Electronic Service	No	OFF_SL_8-133_Official
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	60 S 6th St Ste 1500 Minneapolis, MN 55402-4400	Electronic Service	No	OFF_SL_8-133_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_8-133_Official
Stacy	Dahl	sdahl@minnkota.com	Minnkota Power Cooperative, Inc.	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	OFF_SL_8-133_Official
Justin	Fay	fay@fresh-energy.org	Fresh Energy	408 St. Peter St Ste 220 St. Paul, MN 55102	Electronic Service	No	OFF_SL_8-133_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_8-133_Official
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_8-133_Official
Metric	Giles	metriccsp@gmail.com	Community Stabilization Project	501 Dale St N Saint Paul, MN 55101	Electronic Service	No	OFF_SL_8-133_Official
Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_8-133_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Laura	Goldberg	lgoldberg@nrdc.org	Natural Resources Defense Council	20 N. Upper Wacker Dr. Suite 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_8-133_Official
Jason	Grenier	jgrenier@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_8-133_Official
Jeffrey	Haase	jhaase@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_8-133_Official
Tiana	Heger	theger@mnpower.com	Minnesota Power	30 W. Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_8-133_Official
Joe	Hoffman	ja.hoffman@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	OFF_SL_8-133_Official
Tina	Koecher	tkoecher@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_8-133_Official
Martin	Kushler	mgkushler@aceee.org		28003 Copper Creek Lane Farmington Hills, MI 48331	Electronic Service	No	OFF_SL_8-133_Official
Discovery	Manager	discoverymanager@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_8-133_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_8-133_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ted	Nedwick	tnedwick@nhtinc.org	National Housing Trust	1101 30th Street NW Ste 100A Washington, DC 20007	Electronic Service	No	OFF_SL_8-133_Official
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_8-133_Official
Audrey	Partridge	apartridge@mncee.org	Center for Energy and Environment	212 3rd Ave. N. Suite 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_8-133_Official
James	Phillippo	james.phillippo@wecenergygroup.com	Minnesota Energy Resources Corporation	PO Box 19001 Green Bay, WI 54307-9001	Electronic Service	No	OFF_SL_8-133_Official
Lisa	Pickard	lseverson@minnkota.com	Minnkota Power Cooperative	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	OFF_SL_8-133_Official
Scott	Reimer	reimer@federatedrea.coop	Federated Rural Electric Assoc.	77100 US Highway 71 PO Box 69 Jackson, MN 56143	Electronic Service	No	OFF_SL_8-133_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_8-133_Official
Michael	Sachse	michael.sachse@opower.com	OPOWER	1515 N. Courthouse Rd, 8th Floor Arlington, VA 22201	Electronic Service	No	OFF_SL_8-133_Official
Bruce	Sayler	bruces@connexusenergy.com	Connexus Energy	14601 Ramsey Boulevard Ransey, MN 55303	Electronic Service	No	OFF_SL_8-133_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_8-133_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_8-133_Official
Jeffrey	Springer	jeff.springer@dairylandpower.com	Dairyland Power Cooperative	3200 East Ave S La Crosse, WI 54601	Electronic Service	No	OFF_SL_8-133_Official
Grey	Staples	gstaples@mendotagroup.com	The Mendota Group LLC	1830 Fargo Lane Mendota Heights, MN 55118	Electronic Service	No	OFF_SL_8-133_Official
Analeisha	Vang	avang@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_8-133_Official
Robert	Walsh	bwalsh@mnvalleyrec.com	Minnesota Valley Coop Light and Power	PO Box 248 501 S 1st St Montevideo, MN 56265	Electronic Service	No	OFF_SL_8-133_Official
Ethan	Warner	ethan.warner@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_8-133_Official