MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	December 7, 2023	Agenda Item **4

Company	All Electric Utilities		
Docket No.	E,G999/CI-08-133		
	In the Matter of Commission Review of Utility Performance Incentives for Energy Conservation		
Issue	Should the Commission approve the proposed modifications to the existing Shared Savings Demand-Side Management (DSM) Financial Incentive Mechanism for implementation beginning in 2024, as found in the Department of Commerce, Division of Energy Resources' September 1, 2023, comments?		
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✓ **Relevant Documents**	**Date**
Department, Comments	September 1, 2023
Department, Letter	September 26, 2023
Department, Information Requests	October 3, 2023
Minnesota Energy Resources Corporation, Comments	October 23, 2023
CenterPoint Energy, Comments	October 23, 2023
Minnesota Power, Comments	October 23, 2023

✓ **Relevant Documents**	**Date**
Otter Tail Power, Comments	October 23, 2023
OAG, Letter	October 23, 2023
Xcel Energy, Comments	October 23, 2023
Department, Reply Comments	November 2, 2023
Minnesota Power, Reply Comments	November 2, 2023
Minnesota Energy Resources Corporation, Reply Comments	November 2, 2023
Xcel Energy, Reply Comments	November 2, 2023
Referenced Documents, Previously Before the Commission	
Commission Order	December 9, 2020

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BACKGROUND

Issues Statement

In its December 7, 2023, agenda meeting, the Commission will consider whether to approve the Department of Commerce, Division of Energy Resources' (Department) proposed modifications to the existing Shared Savings Demand-Side Management (DSM) Financial Incentive Mechanism for implementation beginning in 2024.

Overview

The purpose behind the Shared Savings DSM Financial Incentive Plan (Shared Savings Plan) is to motivate Minnesota's investor-owned utilities (IOUs) to maximize cost-effective energy savings by providing the utilities with a portion of the net benefits created when IOU customers invest in utility-sponsored Conservation Improvement Program (CIP) and Energy Conservation and Optimization (ECO) projects. The Commission's December 9, 2020, Order approved the Shared Savings Plan Financial Incentive Mechanism for the 2021-2023 triennium and requested that the Department conduct a stakeholder process "to evaluate ways of improving the shared-savings mechanisms for potential adoption in the 2024-2026 triennium…"[1] The Department worked with the CIP Cost-Effectiveness Advisory Committee to gather stakeholder input and develop updates for the cost-effectiveness methodologies for the 2024-2026 triennial. On September 1, 2023, the Department filed comments with its proposed modifications.

Based on its analysis and conversations with stakeholders, the Department recommends that the Commission approve a 2024-2026 Shared Savings Plan with the following parameters:

1) 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 filed on March 31, 2023 in Docket No. E,G999/CIP-23-46 (Decision) for calculating their net benefits to derive their Shared Savings incentive.
2) 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.
3) 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.
4) 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.
5) Net Benefits Cap of 3.4%.
6) ECO/CIP Expenditures Cap of 15%.
7) 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.

Recommendations 1-2 were uncontested. Implementing recommendations 3-7 would constitute a reduction in financial incentives, and Xcel, Minnesota Power (MP), CenterPoint Energy (CenterPoint), Otter Tail Power (OTP), and Minnesota Energy Resources Corporation (MERC) each contested part or all of them, with the net benefits cap in recommendation 5 and expenditures cap in recommendation 6 garnering much debate. From Staff's perspective, the primary issues for the Commission are deciding appropriate net benefit and expenditure caps, as parties offered varying alternatives for each. An additional difficulty is that in using the Minnesota Cost Test (MCT), the Department must convert the current parameters under the Utility Cost Test (UCT) to what their equivalent would be under the MCT and then modify accordingly, but these conversions were subject to challenge from Xcel. The Office of the Attorney General – Residential Utilities Division (OAG) supports the Department's recommendations in whole.

[1] Commission Order, December 9, 2020, at Order Point 4

Under the Department's recommendations, the following provisions from the current Shared Savings Plan are maintained:

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.[2]

History of Shared Savings Plan

While allowing ECO/CIP cost-recovery may reduce a utility's disincentive to depress energy sales via conservation, it also does not affirmatively encourage the practice of promoting conservation. To that end, the Legislature authorized the Commission to approve a system of financial incentives to promote conservation, under Minn. Stat. § 216B.16, subdivision 6c. The statute requires the Commission to consider various factors in approving incentive plans, including:

(1) whether the plan is likely to increase utility investment in cost-effective energy conservation;
(2) whether the plan is compatible with the interest of utility ratepayers and other interested parties;
(3) whether the plan links the incentive to the utility's performance in achieving cost-effective conservation; and
(4) whether the plan is in conflict with other provisions of chapter 216.

[2] Department Reply Comments, November 2, 2023, at 4.

The Commission first implemented its Shared Savings DSM Financial Incentive Plan in 2000.[3] The incentive formula has changed over time, but currently, the formula includes thresholds, incremental incentives, and caps, which are the primary contested items the Commission is tasked with approving here. Thresholds require that utilities achieve a specified minimum level of savings before receiving incentive payments; above the threshold, utilities receive incremental incentives for each additional amount of energy saved. The incentive is capped in two ways—first, the incentive is capped at a certain percentage of the utility's investment in ECO/CIP projects (referred to as the Expenditures Cap), and second, the incentive is capped at a certain percentage of net benefits generated (referred to as the Net Benefits Cap). These parameters are discussed in Section III of the party discussion.

The enactment of the Energy Conservation and Optimization (ECO) Act on May 21, 2021 changed Minnesota's Conservation Improvement Program (CIP), now called ECO, in several ways, including:

- Energy savings from efficient fuel-switching programs can count towards aggregate savings used to calculate financial incentives for gas utilities.[4]
- The Commission may not approve a financial incentive to encourage efficient fuel-switching programs operated by a public utility providing electric service.[5]
- Load shifting and load management programs for peak demand reductions may be incorporated into the financial incentive mechanism.
- Electric utilities now have an annual energy savings goal of 1.75 percent (up from 1.5 percent) and gas utilities have an annual energy savings goal of 1 percent (down from 1.5 percent) of their respective normalized retail sales.

The Department noted that while the ECO Act lowered the savings goal from 1.5 percent to 1 percent for gas utilities, the Deputy Commissioner had a long-standing practice of approving minimum energy savings goals of 1 percent, per § 216B.214 subd. 1c,[6] so in essence it is unchanged under the Department's recommendation.[7]

In Attachment A, Staff summarizes the Department's analysis of past and current program

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[3] *In the Matter of Requests to Continue Demand-Side Management Financial Incentives Beyond 1998*, Docket No. E, G-999/CI-98-1759, Order Approving Demand-Side Management Financial Incentive Plans (April 7, 2000).

[4] Minnesota Statutes § 216B.241 Subd. 12 (d)

[5] Minnesota Statutes § 216B.241 Subd. 11 (c)

[6] A public utility, consumer-owned utility, or owner of a large customer facility may appeal a decision of the commissioner under paragraph (a) or (b) to the commission under subdivision 2. In reviewing a decision of the commissioner under paragraph (a) or (b), the commission shall rescind the decision if it finds the decision is not in the public interest.

[7] Department Comments, September 1, 2023, at 17.

incentives and savings. The analysis shows that after steadily increasing from 2006 to 2016, average incentives have declined since 2016 for electric and gas utilities, but the decline in incentives has not had a corresponding decline in average savings, which have remained at a high level in the historical context. Over the period 2017-2022, total benefits to Minnesota's electric and gas IOU customers were $1.59 billion and $800 million, respectively.[8]

Record to Date

On September 1, 2023, the Department filed comments with its proposed modifications.

On September 26, 2023, the Department filed a letter clarifying a mistake made in the proposal.

On October 3, 2023, the Department filed responses to 11 information requests (IRs) from Xcel.

On October 23, 2023, CenterPoint, MP, MERC, OTP, Xcel, and the OAG filed comments.

On November 2, 2023, the Department, MP, MERC, and Xcel filed reply comments.

DISCUSSION

I. Uncontested Recommendations

A. Minnesota Cost-effectiveness Test

Utilities have used cost-effectiveness tests established by the California Standard Practice Manual (CaSPM)[9] for more than 30 years. The CaSPM set parameters for assessing programs based on different perspectives: participants, non-participants, all ratepayers, society, and the utility. Historically, IOUs in Minnesota have been using four traditional benefit-cost tests of the CaSPM: the Societal Cost Test (SCT), the Utility Cost Test (UCT), the Participant Cost Test (PCT), and the Ratepayer Impact Measure Test (RIM). Specifically, the Department has considered the SCT as the Primary Test for CIP cost-effectiveness screening, while the other three tests function as secondary tests that provide additional data about utility programs and portfolios. In practice, the traditional CaSPM tests have certain deficiencies, including insufficiency to capture or address pertinent state policies, ad-hoc modifications without clear principles or guidelines, inaccuracy to value efficiency, and lack of transparency in choosing different tests.[10]

[8] Department Comments, September 1, 2023, at 14-16.

[9] National Energy Screening Project (NESP), National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM for DERs), August 2020. Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-04-2020_Final.pdf.

[10] Department *Decision*, in Docket No. 23-46, March 31, 2023, at 3.

Per the Department's February 11, 2020 Decision, the Cost-Effectiveness Advisory Committee (CAC) worked to develop CIP's new primary cost-effectiveness test, which is termed the Minnesota Cost Test (MCT), to answer the question: Which resources have benefits that exceed costs and therefore merit utility acquisition or support on behalf of their customers?[11] Throughout 2022, the Department worked with the CAC to update the cost-effectiveness methodologies that will apply to the 2024-2026 triennial. The new MCT is 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.

The Department recommends that all CIP net benefits for all utilities be evaluated using the MCT and claims it has the following advantages relative to the UCT:

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.
3) The Minnesota Test uses a lower discount rate to value the future relative to the UCT.[12]

The OAG supports the implementation of the MCT and additionally stated it is reasonable to align the cost-effectiveness test and societal discount rate, considered in the next subsection, used in the shared-savings incentive with those that the Department uses in evaluating utilities' portfolios. [13]

Xcel Energy agrees with the Department's proposal to shift to the new Minnesota Test, both for consistency and the inclusion of the value of avoided greenhouse gas emissions that encourages utilities to pursue not only high energy savings, but also savings which maximize value to customers and the climate.[14]

CenterPoint is neutral on the switch from the UCT to the MCT.[15]

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[11] "National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM for DERs) – Overview", p.15.

[12] Department Comments, September 1, 2023, at 1-2.

[13] OAG Comments, October 23, 2023, at 1-2.

[14] Xcel Comments, October 23, 2023, at 2.

[15] CenterPoint Comments, October 23, 2023, at 14.

The Commission can adopt the MCT with **Decision Option 1A**.

B. Societal Discount Rate

Historically, the UCT uses the individual utility discount rates. For example, the applicable rates are 5.34% for Xcel Gas, 5.39% for CenterPoint, and 5.57% for MERC. The Department proposes to use the Societal Discount Rate of 3.3% as approved by the Deputy Commissioner to calculate the MCT Net Benefits[16], which is significantly lower than any of the individual utility discount rates. This largely increases net benefits of the MCT as compared to the old UCT, and as discussed in Section II, the Department's proposed parameters are lower in part to account for this adjustment.

The OAG supports adoption of the Societal Discount Rate.[17] CenterPoint is neutral on the Societal Discount Rate.[18] No other party commented on the rate.

The Commission can adopt the societal discount rate with **Decision Option 1B.**

II. Contested Recommendations

Parties debated the appropriate levels at which benefits were earned, the cap on the amount of benefits that can be earned, and the expenditures cap.

A. Incentive Thresholds and Incremental Benefits

The incentive thresholds determine the minimum level of avoided sales at which the utility begins earning net benefits and the maximum level at which the net benefits cap is avoided. Between the minimum level and maximum, also referred to as the high achievement threshold, there is an incremental increase in the percentage of net benefits awarded for each additional .1% of sales avoided.

Electric IOUs

Because the ECO Act increases the energy savings goals for electric utilities from 1.5% to 1.75%, the Department recommends increasing the minimum level of kWh savings required to trigger financial incentives from 1% to 1.3% of the electric utility's retail sales and to award the utility

[16] Net benefits refer to the present value of utility supply-side costs (e.g., generation, transmission, and distribution costs) minus utility CIP costs. For the 2024-2026 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.

[17] OAG Comments, October 23, 2023, at 2.

[18] CenterPoint Comments, October 23, 2023, at 14.

1.3% of net benefits.[19] The Department additionally proposes increasing the point at which electric utilities achieve maximum net benefits from 1.7% currently to 2%. For each additional .1% of sales achieved above 1.3% and until 2%, the utility would receive an additional .3% of net benefits, up to the net benefits cap discussed in the next subsection.

Table 1: Electric Utilities Incremental Incentives (Department Proposal)

Percent of Retail Sales Avoided	Percent of Net Benefits Awarded
0-1.2%	0%
1.3%	1.3%
1.4%	1.6%
1.5%	1.9%
1.6%	2.2%
1.7%	2.5%
1.8%	2.8%
1.9%	3.1%
2.0% and greater	3.4% (net benefits cap)

Xcel stated that because of “the statute’s indication that the incentive should encourage ‘vigorous and effective’ performance,” the Company recommends a higher threshold than the Department, setting it at 1.5% of retail sales instead of 1.3% and raising the high achievement threshold to 2.2% instead of 2%.[20] Xcel did not comment on the incremental rate of .3%. Their recommendations for higher thresholds were paired with higher net benefit and expenditure caps, as discussed in Section II.B and II.C

Gas IOUs

The Department recommends maintaining the current .7% for initial and 1.2% threshold for max net benefits for gas utilities, as the ECO Act essentially left the gas savings goals the same. The Department proposes an incremental increase of .3% for each additional .1% of retail sales avoided, until the net benefits cap is reached.[21]

[19] Department Comments, September 1, 2023, at 17.

[20] Xcel Comments, September 1, 2023, at 17.

[21] Department Comments, October 23, 2023, at 3.

Table 2: Gas Utilities Incremental Incentives (Department Proposal)

Percent of Retail Sales Avoided	Percent of Net Benefits Awarded
0-.6%	0%
.7%	1.9%
.8%	2.2%
.9%	2.5%
1%	2.8%
1.1%	3.1%
1.2%	3.4% (net benefits cap)

CenterPoint did not contest the thresholds of .7% and 1.2%, but rather contested the gradient, minimum, and maximum of net benefits awarded. They recommend a gas utility receive 2% of net benefits at .7% of sales instead of 1.9% and that for each additional 0.1% of energy savings, the share of net benefits awarded to be increased by additional 0.5% instead of .3% until the net benefits cap is reached.[22] CenterPoint's recommendation of the .5% increment is in part tied to their net benefits cap, discussed in the next section.

No other party commented on the incentive thresholds.

Staff Comment

From Staff's perspective, the Commission's task of deciding the thresholds here, and other parameters discussed below, is as much an art as a science. While Staff does not mean to imply the proposals are arbitrary, the Department and Xcel are also not providing a mathematical rationale for why a parameter should specifically be 2% or 2.2%, and determining which thresholds to implement in 2024-2026 may make most sense in conjunction with approving the other parameters as a broader policy decision that continues the historical trend of decreasing the incentives, as the Department is proposing, maintains the status quo as the utilities desire, or potentially implements a set of parameters that represent a compromise between the Department/OAG and utility positions.

Staff also notes that the higher threshold level is closely connected to the net benefits cap and higher potential expenditures cap, which would be triggered at 2% for an electric utility and 1.2% for gas under the Department's proposal.

B. <u>Net Benefits Cap</u>

The proposed net benefits caps, which implement a ceiling on the maximum share of benefits utilities can earn, are the most heavily contested aspect of the proposal. The electric utility net benefits caps proposed by parties are covered by **Decision Options 1C-1F**. The gas utility net

[22] CenterPoint Comments, October 23, 2023, at 13.

benefits caps proposed by parties are covered by **Decision Options 1G-1J**.

Electric IOUs

Under the MCT, the Department estimated that benefits are 2.5 times higher and asserted that the current net benefits cap of 10% is approximately equivalent to 4% if the Commission implements the new test. On the basis of using the new test, the Department recommends lowering the net benefits cap for electric IOUs from 4% to 3.4%. Xcel recommends a cap of 5.5%, which the Company argued is equivalent to 10% under the UCT, and OTP recommends utility-specific caps. As discussed above, the cap would trigger when utilities reach the maximum benefits threshold, which the Department proposes to be 2% of retail sales for electric IOUs, while Xcel proposes 2.2%.

The Department did not explicitly state the reasoning for the size of the reduction in the proposal (-.6%), but in response to an IR from Xcel, explained that the Department is "continuing the trend of marginally ratcheting down the performance incentive and expects energy savings to continue to grow for gas and electric utilities."[23] The historical decrease is discussed in detail in Attachment A. In addition to this historical trend of reduction, part of the Department's rationale for a broad reduction in incentives is based on a comparison with incentives and savings in other states. Table 3 compares the average performance incentives (column 3) for Minnesota with selected other states. The last column shows each state's respective ranking from the American Council for Energy-Efficient Economy (ACEEE). The Department observed that Minnesota currently has a high average incentive relative to other states, including some that are ranked more highly than Minnesota in energy efficiency, and emphasized that the proposal would continue to be high relative to what other states have previously implemented.[24] They also offered a caveat that because the MCT is unique in the way it calculates net benefits, "it is difficult to find a relevant point of comparison with another state" and that the Department "is not aware of other states that include the same cost benefit categories as the MN Test."[25]

[23] Department Response to Xcel IR 7, October 3, 2023.

[24] Department Comments, September 1, 2023, at 37.

[25] *Id*, at 39.

Table 3: Comparison of Average Performance Incentives per First-Year kWh Saved between Minnesota and Other States with High Energy Efficiency Performance[26]

Utility/State	Period	Average $/kWh	ACEEE State Scorecard
MN	2020-2022	$0.039	#10
MN (Proposed)	2024-2026	$0.031	
CT	2019-2021	$0.028	#9
National Grid RI	2019-2021	$0.028	#7
MA	2019-2021	$0.027	#2
Xcel CO	2019-2022	$0.026	#13
SCE CA	2017-2019	$0.010	#1

In compliance with the Commission's Order, the Department also conducted an analysis comparing the current financial incentives to supply-side investments and found that the current incentives are "extremely generous" to both the electric and gas utilities.[27] This analysis is discussed in detail in Section IV.C.

Xcel, MP, and OTP all oppose the proposed net benefits cap and contested the Department's comparison with other states as justification. Xcel highlighted that in previous discussions in the docket, parties have disputed the applicability of comparing to other states by considering incentives per unit of energy saved or a percent of net benefits, because such comparisons ignore the cost of the efficiency programs themselves, as CenterPoint argued in 2015.[28] Xcel noted the Department acknowledged this in a 2015 report in the instant docket.[29] Further, they explained that while Massachusetts may have a performance incentive of 5.7% of their energy efficiency budgets, the budget was nearly $2 billion for electric programs, and the savings goal of 2.7% of sales is not "dramatically different from those proposed by Minnesota utilities, even as the program budgets are an order of magnitude higher in Massachusetts."[30] Xcel provided the following table comparing the cost of electric efficiency programs per first-year kWh saved.

[26] *Id*, adapted from Table 8.

[27] *Id*, at 35.

[28] Xcel Comments, October 23, 2023, at 8. Quoting CenterPoint Comments, August 17, 2015.

[29] Department of Commerce, A Report on the Impacts of the 2010-2014 Shared Savings Demand-Side Management (DSM) Financial Incentive on Investor-Owned Utility Conservation Achievements and Customer Costs in the current docket, July 14, 2015, at 38.

[30] Xcel Comments, October 23, 2023, at 8.

Table 4: Total Cost of Electric Energy Efficiency Programs per first-year kWh Saved[31]

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

Xcel concluded that if the existing mechanism awards Minnesota's utilities at a higher level than other states, "there is a simple and obvious explanation: Minnesota's utilities are doing a better job at saving energy at a low cost to customers than are utilities in other states."[32]

OTP also challenged the comparison with other states as a basis for reducing incentives. OTP explained that the ACEEE energy efficiency rankings are based on multiple categories, including transportation policies, building energy efficiency policies, and state government initiatives.[33] The "utility and public benefits" category, which analyzes energy savings, efficiency standards, and performance incentives, is only 30% of the weight, and Minnesota ranks fourth overall behind California, and Massachusetts, and Rhode Island.[34] OTP also noted that in the ACEEE's 2021 report, "The Cost of Saving Electricity for the Largest Utilities: Ratepayer-Funded Efficiency Programs in 2018," which is the most recent such report OTP could find, Xcel Minnesota spends much less per kWh saved than utilities in other high performing states like Connecticut, Massachusetts, and California.[35] This comparison is illustrated in Figure 1.

[31] Xcel Comments, October 23, 2023, at 9 (Table 1).

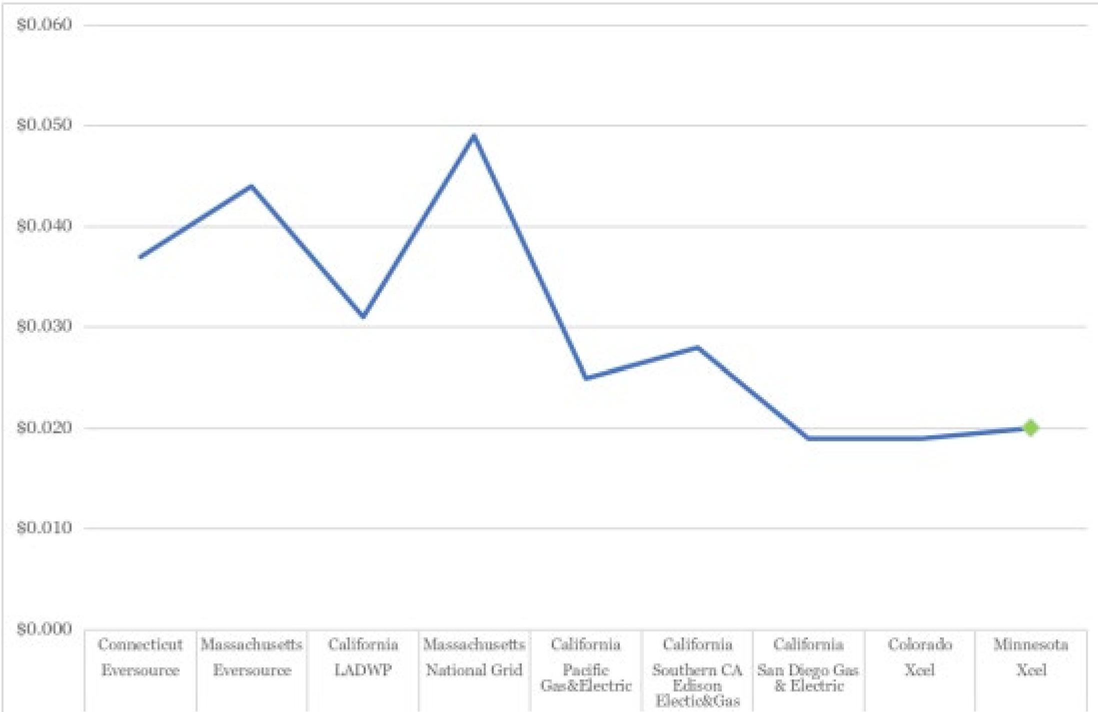
[32] *Id*, at 11.

[33] https://www.aceee.org/sites/default/files/pdfs/u2206.pdf

[34] OTP Comments, October 23, 2023, at 11.

[35] https://www.aceee.org/sites/default/files/pdfs/cost_of_saving_electricity_final_6-22-21.pdf

Figure 1: Levelized Cost per kWh Saved (2018)



Last, OTP argued that much of the higher benefits in other states is a product of their much higher retail electricity prices, which gives them a larger avoided cost from gains in energy efficiency. OTP noted that Minnesota, while ranked 15th, has much lower prices than the other states in the above comparisons, with California having 77% higher prices for example. Table 5 shows a comparison of electricity prices for the discussed states from the EIA in 2021.[36]

Table 5: Electricity Price and Expenditure Estimates (2021)[37]

State	Rank	Prices (Dollars per BTU)				
		Residential	Commercial	Industrial	Transportation	Total
CA	3	66.89	56.21	43.43	34.57	57.75
MA	4	67.09	49.79	44.49	19.09	55.85
RI	5	65.36	45.45	47.06	57.88	54.05
CT	6	64.21	48.25	28.24	36.63	53.7
MN	15	39.57	32.88	24.3	30.43	32.65

[36] https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_fuel/html/fuel_pr_es.html&sid=US

[37] Adapted from OTP Comments, October 23, 2023, at 14 (Table 3).

MP argued that a historical trend of reduction should not be justification for further reduction sans a strong argument for why this trend should continue.[38] In reply comments, they supported OTP and Xcel's arguments that the comparison with other states "does not show the whole picture" by not fully considering the cost to deliver high levels of savings and agreed that Minnesota utilities have kept costs low while delivering energy savings.[39]

Instead of a reduction from 4% to 3.4%, Xcel proposes a net benefits cap of 5.5% for electric utilities. Xcel agreed that a net benefits cap of 4% of MCT was comparable to the existing 10% of UCT according to the Department's analysis of 2019-2022, except that it did not account for ongoing trends in emissions and would penalize utilities that have worked to add more clean energy to their system. One significant difference between the UCT and MCT is the inclusion of the value of avoided carbon emissions in the MCT, and Xcel argued that "as electric utilities have made and continue to make progress in reducing emissions from electricity generation, the emissions avoided through energy efficiency have and will continue to decline, reducing the difference between the UCT and MT net benefits."[40] To account for this, Xcel suggests a nominal increase to the net benefits cap from 4% to 5.5%.[41] In other words, Xcel is proposing a parameter the Company argues would keep the net benefits cap the same, adjusting for the new test and trends in emissions.

OTP also opposes the Department's proposed net benefits cap and suggests that the Commission approve a utility-specific net benefits cap, which they argued is supported by Minn. Stat. § 216B.16.[42,] OTP highlighted that the Department's supply-side analysis, discussed in Section IV.C, showed they are the only electric utility whose current financial incentive pays less than supply-side investments. They noted that under Minnesota Statute, a required criteria for the mechanism is that "implementation of cost-effective conservation is a preferred resource choice" for the utility, which OTP asserted is not the case if the Department projected they would earn less than through supply-side investments. As such, they request a higher cap of 8.6% for themselves. [43]

MP does not object to the utility-specific proposal raised by OTP but stated further record

[38] MP Comments, October 23, 2023, at 3.

[39] MP Reply Comments, November 2, 2023

[40] Xcel Comments Attachment A, October 23, 2023, at 6.

[41] Xcel Comments, October 23, 2023, at 17.

[42] "The Commission may: adopt any mechanism that satisfies the criteria of this subdivision, such that implementation of cost-effective conservation is a preferred resource choice for the public utility considering the impact of conservation on earnings of the public utility." Minnesota Statute § 216B.16 (6c)(c)(3)

[43] OTP Comments, October 23, 2023, at 7.

development would be needed to do this[44] and supports caps of at least 5% to maintain the current level, after adjustment with the MCT.[45] MP did not elaborate on the conversion of the net benefits cap from 10% under the UCT to 5% under the MCT, as opposed to the Department's conversion of 4%, but stated that a higher cap may be appropriate due to inflation.

The OAG agreed with the conclusion of the Department's analysis that Minnesota utilities receive higher incentives than those awarded in states with similar conservation programs and supports the Department's recommendations in whole. The OAG stated that the proposal "will ensure that the incentive continues to encourage utility investment in cost-effective energy conservation- and will protect ratepayers from overpaying for that investment."[46]

In reply comments, the Department maintained that the utilities receive a generous financial incentive relative to other states and argued that the utilities' focus on cost is too narrow an approach for considering achievements in energy efficiency. For example, they noted that "while it is true that Massachusetts, Rhode Island and Connecticut spend more dollars per unit of energy saved, these states also have an older housing stock compared to Minnesota."[47] Further, the Department noted that each time the Commission considers reducing the incentives, the utilities have stated this will reduce savings. However, the Department highlighted that their historical analysis, summarized in Attachment A, demonstrated the utilities have continued to achieve a high level of savings despite gradual reductions in the program since 2016.[48]

Gas IOUs

The Department's proposed net benefits cap of 3.4% also applies to all gas utilities. CenterPoint, MERC, and Xcel oppose the cap. CenterPoint recommends a cap of 4.5%, Xcel recommends a cap of 4%, and MERC recommends a cap of at least 5%.

As with the electric utilities, the Department compared the average incentive in Minnesota for gas utilities with selected other states and their ranking in energy efficiency, illustrated in Table 6 below. They again highlighted that Minnesota has larger incentives than other states rated more highly in efficiency, with only Xcel CO having larger incentives from 2020-2022.

[44] MP Reply Comments, November 2, 2023, at 3.

[45] MP Comments, October 23, 2023, at 3.

[46] OAG Comments, October 23, 2023, at 3.

[47] Department Reply Comments, October 23, 2024, at 15.

[48] Department Reply Comments, October 23, 2023, at 14.

Table 6: Comparison of Average Performance Incentives per First-Year kWh Saved between Minnesota and Other States with High Energy Efficiency Performance[49]

Utility/State	Period	Average $/Dth	ACEEE State Scorecard
MN	2020-2022	$4.22	#10
MN (Proposed)	2024-2026	$3.52	
CT	2019-2021	$3.60	#9
National Grid RI	2020-2022	$3.42	#7
MA	2019-2021	$2.17	#2
Xcel CO	2019-2022	$4.73	#13
SoCalGas CA	2017-2019	$0.40	#1

Xcel again contested the comparisons to other states as rationale for reducing incentives. In Table 7, they show that Xcel Minnesota has a much lower average total cost per Dth than RI, MA, CT, and CT, and a slightly lower average than Xcel Colorado. Xcel recommends the Commission maintain the cap at 4%, accounting for the conversion from the UCT to MCT and noted that their point discussed in the previous section about emission trends is less applicable in the case of gas. Xcel stated the old mechanism does not need an adjustment because it "has been successful at motivating highly effective and highly cost-effective programs."[50]

Table 7: Total Cost of Gas Energy Efficiency Programs per First-Year Dth Saved[51]

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

Like the other utilities, MERC contested the applicability of the state comparisons as justification for reducing the cap, and regarding the higher scores in other states, MERC argued that the "Department fails to account for the distinctive regulatory environments that these

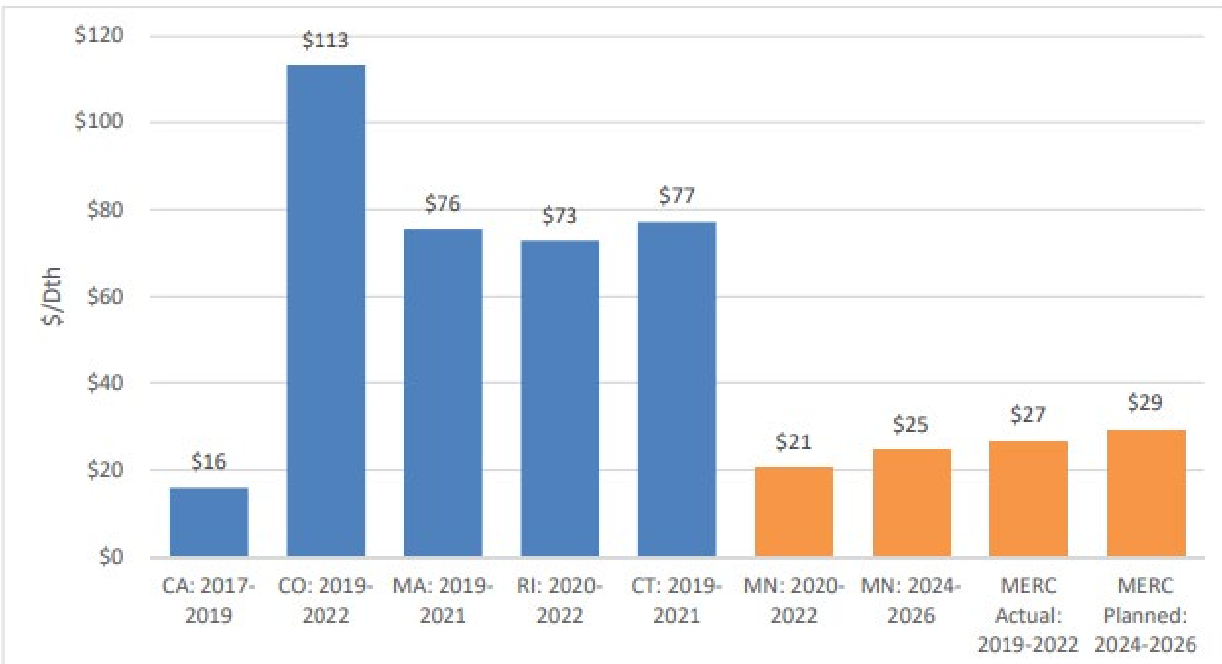
[49] Department Comments, September 1, 2023, adapted from Table 9.

[50] Xcel Comments, October 23, 2023, at 17.

[51] Xcel Comments, October 23, 2023, at 9 (Table 2)

utilities operate in, including overall program budgets and expenditures, and different incentive mechanisms and spending rules."[52] They noted that the Department's analysis did not evaluate the total program budgets in other states, and stated that "it could be argued that utilities with higher program budgets per savings need less of an 'incentive' to drive program performance."[53] In Figure 2, MERC provided a comparison of natural gas program budgets or expenditures per dekatherm over annual natural gas savings for various states.[54] They observed that using this metric, MERC is substantially lower than all comparison states other than California.

Figure 2: Comparison of Portfolio Program Planned and Actual Cost of First Year Energy Savings ($D/th)



MERC also highlighted that the Department is forecasting an approximately 50% reduction in incentives for MERC, which is discussed in the forecasted impacts in Section III, and recommend that their net benefits cap should not be less than 5%. MERC clarified that this could be applied

[52] MERC Comments, October 23, 2023, at 7.

[53] *Id*, at 8

[54] MERC explained that "utility performance incentive data points for CA, CO, MA, RT, and CT were provided by Department Staff, while the utility performance incentive data for MI is sourced from Consumer Energy Company and DTE's annual reports. Gas DSM Budget data points for CA, CT, MA, and RI were provided by Department Staff, while CO and MI were sourced from their annual reports. Utility revenue data is sourced from the United States Energy Information Administration (EIA) data." October 23, 2023, at 8 (Figure 1).

uniformly or specifically to them given their reduction is forecasted to be proportionately larger.[55]

Also in opposition, CenterPoint argued that the proposal would fail to meet the state's goal to incentivize the creation and delivery of cost-effective energy efficiency programs and might discourage utilities from pursuing maximization of net benefits through year-to-year program implementation improvements and long-term program design innovation.[56] CenterPoint additionally contested the state comparisons and argued that these can "conflate 'over rewarding' with 'underperformance.'"[57] CenterPoint provided the following chart which includes states from the Department's comparison and other selected Midwest states.

Figure 3: 2019-2021 Average Energy Efficiency Performance of Natural Gas Utilities, Average Annual Dth Savings (bubble size)[58]

[55] MERC Comments, October 23, 2023, at 10.

[56] CenterPoint Comments, October 23, 2023, at 2.

[57] *Id*, at 7.

[58] *Id*, (Figure 3).

CenterPoint highlighted that Minnesota outperforms the other Midwest states other than Michigan and argued that Minnesota's financial incentive mechanism is preferable to high-cost, high-savings states like Connecticut and Rhode Island and low-cost, low-savings states like Wisconsin and Illinois.

Instead of reducing the cap, CenterPoint recommends that the Commission approve a net benefits cap of 4.5% to keep the consistency on incentivizing utilities during the 2024-2026 Triennial plan and argued that this number is based on the Department's own analysis to convert from the old 10% UCT net benefits cap to 4%, with an additional adjustment for inflation.[59]

In reply comments, the Department maintained its support for the original proposal of a 3.4% net benefits cap. The Department argued that the decrease in the net benefits cap would not disincentivize utilities' energy savings in that the adoption of the MCT and the ECO Act significantly expanded the number of energy efficiency programs in their Triennial plan, including load management (LM) and efficient fuel-switching (EFS) measures, which were previously prohibited from being included in old UCT, and that their inclusion will increase the amount of energy savings in the state. The Department further emphasized that the Commission has been reducing the financial incentive over the past few Triennials, and while the utilities had opposed the reduction each year, their analysis demonstrated that Minnesota has seen continued high levels of energy savings.[60]

Regarding the potential for a 47% reduction in MERC's incentives, the Department explained that "the fall in projected incentives for MERC's incentive is largely due to the projected underachievement relative to their proposed goals."[61] The Department stated that if MERC achieves their goals for the 2024-2026 triennial, the reduction would only be 17% compared to 2020-2022.

Staff Comment

It is unclear to Staff if the electric utilities, in proposing higher net benefit caps, are also implicitly requesting adjustments to the minimum (1.3%) and incremental (.3%) net benefits discussed in II.A. Once again, under the Department's proposal, the benefits would escalate as follows for electric utilities:

[59] *Id*, at 12-13.

[60] Department Reply Comments, November 2, 2023, at 14.

[61] *Id*, at 19.

Table 8: Electric Utilities Incremental Incentives

Percent of Retail Sales Avoided	Percent of Net Benefits Awarded
0-1.2%	0%
1.3%	1.3%
1.4%	1.6%
1.5%	1.9%
1.6%	2.2%
1.7%	2.5%
1.8%	2.8%
1.9%	3.1%
2.0% and greater	3.4% (net benefits cap)

As shown in the second column, the benefits awarded increase at an increment of .3% until the net benefits cap is reached, but the utilities do not propose a similar gradient. For example, Xcel proposes a net benefits cap of 5.5% for electric utilities, with a minimum incentive threshold of 1.5% and a maximum of 2.2%. If the uncontested .3% gradient was maintained and the utilities were earning the also uncontested minimum 1.3% of net benefits at 1.5% of sales, then the utility would only be at 3.4% of net benefits at 2.2%, not 5.5%, unless there was a jump to 5.5% once that level was reached. In other words, Staff believes if the Commission wishes to adjust the net benefits cap using Xcel's, MP's, or OTP's proposals, then the incremental and minimum levels need a corresponding adjustment to be a sensible ladder. In the case of gas, CenterPoint has proposed corresponding adjustments that align the other levels with their maximum net benefits proposal, whereby the benefits increase at a rate of .5% from a minimum of 2% up to 4.5%, so the Commission would not necessarily need to make an adjustment. For MERC's proposed 5%, there would need to be an adjustment.

C. Expenditures Cap

The expenditures cap acts a ceiling on potential earnings measured as a percentage of program expenditures, and like the net benefits cap, is a heavily contested issue. The expenditures caps proposed by parties for all utilities are covered by **Decision Options 1K-1N**.

Electric IOUs

The Department proposes an expenditure cap of 15% for the electric utilities, which is a reduction from 30% previously, and proposes that the cap can be increased to 20% if savings of 2.0% of retail sales are achieved.[62] If the Commission chooses different maximum achievement thresholds (Section II.A), the point at which the higher expenditures cap triggers would be the new high achievement threshold. Xcel proposes a higher cap of 20% and 25% if utilities exceed

[62] Department Comments, September 1, 2023, at 1.

the high-achievement thresholds.[63] MP opposes the continued implementation of an expenditure cap, but if it is included, recommends no lower than 20%.[64] OTP also opposes a spending cap, but if it is to be maintained, recommends a 22% expenditures cap.[65]

As with the reduction in the net benefits cap, the Department justified its proposal in part on the comparison with other states, and the applicable arguments from the Department and the utilities on the relevance of those comparisons are largely the same as those discussed above in Section II.B. Like with the net benefits cap, the Department asserted that a reduction in the expenditures cap is also warranted due to the historical trend of reductions, the inclusion of additional benefits in the MCT, and the expansion of eligible energy efficiency measures under the ECO Act.[66]

MP noted that the expenditures cap was first introduced in the 2017-2019 triennial and has decreased from 40% in 2017 to 30% today. MP argued that expenditure caps introduce "potentially conflicting signals and can detract from the focus on achieving higher net benefits" and stated the Department's proposal to reduce the cap from 30% to 15% "may render the net benefits cap meaningless for most utilities." [67] MP supports removing the cap, and if it is to be maintained, they recommend a cap that is no lower than 20%.

Xcel explained that their proposal of 20% with the possibility for 25% would continue the trend of reducing the cap but would be less "dramatic" than the Department's proposal.[68] Xcel's concerns about comparing with other states were captured in the previous section.

OTP has opposed a spending cap since it was first applied in Minnesota in 2017. OTP argued that including both a percent of net benefits cap and expenditures cap creates conflicting signals to run cost-effective programs, and therefore is "ultimately in conflict with Minnesota Statute §216B.16 Subd. 6c, which contains guidelines for the Commission to establish a financial incentive based on cost-effective of program performance."[69] To illustrate the conflicting incentives, OTP provided the following chart.

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[63] Xcel Comments, October 23, 2023, at 18.

[64] MP Comments, October 23, 2023, at 4.

[65] OTP Comments, October 23, 2023, at 9.

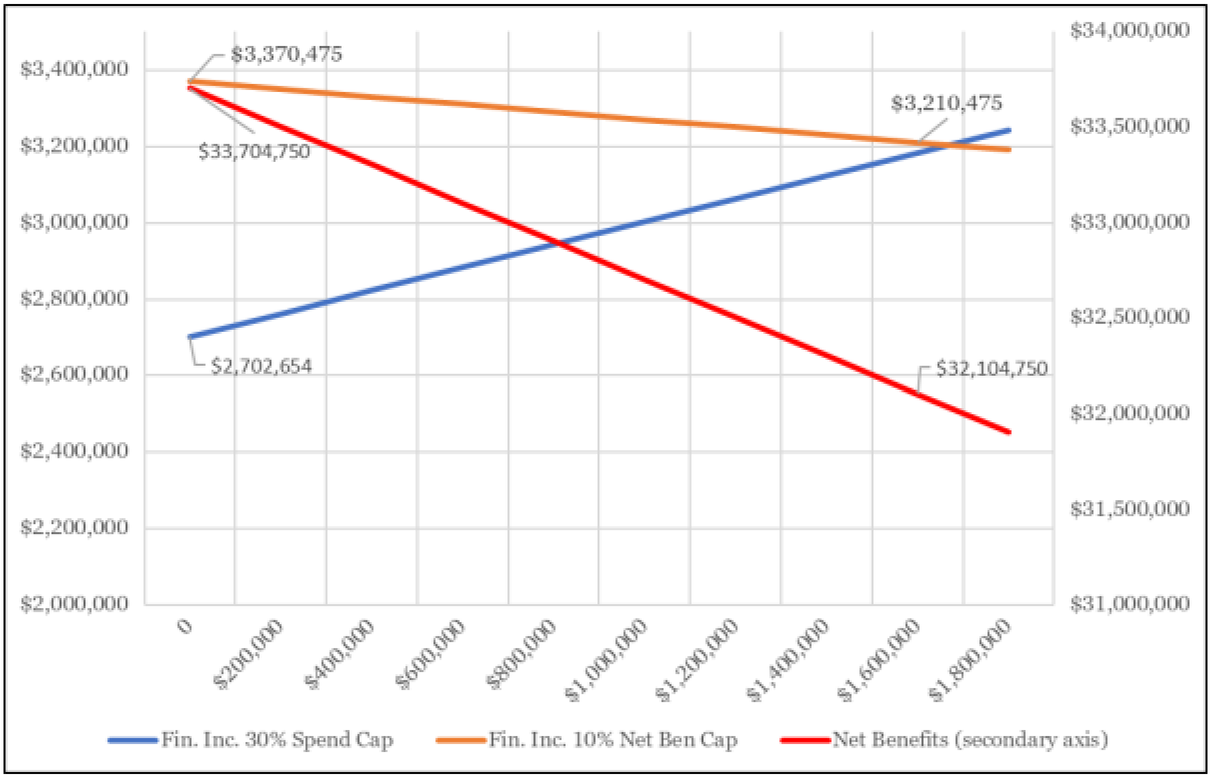
[66] Department Reply Comments, November 2, 2023, at 14.

[67] MP Comments, October 23, 2023, at 4.

[68] Xcel Comments, October 23, 2023, at 16.

[69] OTP Comments, October 23, 2023, at 8.

Figure 4: Otter Tail's Interplay of Expenditures, Spending Cap, and Net Benefit Cap



The x-axis represents incremental increases in spending. OTP explained that the orange line illustrates a utility's potential financial incentive based on 10 percent of net benefits, which decreases as spending increases. The red line represents net benefits, which decreases as spending increases. The blue line shows the 30 percent expenditures cap, which increases as spending increases. Overall, OTP highlighted a scenario in which a utility increases spending by an additional $1.6 million without increasing benefits to customers while getting an approximate $500,000 increase in the financial incentive. [70]

If the expenditures cap is to be maintained, OTP asks the Commission to set the expense cap high enough that it does not impact high-performing portfolios like Otter Tail's, and referenced the policy of South Dakota where they also operate, which has a cap of 30%. OTP recommends that the Commission adopt a 22% expenditures cap.[71]

Gas IOUs

The Department also proposes a 15% expenditure cap for the gas utilities, with the potential for

[70] *Id*, at 8-9.

[71] *Id*, at 9.

20% if they reach 1.2% avoided retail sales.[72]

In comparing gas expenditure caps, the Department found that Minnesota has one of the highest at 35%, with an average being 12-13% nationally. Between 2020 and 2022, Xcel CO's performance incentives as a share of expenditures were between 16% and 18%. The Department additionally provided the following table on expenditure caps for gas utilities. Given these comparisons, the Department argued that its proposed cap of 15% with a potential for 20% would remain "very generous."[73]

Table 9: Expenditures Caps for Incentive Mechanisms for Gas Energy Efficiency Programs[74]

State	Expenditure Cap (as a proportion of program budget)
MI	20%
RI	6.25%
MA	3.6%
AR	8%
CT	8%
MN	35%

Xcel recommends that the expenditure cap levels for gas are also set at 20% and 25% in order to have less dramatic reductions.[75]

While not objecting to the levels of the cap, MERC and CenterPoint both oppose the Department's approach of calculating expenditures without adding the financial incentives as a cost. They both argued that since the financial incentive was counted as a cost for the net benefits calculation as part of the MCT, then it should also be included as a cost for the expenditures cap to ensure symmetry in the caps.[76]

In reply comments, the Department opposes the utilities' recommendation to add the incentive to the expenditures cap for three reasons. First, the Department explained that the incentive is not an expenditure and stated that to their knowledge, no state adds the financial incentive to calculate expenditure caps. Second, the Department explained that because the financial incentive is subtracted from the utility's net benefits in the MCT, symmetry would require that it is subtracted from the expenditures, not added. Finally, the Department also argued that

[72] Department Comments, September 1, 2023, at 1.

[73] Department Comments, September 1, 2023, at 38-39

[74] Department Comments, September 1, 2023, at 39 (Table 10)

[75] Xcel Comments, October 23, 2023, at 18.

[76] CenterPoint Comments, October 23, 2023, at 13. MERC Comments, October 23, 2023, at 11.

recent changes brought by the ECO Act would allow utilities to include expenditures from various programs that would make the expenditures cap proposal generous enough.[77]

III. Adjustment Factors and Projected Impacts

The Department and utilities provided contesting projections of the savings under the Department's proposed net benefit and expenditure caps. In reply comments, the Department provided projections of the utilities' proposals.

In order to make predictions for energy savings, budgets, and net benefits for each utility in the 2024-2026 Triennial plan, the Department usually uses the utilities' triennial filings. However, the Department argued that the utilities' estimates about their future energy savings and net benefits reported in their triennial plans were much lower than their actual energy savings and net benefits most of the time. As such, the Department calibrated an "adjustment factor" using the proposed energy savings, budgets, and net benefits in 2017-2022 filings and the actual ones to make more accurate predictions for the variables of interests in 2024-2026 Triennial plan.[78] For example, Xcel's actual savings from 2017-2022 were 30% higher than its proposed savings, so the Department scaled up Xcel's proposed savings in the 2024-2026 triennial by 30%.

Staff notes that Xcel and OTP both pointed out potential mistakes in their comments in the calculation, and the Department provided updated calculations in its reply comments.[79]
The four figures below were filed in the Department's reply comments after receiving feedback from the utilities on potential errors in the calculations, however it's not clear to Staff whether the utilities feel the errors were completely accounted for.

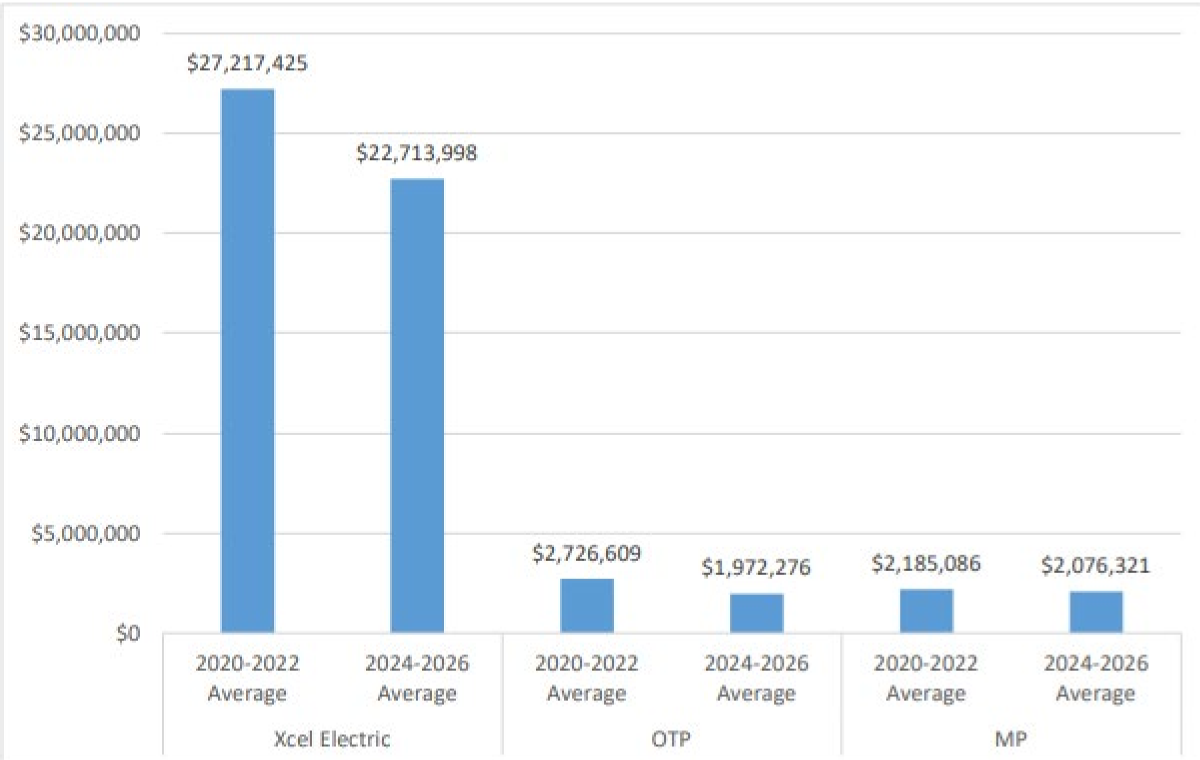
[77] Department Reply Comments, November 2 2023, at 17.

[78] Department Comments, September 1, 2023, at 23.

[79] Xcel Comments, *Attachment A*, October 23, 2023, at 1. OTP Comments, October 23, 2023, at 4.

In Figure 5, the Department compares average incentives for the electric utilities for 2020-2022 with projected 2024-2026 incentives.

Figure 5: Comparison of Electric Utilities' 2020-2022 Average Incentives and Department's Predicted 2024-2026 Incentives

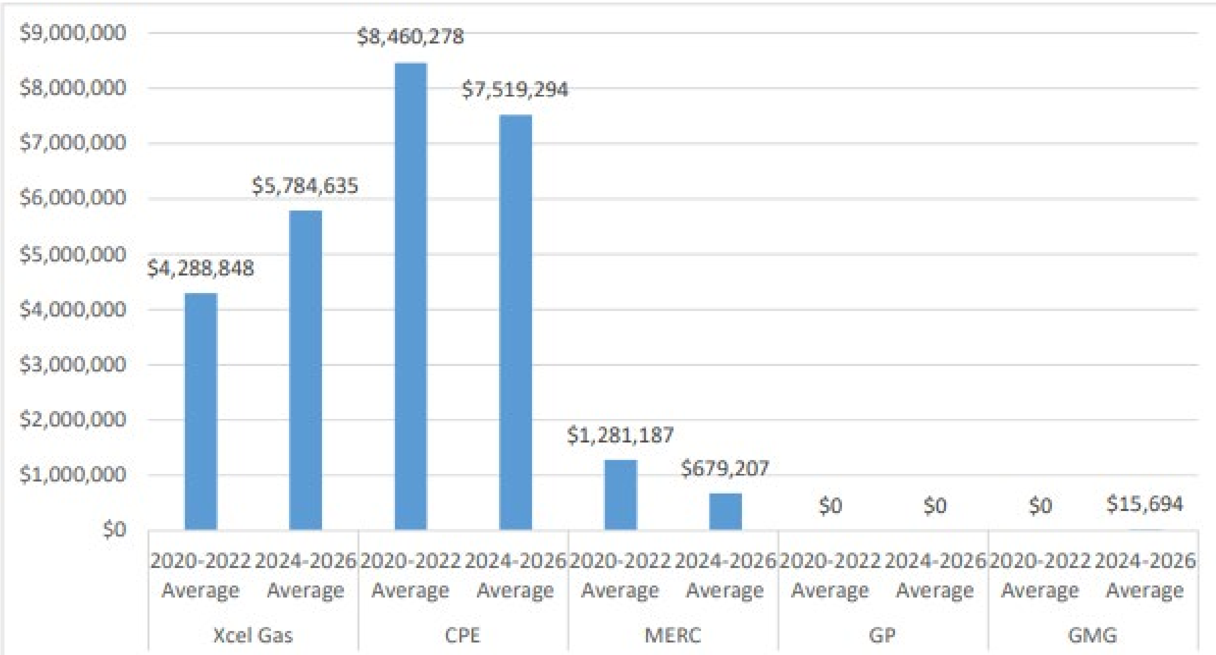


For historical context, the Department also provided the following figure illustrating aggregate projected savings and incentives:

Figure 6: Aggregate First-Year kWh Savings and Aggregate Incentives Paid to Utilities with Department Projections

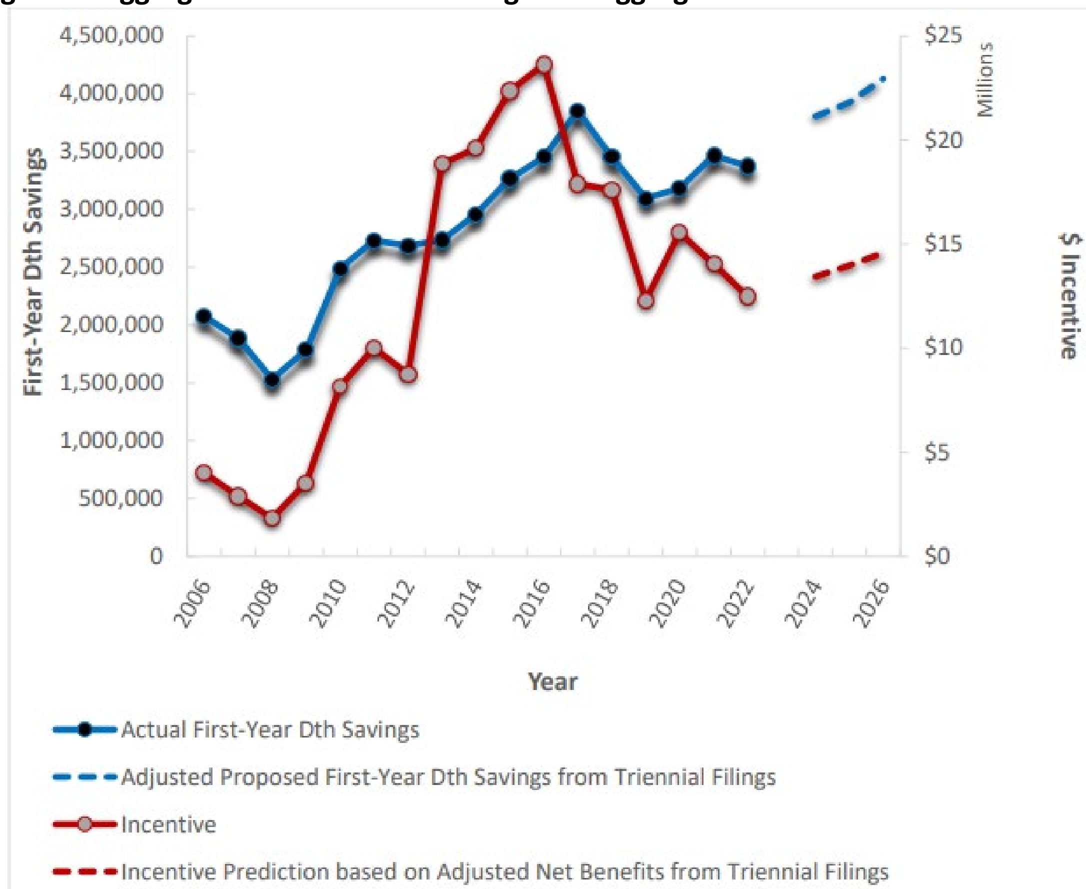
In Figure 7, the Department compares average incentives for the gas utilities for 2020-2022 with projected 2024-2026 incentives.

Figure 7: Comparison of Gas Utilities' 2020-2022 Average Incentives and Department's Predicted 2024-2026 Average Incentives



For historical context, the Department also provided the following figure illustrating aggregate projected savings and incentives for the gas utilities:

Figure 8: Aggregate First-Year Dth Savings and Aggregate Incentives Paid to Gas Utilities



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The Department predicted that under its proposal, the annual incentive for gas and electric utilities combined will cost ratepayers $40.8 million on average from 2024 to 2026, in comparison to $46.1 million from the current triennial.[80]

OTP, Xcel, and CenterPoint challenged the Department's approach of basing the adjustment on the historical under-projection of utility estimates and inflating the triennial filings accordingly, an approach that was maintained in the updated figures above. For example, OTP asserted that "the large LED opportunities we experienced in 2017-2021 are diminishing with high saturation

[80] Department Reply Comments, November 2, 2023, at 13.

among customers" which would limit potential savings going forward.[81] OTP noted that in 2022, results were lower in energy savings, spending, and net benefits than what they proposed. Xcel likewise argued that "application of the Proposed Adjustment Factors relies on an implicit assumption that historic overachievement will persist at the same rate in the future" which they asserted is not necessarily the case.[82] Xcel explained that the degree to which they have exceeded their goals has been declining despite maintaining strong energy savings and net benefits and that they consistently propose saving goals that are above the statutory minimum. Xcel noted that in 2022 they were 11% below their proposed goal but 55% above the statutory goal.

In light of the above arguments, Xcel maintained that its triennial filing is a better predictor than the Department's adjustment. Xcel projected average incentives of $16.4 million for electric and $4.5 million for gas under the Department's proposed mechanism, compared to the Department's projections of $22.7 million and $5.7 million.[83] OTP conducted a different calculation than the Department and projected that they would receive a $1.6 million incentive, compared to the Department's projection of $1.9 million.[84] The Department argued in reply comments that OTP's calculation for the Department's mechanism is incorrect because they excluded LM and EFS, which are maintained as part of the expenditures cap calculation under the Department's proposal.[85]

In addition to disputes about the accuracy of the projections, parties noted that the projected impacts are not uniform across utilities, and in part due to that, OTP, MP, and MERC contemplated utility-specific net benefit caps, which are discussed above in Section II.B. For example, MERC observed that the Department is projecting to cut their average incentive by 47% (Figure 7).[86]

In reply comments, the Department recognized that predicting future outcomes is difficult but stated "this does not mean that consistent patterns of over or under achievement should be ignored" and argued that while imperfect, the approach is unbiased. The Department asserted that due to changes from the Inflation Reduction Act and additional EFS and LM programs that can be included, there are significant changes to the upcoming triennial which can be expected to increase the level of participation and energy savings achievable. The Department

[81] OTP Comments, October 23, 2023, at 3.

[82] Xcel Comments, Attachment A, October 23, 2023, at 3.

[83] Xcel Comments, October 23, 2023, at 13, Figures 3-4.

[84] OTP Comments, October 23, 2023, at 5.

[85] Department Reply Comments, November 2, 2023.

[86] MERC Comments, October 23, 2023, at 6.

additionally noted that some utilities are planning to file modifications after their plans are approved to include new programs which could result in overachievement relative to their goals.[87]

The Department also provided a scenario analysis with five cases inspired by the different utility proposals to reflect the increase in the financial incentives from their proposals, which they asserted result in a significant increase in the burden for ratepayers. As none of utilities asking for higher financial incentives explicitly claimed to reach a higher level of energy savings relative to the Department's own projection, the Department thus assumed the same energy savings level as they projected. Table 10 below shows these different scenarios, each with their respective caps for net benefits and expenditures. Table 11 shows the Department's estimated average annual financial incentives for each scenario between 2024-2026. The Department explained that according to the scenario analysis, each of the alternative proposals would lead to a significant increase in the annual payout of financial incentives, resulting in a substantial increase in the burden for ratepayers. The Department also stated their proposal is in accordance with the Commission's recent orders which reduce the incentive mechanism gradually and "results in a more comparable level to other states in the country".[88]

Table 10: Alternative Scenarios for the Financial Incentive[89]

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

[87] *Id*, at 16.

[88] Department Reply Comments, November 2, 2023, at 20-21.

[89] Department Reply Comments, November 2, 2023, at 20.

Table 11: Financial Incentive Amount in Each Scenario[90]

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

IV. Other Order Requirements

The Commission's December 9, 2020, Order ("Order") required that the Department conduct a stakeholder process to discuss multiple ways of improving the shared-savings mechanism for the 2024-2026 triennium.[91]

A. Incorporation of Lifetime Energy Savings into the Incentive Mechanism

The Order required that the stakeholder process include discussion of "incorporation of lifetime energy savings into the incentive mechanism."[92]

The Department noted that per Minn. Stat. §216B.241, Subd. 2(b), utilities are required to report both lifetime energy savings and cumulative lifetime energy savings in their Triennial Plans, but stated that because the savings goals in Subdb. 1c(b) and Subd. 1c(d) are in annual energy savings, the Department tracked incentive per first-year energy savings from the Shared Savings Financial Incentive Mechanism over time in its historical analysis (Attachment A). The Department additionally explained that when calculating net benefits under the program, future energy savings are discounted, and because the Department proposes to use a lower discount rate one can argue that future energy savings are given greater weight under the proposed mechanism.[93]

CenterPoint stated they agree with the Department that the current financial incentive mechanism and the Department's proposal incorporate long-term energy savings into their design. CenterPoint noted that "the relationship between lifetime energy savings and net benefits also means there is a relationship between an increasing incentive level and how it

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[90] Department Reply Comments, November 2, 2023, at 21.

[91] Commission Order, December 9 ,2020, at Order Point 4.

[92] Commission Order, December 9, 2020, at Order Point 4a.

[93] Department Comments, September 1, 2023, at 31.

encourages utility focus on long-term energy savings."[94]

Aside from the lower discount rate (**Decision Option 1B**), there is not an associated Decision Option with this subsection.

B. Permanent Peak Reductions and Load Flexibility

The Order required that the stakeholder process include discussion of "incorporation of an incentive for utilities that achieve permanent peak reductions through the shared-savings incentive mechanism" and "energy efficiency opportunities to support increased load flexibility (the ability to persistently shape and shift load)."[95]

The Department reported that they asked for feedback from stakeholders on the possibility of awarding financial incentives for LM projects, with and without energy savings opportunities. The positions of the stakeholders were summarized by the Department as follows:

- 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 the load management programs that achieve energy savings included in the utility's past CIP portfolios have been approved using a one-year measure life and have included all program participants who participated in the current year. OTP 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

[94] CenterPoint Comments, October 23, 2023, at 11.

[95] Commission Order, December 9, 2020, at Order Point 4b and 4d.

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."[96]

The Department agreed with OTP and Xcel that under Minn. Stat. 216B.241 Subd. 13. (f),[97] the net benefits of LM programs that include energy savings should be included in the Shared Savings Incentive Mechanism and listed Xcel's Saver's Switch program and OTP's Cool Savings (AC cycling) and Water Heater Store & Save LM programs as possible examples.

Regarding LM programs which do not result in energy savings, the Department recommends that 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 ECO Act. 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 MCT and be included in the total net benefits used to calculate the financial incentive.[98]

CenterPoint stated that because they have not proposed a LM program, they are neutral on the Department's analysis.[99]

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[96] Department Comments, September 1, 2023, at 32.

[97] "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."

[98] Department Comments, September 1, 2023, at 32-33.

[99] CenterPoint Comments, October 23, 2023, at 11.

OTP requests that the Commission adopt a financial incentive for their LM activities and stated the "mechanism for conservation should also be applicable to load management activities."[100] OTP recommends that all new kW and at least half of existing kW derived from LM should be eligible for financial incentive.

Staff Comment
Staff's understanding is that the ECO Act now allows the inclusion of LM programs that do not result in energy savings if the utility achieves savings excluding LM of 1% of retail sales.[101] However, the ECO Act does not specify whether the program has to be new or whether existing programs could be included. The Department argued that the program must be new, while OTP requests that half of the kW derived from existing LM programs should be eligible for inclusion.

Issues related to treatment of load management programs are covered under **Decision Option 1R**.

C. Supply-Side Investments

The Commission's Order additionally required the Department's stakeholder discussion include:

> 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.[102]

To address this, the Department issued 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."[103] The Department additionally requested that Xcel, OTP, and MP provide costs associated with capitalizing an $80 million investment in a wind and solar project. They then took the revenue requirement (RR) stream provided by the utilities in their responses and calculated two measures: (1) the total nominal RR stream obtained by summing the yearly requirements and (2) the net present value (NPV) of the RR. Next, the Department created a first-year energy savings estimate of the $80 million investment by scaling each utility's 2022 ECO performance

[100] OTP Comments, October 23, 2023, at

[101] Minn. Stat. 216B.241 Subd 12(g): A public utility is not eligible for a financial incentive for a load management program in any year in which the utility achieves energy savings below one percent of gross annual retail energy sales, excluding savings achieved through load management program.

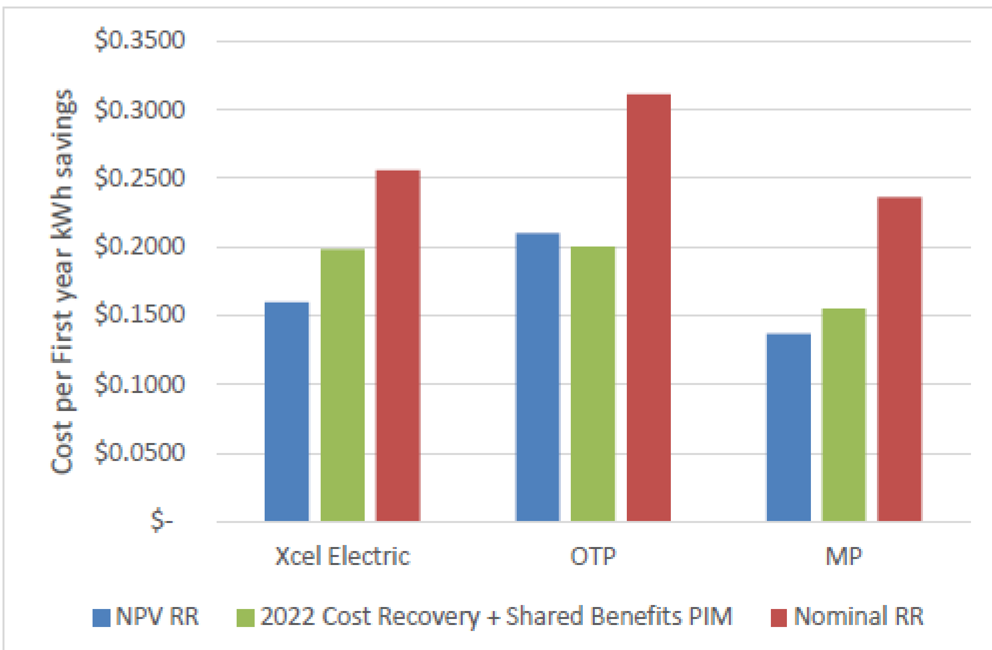
[102] Commission Order, December 9 ,2020, at Order Point 4C.

[103] Department Comments, September 1, 2023, at 33.

and divided the nominal RR and NPV RR measures by the scaled first-year energy savings.

The Department then compared these values to the current financial incentive mechanism, which was also divided by the energy savings. The results for the electric IOUs are in Figure 9 and gas IOUs in Figure 10. They noted that the amount ratepayers paid in 2022 for each unit of first-year energy savings is between NPV RR and Nominal RR per unit of first-year energy savings and concluded that "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 is extremely generous and lucrative for the utilities."[104]

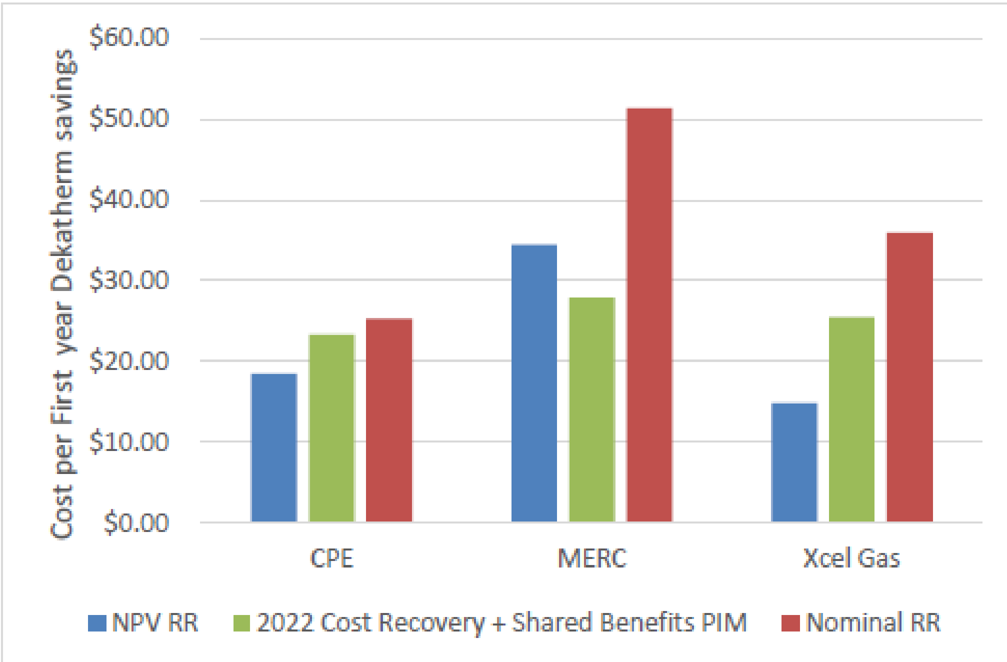
Figure 9: Comparison of Alternative Mechanisms to the 2021-23 CIP Financial Incentive Mechanism for Electric IOUs[105]



[104] *Id*, at 34.

[105] *Id* (Figure 17).

Figure 10: Comparison of Alternative Mechanisms to the 2021-23 CIP Financial Incentive Mechanism for Gas IOUs[106]



In comments, Xcel stated that "estimating revenue requirements per unit of energy saved does not address the question of how a supply-side investment would be rewarded financially" and argued that it is not clear the Department's conclusion, that utilities earn a similar amount from CIP/ECO as they do from similarly-sized supply-side investments, follows from its analysis.[107] Instead, Xcel argued that if this approach "shows anything, it shows simply how much customers would need to pay per unit of energy saved if CIP were recovered under a long-term investment model."[108] They explained that the necessary revenue requirements for a project are affected by a number of factors, such as how the federal production tax credit would reduce the amount of revenue customers need to pay for a wind investment, but this does not affect the utility's return.

Xcel argued the comparison should focus on balancing the rates of return and the length of the investment in order to determine if a short-term investment in energy efficiency is more attractive than a long-term investment in supply-side options. They provided the following hypothetical example:

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[106] *Id*, at 35 (Figure 18).

[107] Xcel Comments, October 23, 2023, at 14.

[108] *Id*.

Table 12: Xcel's Hypothetical Investment Comparison[109]

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

Xcel noted that in this example, the cost of the short-term investment ($96 million) is between the NPV RR and nominal RR of the long-term investment ($80 million and $116.5 million), but explained "this does not mean that the short-term investment earns more than the long-term investment. Rather, it is simply a function of the fact that the rate of return exceeds the discount rate used for the short-term investment."[110]

CenterPoint also argued that the Department's analysis does not provide information to customers or the utilities about the value of each option. CenterPoint explained:

> The chart does not demonstrate whether a more conservative or generous financial incentive will maximize energy savings because all three bars are based on scaling the energy savings using average costs (i.e., Dths per dollar spent). A higher (or lower) incentive potentially encourages higher (or lower) energy savings and therefore even if those additional Dths saved are marginally more costly the overall per Dth saved would remain stable. However, the total energy savings would have increased and secured more benefits for customers.[111]

In reply comments, the Department defended its comparison and stated that their interpretation of the Order is to evaluate how much a specific investment would cost if it was approved under the 2021-2023 CIP financial incentive mechanism vs the cost-of-service model. The cost of the energy efficiency program to regulators is the sum of the investment expenditures from utilities and the financial incentive payout, while in the cost-of-service

[109] Xcel Comments, October 23, 2023, at 15 (Table 3).

[110] *Id*, at 15-16.

[111] CenterPoint Comments, October 23, 2023, at 11.

model, the regulator would pay the annual revenue requirement. The Department explained the latter results in a lower upfront cost but higher lifetime cost and that the NPV of these costs vary depending on how they are discounted. The Department concluded:

> Given we are mostly talking about customer owned behind the meter investments, the Department notes that the utility bears significantly lower financial risk associated with such investments as compared to other assets that would be rewarded through a cost-of-service model. Thus, the fact that the cost to the regulator is comparable even though the utility does not own these assets, shows that the Shared Benefits Financial Incentive Mechanism currently in place is extremely generous and lucrative for the utilities.[112]

STAFF ANALYSIS

The conversion from the UCT to the MCT creates some ambiguity about what net benefits cap parameter constitutes maintaining the status quo, and the Commission may wish to first determine the correct conversion as a baseline before considering whether to adjust the resulting parameter. The Department argued that 10% under the UCT is equivalent to 4.0% under the MCT and reduced this to 3.4% in its recommendation. Alternatively, Xcel argued the 10% cap is equivalent to 5.5% for electric but agreed it converts to 4% for gas, which are Xcel's recommendations.

The Department determined its conversion based on regression analysis of 2019 to 2022 which found a UCT-to-MCT benefits ratio of 2.5, which Xcel did not contest. However, Xcel asserted that the Department's implicit assumption that the ratio would be maintained from 2024-2026 was "unsupported."[113] One significant difference between the UCT and MCT is the inclusion of the value of avoided carbon emissions in the MCT, and Xcel argued that "as electric utilities have made and continue to make progress in reducing emissions from electricity generation, the emissions avoided through energy efficiency have and will continue to decline, reducing the difference between the UCT and MT net benefits."[114] The Department did not respond directly to this point.

Staff finds that while Xcel's argument may have some merit, their recommendation of 5.5% is even less supported than the Department's stance because after arguing that the ratio will decline, Xcel did not actually make any further case for how the conversion works out to 5.5%, which they claimed is maintenance of the status quo. MP and CenterPoint both pointed to

[112] Department Reply Comments, November 2, 2023, at 18.

[113] Xcel Comments Attachment A, October 23, 2023, at 6.

[114] *Id.*

inflation while recommending caps of 5% and 5.5%, respectively, but did not elaborate further on the conversion. Given the record at hand, Staff believes the evidence best supports 4% being the baseline for the current net benefits cap (10% under the UCT).

Staff finds the debates over the incentives across states and the comparison between customer-owned efficiency and utility-owned supply-side investments to have good points on both sides and recognizes that finding a clear apples-to-apples comparison is difficult in both cases.

Regarding maintaining the historical trend of reducing the financial incentive raised by the Department, Staff agrees with MP that precedent is not by itself adequate justification for reducing the financial incentive here. The decision should be made based on the projected marginal impact of the reduction and whether the Commission concludes it can save ratepayers money while still providing a high enough level of incentives for the utilities to maintain their record of high energy savings. However, as highlighted by the Department, Staff notes that previous reductions in the financial incentive do not appear to have adversely affected the level of energy savings.

DECISION OPTIONS

Decision Option 1 is categorized by the portion of the incentive being modified and the type of utility. The first two parts, Decision Options 1A and 1B, are uncontested and adopt the MCT and Societal Discount Rate. The rest of the subparts of Decision Option 1 implement the net benefits cap, expenditures cap, and the thresholds for electric and gas utilities. As Staff noted earlier, if the Commission chooses a net benefits cap for the electric utilities (Decision Options 1C – F) that is not the Department's recommendation of 3.4%, then the amount of net benefits awarded for each additional .1% of savings about the minimum energy savings threshold will have to be adjusted (Decision Option 1P.5). For example, if the Commission adopts Xcel's proposed 5.5% cap (1D), then the Commission would have to write or work with Xcel on a new schedule of incremental benefits because Xcel did not propose an alternative to the Department's. In the case of gas, CenterPoint proposed its own schedule of net benefits (1Q.4) to implement its proposed cap of 4.5% (1I).

Decision Option 2 maintains existing aspects of the program and was uncontested.

Decision Option 3 recognizes aspects of the program that were modified by the ECO Act, which the Department requests the Commission approve and include in the Order for clarity.

1. Approve the 2024-2026 Shared Savings Demand Side Management Financial Incentive Mechanism with the following provisions:

   <u>Minnesota Cost Test</u>

   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. (*Department, Xcel, OAG*)

   <u>Societal Discount Rate</u>

   B. The Societal Discount Rate of 3.3% is used in the calculation of net benefits to discount for future benefits and costs. (*Department, OAG*)

   <u>Net Benefits Cap – Electric</u>

   The Commission must choose one of C-E and modify the choice if also choosing F. All values are predicated on the Commission approving the Minnesota Test in DO 1A.

   C. Set a net benefits cap of 3.4% for electric utilities. (*Department, OAG*)

      OR

   D. Set a net benefits cap of 5.5% for electric utilities. (*Xcel*)

      OR

   E. Set a net benefits cap of 5% for electric utilities. (*MP*)

      OR

   F. Set Otter Tail's net benefits cap at 8.6% (*OTP*).

   <u>Net Benefits Cap – Gas</u>

   The Commission must choose one of G-J.

   G. Set a net benefits cap of 3.4% for gas utilities. (*Department, OAG*)

      OR

H. Set a net benefits cap of 4% for gas utilities. (*Xcel*)

OR

I. Set a net benefits cap of 4.5% for gas utilities. (*CenterPoint*)

OR

J. Set a net benefits cap of 5% for gas utilities. (*MERC*)

<u>Expenditures Cap</u>

The Commission must choose one of K through N.

K. Set an expenditures cap of 15% for all utilities, which increases to 20% if the utility achieves the designated high achievement threshold. (*Department, OAG*)

OR

L. Set an expenditures cap of 15% for all utilities, which increases to 22% if the utility achieves the designated high achievement threshold. (*OTP*)

OR

M. Set an expenditures cap of 20% for all utilities, which increases to 25% if the utility achieves the designated high achievement threshold. (*Xcel, MP*)

OR

N. Remove the expenditures cap. (*MP, OTP*, *Staff notes this is their preferred choice*.)

AND (*O can be paired with any of K-N*)

O. Include financial incentives as a cost for the expenditure caps. (*MERC, CenterPoint*)

<u>Minimum and High-Achievement Thresholds – Electric</u>

For P, the Commission must choose 1 or 2, 3 or 4, and 5 or write an alternative to 5.

P. For electric utilities,

1) Set the minimum energy savings threshold where the utility is allowed to collect a financial incentive to 1.3% of retail sales. (*Department, OAG*)

OR

2) Set the minimum energy savings threshold where the utility is allowed to collect a financial incentive to 1.5% of retail sales. (*Xcel*)

AND

3) Set the high-achievement energy savings threshold to 2.0% of retail sales. (*Department, OAG*)

OR

4) Set the high-achievement energy savings threshold to 2.2% of retail sales. (*Xcel*)

AND

5) Award the utility 1.3% of net benefits at the minimum threshold and for each additional .1% of retail sales avoided, award an additional .3% of net benefits, until the high achievement threshold is reached. (*Department, OAG. Staff notes these increments are based on a 3.4% net benefits cap. Xcel did not propose a different schedule of benefits.*)

<u>Minimum and High-Achievement Thresholds – Gas</u>

Q. For gas utilities,

1) Set the minimum energy savings threshold where the utility is allowed to collect a financial incentive to .7% of retail sales. (*Department, OAG, CenterPoint, Xcel*)

2) Set the high-achievement energy savings threshold to 1.2% of retail sales. (*Department, OAG, CenterPoint, Xcel*)

The Commission must choose 3, 4, or an alternative incremental schedule of benefits.

AND

3) Award the utility 1.9% of net benefits at the minimum threshold and for each additional .1% of retail sales avoided, award an additional .3% of net benefits, until the high achievement threshold is reached. (*Department, OAG. Staff notes these increments are based on a 3.4% net benefits cap*)

OR

4) Award the utility 2% of net benefits at the minimum threshold and for each additional .1% of retail sales avoided, award an additional .5% of net benefits, until the high achievement threshold is reached. (*CenterPoint. Staff notes these increments are based on a 4.5% net benefits cap*)

Load Management

R. For the treatment of LM programs that do not result in energy savings,

1) Award the utility the percent of net benefits equal to the net benefits cap. (*Department, OAG*)

2) Calculate net benefits using the MCT and include the net benefits in the total net benefits used to calculate the financial incentive. (*Department, OAG*)

AND

3) Exclude all kW saved from LM programs that existed before May 25, 2021, from the benefits calculation. (*Department, OAG*)

OR

4) Include half of the kW saved from LM programs existing before May 25, 2021, in the benefits calculations. (*OTP*)

2. Maintain the following provisions from the current Shared Savings DSM Financial Incentive Plan:

    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. (*Department, OAG)*

    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. (*Department, OAG)*

    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% savings goal for gas utilities and 1.75% savings goal for electric utilities. (*Department, OAG)*

    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. (*Department, OAG)*

    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. (*Department, OAG)*

    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. (*Department, OAG)*

3. Approve the addition of the following provisions to the Shared Savings DSM Financial Incentive Mechanism due to the implementation of the ECO Act:

    A. As per Minn. Stat. § 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 towards calculating their financial incentive.

D. Electric utilities are not allowed to count net benefits and energy savings derived from their EFS programs toward calculating their 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 programs that occurred on or after the approval of the Energy Conversation and Optimization Act (May 25, 2021) towards calculating their financial incentive.

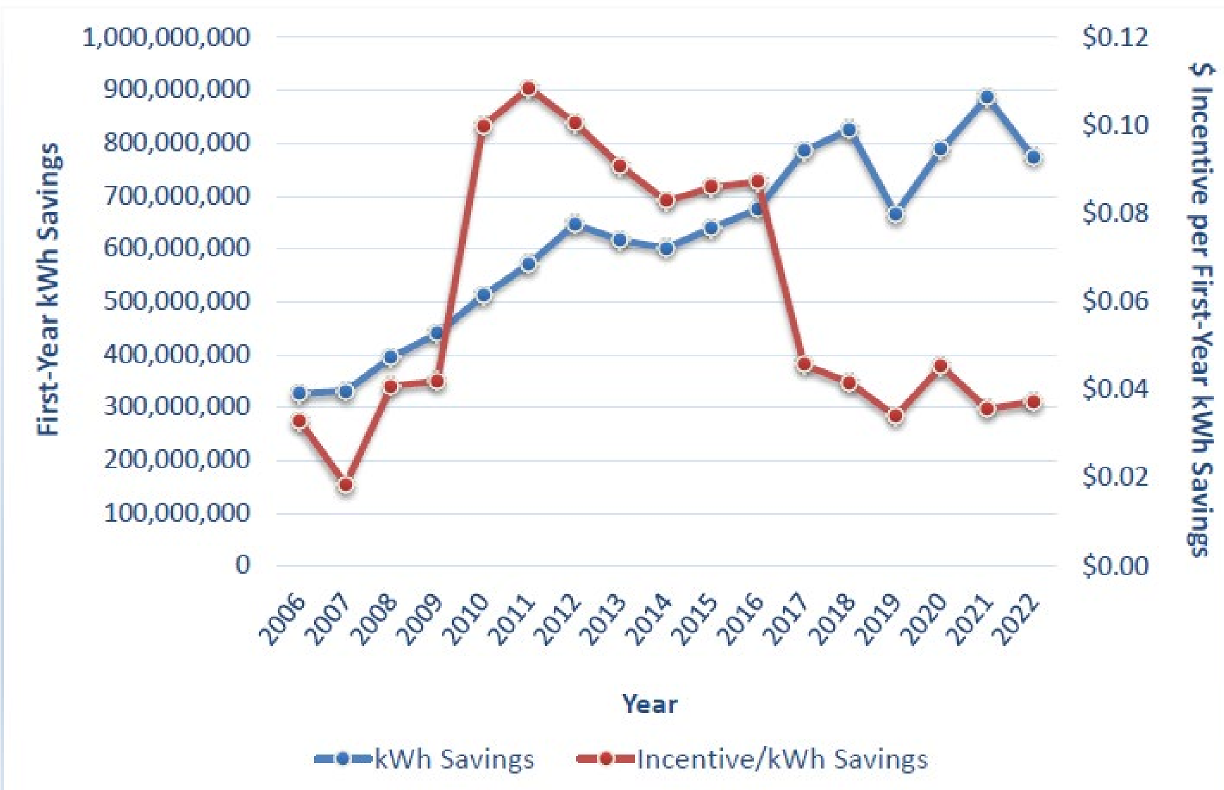
Attachment A: Summary of Department Analysis of Past Incentives and Savings

As context for the proposed recommendations, the Department analyzed savings under the prior and current incentive mechanisms.

A. Analysis of Savings for Electric IOUs

The Department's Figure 1 depicts the first-year[115] kWh savings and incentives for electric IOUs from 2006 to 2022. It illustrates that from 2006 to 2012, overall incentives to IOUs increased before declining from 2012 through 2022. The Department observed that over the entire period, there was a relatively steady increase in energy savings despite incentives declining by roughly half.

Figure 1: 2006-2022 Electric IOU Incentives and First-Year kWh Savings[116]



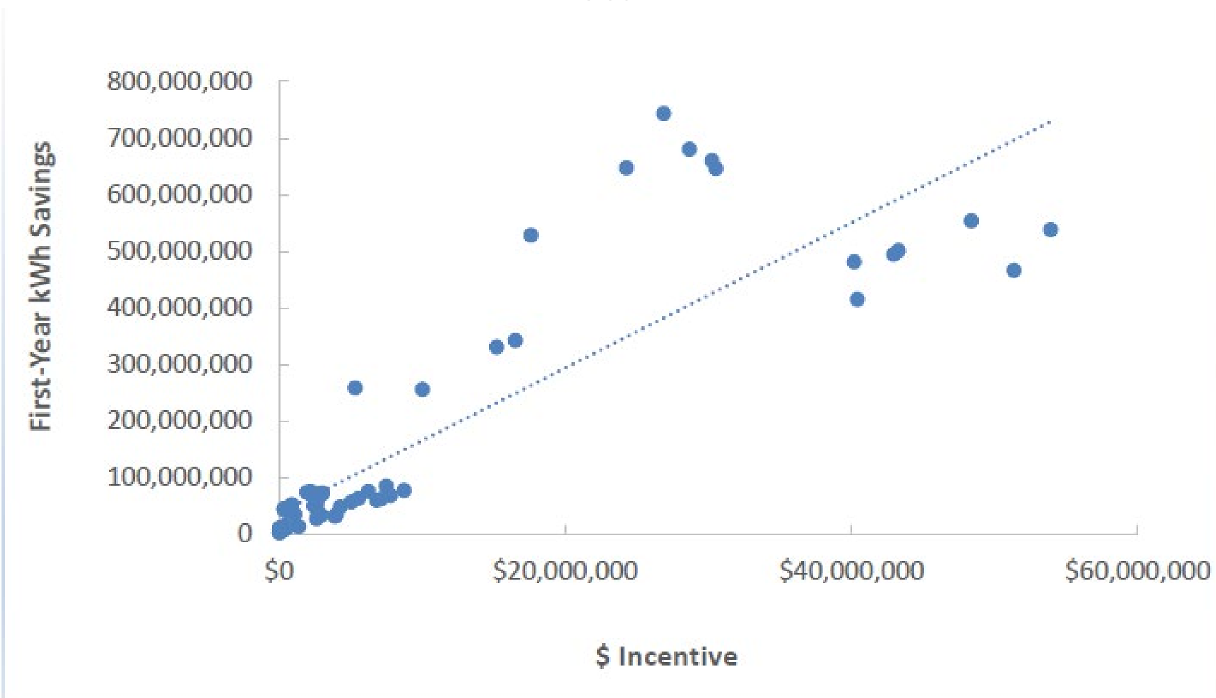
The Department also found that there is a positive correlation between incentives and energy

[115] First-year savings can be thought of as the marginal savings from that year, so as not to double count savings in subsequent years. For example, installing a water heater may provide energy savings in all years of operation, but first-year savings would include the incremental savings from its first year of operation.

[116] Department Comments, September 1, 2023, at 6 (Figure 1)

savings. That is, on average the higher the incentive, the higher the first-year energy savings. Additional analysis with fixed effects, which control for differences across utilities such as location or size, found the same result. The Department noted that "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."[117]

Figure 2: Positive Correlation between Incentives and First-Year Energy Savings for Electric IOUs[118]



The Department further found the value to ratepayers by calculating net benefits minus each utility's Shared Savings incentive for 2006-2022, shown in Figure 3 below. Over the period 2017-2022, total benefits to Minnesota's electric IOU customers was $1.59 billion. The Department noted that from 2016 2018, net benefits declined despite an increase in savings (see Figure 1) due to a decrease in the electric avoided cost assumptions.[119]

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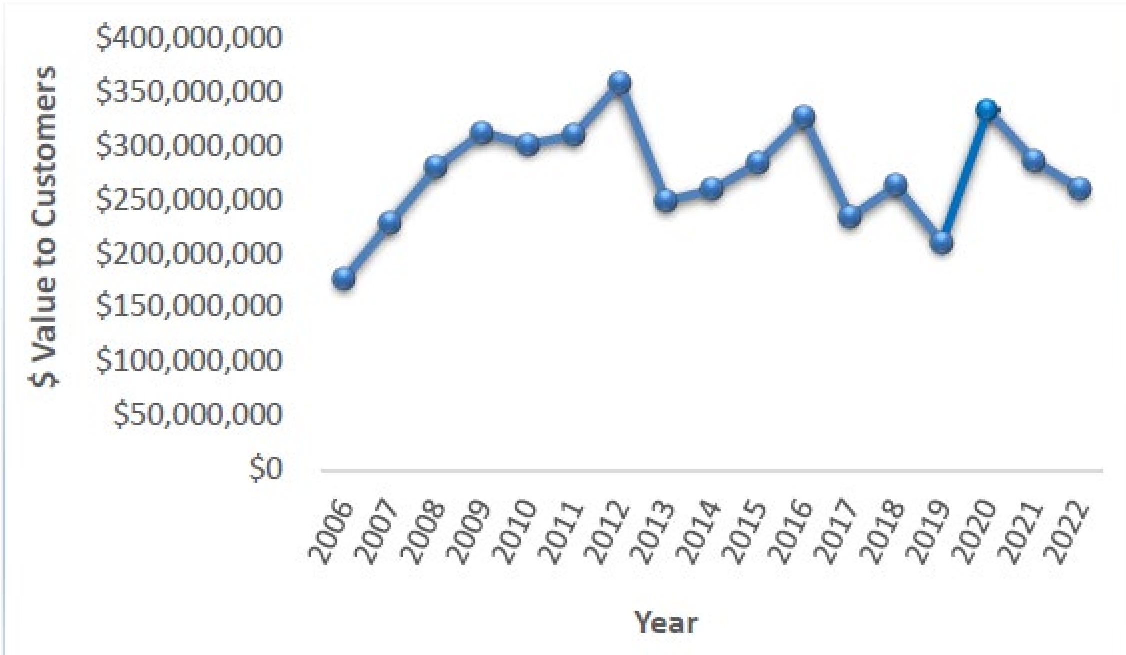
[117] *Id*, at 7

[118] *Id*, at 8 (Figure 3).

[119] *Id*, at 15

Figure 3: Total Value of Electric IOUs' CIP Achievements: Utility Net Benefits Minus Shared Savings Incentives[120]

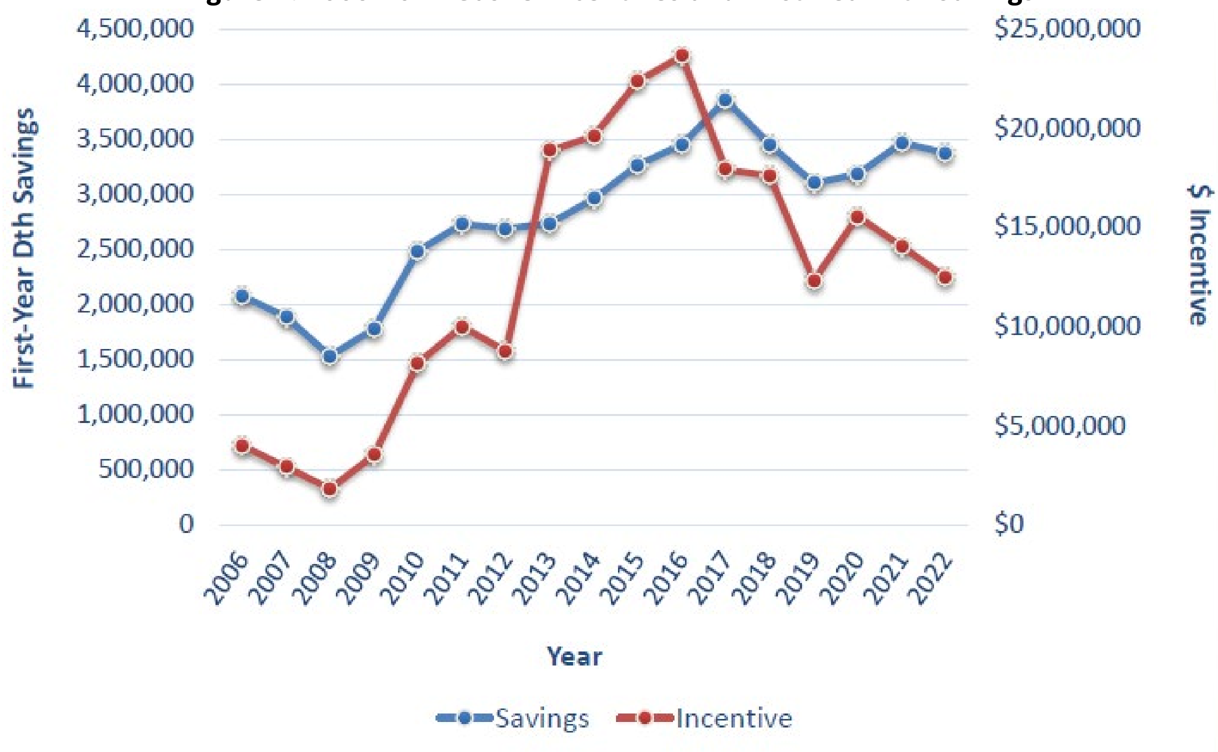


B. <u>Analysis of Savings for Gas IOUs</u>

Like Figure 1, Figure 4 below shows the aggregate first-year Dth savings and incentives for gas IOUs over the period 2006 to 2022. The Department observed that incentives had an increasing trend from 2006 to 2016 and, despite a decline in incentives from 2016 through 2022, savings in 2022 were 50% higher in 2022 than 2006.

[120] *Id*, at 15 (Figure 9)

Figure 4: 2006-2022 Gas IO Incentives and First-Year Dth Savings[121]



As in Figure 2, Figure 5 shows the correlation between incentives and first-year energy savings for gas IOUs and illustrates that on average, gas utilities that received higher incentives from 2006 to 2022 exhibited higher first-year Dth savings. An analysis with fixed effects, which control for differences across utilities such as location or size, found the same result. The results do not necessarily mean that a decrease in incentives will decrease first-year energy savings.

Figure 5: Positive Correlation between Incentives and First-Year Energy Savings for Gas IOUs[122]

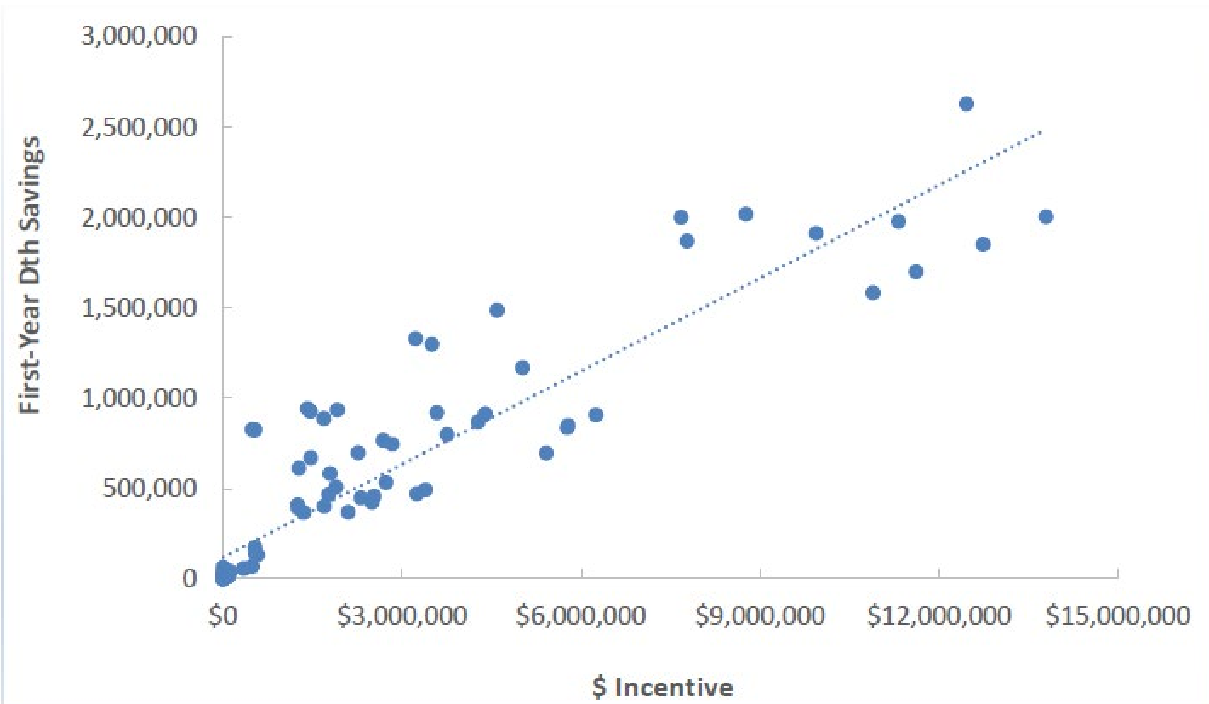


Figure 6 graphs the gas IOUs' net benefit minus shared savings incentives. From 2017 to 2022, the total value to ratepayers was $840 million. The Department noted that the benefits peaked in 2017 due to the extremely high level of net benefits achieved by CenterPoint that year.

[122] *Id*, at 13 (Figure 7).

Figure 6: Total Value of Gas IOUs' CIP Achievements Utility Net Benefits Minus Shared Savings Incentives