**COMMERCE DEPARTMENT**

September 1, 2023

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

RE: **Proposal for Modifications to the Shared Savings DSM Financial Incentive Mechanism for Implementation Beginning in 2024**
Docket No. E,G999/CI-08-133

Dear Mr. Seuffert:

Attached is the Minnesota Department of Commerce, Division of Energy Resources' (the Department) proposal for modifications to the existing Shared Savings Demand-Side Management (DSM) Financial Incentive Mechanism for implementation beginning in 2024.

Based on our analyses and conversations with stakeholders, the Department recommends that the 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

/s/ Hayk Mardanyan
Student Worker

AD/HM/ar

# Before the Minnesota Public Utilities Commission

## Comments of the Minnesota Department of Commerce
## Division of Energy Resources

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

### I. INTRODUCTION

On May 25, 2021, Governor Tim Walz signed the Minnesota Energy Conservation and Optimization Act of 2021 (Minnesota Statutes § 216B.241 or ECO Act). The ECO Act helped modernize Minnesota's Conservation Improvement Program (CIP) by providing pathways to address various challenges. This included additional measures like load management[1], efficient fuel switching[2] and changing the statutory goals for Investor Owned Utilities (IOUs) with respect to energy savings[3].

Throughout 2022, the Department worked with the CIP Cost-Effectiveness Advisory Committee (CAC) in order to update cost-effectiveness methodologies that will apply to the 2024-2026 triennial, taking into account comments from multiple stakeholders, including Minnesota investor-owned electric and gas utilities. Through this process, the Department updated avoided costs estimated for the four existing cost-effectiveness tests and created a new test called the Minnesota Test. These updates are 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. The Decision also outlined how the Minnesota Test would serve as the primary test for screening programs.

During discussions of the CAC, it was brought up that screening of programs and the financial incentive should be based on the same cost-effectiveness test. On December 9, 2022, the Department created a Straw Proposal (Attachment D) and provided it to the Shared Savings Financial Incentive Mechanism Stakeholder Group. In this Straw Proposal, one of the proposals was to base the Shared Savings Financial Incentive Mechanism on the Minnesota Test. Stakeholders mostly supported this proposal to modify the Financial Incentive from being calculated on the basis of Utility Cost Test (UCT) Net Benefits to the net benefits from the Minnesota Test. The Minnesota Test represents a significant change over the UCT that was being used in previous triennials to calculate financial incentives. More precisely:

1) The new Minnesota Test assigns a monetary value to the environmental benefits of greenhouse gas emission reductions and air quality improvement and includes that in the calculation of net benefits, which significantly increases the net benefits of the overall portfolio over the UCT Net Benefits.
2) The new Minnesota Test considers the financial incentive payments to IOUs as a cost and includes that in the calculation of net benefits. This results in a circularity issue which is discussed later in Section III of this Report.

[1] *See* Minn. Stat. § 216B.241, subd. 13.
[2] *See* Minn. Stat. § 216B.2403, subd. 8.
[3] *See* Minn. Stat. § 216B.2403, subd. 1.c Parts (b) and (c).

3) The Minnesota Test uses a lower discount rate to value the future relative to the UCT.

The purpose behind the Shared Savings Demand-Side Management (DSM) Financial Incentive Plan (Shared Savings Plan) is to motivate Minnesota's IOUs to maximize cost-effective energy savings by providing the utilities with a portion of the net benefits[4] created when IOU customers invest in utility-sponsored CIP projects. The current Shared Savings Plan provides an increasing incentive as the CIP investments of the IOUs and their customers result in higher net benefits.

*A. 2021-2023 SHARED SAVINGS INCENTIVE MECHANISM APPROVED DECEMBER 2020*

On December 9, 2020, the Minnesota Public Utilities Commission approved the present Shared Savings DSM Financial Incentive Mechanism, as follows:

1. The Department's recommendations for the 2021–2023 triennium, as stated on pages 31 and 32 and Attachment A of its proposal filed on March 3, 2020, are approved, subject to the following modification.
2. Gas utilities may exceed the 30% CIP Expenditures Cap, up to a maximum of 35%, if they meet or exceed energy savings equaling 1.2% of retail sales; electric utilities may exceed the 30% CIP Expenditures Cap, up to a maximum of 35%, if they meet or exceed energy savings equaling 2% of retail sales.
3. The Commission requests that the Department continue a stakeholder process, under the current docket, to evaluate the development of a low-income shared-savings mechanism (such as proposed by Fresh Energy, et al.) to be adopted, potentially, by the end of 2021, to be used going forward starting January 1, 2022.
4. The Commission requests that the Department continue a stakeholder process, under the current docket, to evaluate ways of improving the shared-savings mechanisms for potential adoption in the 2024–2026 triennium including, but not limited to, discussion of:
   a. incorporation of lifetime energy savings into the Incentive Mechanism,
   b. incorporation of an incentive for utilities that achieve permanent peak reductions through the Shared-Savings Incentive Mechanism,
   c. 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, and
   d. energy efficiency opportunities to support increased load flexibility (the ability to persistently shape and shift load).

[4] Net benefits refers to the present value of utility supply-side costs (e.g., generation, transmission, and distribution costs) minus utility CIP costs. For the current triennial period, the 3.3% Societal Discount Rate, which was calculated using the United States Department of the Treasury's (Treasury) 20-year Constant Maturity (CMT) Rate, is used for discounting future benefits and costs.

Pages 31 and 32 from the Department's proposal filed on March 3, 2020 and referenced in Order Point 1 above stated:

> The Department recommends that the Commission approve a 2021-2023 Shared Savings DSM financial incentive mechanism with the following provisions:
>
> A. For electric utilities:
>     1) Net benefits are calculated using the individual CIP Utility Discount Rates approved by the Deputy Commissioner in Docket No. E999/CIP-18-783 on February 11, 2020.
>     2) For a utility that achieves energy savings of at least 1.0 percent of the utility's retail sales, the utility is allowed to collect a financial incentive.
>     3) For a utility that achieves energy savings equal to 1.0 percent of retail sales, the utility is awarded a share of the net benefits as set forth in Attachment A.
>     4) For each additional 0.1 percent of energy savings the utility achieves, the net benefits awarded to the utility is increased by an additional 0.75 percent until the utility achieves savings of 1.7 percent of retail sales.
>     5) For savings levels of 1.7 percent and higher, the utility is awarded a share of the net benefits equal to the Net Benefits Cap.
>
> B. For gas utilities:
>     1) Net benefits are calculated using the individual CIP Utility Discount Rate approved by the Deputy Commissioner in Docket No. G999/CIP-18-782 on February 11, 2020.
>     2) 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.
>     3) For a utility that achieves energy savings equal to 0.7 percent of retail sales, the utility is awarded a share of the net benefits as set forth in Attachment A.
>     4) For each additional 0.1 percent of energy savings the utility achieves, the net benefits awarded to the utility are increased by an additional 0.75 percent until the utility achieves savings of 1.2 percent of retail sales.
>     5) 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.
>
> C. For all utilities, set a Net Benefit Cap of 10 percent
>
> D. For all utilities, set a Conservation Improvement Program (CIP) Expenditure Cap of 30 percent.

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. 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 1.5 percent savings goal.

D. The energy savings, cost, 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.

The new Shared Savings DSM Incentive Plan shall be in effect for 2021-2023.

## *B. IOU ENERGY SAVINGS PRIOR TO AND DURING CURRENT SHARED SAVINGS INCENTIVE MECHANISM*

The Commission approved the current Shared Savings Incentive Mechanism on December 9, 2020 for the 2021-2023 triennial period.

Below, the Department compares the IOUs' 2017-2018 energy savings and incentives, which occurred under more generous Shared Savings Incentive Mechanism parameters approved by the Commissionon on August 5, 2016, to the IOUs' 2019-2022 energy savings and incentives.[5] (The IOUs' CIP 2023 status reports will be filed between April 1, 2024 and May 1, 2024.)

Table 1 below shows Minnesota Power, Otter Tail Power (Otter Tail) and Xcel Electric's energy savings, the energy savings represented as a percent of retail sales, and each electric IOU's incentive, represented in dollars, incentives as % of CIP expenditures, incentives as % of net benefits and incentives as $/first year kWh saved.

[5] In 2017 the Net Benefits Cap of the Shared Savings Incentive Mechanism was 13.5% and its CIP Expenditures Cap was 40%. In 2018 the Net Benefits Cap of the Shared Savings incentive Mechanism was 12.0% and its CIP Expenditures Cap was 35%.

**Table 1: Electric IOUs' 2017-2022 First-Year Energy Savings and Incentives**

| Utility | Year | First-Year Energy Savings (kWh) | % of Retail Sales | Incentive | Incentive as % of CIP Expenditures | Incentive as % of Net Benefits | Incentive as $/First Year kWh Saved |
|---|---|---|---|---|---|---|---|
| Minnesota Power | 2017 | 72,467,019 | 2.6% | $2,994,840 | 37% | 13.5% | $0.041 |
| | 2018 | 72,479,534 | 2.6% | $2,780,073 | 31% | 12.0% | $0.038 |
| | 2019 | 67,669,222 | 2.5% | $2,353,720 | 28% | 10.0% | $0.035 |
| | 2020 | 70,774,076 | 2.6% | $2,411,672 | 29% | 9.7% | $0.034 |
| | 2021 | 74,539,041 | 2.8% | $1,937,003 | 21% | 10.0% | $0.026 |
| | 2022 | 76,400,068 | 2.9% | $2,206,583 | 23% | 10.0% | $0.029 |
| | | | | | | | |
| Otter Tail Power | | First-Year Energy Savings (kWh) | % of Retail Sales | Incentive | Incentive as % of CIP Expenditures | Incentive as % of Net Benefits | Incentive as $/First Year kWh Saved |
| | 2017 | 52,497,167 | 3.0% | $2,642,360 | 40% | 11.2% | $0.050 |
| | 2018 | 73,255,915 | 4.2% | $3,004,311 | 33% | 8.6% | $0.041 |
| | 2019 | 69,248,477 | 4.0% | $2,718,378 | 30% | 8.1% | $0.039 |
| | 2020 | 70,649,612 | 4.1% | $2,864,948 | 30% | 8.1% | $0.041 |
| | 2021 | 68,779,250 | 4.1% | $2,900,388 | 31% | 9.8% | $0.042 |
| | 2022 | 50,557,160 | 3.0% | $2,414,490 | 31% | 10.0% | $0.048 |
| | | | | | | | |
| Xcel Electric | | First-Year Energy Savings (kWh) | % of Retail Sales | Incentive | Incentive as % of CIP Expenditures | Incentive as % of Net Benefits | Incentive as $/First Year kWh Saved |
| | 2017 | 660,435,156 | 2.3% | $30,241,197 | 28% | 13.5% | $0.046 |
| | 2018 | 680,448,447 | 2.4% | $28,662,695 | 27% | 12.0% | $0.042 |
| | 2019 | 528,899,459 | 1.8% | $17,589,180 | 19% | 10.0% | $0.033 |
| | 2020 | 646,796,991 | 2.3% | $30,500,073 | 29% | 9.9% | $0.047 |
| | 2021 | 743,837,488 | 2.7% | $26,881,000 | 25% | 10.0% | $0.036 |
| | 2022 | 647,675,810 | 2.3% | $24,271,202 | 23% | 10.0% | $0.037 |

Figure 1 below shows the three electric IOUs' aggregated incentives and first-year kWh savings for the years 2006-2022.

**Figure 1: 2006-2022 Electric IOU Incentives and First-Year kWh Savings**

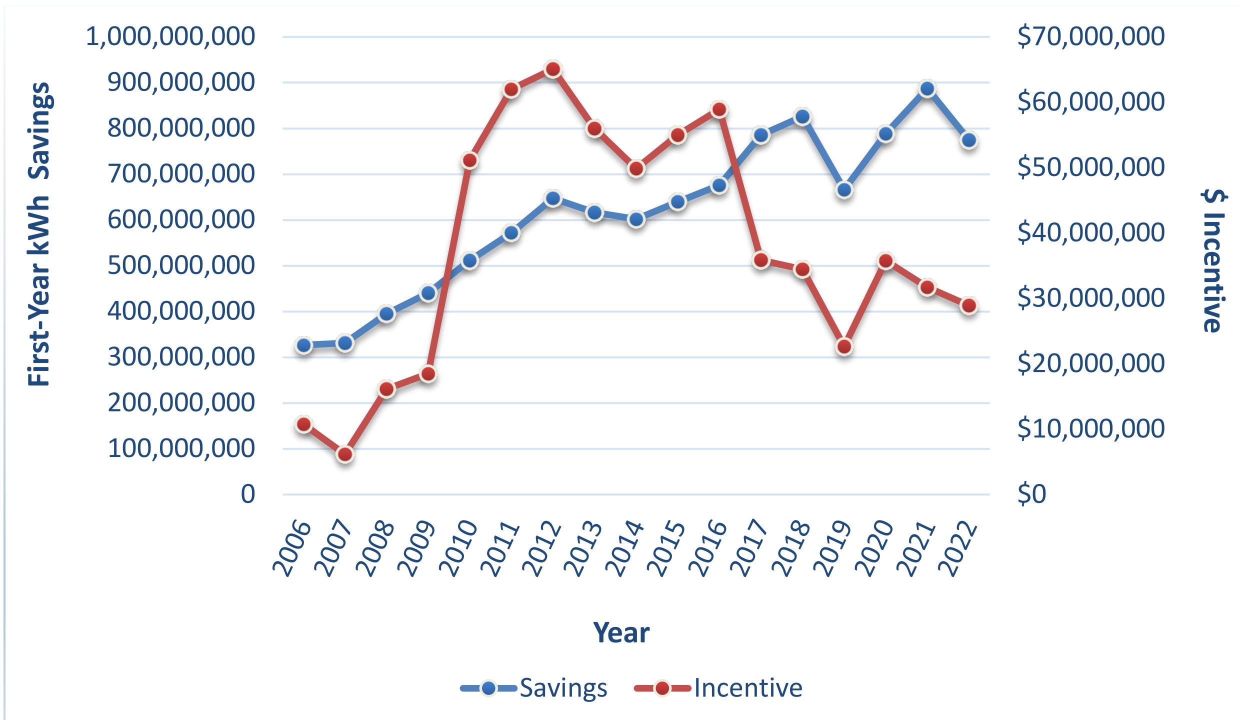
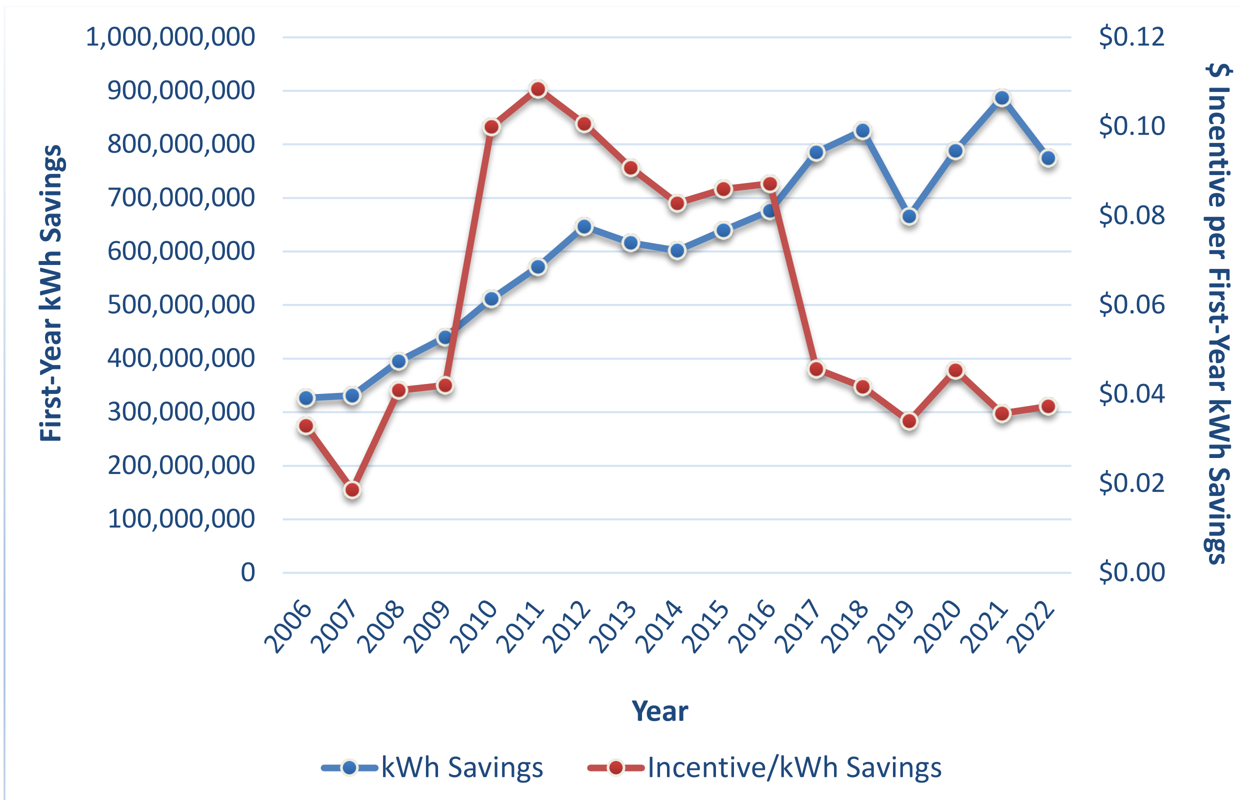



Figure 1 above highlights two key trends: overall incentives to electric IOUs steadily increased during 2006-2012, and then started on a decreasing trend up until 2022. However, the above figure clearly shows a relatively steady increase in first-year electric energy savings during the entire period 2006-2022, even though overall incentives had been more than halved in 2022 compared to 2012.

Figure 2 below shows aggregated incentives per first year kWh savings and first-year energy savings for electric IOUs. The picture shows similar trends as in Figure 1: there is an overall trend of increasing energy savings from 2006 to 2022, whereas the incentives per unit of energy savings had an increasing trend from 2006 to 2011 and a decreasing trend from 2011 to 2022. Compared to 2011, incentives per unit of energy savings were down by more than 2 times, whereas energy savings were up by more than 35%.

**Figure 2: 2006-2022 Electric IOU Incentives per Unit of First-Year Energy Savings and Aggregate First-Year kWh Savings**




The analysis below in Figures 3 and 4 features a positive correlation between incentives awarded to electric utilities and their first-year kWh energy savings. Figure 4 includes utility-level fixed effects, whereas Figure 3 presents the correlation without any fixed effects. The inclusion of utility-level fixed effects is equivalent to subtracting the average energy savings and financial incentives received over 2006-2022 for a given utility from its corresponding annual energy savings and financial incentives, and is used to control for between-utility differences such as location, customer base served, size, etc. Both show a strongly positive correlation between incentives and first-year energy savings. Moreover, Figure 4 confirms that the positive correlation evident in Figure 3 is not an artefact of between-utility differences mentioned above. However, this correlation cannot be interpreted as causal, which is to say that lowering incentives will not necessarily result in a reduction in first-year energy savings for electric utilities. Instead, it summarizes the Shared Savings DSM Financial Incentive Mechanism for the period 2006-2022 and shows that by saving more energy, utilities were able to earn higher financial incentives. In other words, *on average,* electric utilities with higher incentives had more first-year energy savings.

**Figure 3: Positive Correlation between Incentives and First-Year Energy Savings for Electric IOUs (Analysis without Fixed Effects)**

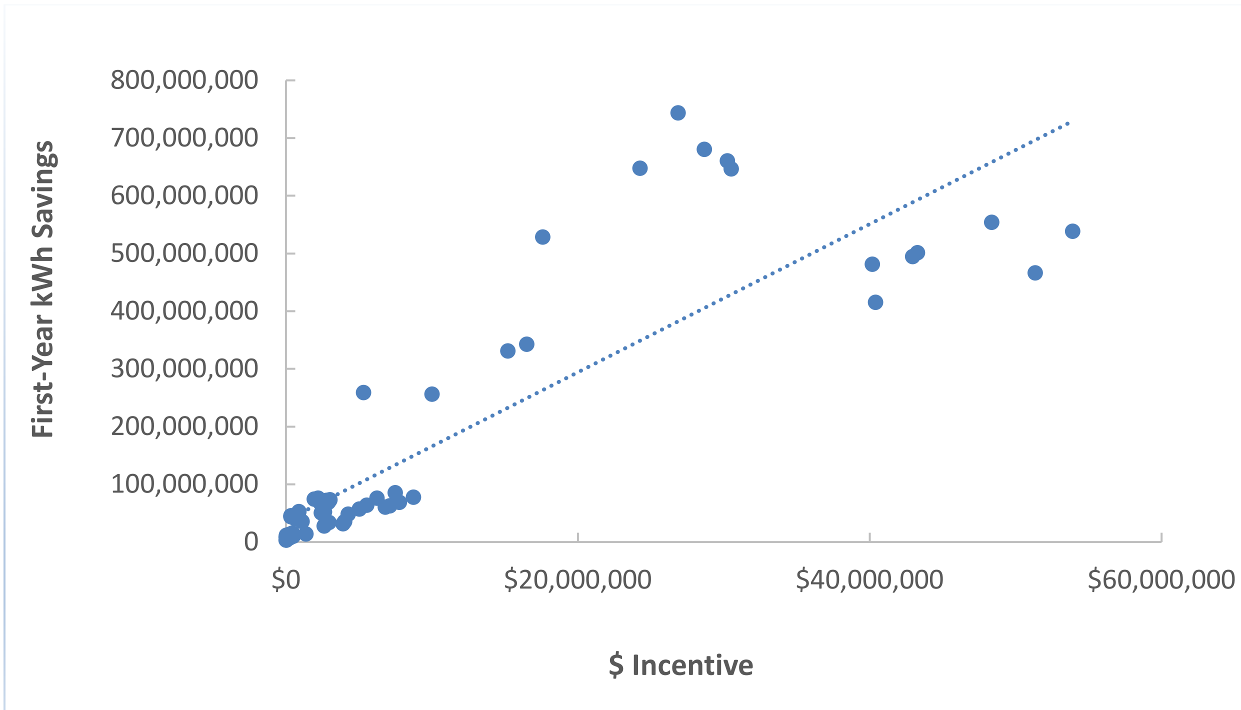


**Figure 4: Positive Correlation between Incentives and First-Year Energy Savings for Electric IOUs (Analysis with Utility-Level Fixed Effects)**

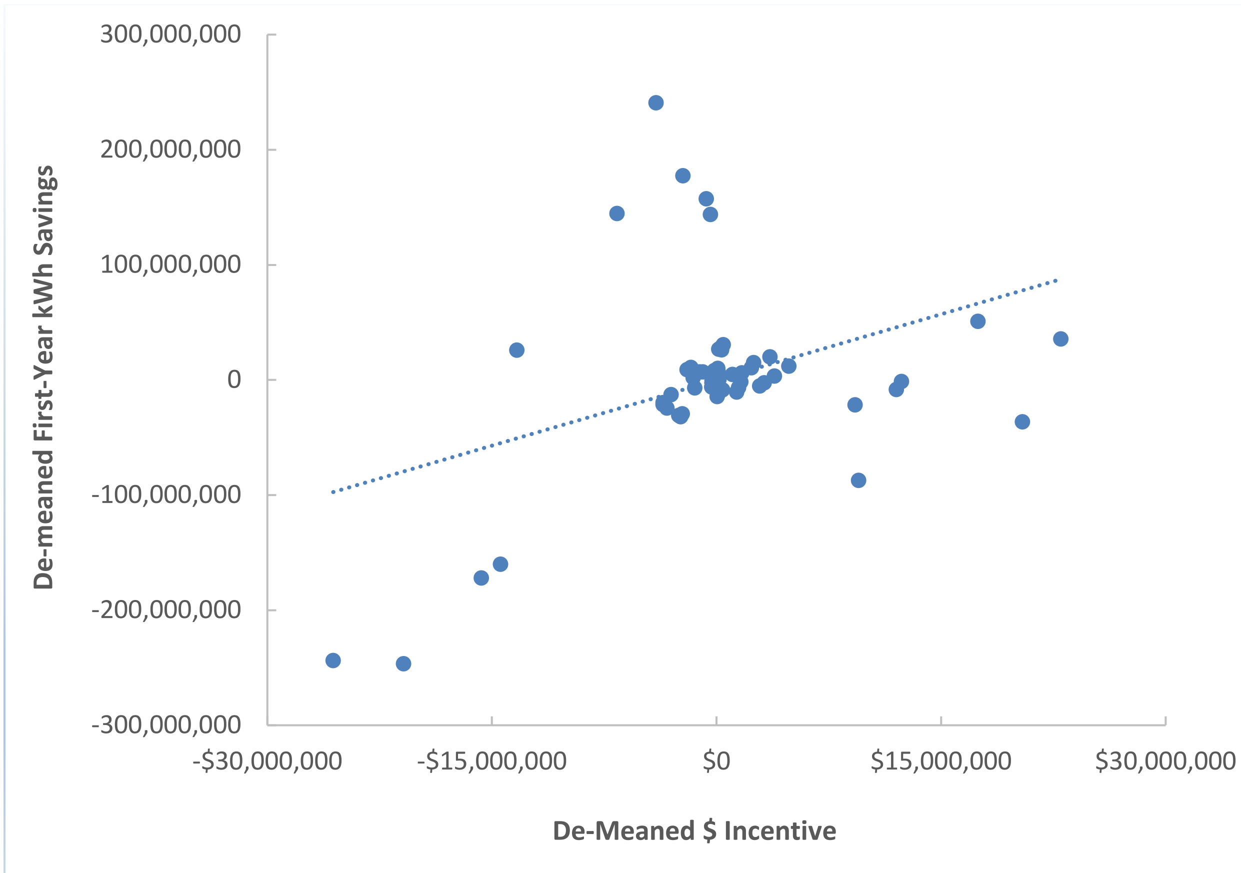


Table 2 below shows CenterPoint Energy (CenterPoint), Great Plains Natural Gas (Great Plains), Minnesota Energy Resources Corporation (MERC), Greater Minnesota Gas (GMG) and Xcel Gas' first-year Dth savings, the first-year Dth savings represented as a percent of retail sales, and each gas IOU's incentives, represented in dollars, incentives as % of CIP expenditures, incentives as % of net benefits and incentives as $/first year Dth saved.

**Table 2: Gas IOU 2017-2022 First-Year Energy Savings and Incentives**

| | | First-Year Energy Savings (Dth) | % of Retail Sales | Incentive | Incentive as % of CIP Expenditures | Incentive as % of Net Benefits | Incentive as $/First Year kWh Saved |
|---|---|---|---|---|---|---|---|
| CenterPoint Energy | 2017 | 2,632,545 | 1.9% | $12,456,038 | 40% | 7.8% | $4.73 |
| | 2018 | 1,980,534 | 1.4% | $11,317,175 | 32% | 12% | $5.71 |
| | 2019 | 2,020,149 | 1.4% | $8,758,401 | 24% | 10% | $4.34 |
| | 2020 | 1,915,114 | 1.4% | $9,935,723 | 28% | 10% | $5.19 |
| | 2021 | 1,871,509 | 1.3% | $7,771,520 | 20% | 10% | $4.15 |
| | 2022 | 2,003,321 | 1.4% | $7,673,591 | 20% | 10% | $3.83 |
| | | | | | | | |
| | | First-Year Energy Savings (Dth) | % of Retail Sales | Incentive | Incentive as % of CIP Expenditures | Incentive as % of Net Benefits | Incentive as $/First Year kWh Saved |
| Great Plains | 2017 | 13,577 | 0.2% | $0 | 0% | 0.0% | $0.00 |
| | 2018 | 36,083 | 0.6% | $0 | 0% | 0.0% | $0.00 |
| | 2019 | 13,175 | 0.2% | $0 | 0% | 0.0% | $0.00 |
| | 2020 | 20,537 | 0.4% | $0 | 0% | 0.0% | $0.00 |
| | 2021 | 15,154 | 0.3% | $0 | 0% | 0.0% | $0.00 |
| | 2022 | 22,575 | 0.4% | $0 | 0% | 0.0% | $0.00 |
| | | | | | | | |
| | | First-Year Energy Savings (Dth) | % of Retail Sales | Incentive | Incentive as % of CIP Expenditures | Incentive as % of Net Benefits | Incentive as $/First Year kWh Saved |
| MERC | 2017 | 402,989 | 0.8% | $1,694,489 | 16% | 10.2% | $4.21 |
| | 2018 | 509,758 | 1.0% | $1,892,566 | 16% | 10.3% | $3.71 |
| | 2019 | 468,544 | 0.9% | $1,771,381 | 15% | 7.9% | $3.78 |
| | 2020 | 367,324 | 0.9% | $1,345,674 | 13% | 7.8% | $3.66 |
| | 2021 | 392,822 | 0.9% | $1,250,934 | 11% | 8.0% | $3.18 |
| | 2022 | 410,281 | 0.9% | $1,246,952 | 12% | 8.3% | $3.04 |

| Greater Minnesota Gas | | First-Year Energy Savings (Dth) | % of Retail Sales | Incentive | Incentive as % of CIP Expenditures | Incentive as % of Net Benefits | Incentive as $/First Year kWh Saved |
|---|---|---|---|---|---|---|---|
| | 2017 | 5,398 | 0.5% | $0 | 0% | 0.0% | $0 |
| | 2018 | 12,137 | 1.1% | $0 | 0% | 0.0% | $0 |
| | 2019 | 12,809 | 1.1% | $0 | 0% | 0.0% | $0 |
| | 2020 | 10,563 | 1.0% | $0 | 0% | 0.0% | $0 |
| | 2021 | 14,460 | 0.8% | $0 | 0% | 0.0% | $0 |
| | 2022 | 17,469 | 1.0% | $0 | 0% | 0.0% | $0 |
| | | | | | | | |
| **Xcel Energy** | | **First-Year Energy Savings (Dth)** | **% of Retail Sales** | **Incentive** | **Incentive as % of CIP Expenditures** | **Incentive as % of Net Benefits** | **Incentive as $/First Year kWh Saved** |
| | 2017 | 799,597 | 1.1% | $3,753,592 | 26% | 12.8% | $4.69 |
| | 2018 | 913,240 | 1.3% | $4,391,216 | 28% | 12.0% | $4.81 |
| | 2019 | 584,761 | 0.8% | $1,790,002 | 13% | 7.1% | $3.06 |
| | 2020 | 868,599 | 1.2% | $4,268,369 | 29% | 9.1% | $4.91 |
| | 2021 | 1,170,229 | 1.5% | $5,020,146 | 27% | 10.0% | $4.29 |
| | 2022 | 920,504 | 1.2% | $3,578,029 | 18% | 10.0% | $3.89 |

Figure 5 below shows the gas IOUs' aggregated incentives and first-year Dth savings for the years 2006-2022.

**Figure 5: 2006-2022 Gas IOU Incentives and First-Year Dth Savings**

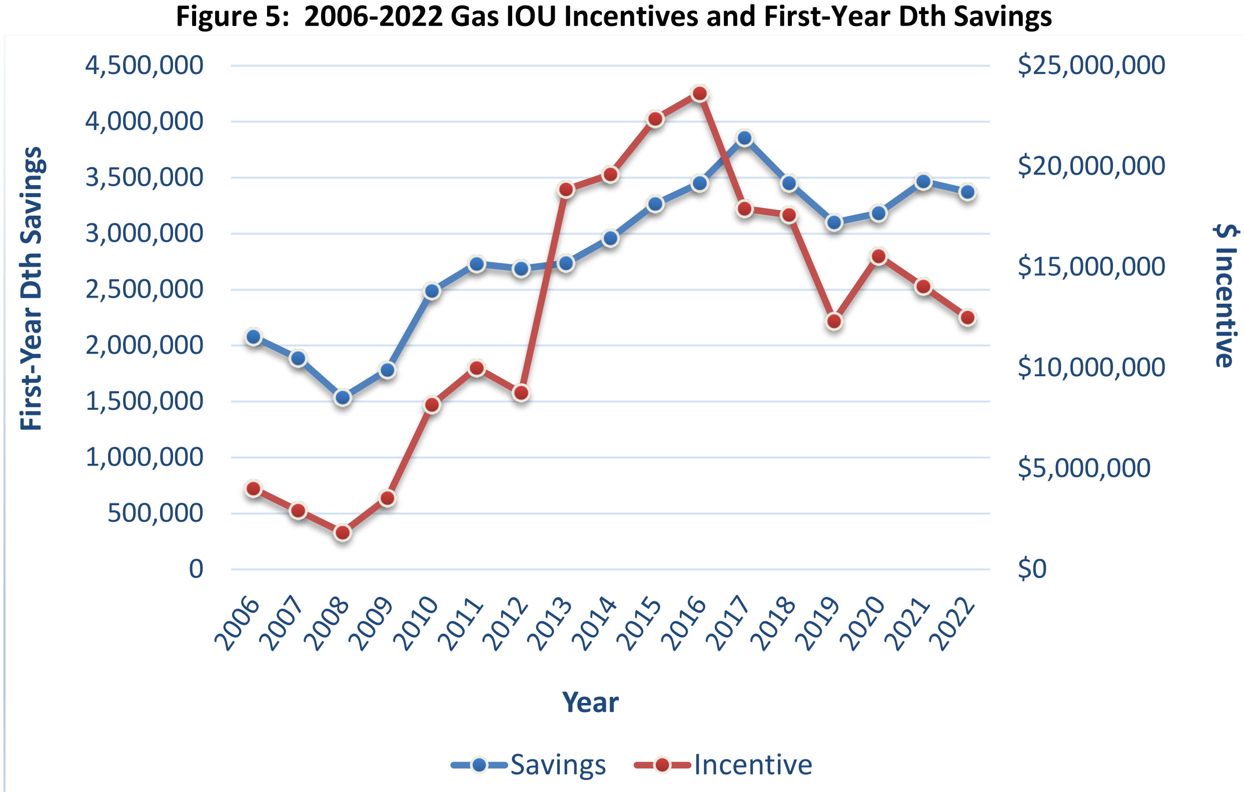


Figure 5 above features multiple trends that need to be discussed. Firstly, incentives had an increasing trend during 2006-2016 and have since decreased significantly up until 2022. There is an increasing trend in energy savings from 2006 to 2022, and there was a more than 50% increase in first-year Dth energy savings in 2022 compared to 2006. Although overall first-year savings were smaller in 2022 compared to 2016, they were larger than in 2020, even though incentives have had a declining trend since 2016.

Figure 6 below shows aggregate first-year energy savings and incentives per first-year Dth saved for all gas IOUs. The figure features the following trends. Firstly, there has been a noticeable increasing trend in gas energy savings from 2006 to 2022, and savings in 2022 were more than 50% more compared to 2006. This is coupled with an increasing trend in incentives per unit of first-year gas energy savings from 2006 to 2013, a relatively constant trend from 2013 to 2016, and a decreasing trend from 2016 to 2022.

**Figure 6: 2006-2022 Gas IOU Incentives per unit of First-Year Energy Savings and First-Year Dth Savings**


Figures 7 and 8 below present an analysis of the correlation between financial incentives paid to gas IOUs over the period 2006-2022 and their first-year Dth savings. The analysis in Figure 8 incorporates utility-level fixed effects, whereas that in Figure 7 does not. The inclusion of fixed effects is equivalent to subtracting the average energy savings and financial incentives over 2006-2022 for each utility from its corresponding energy savings and financial incentives received for each year, in order to control for utility-specific factors such as size, location, customer base differences, etc. Both figures show a strongly positive correlation between incentives paid and first-year Dth savings. Moreover, Figure 8 confirms that the positive correlation presented in Figure 7 is not an artefact of differences between utility-specific factors mentioned above. However, this positive correlation cannot be interpreted as causal. Instead, it means that, *on average,* gas utilities that were paid higher incentives over the period 2006-2022 exhibited higher first-year Dth savings. It does not necessarily mean that decreasing the incentives paid to gas utilities will result in decreased energy savings.

**Figure 7: Positive Correlation between Incentives and First-Year Energy Savings for Gas IOUs (Analysis without Fixed Effects)**

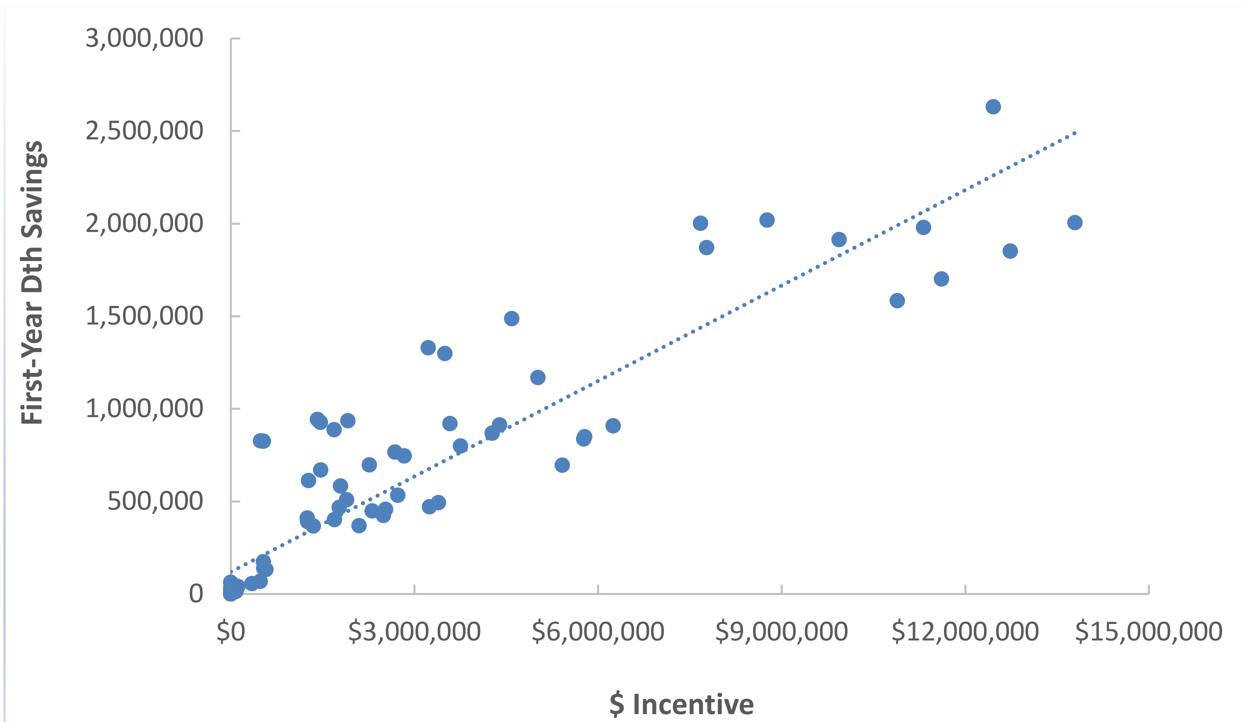


**Figure 8: Positive Correlation between Incentives and First-Year Energy Savings for Gas IOUs (Analysis with Utility-Level Fixed Effects)**

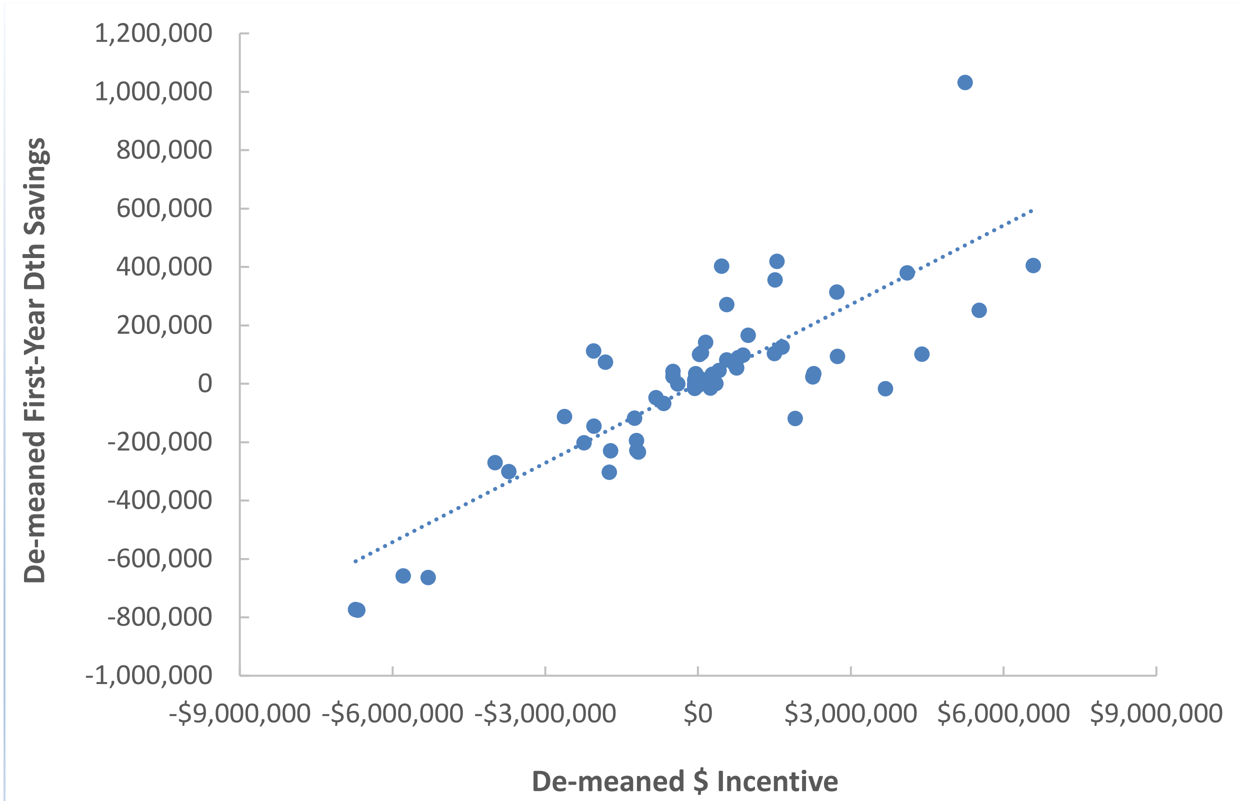



Table 3 below shows each electric IOUs' calculated net benefits for 2017-2022 minus each utility's Shared Savings incentive for each of these years. The calculation shows the total value to ratepayers each year for each electric IOU's CIP achievements.

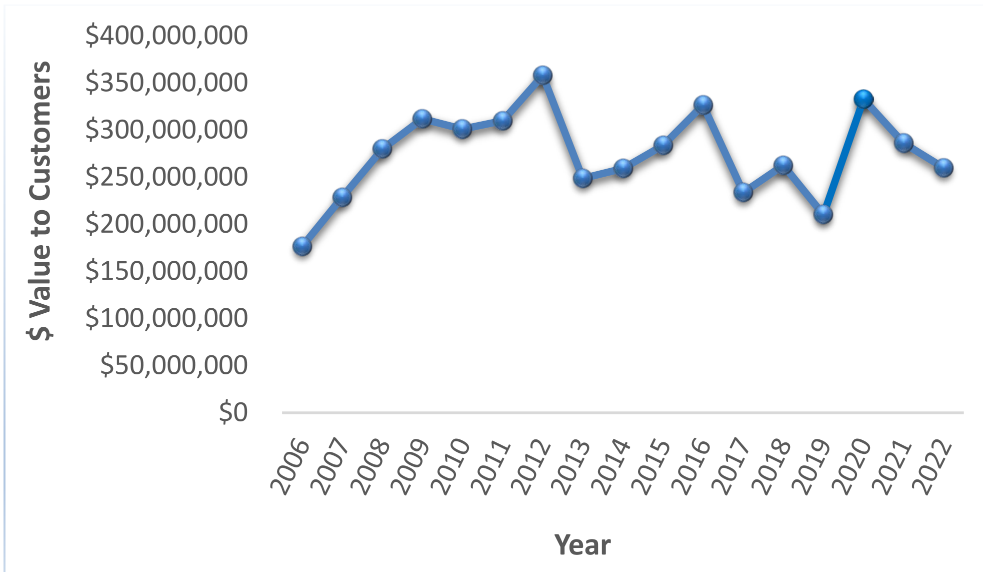
**Table 3: Utility Net Benefits Minus Shared Savings Incentive for Electric IOUs, 2017-2022**

| Year | Minnesota Power | Otter Tail | Xcel | Total Electric |
|---|---|---|---|---|
| 2017 | $19,189,163 | $20,984,158 | $193,767,672 | $233,940,993 |
| 2018 | $20,387,204 | $32,037,359 | $210,193,096 | $262,617,659 |
| 2019 | $21,183,479 | $30,785,984 | $158,302,616 | $210,272,079 |
| 2020 | $22,350,974 | $32,641,160 | $277,739,057 | $332,731,191 |
| 2021 | $17,433,029 | $26,800,127 | $241,929,002 | $286,162,158 |
| 2022 | $19,859,244 | $21,730,409 | $218,440,818 | $260,030,471 |
| 2017-2022 | $120,403,093 | $164,979,197 | $1,300,372,261 | $1,585,754,551 |

Table 3 shows that, using the avoided costs approved at the time of each individual electric CIP triennial, the total benefits to Minnesota's electric IOU customers was an impressive $1.59 billion.

Figure 9 below graphs the electric IOUs' total value of CIP achievements to their customers over the 2006-2022 period.

**Figure 9: Total Value of Electric IOUs' CIP Achievements: Utility Net Benefits Minus Shared Savings Incentives**




The Department notes that the total annual value of the electric IOUs' CIP achievements declined from 2016 to 2017-2018, even though the electric IOUs' energy savings achievements increased (see Figure 1) because the electric avoided cost assumptions declined between the 2014-2016 timeframe and 2017.

Table 4 below shows each gas IOUs' calculated net benefits for 2017-2022 minus each utility's Shared Savings incentive for each of these years. The calculation shows the total value to ratepayers each year for each gas IOUs' CIP achievements.

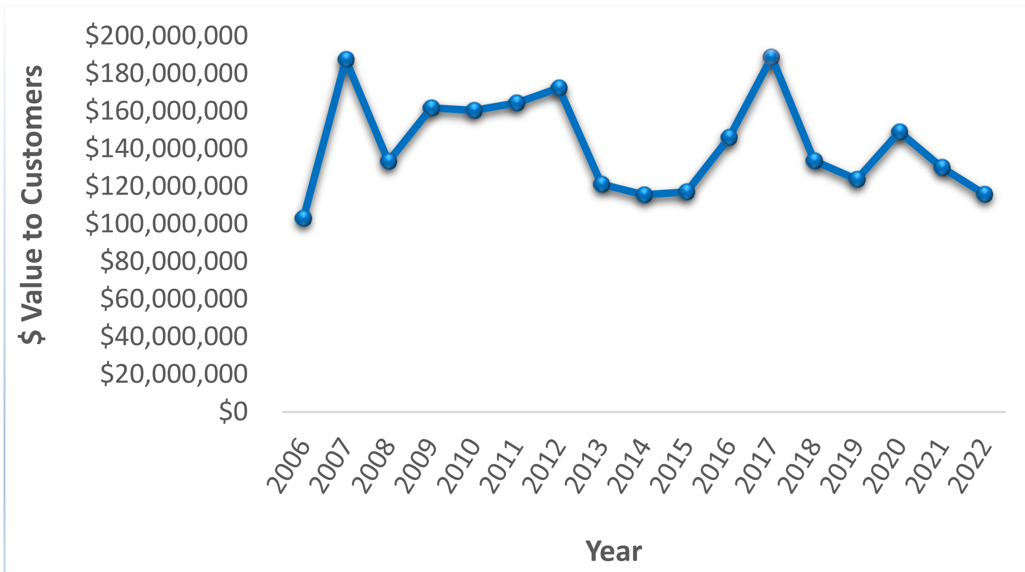
**Table 4: Utility Net Benefits Minus Shared Savings Incentive for Gas IOUs, 2017-2022**

| | CenterPoint | Great Plains | MERC | Xcel | GMG | TOTAL |
|---|---|---|---|---|---|---|
| 2017 | $25,477,689 | $227,111 | $14,866,907 | $25,477,689 | $234,339 | $188,802,318 |
| 2018 | $32,202,251 | $1,235,357 | $16,571,324 | $32,202,251 | $627,549 | $133,629,095 |
| 2019 | $23,421,489 | $227,105 | $20,542,356 | $23,421,489 | $631,332 | $123,647,892 |
| 2020 | $42,533,851 | $619,961 | $15,985,305 | $42,533,851 | $436,248 | $148,996,875 |
| 2021 | $45,181,318 | $251,587 | $14,349,297 | $45,181,318 | $269,151 | $129,995,034 |
| 2022 | $32,202,261 | $445,779 | $13,820,333 | $32,202,261 | $334,997 | $115,865,686 |
| 2017-2022 | $201,018,859 | $3,006,900 | $96,135,521 | $201,018,859 | $2,533,617 | $840,936,901 |

Table 4 shows that, using the avoided costs approved at the time of each individual gas CIP triennial, the total benefits to Minnesota's natural gas IOU customers was an impressive $0.84 billion.

Figure 10 below graphs the gas IOUs' total value of CIP achievements to their customers over the 2006-2022 period.

**Figure 10: Total Value of Gas IOUs' CIP Achievements**
**Utility Net Benefits Minus Shared Savings Incentives**




The total value of gas IOUs' CIP achievements peaked in 2017, as evidenced in Figure 10 above, largely due to the extraordinarily high level of net benefits achieved by CenterPoint that year.

## II. ENERGY CONSERVATION AND OPTIMIZATION (ECO) CHANGES FOR THE 2024-2026 TRIENNIAL THAT WILL IMPACT SHARED SAVINGS INCENTIVES

According to the Department's Straw Proposal Recommendations of December 9, 2022 addressed to the Shared Savings Financial Incentive Mechanism Stakeholder Group (Attachment D), the factors that will impact the new incentive mechanism are the following:

- 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. In particular:
    - Cost-effectiveness methodologies for energy efficiency projects were updated. Most importantly, carbon emission reductions are included as an externality benefit in the new Minnesota Test (MN Test), which greatly increase the overall net benefits for all utilities.
    - The financial incentive is included as a cost in the cost-benefit analyses of every test, except for the Participant Test.
    - Gas and electric avoided costs have been modified.
    - Both participant costs and benefits are absent from the Minnesota Test.

  - The discount rate used for calculating the Minnesota Test Net Benefits is chosen to be the Societal Discount Rate. The Utility Cost Test uses the individual utility discount rates which are significantly higher than the Societal Discount Rate. This significantly increases net benefits of the Minnesota Test as compared to the Utility Cost Test.

- Implementation of the ECO Act, which was signed into law by Governor Tim Walz on May 21, 2021. The Act introduces changes to Minnesota's Conservation Improvement Program (now referred to as the "Energy Conservation and Optimization Program" or "ECO") in several ways. In particular:
  - The ECO Act stipulates that energy savings from efficient fuel-switching programs can count towards aggregate savings used to calculate financial incentives for gas utilities.[6]
  - The ECO Act states that the commission may not approve a financial incentive to encourage efficient fuel-switching programs operated by a public utility providing electric service.[7]
  - The ECO Act states that load shifting and load management programs for peak demand reductions may be incorporated into the financial incentive mechanism.[8]
  - The ECO Act introduces new energy savings goals for electric and gas utilities. Now, electric utilities have an annual energy savings goal of 1.75 percent (up from 1.5 percent)[9] and gas utilities have an annual energy savings goal of 1 percent (down from 1.5 percent)[10] of their respective normalized retail sales,

It is worth noting that although the earlier statutory requirement for gas IOUs was an energy savings goal of 1.5 percent of their retail sales, it has been a long-standing practice in the Deputy Commissioner's Decisions for the Gas Triennial Plans to approve a minimum energy savings goal of 1 percent of the utility's retail sales as per §216B.241, subd. 1c. Thus, the ECO Act essentially keeps the energy savings goal the same for gas IOUs and increases the energy savings goals for the electric IOUs. As a result of the change in energy savings goals for electric utilities set forth in the ECO Act, the Department recommends modifying the minimum level of energy savings required to trigger financial incentives. For electric IOUs, the Department recommends increasing the minimum level of kWh savings required to trigger financial incentives from 1 percent to 1.3 percent of the utility's retail sales. For gas IOUs, the Department recommends keeping the minimum level of Dth savings required to trigger financial incentives unchanged at 0.7 percent of the utility's retail sales. Also, the Department recommends keeping the 1.2 percent of retail sales as the threshold level of Dth savings above which gas utilities qualify for an increase in the CIP Expenditures Cap. Equivalently, we recommend keeping 2 percent as the threshold level of kWh savings above which electric utilities qualify for an increase in the CIP Expenditures Cap.

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[6] Minnesota Statutes § 216B.241 Subd. 12 (d)
[7] Minnesota Statutes § 216B.241 Subd. 11 (c)
[8] Minnesota Statutes § 216B.241 Subd. 13 (f)
[9] Minnesota Statutes § 216B.241 Subd. 1c. Part (b)
[10] Minnesota Statutes § 216B.241 Subd. 1c. Part (c)

As noted above, updates to cost-effectiveness methodologies and avoided cost assumptions were provided in the March 31, 2023 Decision. These updates were carefully devised by the Cost-Effectiveness Advisory Committee (CAC) throughout 2022 in a two-phase process, during regularly scheduled CAC meetings (workshops) facilitated by the Department with assistance from Synapse Energy Economics (Synapse) and the Mendota Group. Synapse also guided the Department throughout the process of developing a new cost-effectiveness test (now called the Minnesota Test) by walking the CAC through the principles and methodologies of developing a jurisdiction-specific cost-effectiveness test as set forth in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM for DERs), and by drafting a Straw Proposal on the new MN Test, which can be found in Appendix F of the Decision.

According to the Decision, the Deputy Commissioner requires the IOUs to use the Utility System Impact (USI) methodology descriptions included in Appendix K. Furthermore, the Deputy Commissioner requires electric IOUs to use the electric avoided capacity and marginal energy cost methodologies and estimates as described in Appendix K of that Decision. The Department also expressed concerns about lack of transparency in marginal energy values used by electric IOUs in their calculations, as this information is considered Trade Secret. As a solution, the Department recommends that the utilities carefully describe the methodologies they use to estimate these marginal energy cost values, to share this data in a form that is not considered Trade Secret, and/or provide a clear and simplified way for interested parties to receive the Trade Secret avoided marginal energy cost data (e.g. through a non-disclosure agreement with the utility).

As to the BENCOST inputs for natural gas IOUs for the 2024-2026 triennial, these were approved by the Deputy Commissioner in the Decision as well and are included in Appendix L of the Decision. For reference, please see the table below, which juxtaposes the BENCOST inputs for the 2021-2023 triennial and the 2024-2026 triennial.

**Table 5: Approved BENCOST Inputs for Natural Gas IOUs in the 2021-2023 Triennial Compared to the 2024-2026 Triennial**

| General Inputs | 2021-2023 BENCOST Inputs | 2024-2026 BENCOST Inputs |
|---|---|---|
| Gas Escalation Rate (%) | 4.69% | 2.61% |
| Non-Gas Escalation Rate (%) | 3.59% | 1.63% |
| Commodity Cost ($/Dth) | $3.25 | $4.52 |
| Peak Reduction Factor (%) | 1.0% | 1.0% |
| Non-Gas Fuel Cost ($/fuel unit) | $26.57 | $44.14 |
| Non-Gas Fuel Loss Factor (%) | 7.70% | 8.22% |
| Gas Environmental Damage Factor ($/Dth) | $2.07/Dth | $3.83/Dth |
| Non-Gas Environmental Damage Factor ($/MWh) | $19.84/MWh | $25.36/MWh |
| GDP Escalation Rate (%) | 2.3% | - |
| Participant Discount Rate (%) | 3.02% (for residentialcustomers)<br><br>Utility WACC (for non-residential customers) | 3.30% (for residential customers);<br><br>CIP Utility Discount Rate (for non-residential customers) |
| Societal Discount Rate (%) | 3.02% | 3.30% |
| CIP Utility Discount Rate (%) | CIP Utility Discount Rate (See Input 12) | CIP Utility Discount Rate (See Input 12) |
| Environmental Compliance | - | 1.40% of the $/MCF commodity cost |

It is also important to mention that the net benefits under new MN Test are significantly higher than those under the Utility Cost Test used in the 2021-2023 triennial as a basis for calculating financial incentives. This stems from the updated cost-effectiveness methodologies. In particular, there are two main differences that drive this increase in net benefits:

1) Reductions in carbon emissions are included as a benefit in the cost-effectiveness analysis and constitute a significant part of the increase in net benefits
2) The new MN Test uses the Societal Discount Rate of 3.30% as approved by the Deputy Commissioner in the Decision, which is lower than discount rates for the individual utilities. For example, here are approved utility discount rates for gas utilities:
    - Xcel Gas: 5.34 percent
    - CenterPoint: 5.39 percent
    - MN Energy Resources: 5.57 percent
    - Greater MN Gas: 5.61 percent
    - Great Plains: 5.79 percent

Note that electric utilities determine their own discount rates, but they also tend to be much higher than the approved Societal Discount Rate of 3.30%. A lower discount rate increases the present value of future benefits derived from ECO programs administered by utilities, and thus represents another source of increase in net benefits.

Another decision made by the Deputy Commissioner that could have the opposite impact on the net benefits is the update to the cost-effectiveness methodology that provides for the inclusion of performance incentives as a cost in all cost-effectiveness tests except for the Participant Test.

The Department issued an IR[11] and asked utilities to calculate their MN Test Net Benefits for years 2019-2021 using the updated avoided costs assumptions for the upcoming 2024-2026 triennial. We received responses from Xcel Energy, Minnesota Power, Otter Tail Power, CenterPoint Energy and Minnesota Energy Resources Corporation. The following table summarizes the Utility Cost Test Net Benefits as reported by the utilities in their respective annual status reports and the MN Test Net Benefits of these utilities for years 2019-2021. Note that the MN Test Net Benefits include the financial incentive as a cost which is calculated as 10 percent of the MN Test Net Benefits.

**Table 6: UCT Net Benefits, MN Test Net Benefits and Their Ratios for All Utilities in 2019-2021**

| Utility | Year | UCT Net Benefits | MN Test Net Benefits | Ratio of MN Test Net Benefits to UCT Net Benefits |
|---|---|---|---|---|
| Xcel Electric | 2019 | $175,891,796 | $385,006,512 | 2.19 |
| | 2020 | $308,239,130 | $611,349,632 | 1.98 |
| | 2021 | $268,810,002 | $758,295,195 | 2.82 |
| OTP | 2019 | $33,504,362 | $49,125,314 | 1.47 |
| | 2020 | $35,506,108 | $50,614,833 | 1.43 |
| | 2021 | $29,700,515 | $50,389,368 | 1.70 |
| MP | 2019 | $23,537,199 | $43,447,290 | 1.85 |
| | 2020 | $24,762,646 | $45,126,122 | 1.82 |
| | 2021 | $19,370,032 | $41,289,581 | 2.13 |
| Xcel Gas | 2019 | $25,211,491 | $62,475,922 | 2.48 |
| | 2020 | $46,802,220 | $106,628,647 | 2.28 |
| | 2021 | $50,201,464 | $117,733,051 | 2.35 |

[11] See Attachment D. Under the Analysis Section, point 2, the Department requested: "Estimates of what the 2019-2021 Shared Savings incentives would have been for each IOU, under the assumptions of each utility's new avoided costs and using the Minnesota Test that will be approved by the Deputy Commissioner. *Could the utilities provide by March 31, 2023.*"

| | | | | |
|---|---|---|---|---|
| CPE | 2019 | $87,584,011 | $204,439,894 | 2.33 |
| | 2020 | $99,357,233 | $183,654,412 | 1.85 |
| | 2021 | $77,715,201 | $195,400,409 | 2.51 |
| MERC | 2019 | $22,313,737 | $47,237,588 | 2.12 |
| | 2020 | $17,330,979 | $35,770,845 | 2.06 |
| | 2021 | $15,600,231 | $39,319,521 | 2.52 |

The table above shows that, in general, Minnesota Test Net Benefits are more than two times higher than the corresponding Utility Test Net Benefits. The regression analysis presented in Attachment C confirms that, as a matter of fact, MN Test Net Benefits are 2.3 times higher on average than UCT Net Benefits.

The Commission has been ratcheting down the Net Benefits Cap in the past triennials (which has historically been based upon UCT Test Net Benefits), such that the cap declined from 13.5% in 2017 to 12% in 2018 to 10% since 2019. The Commission also approved the ratcheting down of the CIP Expenditures Cap from 40% in 2017, to 35% in 2018 to 30% since 2019. The overall impact of changes, as illustrated later below, has been a significant reduction in Minnesota's Shared Savings financial incentives. However, as discussed in Section I of this Report, first-year energy savings have been increasing even though incentives have been declining both in aggregate terms, as well as in terms of incentives awarded per unit of first-year energy savings. Moreover, Minnesota's incentives awarded are very generous compared to other states like Colorado, which themselves have one of the most generous financial incentive programs in the nation, as discussed in Section VI of this Report.

## III. COMPARING THE UTILITY COST TEST AND THE MINNESOTA TEST

Since the MN Test is a new cost effectiveness test created by the Department, it was important to compare its net benefit values to other established tests for benchmarking purposes. To this end, the Department issued IRs to all utilities asking them to compute the MN Test Net Benefit for their 2019-2021 CIP Portfolios.

In order to compare the Utility Cost Test Net Benefits for the 2019-2021 period to the MN Test Net Benefits using the latest avoided cost assumptions that were 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, we use the following model:

$$MCTNB_{i,t} = \beta \times UCTNB_{i,t} - p_{MN,i,t} \times MCTNB_{i,t} + \epsilon_{i,t},$$

Where $MCTNB_{i,t}$ stands for Minnesota Test Net Benefits for utility $i$ in year $t$, $UCTNB_{i,t}$ stands for Utility Cost Test Net Benefits for utility $i$ in year $t$, $p_{MN,i,t}$ is the proportion of the Minnesota Test Net Benefits awarded as incentives to utility $i$ in year $t$, and $\epsilon_{i,t}$ is prediction error. This equation features the circularity issue associated with the way in which the Minnesota Test Net Benefits are calculated: the net benefits depend on the incentive award (which is $p_{MN} \times MCTNB_{i,t}$), which itself depends on the level of net benefits. In pages 257-261 of the Decision it is outlined how this circularity issue can be resolved to calculate the Minnesota Test Net Benefits and the resulting financial incentives in Microsoft Excel.

Using the technique of least-squares estimation to estimate the parameters of the above model, we propose the following conversion formula:

$$p_{MN} \approx 0.4 \times p_{UCT},$$

Where $p_{UCT}$ is the proportion of Utility Cost Test Net Benefits awarded to a utility as financial incentives and $p_{MN}$ is the corresponding proportion of the new Minnesota Test Net Benefits awarded to a utility as financial incentives that will result in a comparable level of incentives as under the old mechanism.

Attachment C summarizes the rigorous estimation procedure and mathematical calculations that were used to arrive at the above conversion formula.

The above relationship provides an easy way to convert a fraction of UCT Net Benefits as financial incentives to a fraction of MN Test Net Benefits as financial incentives. For example, 10 percent of UCT Net Benefits is equivalent to 4 percent of MN Test Net Benefits. Also, 8.5 percent of UCT Net Benefits is equivalent to 3.4 percent of MN Test Net Benefits.

In addition, under the current Shared Savings DSM Financial Incentive Mechanism, for every 0.1% increase in energy savings as percent of retail sales, utilities receive an additional 0.75% of Utility Cost Test Net Benefits as financial incentives, until they reach the Net Benefits Cap. This percentage, expressed as a proportion, corresponds to the number 0.0075. According to the above formula, when converting to a proportion of Minnesota Test Net Benefits, this will be $0.4 \times 0.0075 = 0.003$, or 0.3% of Minnesota Test Net Benefits. Thus, awarding an additional 0.3% of Minnesota Test Net Benefits to utilities for every 0.1% increase in energy savings expressed as percent of retail sales, would be equivalent to the step increases (until the utility achieves the Net Benefits Cap) in the earlier financial incentive mechanism.

## IV. DEPARTMENT PROPOSAL AND ITS PROJECTED IMPACTS

### *1. DEPARTMENT PROPOSAL*

The Department recommends that the Commission approve a Shared Savings DSM Financial Incentive Mechanism for the 2024-2026 Triennial that includes the following general parameters:

A. Each utility should calculate its net benefits using the new Minnesota Test with the Societal Discount Rate as approved by the Deputy Commissioner in the *Decision In the*

*Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities* in Docket No. E,G999/CIP-23-46 on March 31, 2023.

B. For electric utilities, the incentive starts at an energy savings level equal to 1.3% of retail sales. For savings levels of 2.0% and higher, the utility should be awarded a share of the net benefits equal to the Net Benefits Cap.

C. For gas utilities, the incentive starts at an energy savings level equal to 0.7% of retail sales. For savings levels of 1.2% and higher, the utility should be awarded a share of the net benefits equal to the Net Benefits Cap.

D. The Net Benefits Cap should be set at 3.4% of Minnesota Test Net Benefits.

E. The CIP Expenditures Cap should be set at 15%. For gas utilities, this cap is raised to 20% if they achieve energy savings of 1.2% of their normalized retail sales or above that. For electric utilities, this cap is raised to 20% if they achieve energy savings of 2% of their normalized retail sales or above that.

F. The financial incentive would be equal to the lesser of the amount calculated using either the Net Benefits or CIP Expenditures Cap.

The Department includes its more detailed proposal in the Section VII of this Report.

*2. PROJECTED IMPACTS*

Because of the differences between the Minnesota Test and the Utility Cost Test discussed in previous sections, the Department has carefully considered all the factors in order to make a reasonable calibration of Utility Cost Test – based financial incentives to a mechanism that uses the Minnesota Test. Using the Minnesota Test as a basis for calculating the incentives that the utilities receive will ensure that utilities are incentivized to consider the same factors as the regulator when proposing their ECO Triennial Plans. Among these factors are the reductions in greenhouse gas emissions, which is a benefit to the State of Minnesota, and financial incentives paid to utilities, which is a cost for ratepayers.

First, we consider the impact of the new incentive mechanism proposed in Attachment A on each of the utilities' incentives. In order to make predictions about the variables of interest in the 2024-2026 triennial, we use the utilities' triennial filings. However, the triennial filings are not accurate most of the time: more specifically, utilities' estimates about their future energy savings and net benefits reported in their triennial plans end up being much lower than their actual energy savings and net benefits, respectively. Therefore, we compiled a dataset featuring the utilities' proposed first-year energy savings, budgets and net benefits achieved from their triennial plans, and their corresponding actual first-year energy savings, budgets and net benefits achieved from their status reports, spanning the years 2017-2022. Consequently, we calculated an average amount by which actual and proposed numbers differ, by each variable and for each utility. The table below summarizes the "adjustment factors" we used to predict the energy savings, budgets and net benefits for each utility in the 2024-2026 triennial.

**Table 7: Adjustment Factors for Scaling Proposed Energy Savings, Budgets and Minnesota Test Net Benefits for Each Utility in 2024-2026**

| Utility \ Variable | Energy Savings | Budget | Net Benefits |
|---|---|---|---|
| Xcel Electric | 30% | 4% | 71% |
| Otter Tail Power | 56% | 17% | 65% |
| Minnesota Power | 20% | -18% | 27% |
| Xcel Gas | 3% | -10% | 32% |
| CenterPoint Energy | 15% | 3% | 28% |
| Minnesota Energy Resources Corporation | -14% | -4% | -19% |
| Great Plains Natural Gas | -65% | -47% | -71% |
| Greater Minnesota Gas | -12% | 24% | -62% |

For example, the energy savings adjustment factor of 30% for Xcel Electric means that, based on data from 2017-2022, Xcel Electric's actual energy savings were, on average, 30% higher than proposed energy savings from their triennial plans. Therefore, we scale Xcel Electric's proposed energy savings from the 2024-2026 triennial filings up by 30% to arrive at our prediction of Xcel Electric's energy savings in the upcoming triennial. The same method is used for other utilities and other variables.

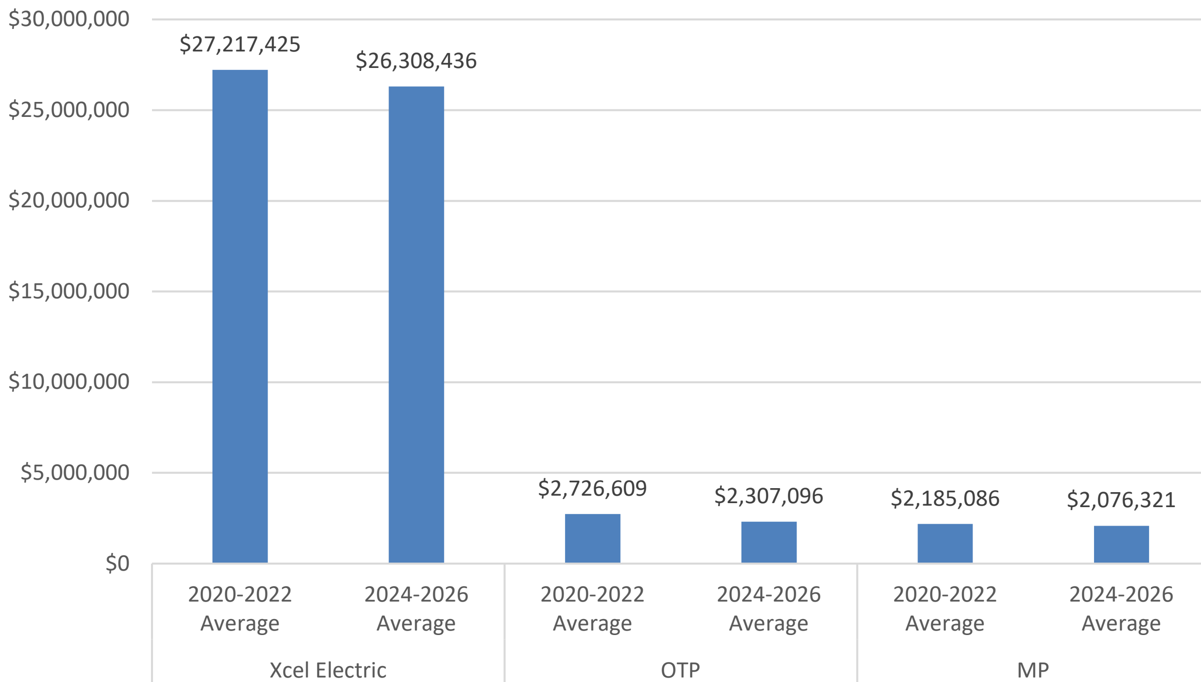
It is important to note that we used Utility Cost Test Net Benefits data from the 2017-2022 period to calculate the MN Test Net Benefits adjustment factor for each utility: this is because, in past triennials, utilities did not report their results for the MN Test, which was introduced only very recently. However, as described in Section III and Attachment C, we assume that MN Test Net Benefits are a constant factor times Utility Cost Test Net Benefits (in fact, on average, MN Test Net Benefits are 2.3 times UCT Net Benefits as described in Attachment C), and therefore the percent difference between proposed and actual UCT Net Benefits is the same as that between proposed and actual MN Test Net Benefits.

In the next two figures below, we analyze how the utilities' average annual incentives would change in the 2024-2026 triennial compared to their average incentives received in 2020-2022. Some utilities see a slight decrease in their incentives, whereas others see a slight increase. On aggregate terms, the average incentive paid to all electric utilities decreases from $32,129,120 in the 2020-2022 period to $30,691,853 for the 2024-2026 triennial. As to gas utilities, the average incentive paid to them decreases only marginally from $14,030,313 in 2020-2022 to $13,918,592 in the 2024-2026 triennial.

On an incentives per first-year unit of energy saved basis, the average incentives paid goes down from $0.039 per first-year kWh saved in the 2020-2022 period to $0.031 per first-year kWh saved in the 2024-2026 triennial period for electric utilities. This is still higher than the corresponding incentives paid per first-year kWh energy savings in other states, described in Section VI. For gas utilities, the average incentive paid per first-year Dth savings goes down from $4.215 in the 2020-2022 period to $3.518 in the 2024-2026 triennial.

The following two figures conduct a comparative analysis of 2020-2022 and 2024-2026 average incentives for each utility separately.

**Figure 11: Comparison of Electric Utilities' 2020-2022 Average Incentives and Their Predicted 2024-2026 Average Incentives**

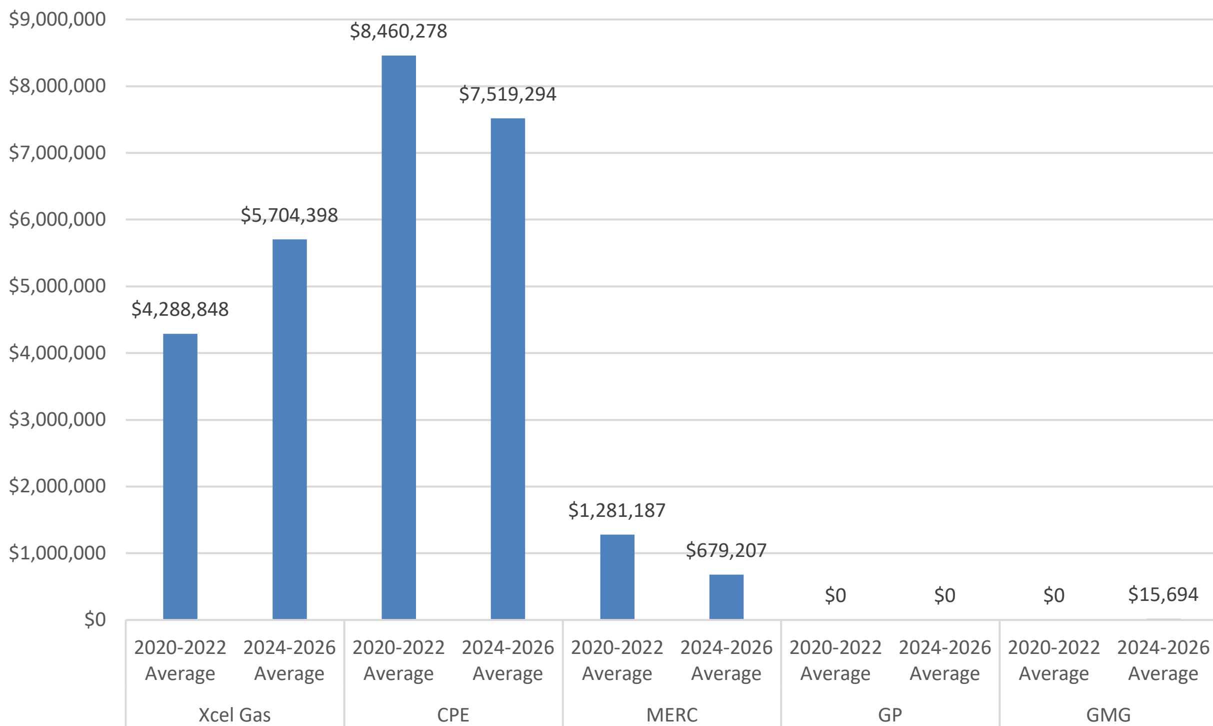



According to the figure above, the electric utilities' average incentives decrease only nominally between 2020-2022 and 2024-2026. Xcel Electric sees a decline in average incentives of about $900,000, OTP's average incentives decline by about $400,000, and MP's average incentives decline by only about $100,000.

The figure below compares the average 2020-2022 financial incentives received by gas utilities to their predicted average 2024-2026 financial incentives. This figure shows that we predict Xcel Gas' average incentives to increase by about $1,400,000[12], whereas the average incentives of CPE and MERC will decrease by about $940,000 and $600,000, respectively. Great Plains did not receive any incentives in the 2020-2022 period and we expect this to hold for the 2024-2026 triennial as well, based on our adjustment of GP's 2024-2026 triennial filing. Finally, GMG has not filed for incentives any time in the past: however, if they decide to do so in the 2024-2026 triennial, we expect them to receive $15,694 annually in financial incentives on average.

[12] Xcel Gas' incentives are increasing by about 33% according to these projection between 2020-22 and 2024-26. The largest contributor of this is the increase in average annual energy savings by 38% from 2020-22 to 2024-26.The major contributors for this large increase in energy savings are the significant expansion of their Residential, Business and Low Income Segments along with the addition of new programs like fuel switching. For more information, please refer to Xcel's filing on June 29, 2023 in Docket No. E,G002/CIP-23-92.

**Figure 12: Comparison of Gas Utilities' 2020-2022 Average Incentives and Their Predicted 2024-2026 Average Incentives**




Next we discuss how the new incentive mechanism proposed in Section VII and Attachment A would affect aggregate incentives, aggregate incentives per first-year unit of energy saved, and first-year energy savings as compared to aggregate data from 2006-2022. The next two figures represent this analysis for electric utilities. These figures show that aggregate incentives paid to electric utilities increase in 2024-2026 as compared to 2022. However, first-year energy savings increase in 2024-2026 compared to 2022 as well, such that incentives paid per first-year unit of kWh savings remain roughly the same. Note that predictions for 2024-2026 were derived by adjusting the utilities' triennial proposals as described earlier in this Section.

**Figure 13: Aggregate First-Year kWh Savings and Aggregate Incentives Paid to Electric Utilities**

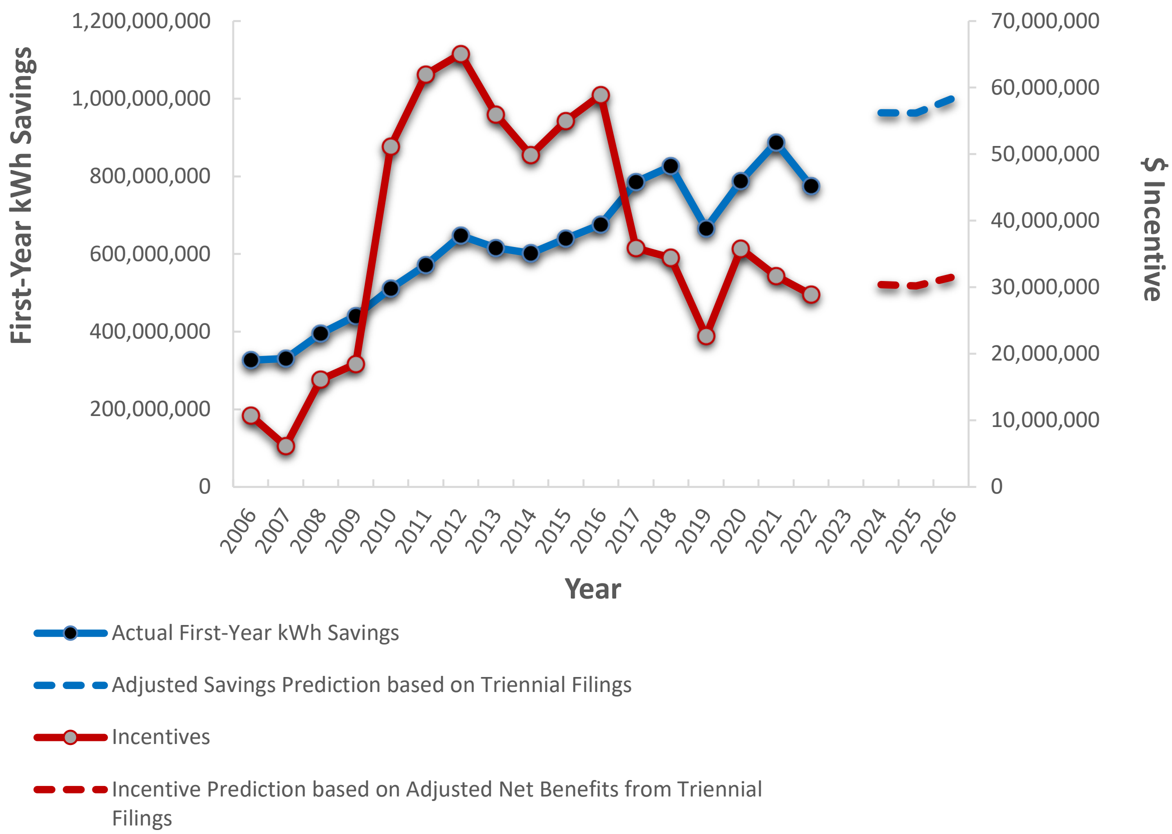
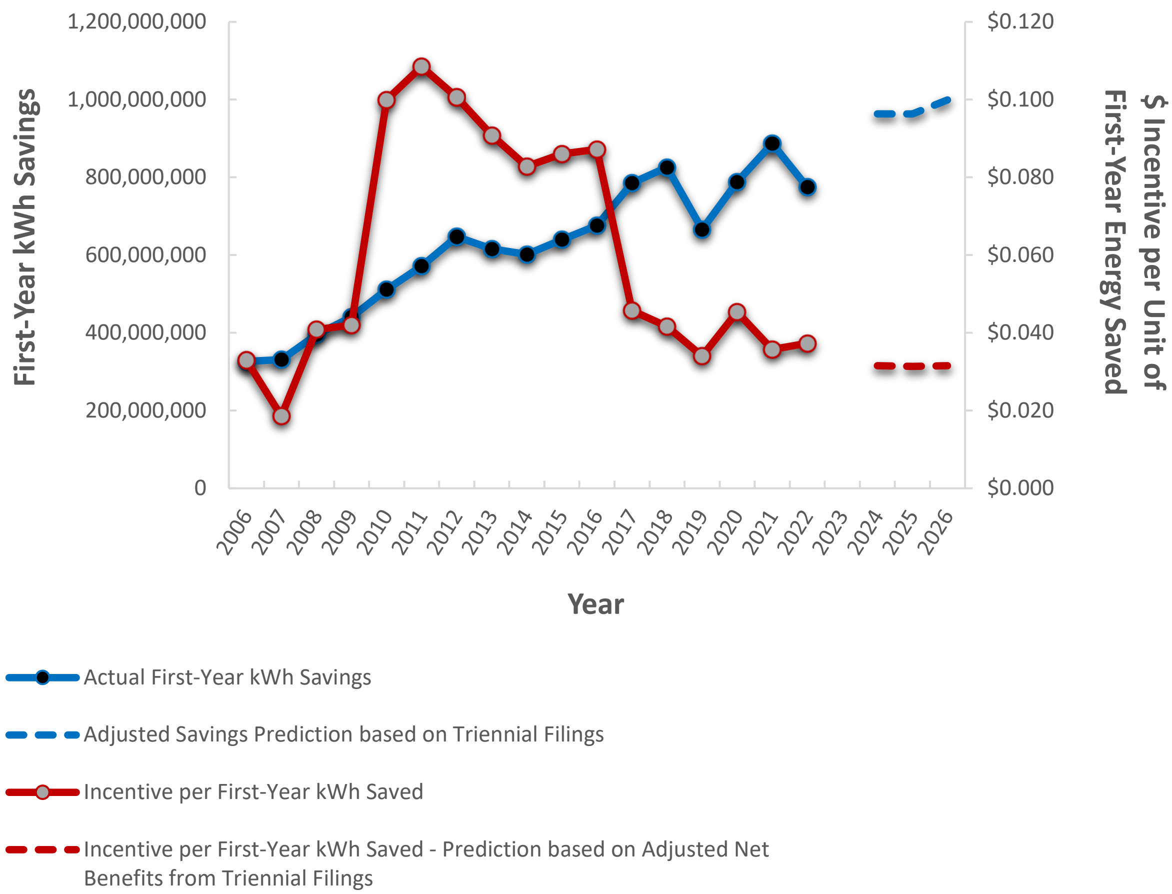


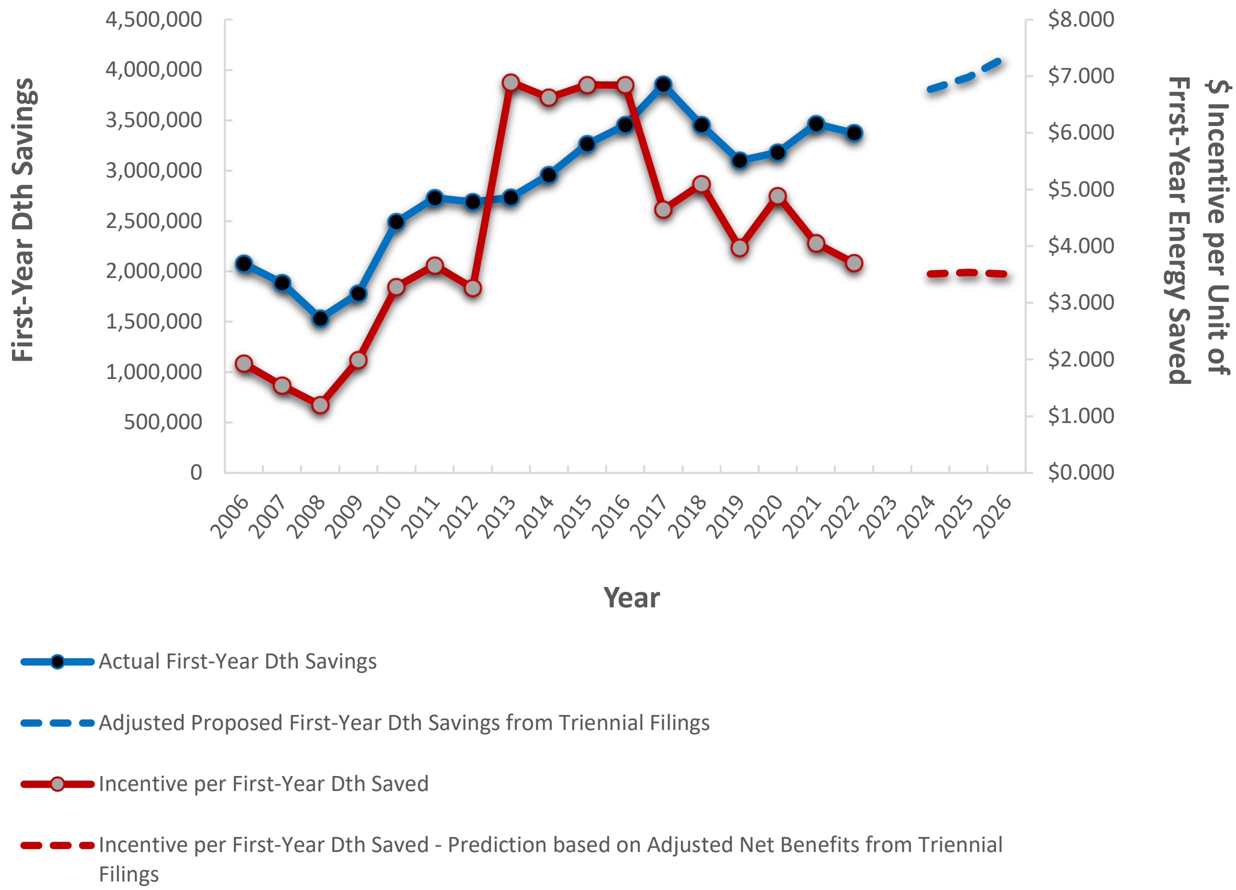
**Figure 14: Aggregate First-Year kWh Savings and Aggregate Incentives Paid per First-Year kWh Energy Savings to Electric Utilities**




The next two figures feature the same analysis for gas utilities. The picture is the same here as well – both aggregate incentives paid and first-year Dth savings increase in 2024-2026 compared to 2022, such that incentives paid per first-year Dth savings remain roughly the same.

**Figure 15: Aggregate First-Year Dth Savings and Aggregate Incentives Paid to Gas Utilities**

**Figure 16: Aggregate First-Year Dth Savings and Aggregate Incentives Paid per First-Year Dth Energy Savings to Gas Utilities**




Based on the analysis presented above, the Department concludes that the new incentive mechanism proposed in Section VII and Attachment A results in reasonable changes to utilities' incentives compared to past trends. Average aggregate incentives for 2024-2026 are reduced by a small amount for both electric and gas utilities compared to the average incentives paid in 2020-2022. We expect aggregate incentives to increase in the 2024-2026 triennial compared to the year 2022 for both electric and gas utilities: however, this increase is coupled with an increase in first-year energy savings, such that incentives per unit of first-year energy saved remain roughly constant in 2024-2026 compared to 2022. The majority of utilities will see a slight decline in their 2024-2026 average incentives compared to those in 2020-2022: the only exceptions are Xcel Gas and GMG (if the latter decides to file for incentives in the upcoming triennial).

## V. ADDITIONAL TOPICS BASED ON ORDER POINT 4[13]

Minnesota has adopted a shared benefits (SB) approach to operationalizing its Performance Incentive Mechanisms (PIM). The rationale has been that a PIM structure based on SB will incentivize the creation and delivery of cost effective energy efficiency programs. As utilities are awarded a share of the net benefits they generate as their financial incentive, they would try to maximize the net benefits of the program to receive the highest possible financial reward. The Department, in close consultantion with the Cost-Effectiveness Advisory Committee (CAC), determines the mechanism of calculating net benefits from various perspectives (Society, Participants, Utility, Ratepayer and the Minnesota Regulator). The current proposed PIM is based on the net benefits of the Minnesota Test.

In the Commission's December 9, 2020 Order in the instant docket, order point 4 stated:

> *The Commission requests that the Department continue a stakeholder process, under the current docket, to evaluate ways of improving the shared-savings mechanisms for potential adoption in the 2024-2026 triennium including, but not limited to, discussion of:*
>
> a. *incorporation of lifetime energy savings into the incentive mechanism,*
> b. *incorporation of an incentive for utilities that achieve permanent peak reductions through the shared-savings incentive mechanism,*
> c. *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,*
> d. *energy efficiency opportunities to support increased load flexibility (the ability to persistently shape and shift load).*

With respect to Order Point 4 part a, the Department notes that utilities report both lifetime energy savings and cumulative lifetime energy savings in their Triennial Plans as per requirements laid out in Minnesota Statutes §216B.241, Subd. 2(b). However, since the energy savings goals as laid out in Minnesota Statutes §216B.241, Subd. 1c(b) and Subd. 1c(d) are in terms of annual energy savings, the Department tracked incentive per first-year energy savings in the Shared Savings Financial Incentive Mechanism comparison over time. When net benefits for any cost-effectiveness test are calculated, the energy savings over the lifetime of the measure are incorporated. Since the utilitity test uses a higher discount rate, future energy savings are discounted to a greater extent. As the previous financial incentive mechanism was based on the utility test net benefits, it can be argued that the mechanism was discounting future energy savings more. In contrast, as the current proposal is based on net benefits calculated using the MN Test, which uses a significantly lower discount rate compared to the Utility Cost Test, future energy savings are given significantly greater weightage in this proposed mechanism compared to the previous Shared Savings Financial Incentive Mechanism. Additionally, by incorporating future energy savings over the lifetime of the measures into the financial mechanism along the same lines as they are incorporated during programmatic review of these plans (through the same MN test), the proposed mechanism helps align the financial incentive with the programmatic approval process used by the Department.

[13] Order Point 4 of Commission's order issued on December 9, 2020 in Docket E,G-999/CI-08-133

To address Order Point 4 Parts b. and d., during discussions with stakeholders, the Department asked for feedback on the possibility of awarding financial incentives for load management projects, with and without energy savings opportunities.

*Positions of stakeholders*

- Marty Kushler of ACEEE stated that he supported an incentive for load management, but it should not detract from the incentive structure for energy efficiency.
- Xcel pointed out that net benefits of load management projects that include energy savings could be included in the Shared Savings Incentive Mechanism, governed by Minnesota Statutes § 216B.16, subd. 6c. Incentives for load management without energy savings would be covered by Minnesota Statutes § 216B.241 subd. 13(f).
- OTP supported the Department's recommendation to include load management net benefits in the Shared Savings Financial Incentive Mechanism. Otter Tail suggested that if ten percent of net benefits from energy conservation projects is approved for the Shared Savings Financial Incentive Mechanism, then ten percent of net benefits resulting from load management activities should be included in the Financial Incentive Mechanism as well.
- Further, OTP stated that, in the past, the load management programs that they have included in their CIP portfolio because they achieved energy savings, have been approved using a one-year measure life and have included all program participants who participated in the current year. Otter Tail believes this methodology of using a one-year measure life for load management participants and including all current year participants, and not just the new participants, is the most accurate way to evaluate the cost-effectiveness of load management programs.
- MP stated that "traditional utility business models and the existing regulatory framework generally leads to utility investment in new generation capacity over load management activities. Providing financial incentives through the CIP/ECO framework would be a meaningful step towards overcoming this barrier during a time when load flexibility is becoming increasingly more important."

*Department discussion*

a. **Load management *with* energy savings.** Minnesota Statutes § 216B.241 Subd. 13. (f) states: "The commission may include the net benefits from a load management activity integrated with an energy efficiency program approved under this section in the net benefits of the energy efficiency program for purposes of a financial incentive program under section Minnesota Statutes § 216B.16, subdivision 6c, if the department determines the primary purpose of the load management activity is energy efficiency." The Department agrees with Xcel and Otter Tail that the net benefits of load management projects that include energy savings should be included in the Shared Savings Incentive Mechanism, governed by Minnesota Statutes § 216B.16, subd. 6c. Examples include Xcel's Saver's Switch and Otter Tail's Cool Savings (AC cycling) and Water Heater Store & Save load management programs.

**b. Load management *without* energy savings.**

Minnesota Statutes § 216B.241 Subd. 13. (d) states: "The commission may approve, modify, or reject a proposal made by the department or a public utility for an incentive plan to encourage investments in load management programs. The commission may approve a proposal that the commission determines:

(1) is needed to increase the public utility's investment in cost-effective load management;

(2) is compatible with the interest of the public utility's ratepayers; and

(3) links the incentive to the public utility's performance in achieving cost-effective load management.

Based on the review of the statute and suggestions made by Xcel and Otter Tail Power, the Department proposes that, for load management programs which do not result in energy savings, the incentive should be based on:

- Net benefits due to increases in load management (reduction in kW) that occurred on or after the approval of the Energy Conservation and Optimization Act (ECO). ECO went into effect on May 25, 2021. Since an incentive ideally should be designed to encourage new behavior rather than rewarding a utility for existing behavior, the Department does not agree with Otter Tail that already existing load management savings should be included.

- The increases in kW savings after the date the ECO Act was implemented may be due to increased kW savings in an existing or new load management program.

- The percent of net benefits awarded should be the same as the maximum cap approved for the Shared Savings Financial Incentive Mechanism.

- The net benefits for qualifying load management projects should be calculated using the MN Test and be included in the total net benefits used to calculate the financial incentive.

To address Order Point 4 Part c, the Department issued Information Requests (IRs) to all utilities asking them to provide spreadsheets that show total annual costs of $80 million of CIP investments over the lifetime of those measures assuming the utility treats those expenditures as capitalized amounts that would be rewarded financially as though they were the capital cost of a new power plant. For the three electric utilities (MP, OTP and Xcel-Electric), the Department also asked them to provide costs associated with capitalizing an $80 million investment in a wind project and a solar project.

If the investment is treated like a supply side investment and rewarded financially through the cost of service model, the utility would have to be paid a stream of revenue requirements (RR) over the life of the investment. The Department took the RR stream provided by the utilities in their IR responses and calculated two measures. The first is the total nominal RR obtained by simply adding up the yearly revenue requirements. The second is the net present value (NPV) of the RR obtained by discounting future RR and converting them to present day values. The Department then created a first-year energy savings estimate of the $80 million investment by scaling the utility's 2022 ECO performance. The two measures (Nominal RR and NPV RR) were then divided by the first-year energy savings which are presented in Figures 17 and 18 below.

To compare this to the current financial incentive mechanism, the Department calculated the total amount utilities received in 2022 as cost recovery for their ECO expenditures and added the financial incentive the utilities received in 2022 for their energy efficiency investments. This was then divided by the total units of energy savings by each utility. This metric was added to Figures 17 and 18 below for comparison.

**Figure 17: Comparison of Alternative Mechanisms to the 2021-23 CIP Financial Incentive Mechanism for Electric IOUs**

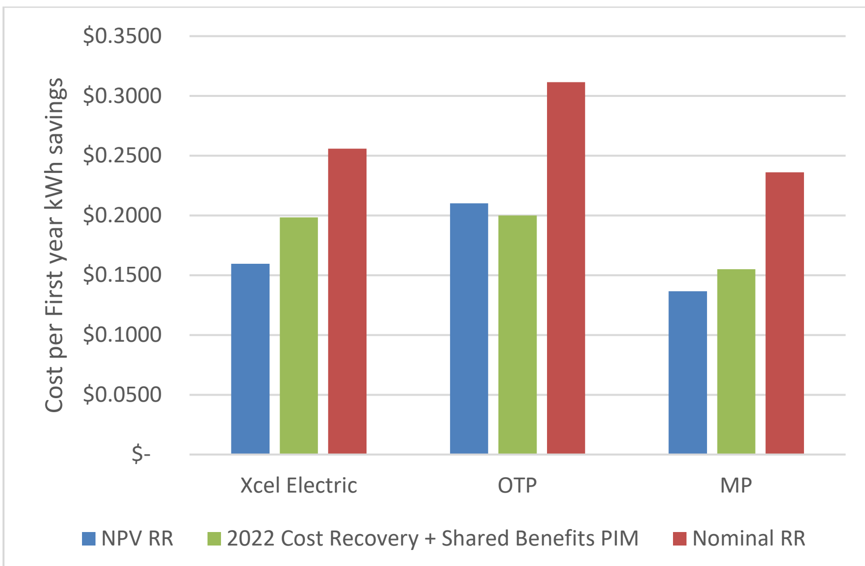
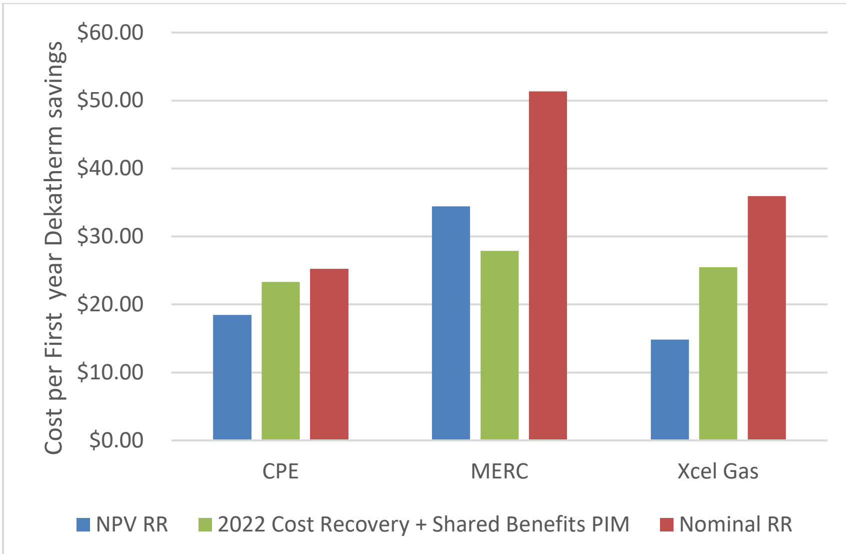


**Figure 18: Comparison of Alternative Mechanisms to the 2021-23 CIP Financial Incentive Mechanism for Gas IOUs**




The above figures show that the current amount ratepayers are paying for each unit of first-year energy savings is mostly in-between the NPV RR and the Nominal RR per unit of first-year energy savings. It should be noted that energy efficiency investments are generally customer-owned, behind-the-meter investments which are fundamentally different from typical supply side utility investments. The fact that ratepayers are still paying an amount close to or often higher than the NPV RR indicates that the Shared Benefits Financial Incentive Mechanism currently in place is extremely generous and lucrative for the utilities.

## VI. MINNESOTA'S INCENTIVES COMPARED TO OTHER STATES

In its 2022 State Scorecard, the American Council for an Energy Efficient Economy (ACEEE) rated Minnesota tenth in the country and first in the Midwest region with respect to their State Energy Efficiency Scorecard.[14]

In the past, the Department has compared Minnesota's Shared Savings DSM Financial Incentive Mechanisms with the DSM financial incentives used in other states. The primary source for our analysis has been ACEEE's publication *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency.* Although ACEEE has not updated this publication since June 9, 2015,[15] the ACEEE published *Snapshot of Energy Efficiency Performance Incentives for Electric Utilities*[15] in December 2018. The Department reached out to ACEEE and asked if there were any recent publications comparing the incentive mechanisms of different states. Unfortunately, ACEEE has not published any recent reports updating their previous analysis.

[14] See page 12 of 2022 State Energy Efficiency Scorecard, accessed at https://www.aceee.org/research-report/u2206
[15] See https://aceee.org/sites/default/files/pims- 121118.pdf

An important factor to keep in mind when comparing Minnesota's incentives to other states is that Minnesota does not adjust its reporting of energy savings for what is called the net-to-gross factor (NTG).[16] Instead, Minnesota utilities report their gross savings. In its 2022 State Scorecard, ACEEE stated that it calculated a median NTG factor of 0.906 for natural gas projects and 0.809 for electric projects.[17] Thus, a Minnesota electric utility's reporting of 1,000,000 kWh would be equal to only 809,000 kWh in a state that reports net savings. Given that Minnesota's energy savings reporting methodology is inflated in comparison to those of other states, any comparison between states can be improved by adjusting Minnesota's estimates.

*A. INCENTIVES ON A $/FIRST-YEAR UNIT OF ENERGY SAVINGS BASIS*

To provide some comparison to our existing and proposed Shared Savings Financial Incentive Mechanism, the Department presents the following comparison with the performance incentives in other states. For Colorado, we use data on the Public Service Company of Colorado (Xcel CO) between 2019 and 2022 through its annual status report filings.[18] It is worth noting that in May 2023, the Colorado Public Utilities Commission adopted a new performance incentive mechanism and we do not know the impacts of the new mechanism. We also collected data on other high-performing states on the ACEEE Scorecard: California,[19] Connecticut,[20] Rhode Island[21] and Massachusetts.[22]

Since utilities in California, Colorado, Connecticut, Rhode Island and Massachusetts reported net energy savings in their annual status reports, the Department used ACEEE's 2022 NTG factor to convert net savings into gross savings. Table 8 below shows a comparison between dollars per kWh of first-year energy saved received as incentives by electric utilities in Minnesota and these states. The values for

[16] Estimates of *gross savings* reflect the changes in energy consumption and/or demand that result from program-related actions taken by participants in an efficiency program, regardless of why they participated. In contrast, a *net savings* approach measures the changes in energy consumption/demand that are specifically attributable to or are a direct result of a particular energy efficiency program that would not otherwise have happened in the absence of the program. The best known reason for why gross energy savings are different from net energy savings is free ridership—an estimate of the number of conservation program participants that would have invested in energy efficient technologies and processes absent the program. A net-to-gross factor represents the fraction that is multiplied by gross savings to estimate the energy savings attributable to a utility energy efficiency program.

[17] ACEEE chose the median net-to-gross ratio of states that reported both net energy savings and gross energy savings to ACEEE.

[18] Xcel CO's 2019 and 2020 Demand-Side Management Annual Status Reports were filed in Proceeding No. 18A-0606EG; Xcel CO's 2021 and 2022 Demand-Side Management Annual Status Reports were filed in Proceeding No. 20A-0287EG.

[19] For the electric side in CA, we collected 2017-2019 data on the Southern California Edison (SCE) Company, and for the gas side in CA we collected 2017-2019 data on the Southern California Gas Company. Data was garnered from the *Energy Efficiency Reporting* webpage of the *California PUC* website.

[20] 2019-2021 aggregate data on Connecticut gas and electric utilities was obtained from the *2021 Plan Update to the 2019-2021 Conservation & Load Management Plan* filed on March 1, 2021 and posted on the *Energy Efficiency Board: Conservation and Load Management Plans* webpage of the *Energize Connecticut* website.

[21] For both gas and electric sides in Rhode Island, we used 2020-2022 data on the National Grid energy company, collected from their *Annual Energy Efficiency Plan for 2022* report filed on October 1, 2021 in *Docket No. 5189*, posted on the *Public Utilities Commission and Division of Public Utilities and Carriers of the State of Rhode Island* website.

[22] For both gas and electric sides in MA, 2019-2021 aggregate data was collected from the October 19, 2018 version of the *2019-2021 Energy Efficiency Plan Term Sheet* posted on the *Plans and Updates* webpage of the *Massachusetts Energy Efficiency Advisory Council* website.

Minnesota in 2024-2026 presented in the table below are based on the Department's forecasts of energy savings as explained in Section IV of this Report.

**Table 8: 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 | $ 0.031 | $ 0.028 | $ 0.028 | $ 0.027 | $ 0.026 | $ 0.010 |

As can be seen in the above table, between 2020 and 2022, the incentives in Minnesota were higher than what electric utilities received in other states. Based on the proposed Shared Savings Incentive Mechanism, the projected incentives in Minnesota for the 2024-2026 triennial are still expected to be slightly higher relative to these states. California and Massachusetts had the lowest incentives per first-year unit of energy saved among these states. According to data from Massachusetts' energy efficiency programs between 2019 and 2021,[23] electric utilities were expected to receive an incentive of $0.027/kWh.[24] In California during 2017-2019, Southern California Edison (a California electric company) received a much lower incentive of $0.010/kWh.[25] It is worth noting that these two states are the highest-performing states in energy efficiency according to ACEEE, with Massachusetts ranked #2 and California #1 in the 2022 ACEEE State Scorecard.

The Department conducted a similar exercise on the gas side, using reported Dth savings and performance incentive values in these states. The Department used the NTG factor for gas utilities from ACEEE's 2022 State Scorecard as reported above. Table 9 below shows a comparison between dollars per Dth of first-year energy saved received by gas utilities in Minnesota and other high-performing states. The 2024-26 values for Minnesota presented in the table below are based on the Department's forecasts of energy savings as explained in Section IV of this Report.

[23] For specifics of Massachusetts' performance incentives, see the *2019-2021 Term Sheet*.
[24] The Department converted the Net Annual savings reported into Gross Annual savings using ACEEE's NTG Ratio of 0.809.
[25] See the *Energy Efficiency Reporting* webpage of the *California PUC* website. The Department converted the Net Annual savings reported for 2018 and 2019 into Gross Annual kWh using ACEEE's NTG Ratio of 0.809.

**Table 9: 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 | $ 3.518 | $ 4.730 | $ 3.596 | $ 3.416 | $ 2.173 | $ 0.402 |

As can be seen in the above table, in 2020-2022 Minnesota's incentives were slighty higher than those received by gas utilities in other states in previous periods, with the exception of Xcel CO. Based on our proposed Shared Savings Incentive Mechanism, the projected incentives for Minnesota in the 2024-2026 triennial are expected to be slightly lower relative to what Xcel CO received between 2020 and 2022. However, it is about the same as the incentives paid per first-year unit of energy saved in Rhode Island and Connecticut, and much higher than those in Massachusetts and California. According to data from Massachusetts' energy efficiency programs between 2019 and 2021,[26] gas utilities were predicted to receive an incentive of $2.173/Dth.[27] In California during 2017-2019, Southern California Gas (a California gas company) received a much lower incentive of $0.402/Dth.[28] It is worth reminding again that Massachusetts and California are ranked #2 and #1 respectively in the 2022 ACEEE State Scorecard for the quality of their energy efficiency projects and initiatives.

*B. INCENTIVES ON A PERCENTAGE OF EXPENDITURES BASIS*

Almost all states set a cap on incentive earnings. The cap is most often based on a percentage of program spending. Caps generally ranged from 5 percent to 20 percent of energy efficiency program spending, with the average cap at 12 to 13 percent of total program spending[29]. Table 10 below shows expenditures caps for multiple states for their gas energy efficiency programs based on an updated 2022 report by Optimal Energy, Inc. prepared for the Ontario Energy Board Staff[30]. Minnesota has allowed one of the highest levels of utility performance incentives measured as a percent of CIP

[26] For specifics of Massachusetts's performance incentives, see the *2019-2021 Term Sheet*.
[27] The Department converted the Net Annual Therm reported into Gross Annual Dth using ACEEE's NTG Ratio of 0.906.
[28] See the *Energy Efficiency Reporting* webpage of the *California PUC* website. The Department converted the Net Annual savings reported for 2018 and 2019 into Gross Annual savings using ACEEE's NTG Ratio of 0.906.
[29] Hayes, Sara, et al. "Carrots for utilities: providing financial returns for utility investments in energy efficiency." *American Council for an Energy-Efficient Economy. Report U* 111 (2011) at 14. Accessed at https://www.aceee.org/sites/default/files/publications/researchreports/U111.pdf
[30] Review and Assessment of Cost Recovery and Performance Incentive Options for Natural Gas Demand Side Management Programs accessed at https://www.rds.oeb.ca/CMWebDrawer/Record/739135/File/document

expenditures, with a cap of 35%. Of the states in ACEEE's top 20 for 2019, only *two* other states had an expenditures cap of 10% or more—Michigan and Colorado. In recent years, Michigan increased its expenditures cap from 15% to 20%.

Between 2020 and 2022, Xcel CO's performance incentives as a share of its expenditures were between 16 and 18 percent. Based on the projected energy savings and expenditures for the 2024-2026 triennial as explained in Section IV and presented in Attachment B of this Report, total utility Shared Savings incentives as a proportion of total utility ECO expenses are forecasted to be around 15 percent, with some utilities receiving a slightly higher and some receiving a slightly lower fraction. Thus, the Department finds that an expenditures cap of 15 percent, which can be relaxed to 20 percent if utilities meet higher savings targets, would still be very generous.

**Table 10: Expenditures Caps for Incentive Mechanisms for Gas Energy Efficiency Programs**

| State | Expenditure Cap (as a proportion of program budget) |
|---|---|
| Michigan | 20% |
| Rhode Island | 6.25% |
| Massachusetts | 3.6% |
| Arkansas | 8% |
| Connecticut | 8% |
| Minnesota | 35% |

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.[31] Massachusetts ranks second in the nation in ACEEE's 2022 State Energy Efficiency Scorecard. For 2021 and 2022, National Grid, which has an Energy Efficiency budget of over $100 million, forecasts to receive 4.7 and 4.5 percent of its expenditures respectively as performance incentives for its energy efficiency program in Rhode Island.[32] Based on the 2023 Plan Update to Connecticut's 2022-2024 Conservation and Load Management Plan,[33] electric and gas utilities are expected to earn incentives that are about 5 percent of their program budgets while the state ranks 9th in the 2022 State Energy Efficiency Scorecard. These comparisons show that there is still room to reduce Minnesota's incentives further while simultaneously improving the state's position as a leader among national energy efficiency programs.

### *C. INCENTIVES ON A PERCENTAGE OF NET BENEFITS BASIS*

Since the MN Test is unique in the way it calculates net benefits, it is difficult to find a relevant point of comparison with another state. In particular, the Department is not aware of other states that include the same cost benefit categories as the MN Test. Since this test diverges significantly from other cost-effectiveness test net benefits, the Department does not have any relevant comparisons.

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[31] For specifics of Massachusetts's performance incentives, see the *2019-2021 Term Sheet*.
[32] See the *Annual Energy Efficiency Plan for 2022* report filed by the National Grid energy company on October 1, 2021 in *Docket No. 5189*, posted on the *Public Utilities Commission and Division of Public Utilities and Carriers of the State of Rhode Island* website.
[33] See the *2022-2024 Conservation and Load Management Plan* filed on 11/01/2022.

## VII. DEPARTMENT CONCLUSIONS AND RECOMMENDATIONS

1. 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.

The level of MN Test Net Benefits a utility accrues for achieving the threshold level of savings is calculated according to the following formula:

$$
\begin{aligned}
&Percent\ of\ Net\ Benefits\ Awarded = \\
&\min\{Net\ Benefits\ Cap,\ Net\ Benefits\ Cap + 3.0 \times (Energy\ Savings\ Benchmark\ Achieved - \\
&Energy\ Savings\ Benchmark\ Corresponding\ to\ Net\ Benefits\ Cap)\} \\
&\times \mathbb{1}\{Energy\ Savings\ Benchmark\ Achieved \geq Energy\ Savings\ Threshold\}
\end{aligned}
$$

Below find the net benefits award charts for electric and natural gas IOUs corresponding to the above formula. The terms used in the formula are also explained on the next page.

ATTACHMENT A

**INCREMENTAL INCENTIVES CHART (ELECTRIC INVESTOR-OWNED UTILITIES)**

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*(The underline in the first column identifies the* ***Energy Savings Threshold*** *level required to trigger awards; The underline in the second column identifies the minimum level of incentive awards. The double-underline in the second column identifies the* ***Energy Savings Benchmark Corresponding to Net Benefits Cap****. The double-underline in the second column identifies the* ***Net Benefits Cap****.)*

| **Achievement Level (percent of retail sales avoided)** | **Percent of Net Benefits Awards** |
|---|---|
| 0.0% | 0.00% |
| 0.1% | 0.00% |
| 0.2% | 0.00% |
| 0.3% | 0.00% |
| 0.4% | 0.00% |
| 0.5% | 0.00% |
| 0.6% | 0.00% |
| 0.7% | 0.00% |
| 0.8% | 0.00% |
| 0.9% | 0.00% |
| 1.0% | 0.00% |
| 1.1% | 0.00% |
| 1.2% | 0.00% |
| 1.3% | 1.30% |
| 1.4% | 1.60% |
| 1.5% | 1.90% |
| 1.6% | 2.20% |
| 1.7% | 2.50% |
| 1.8% | 2.80% |
| 1.9% | 3.10% |
| 2.0% | 3.40% |
| 2.1% | 3.40% |
| 2.2% | 3.40% |
| 2.3% | 3.40% |
| 2.4% | 3.40% |
| 2.5% | 3.40% |

**INCREMENTAL INCENTIVES (NATURAL GAS INVESTOR-OWNED UTILITIES)**

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*(The underline in the first column identifies the* ***Energy Savings Threshold*** *level required to trigger awards; The underline in the second column identifies the minimum level of incentive awards. The double-underline in the second column identifies the* ***Energy Savings Benchmark Corresponding to Net Benefits Cap.*** *The double-underline in the second column identifies the* ***Net Benefits Cap.****)*

| Achievement Level (percent of retail sales avoided) | Percent of Net Benefits Awards |
|---|---|
| 0.0% | 0.00% |
| 0.1% | 0.00% |
| 0.2% | 0.00% |
| 0.3% | 0.00% |
| 0.4% | 0.00% |
| 0.5% | 0.00% |
| 0.6% | 0.00% |
| <u>0.7%</u> | <u>1.90%</u> |
| 0.8% | 2.20% |
| 0.9% | 2.50% |
| 1.0% | 2.80% |
| 1.1% | 3.10% |
| <u>1.2%</u> | <u>3.40%</u> |
| 1.3% | 3.40% |
| 1.4% | 3.40% |
| 1.5% | 3.40% |
| 1.6% | 3.40% |
| 1.7% | 3.40% |
| 1.8% | 3.40% |
| 1.9% | 3.40% |
| 2.0% | 3.40% |
| 2.1% | 3.40% |
| 2.2% | 3.40% |
| 2.3% | 3.40% |
| 2.4% | 3.40% |
| 2.5% | 3.40% |

**Table B-1: Projected Outcomes for Electric and Gas IOUs Based on the Proposed Shared Savings Incentive Mechanism for 2024**

| | 2024 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Electric IOUs | | | Gas IOUs | | | | |
| CIP Incentive Scenario | **Xcel Electric** | **Otter Tail Power** | **Minnesota Power** | **Xcel Gas** | **CenterPoint Energy** | **MERC** | **Great Plains Natural Gas** | **Greater Minnesota Gas** |
| Incentives with the Financial Incentive Mechanism Outlined in Attachment A | $26,029,110 | $2,303,971 | $2,055,196 | $5,133,321 | $7,519,294 | $692,803 | $0 | $15,694 |
| Incentives as % of CIP Expenditures | 15.8% | 19.7% | 20.0% | 19.2% | 14.6% | 4.8% | 0.0% | 2.4% |
| Incentives as % of Net Benefits | 3.4% | 3.4% | 3.3% | 3.4% | 3.4% | 2.2% | 0.0% | 2.2% |
| Incentives as $/First-Year Unit of Energy Saved | $0.033 | $0.030 | $0.023 | $4.065 | $3.530 | $1.836 | $0.000 | $0.929 |
| Percent Change in Incentives as Compared to the Average in 2020-2022 | -4.4% | -15.5% | -5.9% | 19.7% | -11.1% | -45.9% | N/A* | N/A* |

* The percentage change cannot be calculated as the Financial Incentive in 2022 was $0.

Shaded area denotes scenarios in which the utility would encounter the CIP Expenditures Cap and thus would not receive maximum award based on net benefits

**Table B-2: Projected Outcomes for Electric and Gas IOUs Based on the Proposed Shared Savings Incentive Mechanism for 2025**

| | 2025 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Electric IOUs | | | Gas IOUs | | | | |
| CIP Incentive Scenario | **Xcel Electric** | **Otter Tail Power** | **Minnesota Power** | **Xcel Gas** | **CenterPoint Energy** | **MERC** | **Great Plains Natural Gas** | **Greater Minnesota Gas** |
| Incentives with the Financial Incentive Mechanism Outlined in Attachment A | $25,840,410 | $2,277,189 | $2,086,883 | $5,673,760 | $7,519,294 | $688,746 | $0 | $15,694 |
| Incentives as % of CIP Expenditures | 14.9% | 19.5% | 20.0% | 19.0% | 13.6% | 4.7% | 0.0% | 2.4% |
| Incentives as % of Net Benefits | 3.4% | 3.4% | 3.4% | 3.4% | 3.4% | 2.2% | 0.0% | 2.2% |
| Incentives as $/First-Year Unit of Energy Saved | $0.032 | $0.030 | $0.024 | $4.208 | $3.473 | $1.825 | $0.000 | $0.929 |
| Percent Change in Incentives as Compared to the Average in 2020-2022 | -5.1% | -16.5% | -4.5% | 32.3% | -11.1% | -46.2% | N/A* | N/A* |

* The percentage change cannot be calculated as the Financial Incentive in 2022 was $0.

**Table B-3: Projected Outcomes for Electric and Gas IOUs Based on the Proposed Shared Savings Incentive Mechanism for 2026**

| | 2026 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Electric IOUs | | | Gas IOUs | | | | |
| CIP Incentive Scenario | **Xcel Electric** | **Otter Tail Power** | **Minnesota Power** | **Xcel Gas** | **CenterPoint Energy** | **MERC** | **Great Plains Natural Gas** | **Greater Minnesota Gas** |
| Incentives with the Financial Incentive Mechanism Outlined in Attachment A | $27,055,789 | $2,340,129 | $2,086,883 | $6,306,112 | $7,519,294 | $656,072 | $0 | $15,694 |
| Incentives as % of CIP Expenditures | 15.7% | 20.0% | 19.9% | 18.9% | 12.9% | 4.6% | 0.0% | 2.4% |
| Incentives as % of Net Benefits | 3.4% | 3.3% | 3.4% | 3.4% | 3.4% | 2.2% | 0.0% | 2.2% |
| Incentives as $/First-Year Unit of Energy Saved | $0.033 | $0.030 | $0.023 | $4.323 | $3.327 | $1.739 | $0.000 | $0.929 |
| Percent Change in Incentives as Compared to the Average in 2020-2022 | -0.6% | -14.2% | -4.5% | 47.0% | -11.1% | -48.8% | N/A* | N/A* |

* The percentage change cannot be calculated as the Financial Incentive in 2022 was $0.

Shaded area denotes scenarios in which the utility would encounter the CIP Expenditures Cap and would not receive maximum award based on net benefits

**Derivation of the Conversion Formula for Switching from Utility Cost Test - Based Incentives to Minnesota Test - Based Incentives**

This attachment deliberates the process by which the Department converts the Shared Savings DSM Financial Incentive Mechanism, which has been using the Utility Cost Test, to the new Minnesota Test Net Benefits. The model proposed in Section III of this report is the following:

$$MCTNB_{i,t} = \beta \times UCTNB_{i,t} - p_{MN,i,t} \times MCTNB_{i,t} + \epsilon_{i,t},$$

where $MCTNB_{i,t}$ stands for Minnesota Test Net Benefits for utility $i$ in year $t$, $UCTNB_{i,t}$ stands for Utility Cost Test Net Benefits for utility $i$ in year $t$, $p_{MN,i,t}$ is the proportion of the Minnesota Test Net Benefits awarded as incentives to utility $i$ in year $t$, and $\epsilon_{i,t}$ is a zero-mean prediction error.

Rearranging the above equation, we get:

$$MCTNB_{i,t} = \frac{\beta}{1+p_{MN,i,t}} \times UCTNB_{i,t} + \eta_{i,t},$$

where $\eta_{i,t} = \frac{\epsilon_{i,t}}{1+p_{MN,i,t}}$ is a new zero-mean prediction error.

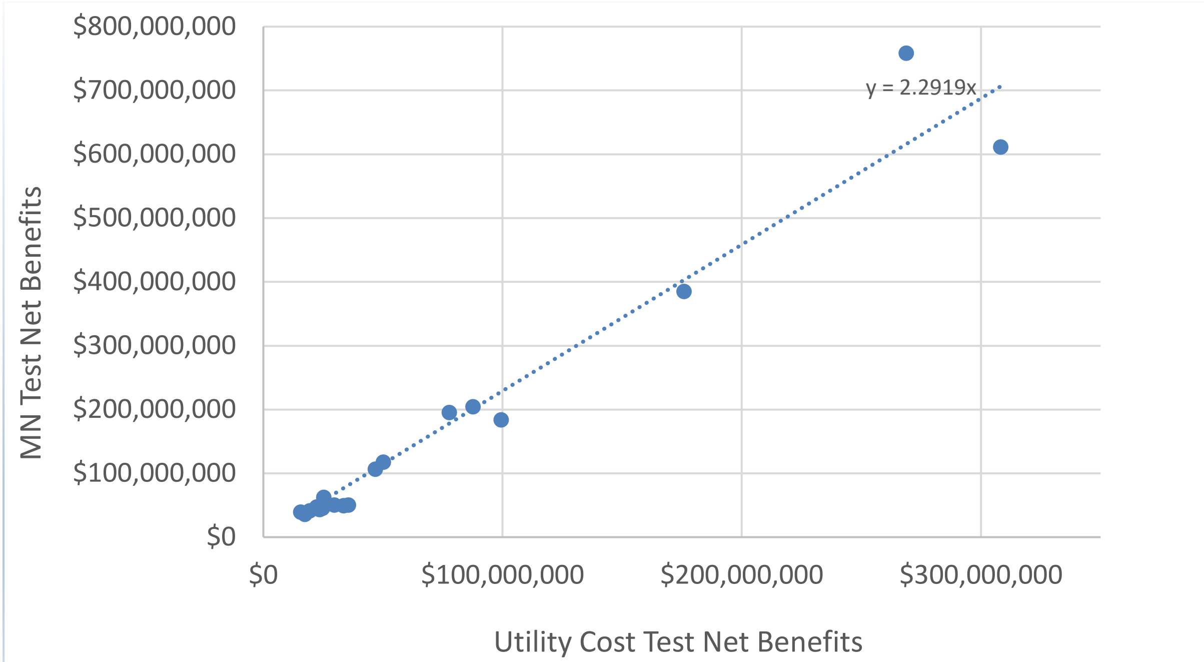
The Department asked utilities to calculate their Minnesota Test Net Benefits for the years 2019-2022 using the cost-effectiveness methodologies and avoided cost inputs approved by the Deputy Commissioner of the Department in the *Decision In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities* (Decision) filed on March 31, 2023 in Docket No. E,G999/CIP-23-46. The Department received responses from Xcel Energy (Electric and Gas Divisions), Minnesota Power, Otter Tail Power, CenterPoint Energy and Minnesota Energy Resources Corporation. Overall, we have 6 utilities over 3 years, which amounts to 18 data points. In the data that the Department collected from utilities, the share of MN Test Net Benefits awarded as incentives is 10%, which was the old Net Benefits Cap under the financial incentive mechanism for the 2021-2023 triennial. For some utilities, the calculations were incorrect, and we had to manually adjust the financial incentive to be 10% of MN Net Benefits. Thus, we set $p_{MN,i,t} = 0.1$ for all utilities $i$ and all periods $t$.

If we introduce a new coefficient $\gamma$ defined as $\gamma \equiv \frac{\beta}{1+p_{MN,i,t}} = \frac{\beta}{1.1}$, then we need to estimate the following equation:

$$MCTNB_{i,t} = \gamma \times UCTNB_{i,t} + \eta_{i,t},$$

with the variables and coefficients defined above. In order to estimate $\gamma$, we use the method of ordinary least squares, imposing a further constraint that the line of best fit must go through the origin. The scatterplot and the line of best fit are presented below:

**Figure C-1: Regression of MN Test Net Benefits on Corresponding Utility Cost Test Net Benefits for Minnesota Utilities in the Period 2019-2022**




As seen from the plot above, the OLS estimate for the coefficient $\gamma$ is $\hat{\gamma} \approx 2.29$, correct to 2 decimal places. As we had $\gamma \equiv \frac{\beta}{1.1}$, we get an estimate for the coefficient β: $\hat{\beta} \approx 1.1 \times 2.29 = 2.52$, correct to 2 decimal places. To put this in words, Minnesota Test Net Benefits are on average about 2.5 times higher than Utility Cost Test Net Benefits. Then our formula for converting Utility Cost Test Net Benefits to Minnesota Test Net Benefits is the following:

$$MCTNB_{i,t} = \frac{2.52}{1+p_{MN,i,t}} \times UCTNB_{i,t} + \eta_{i,t},$$

with all the variables as defined above. As $\eta_{i,t}$ is a zero-mean prediction error, we can take expectations on both sides and write the following:

$$MCTNB_{i,t} \approx \frac{2.52}{1+p_{MN,i,t}} \times UCTNB_{i,t}.$$

This is the formula we use to convert Utility Cost Test Net Benefits to Minnesota Test Net Benefits.

However, our goal is to convert the Utility Cost Test – Based Incentives Mechanism to one based on the new Minnesota Test. Suppose that the Department decides to award $p_{UCT}$ proportion of Utility Cost Test Net Benefits as incentives, and that the corresponding proportion of MN Test Net Benefits is $p_{MN}$, such that the overall financial incentive award is the same under both schemes:

$$Financial\ Incentive\ Award = p_{MN} \times MCTNB = p_{UCT} \times UCTNB$$

But we also derived the following: $MCTNB = \frac{2.52}{1+p_{MN}} \times UCTNB$. Combining these two equations, we get:

$$p_{MN} \times \frac{2.52}{1+p_{MN}} \times UCTNB = p_{UCT} \times UCTNB.$$

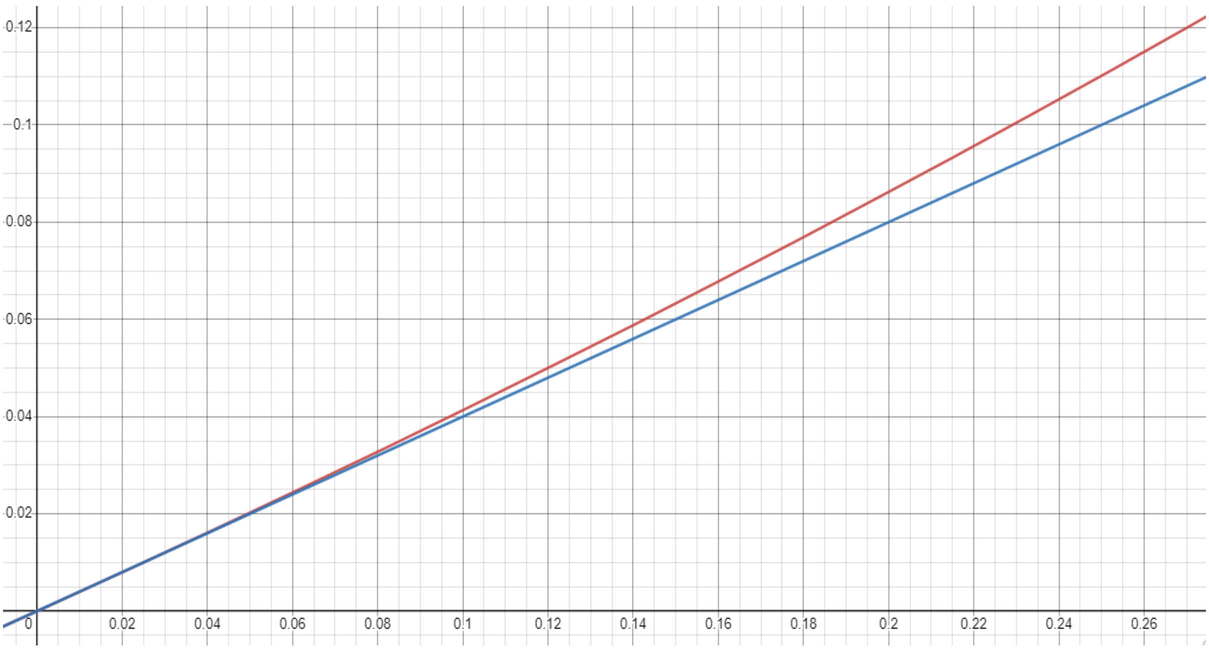
Cancelling UCTNB on both sides and rearranging terms, we get the following conversion formula:

$$p_{MN} = \frac{p_{UCT}}{2.52 - p_{UCT}}$$

In other words, the function converting Utility Cost Test – Based Incentive proportions to ones based on the Minnesota Test is $f(x) = \frac{x}{2.52-x}$. This function is nonlinear, caused by the fact that financial incentives depend on the level of MN Test Net benefits, which themselves depend on the level of financial incentives, referred to in this report as the "circularity issue". However, the Department suggests a linear approximation to this conversion function below.

Note that the proportions that the Department is considering range between 0 and 0.085. For these values, the function can be approximated linearly. At $x = 0$, the function evaluates to $f(x) = 0$, and at $x = 0.085$, it evaluates to $f(x) \approx 0.035$, thus the approximating line going through these points is $f(x) = 0.4x$. To see how well this line approximates the original conversion function, consider the figure below.

**Figure C-2: Linearization of the Nonlinear Conversion Function Used to Convert the Utility Cost Test – Based Incentives Scheme to a Scheme Based on the New Minnesota Test**



The red curve is the original conversion function $f(x) = \frac{x}{2.52-x}$, and the blue line represents the approximating linear conversion function given by $f(x) = 0.4x$. The figure shows this linear function does a near-perfect job of approximating the original nonlinear conversion function on the interval from 0 to 0.085 (0% to 8.5% correspondingly), which is the interval the Department is currently considering for incentive awards.

Finally, this gives rise to the following conversion formula:

$$p_{MN} \approx 0.4 \times p_{UCT},$$

where $p_{MN}$ is the proportion of Minnesota Test Net Benefits awarded as financial incentives, and $p_{UCT}$ is the corresponding proportion of Utility Cost Test Net Benefits awarded as incentives. Note that $p_{MN}$ and $p_{UCT}$ are proportions: to convert them to percentages, multiply by 100.

This conversion formula was used in Section III of this Report to construct a new Shared Savings DSM Financial Incentive Mechanism based on the new Minnesota Test.

| | |
|---|---|
| **From:** | Zoet, Adam (COMM) |
| **To:** | De, Adway (COMM) |
| **Subject:** | FW: Shared Savings Financial Incentive Mechanism Stakeholder Group |
| **Date:** | Wednesday, August 09, 2023 4:27:00 PM |
| **Attachments:** | Order Approving 2021-2023 Shared Savings Mechanism, Docket 08-133.pdf |

**From:** Davis, Christopher (COMM) <christopher.davis@state.mn.us>
**Sent:** Friday, December 9, 2022 3:46 PM
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**Subject:** Shared Savings Financial Incentive Mechanism Stakeholder Group

Good afternoon

Thanks for agreeing to participate in the 2024-2026 Shared Savings financial incentive mechanism stakeholder process.

Our original intent with this email was to seek input on a proposed timeline for the process, but as you will see below, we also made some straw proposal recommendations for some key components of the new mechanism.

**Factors That Will Impact the New Incentive Mechanism**

Crafting of the new incentive mechanism will require consideration of the following:

- The Commission's December 9, 2020 Order approving the 2021-2023 incentive mechanism in Docket No. E,G-999/CI-08-133,
- Implementation of the ECO act,
- Changes to the CIP cost-effectiveness tests, and
- Changes in gas and electric avoided costs.

**The Commission's December 9, 2020 Order (Attached to email)**

Order Point 4 from the Commission's Order regarding the 2021-2023 Shared Savings mechanism stated the following:

The Commission requests that the Department continue a stakeholder process, under the current docket, to evaluate ways of improving the shared-savings mechanisms for potential adoption in the 2024–2026 triennium including, but not limited to, discussion of:

a. incorporation of lifetime energy savings into the incentive mechanism,
b. incorporation of an incentive for utilities that achieve permanent peak reductions through the shared-savings incentive mechanism,
c. 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, and
d. energy efficiency opportunities to support increased load flexibility (the ability to persistently shape and shift load).

In addition, the Order contemplated further stakeholder development of an incentive tied to the performance of low-income energy efficiency programs.

**Department Straw Proposal Recommendations on Some Components of the 2024-2026 Shared Savings Incentive Mechanism.**

1. **Base the Shared Savings incentive on the version of the "Minnesota Test" approved by the Department**. The Department recommends this approach because it would:
    - Use the same cost-effectiveness test that the Department will use as the primary test for reviewing and approving CIP programs. This approach will help align the utility's desire for earning a financial reward with the Department's objective of promoting cost-effective energy efficiency programs.
    - Place more emphasis on lifetime energy and demand savings because the lower societal discount rate used in the Minnesota Test will place a higher value on energy savings, demand savings and GHG emissions achieved in later years.
2. **Provide an incentive to encourage gas utilities to promote efficient fuel switching (EFS) measures in years when the utility achieves energy savings above one percent of gross annual retail energy sales, excluding savings achieved through fuel-switching programs.** In the Shared Savings incentive, a gas utility could:
    a. Convert the annual increase in kWh of electricity into Btus;
    b. Convert the annual reduction in Dth of gas into Btus;
    c. Calculate the annual net reduction of Btus into Dth;
    d. Add the EFS measure's equivalent annual reduction in Dth to the gas utility's other first-year Dth savings,
    e. Calculate the EFS measure's lifetime net benefits and add these net benefits to the utility's Minnesota Test net benefits from traditional energy conservation improvements.
3. **Provide an incentive for load management programs if needed to increase the public utility's investment in cost-effective load management.** Minnesota Statutes 216B.2401 states:

    > "Load management" means an activity, service, or technology that changes the timing or the efficiency of a customer's use of energy that allows a utility or a customer to: (1) respond to local and regional energy system conditions; or (2) reduce peak demand for electricity or natural gas. Load management that reduces a customer's net annual energy consumption is also energy conservation.

- The Department recommends that the Minnesota Test's net benefits for load management that "reduce peak demand for electricity or natural gas" be incorporated into the Shared Savings incentive mechanism (which is allowed under Minnesota Statutes 216B.16, subd. 6c).

  The Department requests that stakeholders provide examples of load management that "responds to local and regional energy system conditions," and from Order Point 4 d, "energy efficiency opportunities to support increased load flexibility (the ability to persistently shape and shift load)" that could be approved under Minnesota Statutes 216B.241 Subd. 13 (d)-(h). *The Department request that stakeholders provide these examples and discuss the need for and recommendations for an incentive design by January 31, 2023.*

4. **The Department believes it may be premature to include a low-income program component to the 2024-2026 Shared Savings mechanism at this stage.** On May 18, 2020 Fresh Energy, National Housing Trust, and Natural Resources Defense Council submitted comments on the Department's proposal for the 2021-2023 Shared Savings financial incentive mechanism. The group recommended that the Commission modify the Department's proposal to include a low-income performance metric. In its December 9, 2020 Order Approving 2021-2023 Parameters for Shared Savings Demand-Side Management Financial Incentive Mechanism, the Commission stated:

> The Commission appreciates Fresh Energy, et al.'s proposal for an incentive tied to performance of low-income energy efficiency programs and will request that the Department continue a stakeholder process to evaluate this and other similarproposals. Although parties largely supported Fresh Energy, et al.'s ideas, there were some remaining questions that will need to be discussed by stakeholders before a low-income incentive can be implemented.
>
> The Commission anticipates that this stakeholder process will result in a well-developed proposal for a low-income energy efficiency incentive that could be implemented beginning in 2022.
> Although there are a number of questions that stakeholders will need to discuss, this timeline is intended to ensure that issues are resolved expeditiously.

Since the Commission's 2020 Order, the investor-owned utilities mandatory low-income CIP expenditure requirements were increased. For natural gas IOUs, the low-income spending requirement increased from 0.4% to 1% of residential gross operating revenue[1]. For electric IOUs the requirement went up from 0.2% to 0.4% (beginning 2022) and 0.6% (beginning 2024)[2]. At this point, there is not sufficient actual results of the legislation's impact on IOU low-income CIP programs to determine if a low-income performance incentive would be in the public interest.

**Analysis**

In the past the Department and stakeholders have provided analysis that helps illuminate the impact of future incentives. Below the Department lists suggestions for helpful analysis.

1. Figure showing actual first-year energy savings and actual Shared Savings incentive for each IOU for 2019-2021. *The Department will provide by December 21, 2022.*
2. Estimates of what the 2019-2021 Shared Savings incentives would have been for each IOU, under the assumptions of each utility's new avoided costs and using the Minnesota Test that will be approved by the Deputy Commissioner. *Could the utilities provide by March 31, 2023.*
3. In regard to Order Point 4c, by December 15, 2022 the Department will submit a request to IOUs to conduct an analysis for how a similar-sized (in terms of cost) supply-side investment would be rewarded financially through the cost-of-service model, and "alternative mechanisms." *The Department proposes a due date of January 16, 2023.*

**Other Due Dates**

- By January 31, 2023 stakeholders provide feedback on the contents of this memo, including the straw proposals, and proposed timelines.
- Stakeholder group meeting in the middle of April 2023 where Department would present analysis and draft proposal.
- Department files proposal in May 2023.
- Reply Comments due June 2023.
- Commission approves modified Shared Savings incentive mechanism before end of year 2023.

**Question**

Commission's Order Point 4 b states: incorporation of an incentive for utilities that achieve *permanent peak reductions* through the shared-savings incentive mechanism. The Department concludes that the only DSM measure that would provide "permanent peak reductions" would be energy conservation improvements that include peak demand savings. Do stakeholders know of measures that might qualify under this parameter? *Responses could be included in January 31, 2023 comments.*

*Best,*

*Chris*

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[1] Minn. Stat. §216B.241 subd. 7(a)

[2] Minn. Stat. §216B.241 subd. 7(a)

**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**
**Comments**

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

Dated this **1st** day of **September 2023**

**/s/Sharon Ferguson**

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| Samantha | Norris | samanthanorris@alliantenergy.com | Interstate Power and Light Company | 200 1st Street SE PO Box 351<br><br>Cedar Rapids,<br>IA<br>524060351 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |

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| James | Phillippo | james.phillippo@wecenergygroup.com | Minnesota Energy Resources Corporation | PO Box 19001<br><br>Green Bay, WI 54307-9001 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |
| Lisa | Pickard | lseverson@minnkota.com | Minnkota Power Cooperative | 5301 32nd Ave S<br><br>Grand Forks, ND 58201 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |
| Scott | Reimer | reimer@federatedrea.coop | Federated Rural Electric Assoc. | 77100 US Highway 71<br>PO Box 69<br>Jackson, MN 56143 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |
| Generic Notice | Residential Utilities Division | residential.utilities@ag.state.mn.us | Office of the Attorney General-RUD | 1400 BRM Tower<br>445 Minnesota St<br>St. Paul, MN 551012131 | Electronic Service | Yes | OFF_SL_8-133_E G99 CI-08-133 |
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| Bruce | Sayler | bruces@connexusenergy.com | Connexus Energy | 14601 Ramsey Boulevard<br><br>Ransey, MN 55303 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |
| Christine | Schwartz | Regulatory.records@xcelenergy.com | Xcel Energy | 414 Nicollet Mall FL 7<br><br>Minneapolis, MN 554011993 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |
| Will | Seuffert | Will.Seuffert@state.mn.us | Public Utilities Commission | 121 7th Pl E Ste 350<br><br>Saint Paul, MN 55101 | Electronic Service | Yes | OFF_SL_8-133_E G99 CI-08-133 |
| Jeffrey | Springer | jeff.springer@dairylandpower.com | Dairyland Power Cooperative | 3200 East Ave S<br><br>La Crosse, WI 54601 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Grey | Staples | gstaples@mendotagroup.com | The Mendota Group LLC | 1830 Fargo Lane<br>Mendota Heights, MN 55118 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |
| Robert | Walsh | bwalsh@mnvalleyrec.com | Minnesota Valley Coop Light and Power | PO Box 248<br>501 S 1st St<br>Montevideo, MN 56265 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |
| Ethan | Warner | ethan.warner@centerpointenergy.com | CenterPoint Energy | 505 Nicollet Mall<br>Minneapolis, Minnesota 55402 | Electronic Service | No | OFF_SL_8-133_E G99 CI-08-133 |