COMMERCE DEPARTMENT

November 2, 2023

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Reply Comments of the Minnesota Commerce Department, Division of Energy Resources**
Docket No. E,G999/CI-08-133

Dear Mr. Seuffert:

Attached are the Reply Comments of the Minnesota Commerce Department, Division of Energy Resources (Department), in the following matter:

> Proposal for Modifications to the Shared Savings DSM Financial Incentive Mechanism for Implementation Beginning in 2024

Based on our review of the initial comments of other parties in this matter, the Department continues to recommend that the Minnesota Public Utilities Commission (Commission) approve a 2024-2026 Shared Savings financial incentive mechanism with the following parameters:

- IOUs use the new Minnesota Test outlined in the Department's *Decision In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities* (Decision) filed on March 31, 2023 in Docket No. E,G999/CIP-23-46 for calculating their net benefits to derive their Shared Savings incentive.
- IOUs use the 3.3% Societal Discount Rate approved by the Deputy Commissioner of the Department in the Decision for calculating the new Minnesota Test Net Benefits to derive their Shared Savings incentive.
- Electric utilities' incentive starts at energy savings of 1.3% of retail sales; 3.4% of net benefits is awarded at energy savings of 2.0% of retail sales and above.
- Gas utilities' incentive starts at energy savings of 0.7% of retail sales; 3.4% of net benefits is awarded at energy savings of 1.2% of retail sales and above.
- Net Benefits Cap of 3.4%.
- ECO/CIP Expenditures Cap of 15%.

- IOUs are allowed to exceed the 15% Expenditures Cap, up to a maximum of 20%, if gas utilities meet or exceed energy savings equaling 1.2% of retail sales and if electric utilities meet or exceed energy savings equaling 2.0% of retail sales;

The Department is available to answer any questions that the Commission may have.

Sincerely,

/s/ ADWAY DE, PH.D.
Public Utilities Rates Analyst

AD/ad
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Commerce Department
Division of Energy Resources

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

I. INTRODUCTION

On September 1, 2023, the Minnesota Department of Commerce, Division of Energy Resources (Department), submitted its *Proposal for Modifications to the Shared Savings DSM Financial Incentive Mechanism for Implementation Beginning in 2024* in Docket No. E,G999/CI-08-133 (Proposal).

A. DEPARTMENT PERFORMANCE INCENTIVE PROPOSAL

1. Specifically, the Department recommends that the Commission approve a 2024-2026 Shared Savings DSM Financial Incentive Mechanism with the following provisions:

    A. For all utilities, the net benefits are calculated using the new Minnesota Test as outlined in The Department's *Decision In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities* (Decision) approved by the Deputy Commissioner in Docket No. E,G999/CIP-23-46 on March 31, 2023

    B. For all utilities, set a Net Benefits Cap of 3.4 percent of net benefits.

    C. For all utilities, set a Conservation Improvement Program (CIP) Expenditure Cap of 15 percent.

    D. The Societal Discount Rate is used in the calculation of net benefits to discount for future benefits and costs. This rate can be found in the Decision and was calculated using the United States Department of the Treasury's (Treasury) 20-year Constant Maturity (CMT) Rate.

    E. For electric utilities:
        1) For a utility that achieves energy savings of at least 1.3 percent of the utility's retail sales, the utility is allowed to collect a financial incentive.
        2) For a utility that achieves energy savings of at least 1.3 percent of retailsales, the utility is awarded a share of the net benefits as set forth in Attachment A.
        3) For each additional 0.1 percent of energy savings the utility achieves, the share of net benefits awarded to the utility is increased by an additional 0.3 percent until the utility achieves savings of 2.0 percent of retail sales.
        4) For savings levels of 2.0 percent and higher, the utility is awarded a share of the net benefits equal to the Net Benefits Cap.
        5) Electric IOUs are allowed to exceed the Expenditures Cap, up to a maximum of 20%, if they meet or exceed energy savings equaling 2.0% of retail sales

F. For gas utilities:
   1) For a utility that achieves energy savings of at least 0.7 percent of the utility's retail sales, the utility is allowed to collect a financial incentive.
   2) For a utility that achieves energy savings of at least 0.7 percent of retailsales, the utility is awarded a share of the net benefits as set forth in Attachment A.
   3) For each additional 0.1 percent of energy savings the utility achieves, the share of net benefits awarded to the utility is increased by an additional 0.3 percent until the utility achieves savings of 1.2 percent of retail sales.
   4) For savings levels of 1.2 percent and higher, the utility is awarded a share of the net benefits equal to the Net Benefits Cap.
   5) Gas IOUs are allowed to exceed the Expenditures Cap, up to a maximum of 20%, if they meet or exceed energy savings equaling 1.2% of retail sales.

2. The following provisions from the current Shared Savings DSM Financial Incentive Plan are maintained, as follows:

   A. CIP-exempt customers shall not be allocated costs for the Shared Savings Incentive Mechanism. Sales to CIP-exempt customers shall not be included in the calculation of utility energy savings goals.

   B. If a utility elects not to include a third-party CIP project, the utility cannot change its election until the beginning of subsequent years.

   C. If a utility elects to include a third-party project, the project's net benefits and savings will be included in the calculation of the energy savings and will count toward the 1.0 percent savings goal for gas utilities and 1.75% savings goal for electric utilities.

   D. The energy savings, costs, and benefits of modifications to non-third-party projects will be included in the calculation of a utility's DSM incentive.

   E. The costs of any mandated, non-third-party projects (e.g., the 2007 Next Generation Energy Act assessments, University of Minnesota Initiative for Renewable Energy and the Environment costs) shall be excluded from the calculation of net benefits and energy savings achieved and incentive awarded.

   F. Costs, energy savings, and energy production related to Electric Utility Infrastructure Costs, solar installation, and biomethane purchases shall not be included in energy savings for DSM financial incentive purposes.

3. The following provisions are added due to the implementation of the ECO Act, as follows:

   A. As per MN Statutes 216b.241 Subd. 7(i), "[t]he costs and benefits associated with any approved low-income gas or electric conservation improvement program that is not cost-effective when considering the costs and benefits to the public utility may, at the discretion of the utility, be excluded from the calculation of net economic benefits for purposes of calculating the financial incentive to the public utility. The energy and demand savings may, at the discretion of the public utility, be applied toward the calculation of overall portfolio energy and demand savings for purposes of determining progress toward annual goals and in the financial incentive mechanism."

B. Both electric and gas utilities are allowed to count their expenditures on efficient fuel-switching (EFS) and load management (LM) programs in calculation of their Expenditures Cap.

C. Gas utilities that have achieved energy savings at or above 1% of retail sales, excluding savings achieved through fuel-switching programs, are allowed to count net benefits and energy savings derived from their efficient fuel-switching (EFS) programs toward calculating their financial incentive.

D. Electric utilities are not allowed to count net benefits and energy savings derived from their efficient fuel switching (EFS) programs toward calculating their financial incentive.

E. Both electric and gas utilities that have achieved energy savings at or above 1% of retail sales excluding savings achieved through load management programs, are allowed to count the increased net benefits and energy savings derived from their load management (LM) programs that occurred on or after the approval of the Energy Conservation and Optimization Act (on May 25, 2021) towards calculating their financial incentive.

The new Shared Savings DSM Financial Incentive Plan shall be in effect for 2024-2026.

B. INITIAL COMMENTS ON DEPARTMENT PROPOSAL

On October 23, 2023, the following parties submitted comments on the Department's proposal:

- CenterPoint Energy (CenterPoint or CPE);
- Minnesota Energy Resources Corporation (MERC);
- Office of Attorney General—Residential Utilities Division (OAG-RUD);
- Minnesota Power (MP)
- Otter Tail Power Company (OTP); and
- Xcel Energy (Xcel).

The Department briefly summarizes each parties' recommendations below.

1. CPE

CPE made the following recommendations:

- CPE was neutral on the switch from the UCT to the MN Test (Recommendation 1A).
- The Commission should adopt a net benefits cap of 4.5 percent of MN Test net benefits. (response to Recommendation 1B). With recent policy changes and a shift to the MN

Test, this is the cap best suited to incentivize continuation of existing levels of long-term investments in innovative energy efficiency programs and projects.

- CPE was neutral on the expenditures cap and the societal discount rate (Recommendation 1C-D).
- CPE recommends changes to the implementation of the MN Test NB cap (response to Recommendation 1F 2-3) and neutral on other elements of implementation (Recommendation 1F 1, 4-5):
  - 2) For a gas utility that achieves energy savings of at least 0.7 percent of retail sales, the utility is awarded a share of the NBs of 2 percent.
  - 3) For each additional 0.1 percent of energy savings, the gas utility achieves, the share of NBs awarded to the utility is increased by an additional 0.5 percent until the utility achieves savings of 1.2 percent of retail sales.
- CPE supports recommended provisions for gas utilities in Recommendation 2A-F and 3A-E.
- CPE recommended the PUC include a provision in its order about the financial incentive counting as a cost in NBs calculations for the purpose of calculating the financial incentive. If the financial incentive will count as a cost in the calculation of NBs, the Company also recommends that the financial incentive is similarly counted as a cost for the expenditures cap as well.

2. MERC

MERC made the following recommendations:

- The Commission should establish a net benefits cap of no less than 5 percent.
- The Commission should add the incentive award as a cost to expenditures for the purposes of the Incentive Mechanism calculation.

3. OAG-RUD

OAG-RUD made the following recommendation:

- The Commission should adopt the Department's proposed changes to the shared-savings incentive mechanism.

4. MP

MP made the following recommendations:

- Minnesota Power recommends a percent (of Minnesota Test) net benefits cap of at least 5% to maintain similar incentive levels as the current mechanism.
- Minnesota Power recommends an expenditure cap no lower than 20 percent.

5. OTP

OTP made the following recommendations:

- The Commission set a financial incentive cap on Otter Tail's net benefits at a maximum of 8.6 percent and the cap on expenditures at 22 percent, assuming the utility achieves two percent or greater of energy savings.
- Each utility should have its own net benefits cap.
- The Commission should adopt a financial incentive for OTP's load management activities that include all new kW and at least half of existing kW derived from its load management programs.

6. XCEL

Xcel made the following recommendations:

- 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).

II. DEPARTMENT ANALYSIS

Below, the Department addresses the issues raised by the utilities.

A. CORRECTIONS TO THE DEPARTMENT'S PROJECTIONS

Xcel in its comments stated that the "*Proposed Adjustment Factors were calculated from inaccurate data*"[1]. The Department reviewed the explanation and recognizes that there was a mistake in the Department's calculations for the adjustment factors. The Department collected data on the proposed plans from the Triennial Filings of the utilities and data on the actual achievements from the annual status reports. Since the savings, spending, and net benefits of the One Stop Efficiency Shop program were not included in the Triennial Plan but included in the status reports, it led to an overestimate of the adjustment factors for Xcel. The Department agrees with the adjustment factors calculated by Xcel in Table A2 of its initial comments. However, the Department did not consider the savings, spending, and net benefits of One Stop Efficiency Shop program for the 2024-26 Triennial leading to an underestimate of Xcel's financial incentive. The Department corrected both of these mistakes and presents its revised forecast for the projected incentives below.

Otter Tail pointed out that the Department's calculation of its financial incentive was incorrect due to inclusion of EFS, LM, low income, POP Solar, and regulatory assessments. The Department agrees that some of these items should not be included in the incentive calculation and recalculated its projections with the data provided by OTP. The Department notes however, that it's proposal stated:

> *Both electric and gas utilities that have achieved energy savings at or above 1% of retail sales excluding savings achieved through load management programs, are allowed to count the increased net benefits and energy savings derived from their load management (LM) programs that occurred on or after the approval of the Energy Conservation and Optimization Act (on May 25, 2021) towards calculating their financial incentive.*

Thus, the Department excluded POP Solar, assessment, low income programs, and EFS from the net benefit calculations but included net benefits from the LM program. Otter Tail also excluded its expenses on LM and EFS from its calculation of the expenditure cap, which is contrary the Department's proposal, that stated:

> *Both electric and gas utilities are allowed to count their expenditures on efficient fuel-switching (EFS) and load management (LM) programs in calculation of their Expenditures Cap.*

The above provision of including the expenses but not including the net benefits of EFS program for electric utilities is consistent with other existing programs like OTP's POP solar program. Additionally, this can encourage electric utilities to spend on EFS programs by increasing their expenditure cap.

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[1] Page 1 of Attachment 1 in Xcel's comments in Docket No.E,G999/CI-08-133 filed on Oct 23, 2023.

Lastly, the ECO statute does not prohibit including EFS expenses while calculating the expenditure cap. Based on these corrections, the following figures represent the Department's forecasts for projected incentives for the electric and gas investor-owned utilities.

Figure 1: Comparison of Electric Utilities' 2020-2022 Average Incentives and Their Predicted 2024-2026 Average Incentives

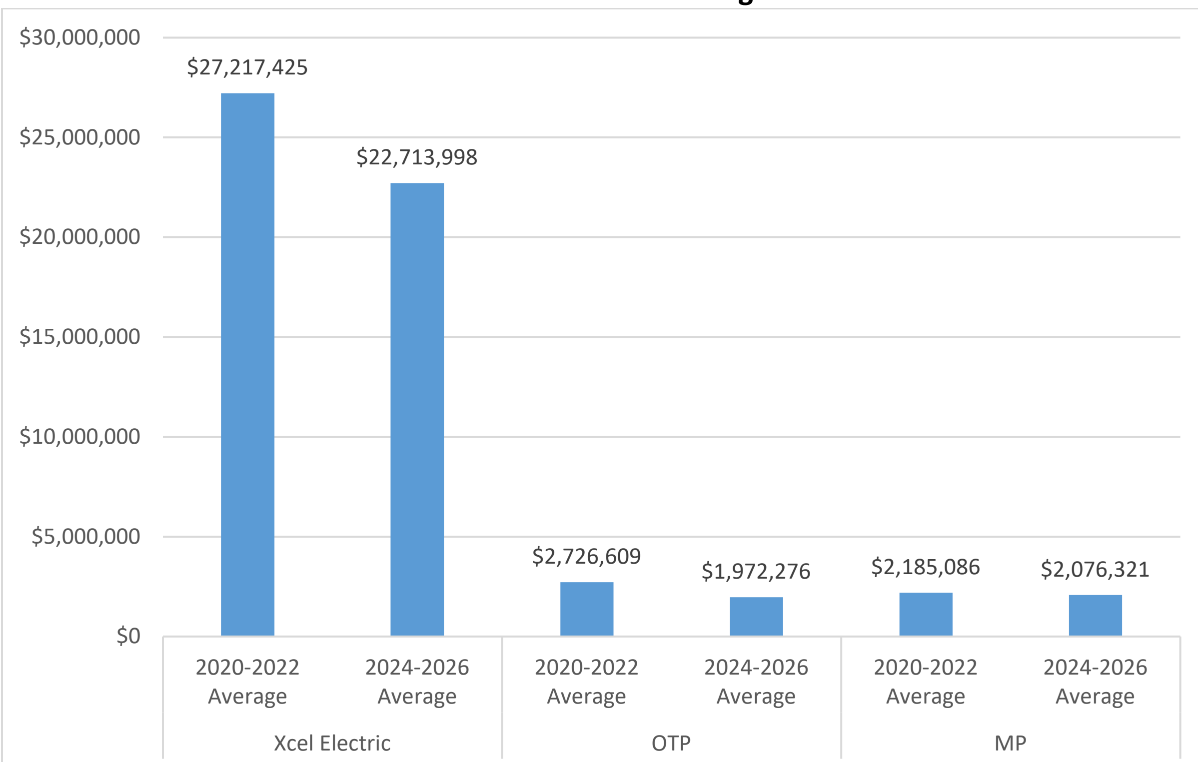
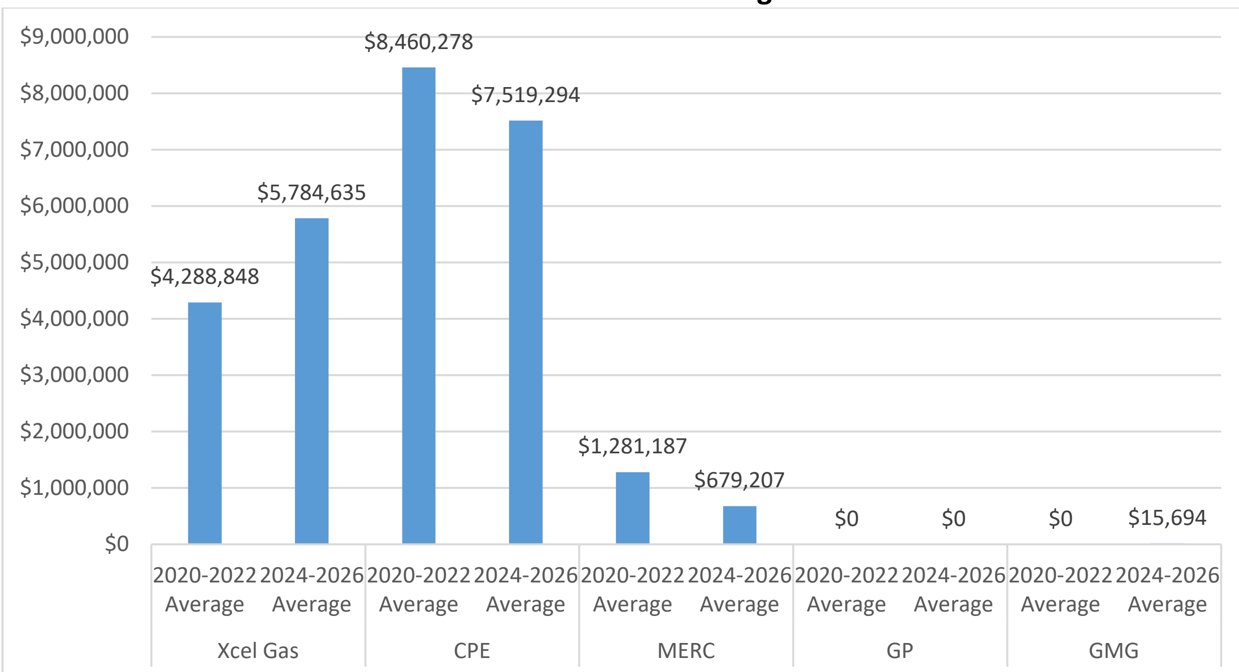


Figure 1 above shows that the projected incentives for Xcel for the 2024-26 period is about a million dollars higher than what Xcel showed in Figure 3 of its filing. As explained above, this is because One Stop Efficiency Shop was not included in the earlier projections made by the Department. Additionally, the decline in OTP's projected incentives is due to the exclusion of EFS, low income, POP Solar and regulatory assessments. Following the Department's proposal to include incremental LM net benefits installed after the passage of the ECO Act, net benefits from LM are included in the figure above.

Figure 2 below shows a comparison of projected annual incentives during 2024-2026 to 2020-2022 for the gas utilities. The new projected incentives for Xcel gas are higher than what was in the Department's original proposal. This is because the original projections in the Department's proposal did not include the net benefits from One Stop Efficiency Shop. The projections for the other utilities remain unchanged.

Figure 2: Comparison of Gas Utilities' 2020-2022 Average Incentives and Their Predicted 2024-2026 Average Incentives



To help contextualize these results, the Department compared the projected incentives with historical data by looking at electric utilities and gas utilities separately. The figure below shows the total incentives and first year energy savings of the electric utilities since 2006 along with the projected values for the 2024-26 Triennial.

Figure 3: Aggregate First-Year kWh Savings and Aggregate Incentives Paid to Electric Utilities

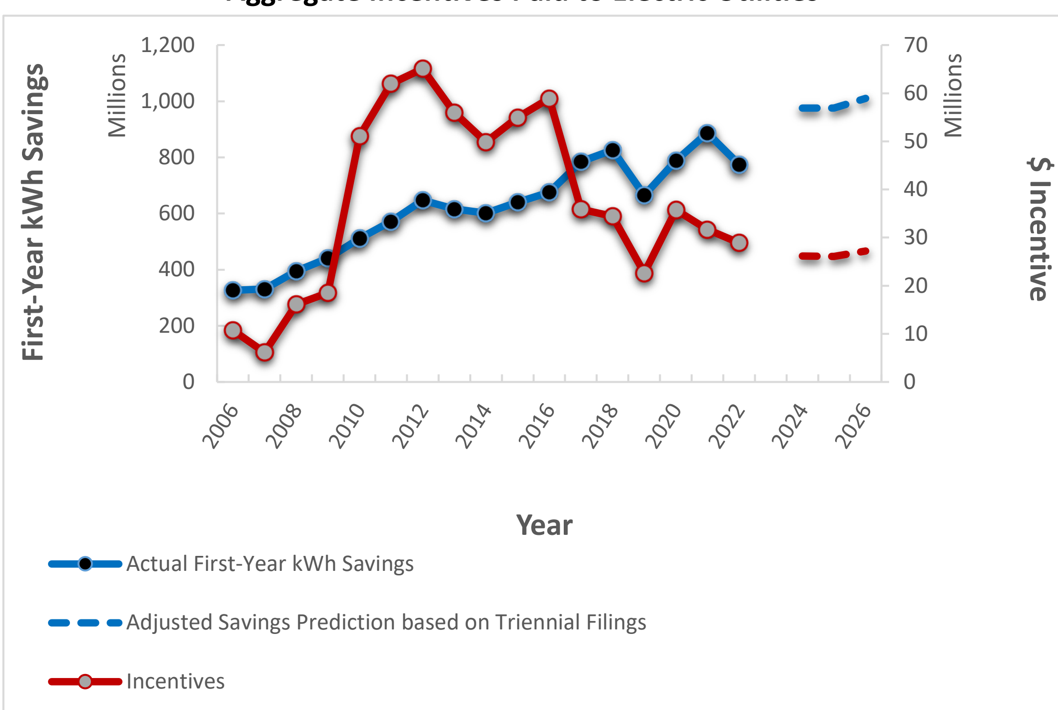
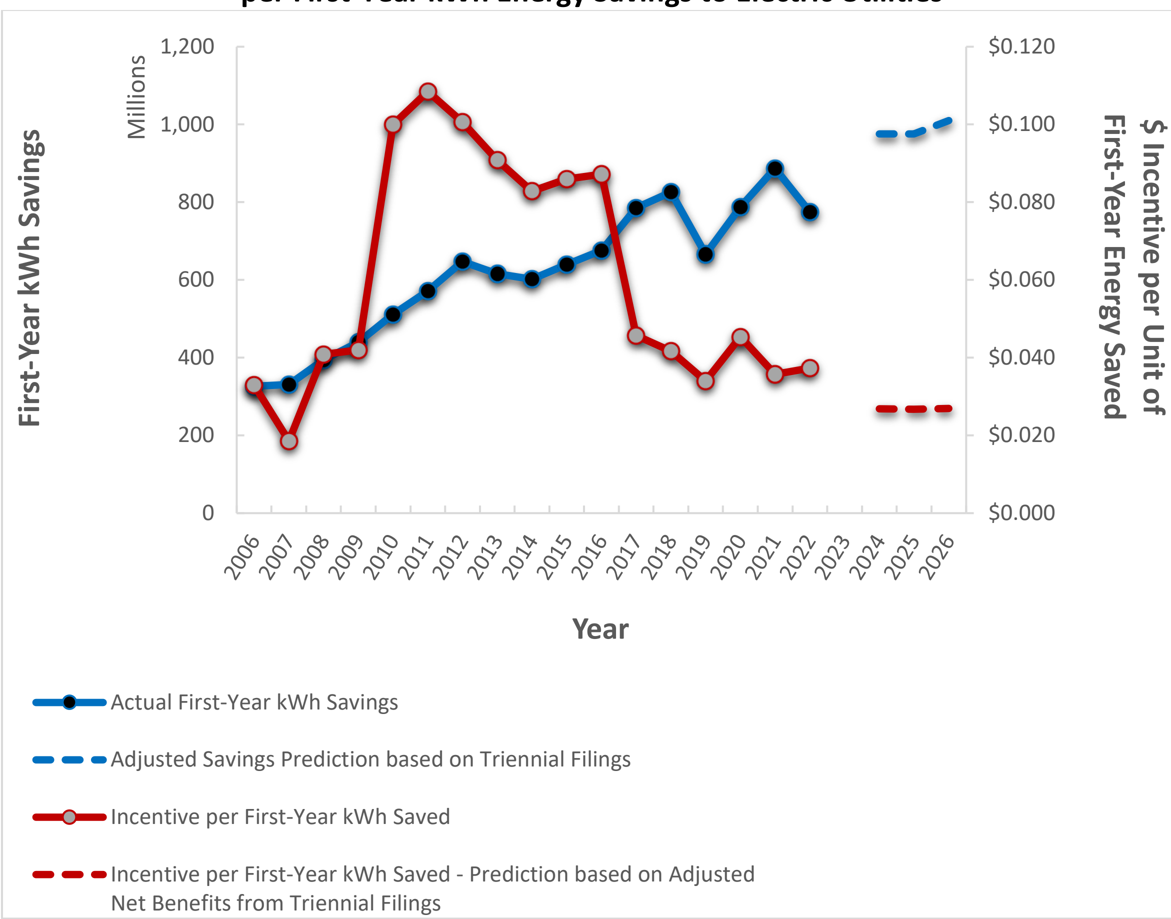


Figure 4 below shows the same data but in terms of incentives paid out per kWh of first year energy saved along with energy savings. The Department believes the projected reductions in the incentive per kWh are reasonable and consistent with the Commission's historic approach of gradually decreasing the financial incentive and bringing it closer to what utilities achieve in other states that rank high in the ACEEE scorecard.

Figure 4: Aggregate First-Year kWh Savings and Aggregate Incentives Paid per First-Year kWh Energy Savings to Electric Utilities



The Department compiled similar figures for gas utilities to contextualize the level of incentives with historical data. Figure 5 shows Department projections that gas utilities should see an increase in dekatherms saved and total incentives paid on the basis of the currently proposed mechanism.

Figure 5: Aggregate First-Year Dth Savings and Aggregate Incentives Paid to Gas Utilities

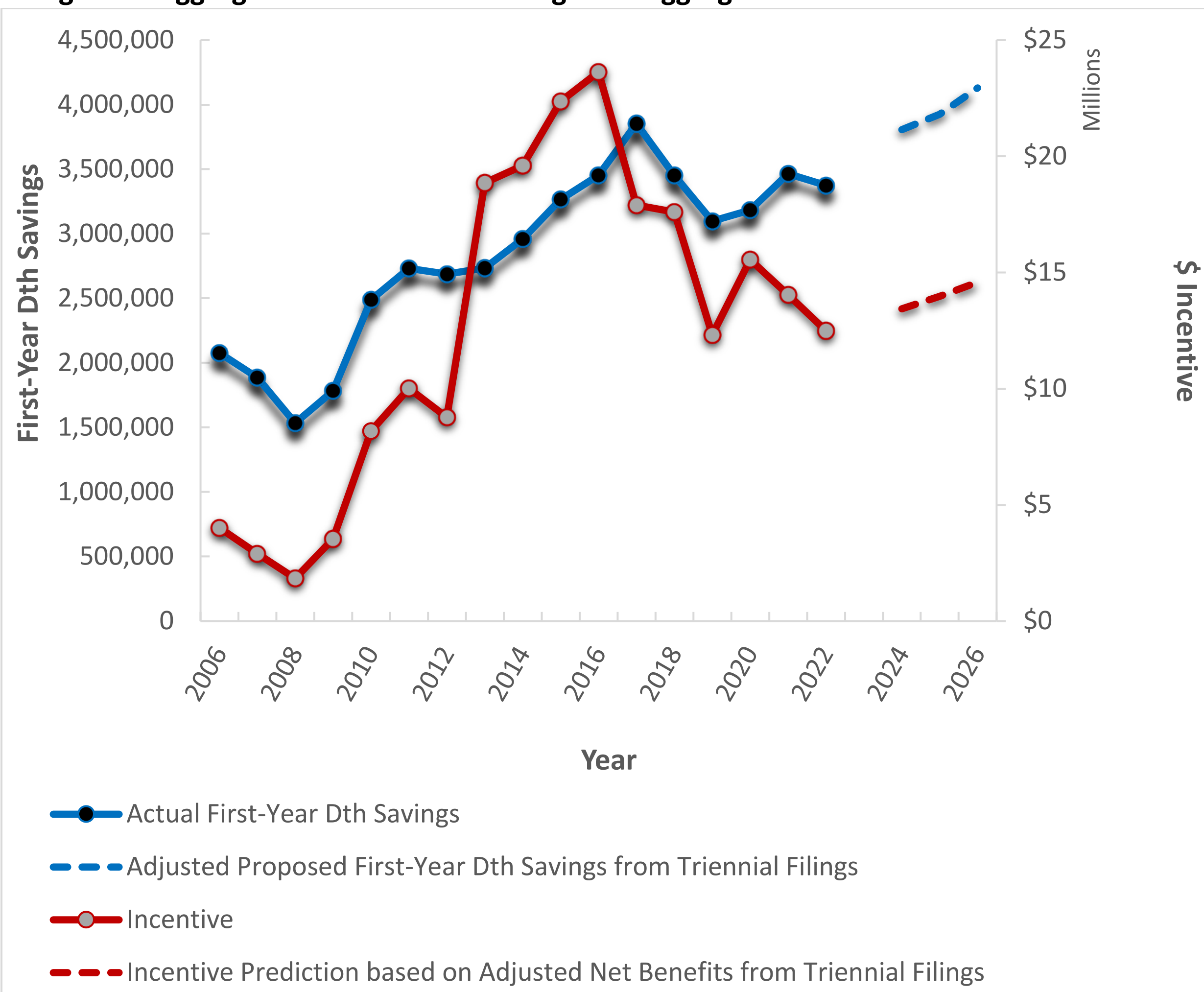
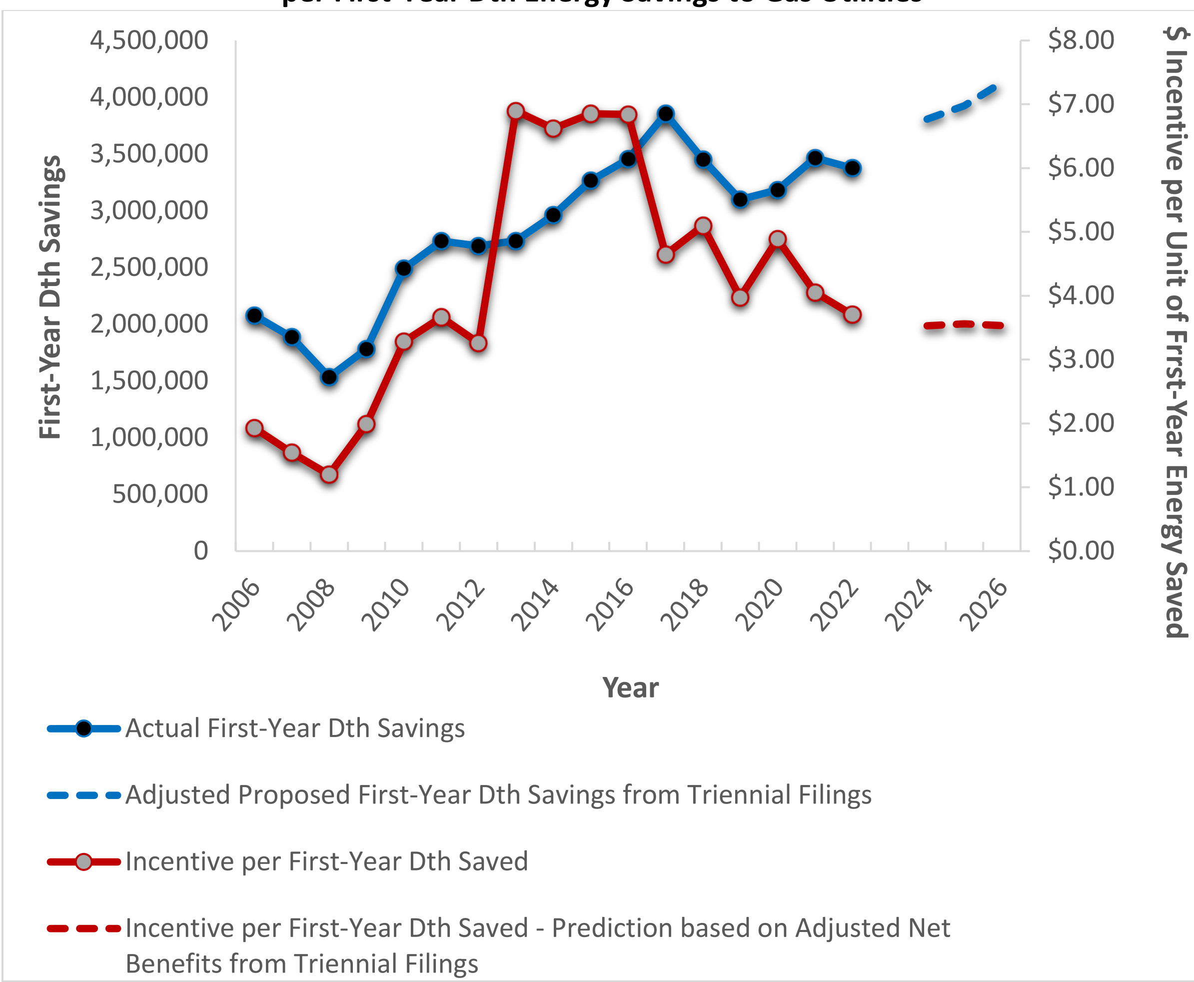


Figure 6 below shows the same data but in terms of incentives paid out per dekatherm of first year energy saved along with energy savings. The Department believes the projected reductions in the incentive per dekatherm are reasonable and consistent with the Commission's historic approach of gradually reducing the financial incentive and brings it closer to what utilities achieve in other states that rank high in the ACEEE scorecard.

Figure 6: Aggregate First-Year Dth Savings and Aggregate Incentives Paid per First-Year Dth Energy Savings to Gas Utilities



Overall, the Department predicts that the annual incentive for gas and electric utilities combined will cost ratepayers $40,761,425 on average between 2024 and 2026. This is compared to $46,159,432 on average annually between 2020 and 2022. This represents a 11.7 percent reduction in the average annual financial incentive payout relative to 2020-2022. To understand how the proposed values compare with other states, the Department reproduces two tables from its proposal with the corrected values for Minnesota for the 2024-26 period.

Table 1: Comparison of Average Performance Incentives per First-Year kWh Saved between Minnesota and Other States with High Energy Efficiency Performance per ACEEE

2020-2022 Average $/kWh in MN (#10 in ACEEE State Scorecard)	2024-2026 Average $/kWh in MN (#10 in ACEEE State Scorecard)	2019-2021 Average $/kWh in CT (#9 in ACEEE State Scorecard)	2020-2022 Average $/kWh for National Grid in RI (#7 in ACEEE State Scorecard)	2019-2021 Average $/kWh in MA (#2 in ACEEE State Scorecard)	2019-2022 Average $/kWh for Xcel CO (#13 in ACEEE State Scorecard)	2017-2019 Average Aggregate $/kWh for SCE in CA (#1 in ACEEE State Scorecard)
$ 0.039	$ 0.027	$ 0.028	$ 0.028	$ 0.027	$ 0.026	$ 0.010

Table 2: Comparison of Average Performance Incentives per First-Year Dth Saved between Minnesota and Other States with High Energy Efficiency Performance per ACEEE

2020-2022 Average Aggregate $/Dth in MN (#10 in ACEEE State Scorecard)	2024-2026 Average Aggregate $/Dth in MN (#10 in ACEEE State Scorecard)	2019-2022 Average $/Dth for Xcel CO (#13 in ACEEE State Scorecard)	2019-2021 Average Aggregate $/Dth in CT (#9 in ACEEE State Scorecard)	2020-2022 Average $/Dth for National Grid in RI (#7 in ACEEE State Scorecard)	2019-2021 Average Aggregate $/Dth in MA (#2 in ACEEE State Scorecard)	2017-2019 Average Aggregate $/Dth for SoCalGas in CA (#1 in ACEEE State Scorecard)
$ 4.215	$ 3.541	$ 4.730	$ 3.596	$ 3.416	$ 2.173	$ 0.402

The comparisons demonstrate that the incentive levels contained in the proposed mechanism are comparable to utilities in other states.

B. NEED FOR REVISION OF THE FINANCIAL INCENTIVE MECHANISM

Utilities were mostly against the decrease in financial incentives that would result from the Department's proposal. However, the Department took a balanced approach by considering the interests of ratepayers, shareholders of the company, and the overall policy goals of the state. The overall recommendation of a net benefits cap of 3.4 percent of MN Test net benefits takes into account multiple relevant factors:

Firstly, the Department has started using a new cost effectiveness test, the MN Test for screening energy efficiency programs. Based on data provided by utilities for their 2019-2021 programs, the MN Test net benefits are 2.3 times higher on average than UCT Net Benefits. This necessitates a significantly lower net benefits cap based on the MN Test compared to the earlier cap based on the Utility Cost Test. The Department's proposal shows how a 10 percent cap on the Utility Cost Test net benefits is equivalent to a 4 percent cap on the MN Test based on this data.

Secondly, since the MN Test acknowledges more benefits from efficiency programming than other existing cost effectiveness tests, it will be easier for utilities to include additional programs in their Triennial plan compared to earlier years.

Thirdly, adoption of the ECO Act significantly expanded the number of energy efficiency measures that are now eligible to be included in a utility's Triennial plan. Measures that include LM and EFS, that were previously prohibited from being included in energy efficiency programs are now eligible. It is worth noting that these measures are part of the growing solutions touted by many, including utilities, as a key to decarbonization. Ceteris paribus, the move to allow the inclusion of these programs is expected to increase in the amount of energy savings achieved in the state.

Fourthly, Minnesota has had a history of having one of the highest financial incentives for energy efficiency programs in the country. The Department has over the years consistently pointed this out by comparing Minnesota's incentives to those in other states. The comparisons in Tables 1 and 2 based on the projected incentives for gas and electric utilities show that the Department's proposal is very reasonable. Minnesotans should not be burdened to pay significantly more than the top performing states[2] in the country.

Lastly, the Commission has been reducing the financial incentive over the past few Triennials. While the utilities have opposed this reduction each time and argued that it would lead to lower energy savings, the data has proved otherwise. Minnesota has continued to see a robust growth in its energy savings, as depicted in Figures 3 to 6. The Department expects this trend will continue with the conducive environment created by the ECO Act, greater federal support through the Inflation Reduction Act, and use of the new MN Test as its primary cost-effectiveness test.

Based on the above reasons, the Department concludes that the current financial incentive is in need of revision to better reflect realities of the current environment.

C. COMPARISON OF INCENTIVES TO OTHER STATES

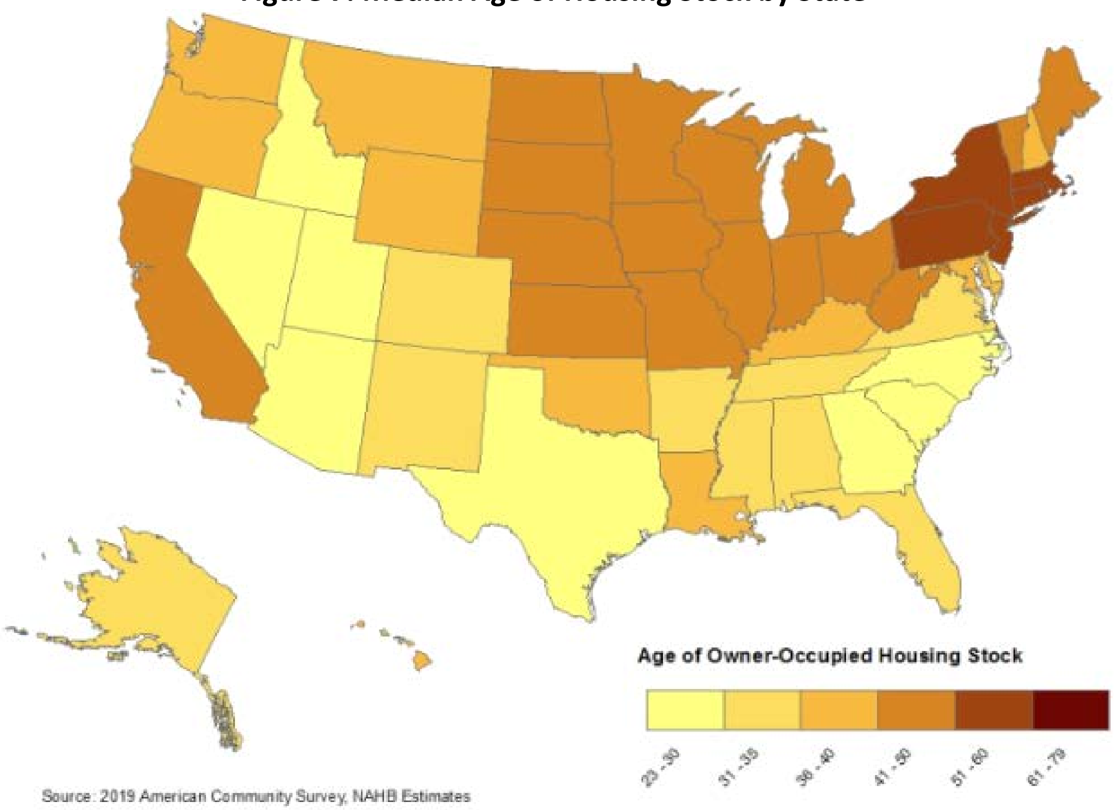
Multiple utilities pointed out concerns with the Department's comparisons between Minnesota and other states in the Proposal. One of the central issues they raised pointed to the higher cost of energy efficiency programs in the states the Department selected. In fact, CPE stated that the Department's interstate comparison "*can conflate "over rewarding" with "underperformance".*"
The Department reviewed the analysis provided by the utilities and concludes the utilities consideration of "performance" or achievement is too narrow. While cost is one aspect, ignoring other

[2] As per the 2022 ACEEE state scorecard.

aspects can lead to misleading interpretations. Instead, the Department chose a more holistic interpretation of achievement by looking at results of the ACEEE score card. ACEEE has been publishing state scorecards since 2006 and collects a wide variety of data, including costs, to create its ranking. As Minnesota strives to become a national leader in energy efficiency, such comparisons do provide valuable insights.

The Department also notes that the cost of energy efficiency can depend on various things, including but not limited to the age of the housing stock in a state. While it is true that Massachusetts, Rhode Island and Connecticut spend more dollars per unit of energy saved, these states also have an older housing stock compared to Minnesota. As can be seen in Figure 7 below, there is considerable heterogeneity in the median age of the housing stock by state.

Figure 7: Median Age of Housing Stock by State[3]



Overall, the Department continues to support a comparison with other leading states in the country as per the ACEEE state score card rankings as we re-evaluate the reasonableness of our shared savings financial incentive mechanism.

[3] Accessed at https://eyeonhousing.org/2021/03/age-of-housing-stock-by-state-3/

D. COMPARISON OF INCENTIVES WITH PAST PERFORMANCE

Multiple utilities raised concerns about the Department's approach to use historical data to predict future outcomes. In particular, utilities pointed out several unique aspects of their performance in various years. This was in response to the Department's development of various utility specific adjustment factors based on the past five years data to forecast potential biases in proposed Triennial plans and project outcomes for the 2024-2026 period.

Xcel provided a comparison of its proposed and actual outcomes over the last 5 years in Figures A-1 to A-3 in Attachment A of its filing. However, Xcel did not provide any estimates of its expected difference between proposed and actual outcomes over the next Triennial. Otter Tail claimed that the "accuracy in results will be within approximately 10 percent of its initially proposed 2024-2026 ECO plan"[4] without providing any quantitative calculation to get to this value. CPE noted how large custom projects can create unique challenges that can lead to changes in overperformance relative to the proposed results. Unfortunately, CPE did not provide any quantitative estimate of its expected over achievement over the next Triennial.

The Department notes predicting future outcomes is always a challenge. However, this does not mean that consistent patterns of over or under achievement should be ignored. To generate reasonable estimates of future outcomes, the Department applied a simple and straightforward methodology, whereby each adjustment factor was calculated on the basis of proposed and actual outcomes for each utility over the last 5 years. The Department took a 5-year period so that the adjustment factor averages out year-to-year fluctuations of these variables. Furthermore, the Department calculated utility specific factors, recognizing that biases in initial estimates can vary by utility. While this may not be perfect and actual outcomes can still vary, the Department believes its approach leads to an unbiased prediction methodology.

Furthermore, the 2024-2026 Triennial will include significant changes compared to previous Triennials. Incentives from the Federal government through the Inflation Reduction Act are expected to increase participation relative to previous years. There are additional EFS and LM programs that utilities are including in their Triennial for the first time. It's worth noting some utilities are planning to file modifications after their Triennial Plans get approved to include these new programs in their portfolio which could result in significant overachievement relative to the proposed goals. Furthermore, with the change in the primary cost effectiveness test, there are newer cost-effective measures that will pass utility screening now that did not pass earlier. All of these changes can be expected to significantly increase the number of new program offerings and the level of participation and energy savings achievable.

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[4] OTP Comments at 4 (October 23, 2023).

E. ADDING THE INCENTIVE TO TOTAL EXPENDITURES

MERC argued that the financial incentive should be added to the utilities expenditures and the expenditure cap should be calculated as a percentage of the sum. MERC stated, "*[t]his adjustment is important to maintain symmetry among the various components of the Incentive Mechanism.*"[5] CPE stated, "*If the financial incentive will count as a cost in the calculation of NBs, the Company also recommends that the financial incentive is similarly counted as a cost for the expenditures cap as well.*"[6]

The Department notes that adding the financial incentive to the expenditures would help increase the expenditure cap. The Department opposes this recommendation for the following three reasons.

Firstly, the financial incentive is not a utility expenditure and should not be added to calculate expenditure caps. The Department is not aware of any state that adds the financial incentive to calculate expenditure caps.

Secondly, the financial incentive is subtracted from the utility's net benefits in the MN Test. Adding the financial incentive to the utility's expenditures does not create any symmetry. Symmetry would require the same quantity to be subtracted from both. The Department does not think these calculations need to be symmetrical but points out the proposal from MERC does not create symmetry as they claim.

Lastly, the proposed expenditures cap in the Proposal is generous enough and the Department predicts utilities will not be hitting the cap. Recent changes brought about by the ECO Act allow utilities to include expenditures from various programs in the utility's expenditure that will substantially increase the total expenditure cap. Thus, the Department concludes its proposed expenditure caps are generous enough and do not merit any modifications.

F. INTERPRETING THE COST-OF-SERVICE ANALYSIS

Some utilities raised the concern that the Department's analysis does not support the conclusion that "*the Shared Benefits Financial Incentive Mechanism currently in place is extremely generous and lucrative for the utilities*"[7]. The Department notes that the purpose of this analysis is not to argue that a cost-of-service model is the right approach to incentivizing energy efficiency in Minnesota. The type of investments being made through an energy efficiency program are fundamentally different from utility assets. Furthermore, energy efficiency investments are mostly customer owned and behind the meter. Thus, it is reasonable that the amount ratepayers should pay for energy efficiency investments should be substantially lower than investments in supply side assets.

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[5] MERC Comments at 11 (October 23, 2023).
[6] CPE Comments at 15 (October 23, 2023).
[7] Department Comments at 35 (Sept. 1, 2023).

The Commission's order point 4.c[8] stated:

> "comparison of alternative mechanisms, along with the approved 2021-2023 CIP financial incentive mechanism, 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."

The Department interprets this to mean, how much would a specific investment cost if it was approved under the 2021-2023 CIP financial incentive mechanism vs the cost-of-service model. Investments made by utilities within their energy efficiency programs are recovered through the CIP trackers annually and in addition, utilities receive a financial incentive based on those expenditures. Thus, the regulator's cost of using such a mechanism is the sum of the investment expenditures themselves and the financial incentive payout.

On the other hand, if these investments were rewarded through the cost-of-service model, the regulator would have to pay the annual revenue requirement every year, throughout the life of the asset. This would result in a lower upfront cost but a higher lifetime cost. Depending on how one discounts future costs, they can draw their own conclusions about the net present values of these expenses.

The Department's analysis showed that under the former scheme, the amount that regulators end up paying per unit of first year energy saved is comparable or mostly higher than the net present value of what the regulator would have to pay under the second scheme. Given we are mostly talking about customer owned behind the meter investments, the Department notes that the utility bears significantly lower financial risk associated with such investments as compared to other assets that would be rewarded through a cost-of-service model. Thus, the fact that the cost to the regulator is comparable even though the utility does not own these assets, shows that the Shared Benefits Financial Incentive Mechanism currently in place is extremely generous and lucrative for the utilities.

G. IMPACT OF THE PROPOSAL ON SMALLER UTILITIES

Utilities raised concerns about the "one-size-fits-all" approach in the Proposal. MERC argued that the proposal "does not take into account the unique characteristics and differences among each utility's customer base and service territory"[9]. OTP proposed that "[t]he Commission should approve a separate percent of net benefits cap specific to each utility, since the incentive is based on net benefits that are driven by utility-specific avoided costs.[10]"

The Department opposes the recommendation that the Commission should create utility specific incentive mechanisms for energy efficiency programs. The energy efficiency requirements laid out by the ECO statute apply uniformly to electric and gas IOUs. MERC does not have a different energy

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[8] Commission's December 9, 2020 Order in the instant docket
[9] MERC Comments at 2 (October 23, 2023).
[10] OTP Comments at 7 (October 23, 2023).

savings goal compared to another gas IOU even though each has different service territory. OTP does not have a different energy savings goal compared to another electric IOU even though each has different avoided costs. The proposed financial incentive mechanism is consistent with the Commission's approach of uniformly applying net benefit percentages as incentive caps. The proposed financial incentive mechanism adjusts the minimum achievements required to earn the financial incentive as per statutory energy savings goals for electric and natural gas utilities.

It is also worth highlighting the impracticality of such an approach. Creating utility specific financial incentive mechanisms would imply creating 8 different mechanisms for each of the IOUs. This would be significantly burdensome for Department staff and does not guarantee a substantial increase in energy savings for the state. The Department is also not aware of any other state in the country that has taken such an approach.

MERC raised the concern that their "incentive is expected to be reduced by nearly half (47 percent) compared to the 2020-2022 incentive mechanism. If implemented as proposed, the impacts of the Department's recommended modifications would be substantial and would reflect a departure from the Commission's historical practice of implementing gradual changes to the Incentive Mechanism over time.[11]" The Department notes the fall in projected incentives for MERC's incentive is largely due to the projected underachievement relative their proposed goals. If MERC were to achieve the goals that they have proposed for the 2024-2026 Triennial, their incentives under the new proposal would be $1,060,987 annually on average which represents a 17 percent reduction in their incentive compared to the average annual incentive between 2020-2022. Thus, the bulk of the expected reduction in incentive is due to the projected underperformance of MERC.

OTP raised the concern that "[w]hen comparing 2024 to Otter Tail's 2020 financial incentive of $0.0425/kWh, the Company's financial incentive decreases by 56 percent"[12] The Department cautions that one needs to be careful while interpreting this specific result. Firstly, OTP picked specific years to make this percentage decrease seem large. OTP's performance was relatively better in 2020 leading to a skewed result. Instead, comparing the average incentive they received annually between 2020-2022 vs the projected incentives for 2024-2026 shows a significantly lower reduction. Secondly, OTP's projected incentives are based on the net benefit numbers they provided which assumes all LM net benefits are excluded from the financial incentive calculation. However, the Department's proposal does allow a utility to include net benefits of its LM programs into calculation of its financial incentive as long as the program occurred on or after the approval of the ECO Act (on May 25, 2021) (Recommendation 3.E in the Proposal). Based on both these changes, the Department predicts OTP is expected to see a 28 percent reduction in its incentives or half the reduction relative to what they claim.

[11] MERC Comments at 2 (October 23, 2023).
[12] OTP Comments at 5 (October 23, 2023).

H. IMPACT OF ALTERNATIVE PROPOSALS FROM UTILITIES

Each of the alternative proposals from the utilities would include a significant increase in the financial incentive for the utilities resulting in a significant increase in the burden for rate payers. While each of the utilities provided their own alternative proposals, they did not calculate the overall increase in total financial incentive expected from their proposal. In the spirit of transparency, the Department provides the projected estimates for each of these alternatives in this section.

To present this analysis, the Department created 5 different scenarios that are inspired by the different utility proposals. Table 3 below shows these different scenarios, each with their respective caps for net benefits and expenditures. (E) denotes the caps for that row apply only to electric utilities while (G) denotes the caps for that row apply only to gas utilities. (E&G) denotes the caps apply to both electric and gas utilities.

Table 3: Alternative Scenarios for the Financial Incentive

Name	Inspired by:	Net Benefits Cap	Exp Cap for high performers[13]
Scenario 1	Xcel Electric (E)	5.5%	25.0%
	Xcel Gas (G)	4.0%	25.0%
Scenario 2	MERC (G)	5.0%	25.0%
	MP (E)	5.0%	25.0%
Scenario 3	OTP (E&G)	8.6%	22.0%
Scenario 4	CPE (E&G)	4.5%	20.0%
Scenario 5	Status Quo (E&G)	4.0%	20.0%
Dept. Proposal	Dept Proposal (E&G)	3.4%	20.0%

While all the utilities asked for higher financial incentives relative to the Department's Proposal, none of them claimed to reach a higher level of energy savings relative to the Department's projections for 2024-2026. Thus, in the following analysis, the Department assumes achievements are projected to be the same as what was laid out in the Department's proposal with additional corrections as described in Section II, Part A of these reply comments. Table 4 below shows the Department's projections of average annual incentives that would have to be paid in total (gas and electric utilities combined) for each scenario between 2024-2026.

[13] An electric utility is considered a high performer if they achieve an energy savings of or above 2 percent of their non-exempt retail sales. A gas utility is considered a high performer if they achieve an energy savings of or above 1.2 percent of their non-exempt retail sales. The expenditure cap is 15 percent for all other utilities.

Table 4: Financial Incentive payout in each scenario

	Total Avg. Annual Incentive	Change from 2020-2022
2020-2022	$46,159,432	0.0%
Scenario 1	$58,000,818	25.7%
Scenario 2	$58,023,342	25.7%
Scenario 3	$63,977,041	38.6%
Scenario 4	$51,148,942	10.8%
Scenario 5	$46,709,668	1.2%
Dept. Proposal	$40,761,425	-11.7%

As can be seen from Table 4 above, each of the Scenarios from 1 to 4 would lead to a substantial increase in the annual payout of financial incentives. The Department's Proposal represents a reasonable reduction in the incentive that is in line with the Commission's recent orders reducing the incentive mechanism gradually and results in a more comparable level to other states in the country.

III. CONCLUSION AND RECOMMENDATION

The Department concludes the Proposal for the financial incentive for the 2024-2026 Triennial provides updates that reflect the new environment we are in after passage of the ECO Act, the adoption of the new cost effectiveness methodology, and the availability of increased federal funding through the Inflation Reduction Act. The Proposal strikes a reasonable balance between the interest of ratepayers and the interest of shareholders of the utilities. The Proposal is consistent with an average annual decrease of 11.7 percent for the overall incentive payments and an increase in overall energy savings achievements in the state by 19.5 percent relative to 2020-2022.

Furthermore, each of the scenarios modeled along the lines proposed by the utilities would result in a substantial increase in costs for the ratepayers ands would make Minnesota's incentives substantially higher than most of the top performing states on the ACEEE state scorecard.

Thus, the Department recommends that the Commission approve a 2024-2026 Shared Savings DSM financial incentive mechanism as laid out in its original proposal filed on September 1, 2023, without any modifications.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Reply Comments

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

Dated this **2nd** day of **November 2023**

/s/Sharon Ferguson

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