DECISION

BEFORE THE DEPUTY COMMISSIONER OF THE MINNESOTA DEPARTMENT OF COMMERCE

MICHELLE GRANSEE, DEPUTY COMMISSIONER

In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities	Issue Date: March 31, 2023 Docket No. E,G999/CIP-23-46

PROCEDURAL HISTORY

Throughout 2022, Staff of the Minnesota Department of Commerce, Division of Energy Resources (Staff) held extensive discussions with the CIP Cost-Effectiveness Advisory Committee (CAC or the Committee), regarding the gas and electric investor-owned utilities' (IOU) cost-effectiveness methodologies that will apply to the 2024-2026 Conservation Improvement Program (CIP) Triennial Plans.

On February 16, 2023, Staff filed their Analysis, Recommendations, and Proposed Decision (Proposed Decision). The Proposed Decision provided a summary of the CAC's activities and presented Staff's key recommended cost-effectiveness methodology updates for the 2024-2026 CIP Triennials.

By the end of the comment period on March 6, 2023, the Minnesota Department of Commerce (the Department) received comments on Staff's Proposed Decision from Center for Energy and Environment, CenterPoint Energy, City of Minneapolis and City of St. Louis Park, Fresh Energy, Minnesota Energy Resources Corporation, Midwest Energy Efficiency Alliance, Minnesota Power, Otter Tail Power, and Xcel Energy.

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Definition of Terms and Acronyms

American Council for an Energy-Efficient Economy	ACEEE
California Standard Practice Manual	CaSPM
Center for Energy and Environment	CEE
CenterPoint Energy	CPE
Conservation Applied Research and Development	CARD
Conservation Improvement Program	CIP
Consumer-Owned Utility	COU
Cost-Effectiveness Advisory Committee	CAC, Committee
Distributed Energy Resource	DER
Energy Conservation and Optimization Act	ECO Act
Efficient Fuel-Switching	EFS
Great Plains Natural Gas	GP
Greater Minnesota Gas	GMG
Integrated Resource Plan	IRP
Investor-Owned Utility	IOU
Load Management	LM
Midwest Independent System Operator's	MISO
Minnesota Department of Commerce	The Department
Minnesota Energy Resources Corporation	MERC
Minnesota Power	MP
Minnesota Public Utilities Commission	PUC
Minnesota Cost Test	MCT
National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources	NSPM for DERs

Non-Energy Benefit	NEB
Non-Energy Impact	NEI
Otter Tail Power	OTP
Participant Cost Test	PCT
Ratepayer Impact Measure Test	RIM
Societal Cost Test	SCT
Staff of the Minnesota Department of Commerce	Staff
Synapse Energy Economics	Synapse
Technical Reference Manual	TRM
Technical Reference Manual Advisory Committee	TRMAC
Transmission and Distribution	T&D
Utility Cost Test	UCT
Utility System Impact	USI
Weighted Average Cost of Capital	WACC
Xcel Energy	Xcel

Sections A, B, C, and D of this Decision contain content that is pulled directly from Staff's Proposed Decision regarding their analysis and recommendations to the Deputy Commissioner. Appendices B, C, D, E, F, G, H, and I also contain content that is pulled directly from Staff's Proposed Decision.

Section E (Comments by Interested Parties), and Section F (Deputy Commissioner's Decision) of this Decision contain new content that was not included in Staff's Proposed Decision. Appendices A, J, K, and L also contain new content that was not included in Staff's Proposed Decision.

A. Background (From Proposed Decision)

Prior to the submission of IOU CIP Triennial Plans, the Department leads an effort to examine and update the cost-effectiveness methodologies that Minnesota's IOUs use to evaluate their CIPs. This role is consistent with the Department's responsibility to ensure that utilities procure cost-effective programs systematically and aggressively and that evaluations and reporting are accurate. For context, Minnesota's seven IOUs are as follows:

- CenterPoint Energy (CPE)
- Great Plains Natural Gas (GP)
- Greater Minnesota Gas (GMG)
- Minnesota Energy Resources Corporation (MERC)
- Minnesota Power (MP)
- Otter Tail Power (OTP)
- Xcel Energy (Xcel)

Throughout 2022, Staff held extensive discussions with the CAC, regarding the gas and electric IOUs' cost-effectiveness methodologies that will apply to the 2024-2026 CIP Triennial Plans. Staff greatly appreciate the significant contributions that Committee members provided as part of this process and the technical assistance and meeting facilitation provided by The Mendota Group and Synapse Energy Economics (Synapse).

This Proposed Decision provides a summary of the CAC's activities and presents Staff's key recommended cost-effectiveness methodology updates for the 2024-2026 CIP Triennials.

1. Cost-Effectiveness Advisory Committee

The Department created the CAC to act as a forum for discussing how to update components of cost-effectiveness models and integrate these into the CIP process. The Committee is tasked with exploring updates to the cost-effectiveness methodologies that Minnesota IOUs use to evaluate their CIP programs and portfolios. A list of the CAC's members is included in Appendix A.

The CAC does not have formal authority to update the cost-effectiveness tests that utilities will use to evaluate CIP programs. The Committee functions similar to the Department's Technical Reference Manual Advisory Committee (TRMAC), which is tasked with recommending updates to measure technical assumptions. These recommendations, in turn, are incorporated into a Staff Proposed Decision. Interested parties can then provide comments on the Proposed Decision and these comments inform the Deputy Commissioner's Final Decision.

The Department initially launched the CAC in January 2021.[1] Convening the Committee responded to a point in the Deputy Commissioner's February 11, 2020 Decision (Dockets G999/CIP-18-782 and E999/CIP-18-783).[2] Specifically, the Decision directed Staff to explore an initial scope of cost-effectiveness issues, which are outlined in Appendix B, along with the following two additional issues:

- Discount Rates: "The Deputy Commissioner directs Staff to examine discount rates again as part of the 2024-2026 cost-effectiveness process in order to determine whether any changes to discount rates are appropriate for that particular Triennial period."

- Transparency of Electric Avoided Costs: "The Deputy Commissioner directs Staff to include improvements to the transparency of electric avoided costs as one of the priority cost-effectiveness issues to explore leading up to the 2024-2026 CIP Triennials."

The Committee took a break in mid-2021 while the Minnesota Legislature deliberated over significant changes to the law that would meaningfully affect utility CIPs. Ultimately, the Legislature passed the Energy Conservation and Optimization Act (ECO Act), and Governor Tim Walz signed it into law on May 25, 2021.[3] The ECO Act primarily serves to modernize CIP to provide a more holistic approach to energy efficiency programming. Notable highlights of ECO include: providing participating electric and natural gas utilities the opportunity to optimize energy use and delivery through the inclusion of load management[4] and efficient fuel switching programs[5]; raising the energy savings goals for the state's electric IOUs;[6] more than doubling the low-income spending requirement for all IOUs;[7] providing greater planning flexibility for participating municipal and cooperative utilities,[8] and including activities to improve energy efficiency for public schools.[9]

The Department reconvened the CAC after the Commissioner of Commerce, on March 15, 2022, signed a regulatory CIP Decision establishing guidance to implement key provisions of the ECO Act.[10]

Much of the CAC's activities during 2022 focused on proceeding through the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources' (NSPM for DERs)[11] 5-step process to develop the Primary Test that Minnesota IOUs will use to evaluate their 2024-2026 CIPs.

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[1] Although the CAC includes representatives from Consumer-Owned Utilities (COUs), COUs were not expected to actively participate in the CAC given that the Department is not currently requiring that COUs submit detailed cost-effectiveness analyses for their CIPs. Instead, based on the presumption that cost-effectiveness is generally imbedded into COU programs as member-owned or city-owned utilities and an expectation that COUs will follow Technical Reference Manual (TRM) guidance, COUs will simply need to confirm during their annual reporting that that their CIP portfolio considers the costs and benefits to ratepayers, utility, participants, and society.
[2] *Deputy Commissioner's Decision – In the Matter of CIP Gas and Electric Utilities 2021-2023 Cost Effectiveness Review*, Docket Nos. G999/CIP-18-782, E999/CIP-18-783, February 11, 2020.
[3] Minnesota Energy Conservation and Optimization Act of 2021
[4] See Minn. Stat. § 216B.241, subd. 13.
[5] See Minn. Stat. § 216B.2403, subd. 8.
[6] Minn. Stat. § 216B.241, subd. 1c(b).
[7] Minn. Stat. § 216B.241, subd. 7(a).
[8] Minn. Stat. § 216B.2403, subd. 3.
[9] See Minn. Stat. §§ 216B.2403, subd 3(j) and 216B.241, subd. 2(i).
[10] https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90098F7F-0000-C11B-B04F-C063DF81A5F9}&documentTitle=20223-183807-01
[11] National Energy Screening Project (NESP), National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources(NSPM for DERs), August 2020. Available at:

2. National Standard Practice Manual for Distributed Energy Resources

For more than 30 years, utilities have used cost-effectiveness tests established by the California Standard Practice Manual (CaSPM).[12] The CaSPM sought to apply economic principles to the evaluation of demand-side programs as alternatives to supply-side resources (power plants and gas supply). It set parameters for assessing programs based on different perspectives, namely: participants, non-participants, all ratepayers, society, and the utility.

Minnesota Statutes dictate that Minnesota utilities and stakeholders examine "the costs and benefits to society, the utility, the participant, and ratepayers."[13] In practice, this has resulted in Minnesota's use of the CaSPM's four traditional benefit-cost tests: the Societal Cost Test (SCT), the Utility Cost Test (UCT), the Participant Cost Test (PCT), and the Ratepayer Impact Measure Test (RIM). Historically, while the utilities develop estimates for all four tests in their CIP plans and status reports, the Department has considered the SCT the Primary Test for CIP cost-effectiveness screening. The other three tests function as secondary tests that provide additional useful data about utility programs and portfolios. In addition, net benefits from the UCT have historically been used to determine utility performance incentives.

A large group of experts in the field of distributed energy resource (DER) program development and analysis established the NSPM for DERs as a means of updating the methods utilities and other DER practitioners use to assess the value of DER programs. [14] The NSPM for DERs seeks to modernize the CaSPM and advance the discourse related to how utilities develop, assess, select, and report on DERs. According to the authors:

- The traditional (CaSPM) tests often do not capture or address pertinent state policies;
- The traditional tests are often modified by states in an ad-hoc manner, without clear principles or guidelines;
- Efficiency is not accurately valued in many jurisdictions, and
- There is often a lack of transparency on why tests are chosen and how they are applied.[15]

3. Commerce Deputy Commissioner Decisions and Application of NSPM for DERs

Utilities regularly update their cost-effectiveness model inputs to coincide with the relevant planning period (IOUs currently submit CIP triennial plans that outline their proposed CIPs for the subsequent

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https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-04-2020_Final.pdf.

[12] "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects", October 2001. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf. The California Public Utilities Commission (CPUC) published the first "Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs" in 1983.

[13] Minn. Stat. § 216B.241, subd. 1c.

[14] "National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources." The Manual was subsequently modified and expanded to apply to all Distributed Energy Resources (DERs) and renamed "The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources." https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

[15] "National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM for DERs) – Overview", March 2022, p. 4. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

three years[16]). As part of this triennial process, the Department historically has updated the primary inputs that are incorporated into the gas BENCOST cost-effectiveness model, the electric IOUs have been responsible for updating their cost-effectiveness modeling inputs and, as part of its review of Triennial plans, Staff assess these inputs for reasonableness.

The Deputy Commissioner, in the February 11, 2020 Decision, adopted changes to BENCOST and electric utility modelling assumptions and discount rates for cost-effectiveness tests, and directed staff to "implement the initial scope of cost-effectiveness issues outlined in Section VI of this Decision *[Appendix B]* that the Department will explore in coordination with a Cost-Effectiveness Advisory Committee leading up to the 2024-2026 CIP Triennials."[17]

Of note, Staff's Proposed Decision and the Deputy Commissioner's Decision were informed by a report the Department commissioned as part of the Conservation Applied Research and Development (CARD) program. The report, authored by Synapse and titled "Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota" (Synapse Report) recommended that Minnesota apply the NSPM's principles to revise the State's energy efficiency cost-effectiveness tests. [18] Specifically, the Synapse Report recommended that decisionmakers consider:

- Establishing a "Minnesota Test";
- Whether to include Participant Impacts in the Primary Test (e.g. Non-Energy Impacts or NEIs);
- Whether to include other fuel impacts in the Primary Test; and
- Whether to include missing elements of the Utility Cost Test.

In order to comprehensively evaluate the relevant cost-effectiveness parameters, the NSPM for DERs recommends engaging in a 5-step process to define the Primary Test that should be used to evaluate DERs. The 5-steps are the following:

Step 1. Articulate Applicable Policy Goals.
Step 2. Include All Utility System Impacts.
Step 3. Decide Which Non-Utility System Impacts to Include.
Step 4. Ensure that Benefits and Costs are Properly Addressed.
Step 5. Establish Comprehensive, Transparent Documentation.

[16] Prior to 2006, utilities filed biennial plans. In 2006, Xcel Energy proposed its first Triennial Plan, an approach ultimately adopted by all IOUs.
[17] Deputy Commissioner Decision, "CIP Gas and Electric Utilities – 2021-2023 Cost-Effectiveness Review" (Docket Nos. G999/CIP-18-782, E999/CIP-18-783), February 11, 2020, p. 35.
[18] "Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota: Application of the National Standard Practice Manual to Minnesota", August 8, 2018, Conservation Applied Research and Development (CARD) Report, Prepared for Minnesota Department of Commerce, Division of Energy Resources by Synapse Energy Economics, Inc., p. 8 (hereafter termed the "Synapse Report"). https://mn.gov/commerce-stat/pdfs/card-synapse-cost-effectiveness.pdf.

According to the NPSM, the 5-step process is designed to produce a Primary Test that answers the question: **Which resources have benefits that exceed costs and, therefore, merit utility acquisition or support on behalf of their customers?**[19] The distinction between Primary and Secondary tests is that the Primary Test is the test that determines which measures and programs to include in the utility's portfolio and how the utility and regulator will decide whether their portfolio is "cost effective."[20] Secondary Tests are also important but tend to answer different questions such as: how much will utility bills on average be reduced (UCT), and how much will cost-effectiveness change if an additional policy goal is added or removed from the Primary Test? CIP historically has used the SCT as its Primary Test. Secondary Tests have included the UCT, the PCT, and the RIM.

Importantly, the NSPM for DERs also presents a set of principles to help guide jurisdictions in the development or revision to primary and secondary tests for evaluation of DERs. These principles are:

1. Recognize that DERs can provide energy system needs and should be compared with other energy resources and treated consistently in Benefit-Cost Analyses (BCA).
2. Align cost-effectiveness tests with the jurisdiction's applicable policy goals.
3. Ensure symmetry across costs and benefits.
4. Account for all relevant, material impacts (based on applicable policies), even if hard to quantify.
5. Conduct a forward-looking, long-term analysis that captures incremental impacts of DER investments.
6. Avoid double-counting through clearly defined impacts.
7. Ensure transparency in presenting the benefit-cost analysis and results.
8. Conduct BCAs separate from Rate Impact Analyses because they answer different questions.[21]

4. Cost-Effectiveness Advisory Committee Meetings

Per the Department's February 11, 2020 Decision, the CAC followed a process to develop CIP's new primary cost-effectiveness test, which is termed the Minnesota Cost Test (MCT). The Department invited Synapse to assist the CAC by conducting workshops to walk through the NSPM for DERs' 5-step process for developing a primary cost-effectiveness test. From the outset, Synapse indicated to the CAC that the quality of results from the Committee's workshops would depend upon active participation by and robust input from Committee members.

Throughout 2022, the CAC held eight meetings, with the first meeting serving as a kick-off. During meetings two through four, Synapse guided the CAC through the first three steps of the 5-step process to develop a Primary Test. In June 2022, based on input received from CAC members and prior to the fourth meeting, Synapse developed and distributed to the group a Straw Proposal for the MCT. Synapse presented the Straw Proposal at the fourth meeting and members engaged in robust discussions about its elements. The Department asked participants to provide written comments in response to the Straw Proposal. These comments are summarized in Appendix G.

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

[20] Per historical Department guidance, Minnesota IOU Conservation Improvement Programs must be cost-effective based on the Societal Test at the "segment" level. In other words, individual measures or programs need not be cost-effective but the segments (Residential, Commercial, etc.) into which programs are grouped must be cost-effective.

[21] CAC NSPM Workshop 1, May 4, 2022, slide 6.

Following the process to define the new MCT, The Mendota Group facilitated the CAC during meetings five through eight to develop appropriate methodologies to quantify the impacts that utilities will incorporate into their cost-effectiveness modeling to evaluate programs for the 2024-2026 CIP triennial plans.

The eight CAC meetings were held on the following dates:

- **Meeting #1: April 22, 2022** – Advisory Committee Kick-Off Meeting.

- **Phase I: Workshops on NSPM for DERs**
    - **Meeting #2: May 4, 2022** – NSPM Workshop on Step 1: Identify and discuss Minnesota applicable policy goals.
    - **Meeting #3: May 18, 2022** – NSPM Workshop on Step 2: Include all Utility System Impacts.
    - **Meeting #4: June 15, 2022** – NSPM Workshop on Step 3: Decide Which Non-Utility System Impacts to Include.
    - **Meeting #5: August 12, 2022 –** Discuss Working Group Report; Next Phase of CAC Process (Quantifying and Documenting Impacts); and Priority Impacts, Tasks, and Timeline.

- **Phase II: Developing Methodologies and Quantifying Impacts**
    - **Meeting #6: September 07, 2022 –** Cost-effectiveness and Program Design, Purpose and Structure of Secondary Tests; Key Takeaways from Homework Assignment #1.
    - **Meeting #7: October 14, 2022 –** Draft Utility System Impact Methodology Descriptions, Efficient Fuel-Switching and Load Management Cost-Effectiveness Analysis Guidelines, Plan for Feedback on Utility System Impact Methodologies and Estimating Process, Plan for Developing Other Required Information.
    - **Meeting #8: November 18, 2022 –** Utility System Impact Methodology Descriptions (Agreement, Disagreement, Recommendations), Content and Process for Developing Efficient Fuel-Switching and Load Management Guidance, Next Steps on Avoided Electric Energy/Capacity Costs and Updates to BENCOST Values, Next Steps Leading Up to Staff's Proposed Decision Filing.

The following sections provide a summary of the CAC's Phase I and Phase II activities. Additionally, interested parties can find CAC resources (meeting notes, presentations, and reports) that are uploaded to the following webpage: https://mendotagroup.com/mn-cost-effectiveness-ac/

B. Phase I of CAC Process: Workshops on NSPM for DERs (From Proposed Decision)

The NSPM for DERs aims for stakeholders to take a thoughtful, methodical, and comprehensive approach to developing the cost-effectiveness tests that will be used for DER evaluation and reporting purposes.

It should be noted that Synapse recommended from the outset, consistent with the NSPM for DERs, that the MCT apply to all DERs, not just conservation, energy efficiency, efficient fuel switching, and load management. Other DERs could include storage and on-site distributed energy such as solar. Although not explicitly discussed during CAC meetings, this remains a possibility. However, the CAC has focused its efforts on developing tests that could be applied to CIP, which includes energy efficiency and conservation, load management, and efficient fuel-switching programs.

In concept, cost-effectiveness tests are evaluating efficient measures (usually energy-consuming equipment) in terms of the benefits (avoided costs) they produce and costs incurred to implement the measures relative to standard or "baseline" measures. The CaSPM tests are fairly narrow in terms of the utility system and non-utility system costs and utility system and non-utility system benefits that are included in the main tests. Although the NSPM for DERs agrees with the CaSPM's use of utility system and non-utility system impacts, the NSPM for DERs broadens these categories to include additional quantifiable factors that are flagged for inclusion if they align with state policies.

The next sections describe the process that the CAC followed to analyze the factors to include in the Primary Test.

1. Step 1 – Articulate Applicable Policy Goals

The first step of the NSPM for DERs' 5-step process involves collecting the jurisdiction's policies that relate to categories identified for consideration in the cost-effectiveness tests and analyzing these policies to determine which policies are most applicable. As part of this exercise, Synapse emphasized the importance of grounding the jurisdiction's cost-effectiveness tests in policy goals as defined in statute, Commission orders, energy plans, and Executive orders. Analyzing policy goals is considered particularly important for determining the non-utility system impacts that should be included in the tests. These non-utility system impacts primarily relate to those that affect participants and, more broadly, society.[22]

Key in listing relevant policy goals is aligning them with non-utility system impacts that could be included in tests. The non-utility system impacts that could be affected by policy goals are included in Table 1.

Table 1 - Categories of Non-Utility System Impacts[23]

Category	Impact
Participant	Participant costs
	Participant benefits
Other fuels	Other fuels
Water	Water
Low-income	Low-income
Societal	GHG emissions
	Other environmental
	Public health
	Macroeconomic

[22] These contrast with utility system impacts (avoided costs) which, in Minnesota include marginal energy and capacity costs, transmission and distribution system costs, and costs associated with greenhouse gas reductions (GHGs).
[23] CAC NSPM Workshop 1, May 4, 2022, slide 26.

Category	Impact
	Energy Security
	Energy Equity
	Resilience

Staff produced a Minnesota Policy Inventory that compiled relevant Minnesota statutes and rules to serve as the basis for identifying applicable policy goals and mapping them to potential impact categories for use in the MCT. This document is included in Appendix C.

2. Step 2 – Include All Utility System Impacts

As homework following workshop one, Synapse asked CAC members to fill out a matrix designating which Non-Utility System impacts should be included in Minnesota's Primary Test (informed by the inventory and their own or their organization's views). Appendix D includes a table summarizing the responses. This information was considered preliminary given that CAC members were just learning about the Non-Utility System impacts that could be included and how they related to the Primary Test; they also had not yet had a chance to review Staff's Minnesota Policy Inventory. Synapse ultimately used this information, combined with discussions among participants and their own expertise to produce a Straw Proposal.

During workshop two, the CAC reviewed information provided by IOU participants about Utility System Impacts (USI) included in current CIP electric and gas cost-effectiveness tests, reviewed responses to Homework 1 (identifying Non-Utility System impacts to include in Minnesota's Primary Test), and discussed Non-Utility System impacts in the context of Minnesota policies. The information IOUs provided about what USIs are currently included in their CIP cost-effectiveness tests is in Appendix E.

As Synapse indicated during the workshop, USIs are foundational to DER cost-effectiveness analyses. DER program USIs indicate the extent to which DERs increase or decrease total Utility System costs. Synapse also emphasized that it is important to recognize the first principle that should guide development of a Primary Test, that DERs should be treated as a Utility System resource and that BCAs should account for all relevant, material impacts. In other words, similar to more traditional utility resources that have historically served customer electricity and gas needs (fossil and nuclear-fueled power plants and natural gas supplies), DERs include attributes that are not always quantified or factored into cost-effectiveness analyses.

Synapse also pointed out that it is important to distinguish between the question of *whether* an impact should be included in the test and the impact's *value.* The reason it is important to separate these two considerations is that whether or not an item can be valued or quantified should not dictate whether the impact is relevant. Synapse noted that it is helpful to categorize impacts as Utility System or Non-Utility System (participant, societal) to analyze how each fits into the cost-effectiveness framework.

Although workshop two did not focus on the differences in USIs between utilities and how each is included in their cost-effectiveness analyses, this is a topic that was discussed in subsequent CAC meetings. As shown in Appendix E, utilities currently differ in terms of the USIs they include in their cost-effectiveness analyses. The Deputy Commissioner's February 11, 2020 Decision emphasized the need to improve the transparency of avoided electric marginal energy and capacity costs. Similarly, transparency regarding what USIs utilities include in tests is also important.

The remainder of workshop two delved into greater detail on Non-Utility System impacts, their definitions, and which impacts the CAC believed should be included in the MCT. The categories of Non-Utility System impacts as shown in Table 1 are: Participant, Other Fuels, Water, Low-Income, and Societal. With respect to Participant Impacts (the category that received the most discussion), Synapse highlighted that most Participant Impacts are benefits, some are large and can be as (if not more) important to customers than energy benefits, they can vary across programs, and they can be difficult to quantify (and, therefore, frequently need to be based on approximations).[24] The term often used to describe non-energy impacts that may be included in cost-effectiveness tests is Non-Energy Benefits (NEBs) or Non-Energy Impacts (NEIs).

Participant Impacts, though, also include participant costs to purchase energy efficient equipment; Participants Costs are an input currently included in the Minnesota SCT and PCT.[25] In fact, Participant Costs, usually measured (for energy efficiency measures) in terms of the "incremental" cost associated with more efficient equipment relative to baseline (code or industry standard practice) equipment, have been a part of the CaSPM's Total Resource Cost Test, SCT, and PCT since their inception. As provided in the NSPM for DERs, however, this results in asymmetry in these calculations because the tests include participant costs but few, if any, participant benefits.[26] This violates principle 3 of the NSPM for DERs to "ensure symmetry across costs and benefits."

As shown in Appendix D, CAC members generally supported including Participant benefits and other Non-Utility System impacts in the Primary Test. Notable areas of agreement related to including Participant Costs and Benefits (with few saying "no"), Other Fuels, Water, and Low Income (LI). Among societal considerations, participants ranked including Greenhouse Gases (GHGs) highest (which makes sense since the current SCT includes a GHG factor), followed by Criteria Air Emissions, Energy Security, and Energy Equity. The strongest "no" votes related to including Societal factors Solid Waste and Land impacts. The areas not otherwise considered priorities based on "yes" votes (high "maybe" votes) included "Other Environmental" (8), Public Health (7), Macroeconomic (7), and Resilience (6).

Based on input received during the first two workshops, Synapse put together a Straw Proposal for presentation in workshop three. The Straw Proposal is provided in Appendix F.

As mentioned previously, the votes shows in Appendix D were considered preliminary because participants did not yet have full definitions of each of the items and had not had a discussion about the items. This occurred in subsequent workshops. Participant responses to the Synapse Straw Proposal, as discussed in Section 4, were based on more complete information.

3. Step 3 – Decide Which Non-Utility System Impacts to Include

a. Synapse Straw Proposal

i. Summary

Synapse took information gathered from CAC members and the Minnesota policy review and applied their understanding of the NSPM for DERs to develop a Straw Proposal of impacts that they

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[24] As highlighted by the NSPM's Principle 3, "account for all relevant, material impacts (based on applicable policies), even if hard to quantify", the need approximate is not a reason for not including such impacts.

[25] It is also incorporated into Minnesota's Technical Reference Manual for deemed measures.

[26] We note this as "few" because utilities have frequently included participant benefits such as operations and maintenance savings (including other fuel savings) in their netting of participant costs.

recommended the MCT include. The full Straw Proposal is provided in Appendix F. It is worth repeating here the NSPM for DERs principles for developing a jurisdiction's BCA test that Synapse used in developing its Straw Proposal:

- Principle 1: Treat DERs as a Utility System Resource. DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.
- Principle 2: Align with Policy Goals. Utilities invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the state's applicable policy goals and objectives.
- Principle 3: Ensure Symmetry. Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.
- Principle 4: Account for Relevant, Material Impacts. Cost-effectiveness tests should include all relevant (according to applicable policy goals) material impacts including those that are difficult to quantify or monetize.
- Principle 5: Conduct Forward-Looking, Long-term, Incremental Analyses. Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.
- Principle 6: Avoid Double-Counting Impacts. Cost-effectiveness analyses present a risk of double-counting benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double-counting.
- Principle 7: Ensure Transparency. Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.
- Principle 8: Conduct BCAs Separately from Rate Impact Analyses. Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses, and therefore should be conducted separately from rate impact analyses.[27]

A summary of the items Synapse included in and excluded from the Straw Proposal are shown in Table 2 below, along with indications of whether the item maps to Minnesota policy and how CAC members voted following workshop one.

Table 2 - Synapse Straw Proposal

	Category	Impact	Straw Proposal	Map to Policy	Homework Assignment		
					Yes	Maybe	No
Utility System	Electric Utility System	All	✓	N/A			
	Gas Utility System	All	✓	N/A			
Non-Utility System	Other Fuels	Other Fuels	✓	✓	9	3	0
	Water	Water	-		7	2	3

[27] NSPM for DERs, pg. iv.

	Category	Impact	Straw Proposal	Map to Policy	Homework Assignment		
					Yes	Maybe	No
	Participant	Participant Costs	✓	✓	7	4	1
		Participant Benefits	✓	✓	5	6	1
	Low-Income	Low-Income	✓	✓	7	3	1
Societal	Societal Impacts	GHG Emissions	✓	✓	12	0	0
		Criteria Air Emissions	✓	✓	6	5	0
		Solid Waste	Include in Other Environmental	✓	1	6	5
		Water Impacts	Include in Other Environmental		4	5	3
		Land Impacts	Include in Other Environmental		1	6	5
		Other Environmental	✓	✓	1	8	3
		Public Health	-		3	7	2
		Economic and Jobs	✓	✓	1	7	3
		Energy Security	✓	✓	6	3	3
		Energy Equity	✓	✓	5	6	1
		Resilience	-	✓	4	6	1

ii. Utility System Impacts

As provided in Step 2, the NSPM for DERs states that all USIs should be included in the Primary Test. This is important, as Synapse indicated, because, "It allows for DERs like energy efficiency to be treated consistently with other utility resources and ensures that at a minimum the cost-effectiveness test will show whether total Utility System costs are reduced or increased by the investment in energy efficiency."[28]

The Straw Proposal recommended set of electric and gas system impacts are shown in Tables 3 and 4. As Synapse observed, not all of these appear to be currently incorporated into MN BCAs. They also noted that it is vital that anything considered a regulatory cost or mandated cost be included as a Utility System Cost but that these elements, if already embedded within other Utility System Costs (e.g. Risk, Reliability, Resilience), should not be separately quantified in the cost-effectiveness test as this would double count the impacts. This observation would also extend to a social cost of carbon (GHGs) which should either be counted as a Utility System cost if it is considered a mandated or regulatory cost or as a Societal impact, but not in both.

[28] Straw Proposal, page 3.

Synapse recommended that regulators and utilities endeavor to quantify these items for the next CIP triennial and, if this is not possible given the timeframe, to prioritize those that have the greatest impacts and potentially use proxies or adders where gaps exist.

Table 3 – Synapse Proposed Electric Utility System Impacts Category

Category	Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load.
	Environmental Compliance	Actions to comply with environmental regulations. This can include compliance with federal regulations like the Clean Air Act or state or local greenhouse gas emissions mandates.
	Renewable Portfolio Standard Compliance	Actions to comply with renewable portfolio standards or clean energy standards.
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption.
	Ancillary Services	Services required to maintain electric grid stability and power quality (i.e., frequency regulation, voltage regulation, spinning reserves, and operating reserves).
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably.
	Transmission System Losses	Electricity lost through the transmission system.
Distribution	Distribution Costs	Maintaining the availability of the distribution system to transport electricity safely and reliably; includes capacity, O&M, voltage.
	Distribution System Losses	Electricity lost through the distribution system.
General	Program Incentives	Utility financial support to participants or other market actors; typically includes rebates, upstream payments, interest rate buy-down.
	Program Administration Costs	Utility outreach to trade allies, technical training, marketing, payments to third-party consultants, and administration and management of energy efficiency programs.
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of energy efficiency programs.
	Credit and Collection Costs	Utility costs associated with arrearages, disconnections, and reconnections.
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks.
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions.

Table 4 - Synapse Proposed Gas Utility System Impacts Category

Category	Impact	Description
Commodity/ Supply	Fuel	Purchasing gas at specific locations on the gas system and the variable cost of getting the gas where, and when, it will be used.
	Capacity & Storage	The gas and storage capacity required to meet forecasted peak load.
	Environmental Compliance	Actions to comply with environmental regulations.
	Market Price Effects	The decrease (or increase) in wholesale prices as a result of reduced (or increased) customer consumption.
Transportation	Transportation	The transport of gas from delivery points located on interstate and intrastate pipelines to distribution utility city gate.
Delivery	Delivery	Delivery of gas from the city gate to retail customers.
General	General	Same as Electric Utility System Impacts

iii. Non-Utility System Impacts

Non-Utility System impacts include Participant Impacts, Water Impacts, Other Fuels Impacts, Low-Income Participant Impacts, and Societal Impacts. Notably, Synapse further breaks Participant Impacts into Participant Energy and Participant NEIs.

Specific to Societal Impacts, Synapse stated in the Straw Proposal, that they are intended to "capture the impacts of energy efficiency to society, incremental to what may already be embedded in Utility System impacts."[29]

It is important that Non-Utility System Impacts not be double counted with USIs. For example, Criteria Air Emissions could also be included within Other Environmental. Economic and jobs relates to economic development and jobs resulting from DERs (both based on those who deliver the programs and the supply chains that benefit from the programs) and can be quantified based on changes in employment, personal income, increased tax revenues, and gross domestic product. Energy Equity relates to providing DERs to all customers, regardless of, among other criteria, ability, race, or socioeconomic status.

The list of Non-Utility System impacts that Synapse recommended to include in the MCT are shown in Table 5. The items to include in the Non-Utility System Impacts were based on linkages to Minnesota policy and input from CAC members.

[29] Straw Proposal, page 9.

Table 5 - Synapse Proposed Non-Utility System Impacts

Type	Impact	Description
Participant Energy Impacts[30]	Participant portion of DER costs	Costs incurred to install and operate DERs
	Participant transaction costs	Other costs incurred to install and operate DERs
	Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER. Should be incremental to that included in Utility System Impacts.
	Reliability	The ability to prevent or reduce the duration of host customer outages. Should be incremental to that included in Utility System Impacts.
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions. Should be incremental to that included in Utility System Impacts.
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
Participant Non-Energy Impacts	Water	Changes in water consumption resulting from a DER (e.g., reductions from low-flow showerheads, spray valves, clothes washers)
	Asset value	Changes in the value of a home or business resulting from a DER (e.g., increased building value, improved equipment value, extended equipment life)
	Productivity	Changes in a customer's productivity (e.g., changes in labor costs, operational flexibility, O&M costs, reduced waste streams, reduced spoilage)
	Economic well-being	Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)
	Comfort	Changes in comfort level (e.g., thermal, noise, and lighting impacts)
	Health & safety	Changes in customer health or safety (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths)

[30] The participant energy impacts should be included only if reasonable estimates of participant non-energy impacts are included as well, in order to ensure symmetry.

Type	Impact	Description
	Empowerment & control	The satisfaction of being able to control one's energy consumption and energy bill
	Satisfaction & pride	The satisfaction of helping to reduce environmental impacts (e.g., one of the reasons why residential customers install rooftop PV)
Other Fuels	N/A	The impact of other fuels captures the impacts on fuels that are not provided by the relevant utility, for example, electricity (for a gas utility), gas (for an electric utility), oil, propane, gasoline, and wood.
Low-Income	N/A	Benefits to low-income customers can be separately monetized to include values such as Safety-Related Emergency Calls, Thermal Comfort, Noise Reduction, Home Durability, Equipment Maintenance, Health Benefits, and/or Improved Safety, to cite some examples. Although currently MN Low-Income programs need not pass the Societal Test to be included in utility portfolios, Synapse suggests that the MCT could include Low-Income-specific elements as an alternative to the current approach.
Water[31]	N/A	Investments in energy efficiency can reduce water consumption.
Societal Impacts	GHG Emissions	Non-embedded GHG emissions. Should be incremental to values included in Utility System impacts.
	Criteria Air Emissions	Emissions of criteria pollutants such as carbon monoxide, lead, nitrogen oxides, ground-level ozone, particulate matter, and sulfur oxides.
	Other Environmental[32]	Catch-all for all other environmental impacts to include other air emissions, solid waste, land, water, and other environmental impacts.
	Economic and Jobs (Macroeconomic)	Incremental economic development and job impacts.
	Energy Security	Reduction in imports of various forms of energy to help inform the goals of energy independence and security.
	Energy Equity	Energy equity requires intentionally designing systems, technology, procedures, and policies that lead to the fair and just distribution of benefits in the energy system.

[31] Synapse does not include water in its Straw Proposal because there was no clear linkage to Minnesota policy. This item is included definitional purposes.
[32] As shown in Table 3, Other Environmental consolidates the previously enumerated Solid Waste, Water, and Land Impacts but also includes other environmental impacts.

Type	Impact	Description
	Public Health[33]	Energy resources can create health impacts for populations impacted by fuel extraction, combustion and transportation.
	Resilience	Resilience impacts beyond those experienced by utilities or host customers. This resilience is different from Utility System Impact resilience.

b. Discussion During Workshop 3

Workshop three focused on discussing the Straw Proposal and Synapse's rationale for items it chose to include or exclude in the proposed Primary Test. Importantly, on the topic of whether to include Participant Costs and Participant Benefits, the Straw Proposal opted to include both, and suggested a set of NEIs that Minnesota could include in its test.

The first part of the meeting discussed Participant Impacts and how including Participant NEIs can affect programs differently within a utility's portfolio. Synapse observed that NEIs typically have the largest impact on residential and low-income programs due to the types of measures commonly included such as weatherization and heating systems that have relatively large NEI values related to health, comfort, and safety compared to measures found in commercial programs. Using a Rhode Island example, Synapse demonstrated this observation (see Table 6).

Table 6 – Example Magnitude of Non-Energy Impacts on Sectoral Programs[34]

Sector	Program	NEIs as % of Total Benefits
Residential	New Construction	2%
	HVAC	3%
	Single-Family Retrofit	8%
	Multi-Family Retrofit	31%
	Behavioral	0%
	Products	0%
Low-Income	Single-Family Retrofit	44%
	Multi-Family Retrofit	47%
Commercial & Industrial	New Construction	5%
	Retrofit	14%
	Small Business	15%

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[33] Synapse does not include Public Health or Societal-Impacts associated with Resilience in its Straw Proposal because there was no clear linkage to Minnesota policy. These items are included definitional purposes.
[34] National Grid Rhode Island, 2022 Energy Efficiency Plan, Attachment 5, Table E-6 (without CHP Project and Economic Benefits).

This portion of the meeting also discussed the ways utilities can develop NEIs to include in their analyses. Table 7 provides further detail on the Participant Costs and Participant Benefits included in the Synapse Straw Proposal.

Table 7 - Participant Impact Detail

Type	Participant Impact	Description
Participant	Participant portion of DER costs	Costs incurred to install and operate DERs
	Participant transaction costs	Other costs incurred to install and operate DERs
	Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER
	Reliability	The ability to prevent or reduce the duration of host customer outages
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
	Participant NEIs	Benefits and costs of DERs that are separate from energy-related impacts

NEIs	Description
Water	Changes in water consumption resulting from a DER (e.g., reductions from low-flow showerheads, spray valves, clothes washers).
Asset value	Changes in the value of a home or business as a result of the DER (e.g., increased building value, improved equipment value, extended equipment life)
Productivity	Changes in a customer's productivity (e.g., changes in labor costs, operational flexibility, O&M costs, reduced waste streams, reduced spoilage)
Economic well-being	Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)
Comfort	Changes in comfort level (e.g., thermal, noise, and lighting impacts)
Health & safety	Changes in customer health or safety (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths)
Empowerment & control	The satisfaction of being able to control one's energy consumption and energy bill
Satisfaction & pride	The satisfaction of helping to reduce environmental impacts (e.g., one of the reasons why residential customers install rooftop PV)

Examples of ways that NEIs can be estimated include: through jurisdiction and program-specific studies, by leveraging existing studies that have already quantified NEIs though primary research (CA, MA, RI), and developing NEI proxies (this typically done as a percentage adder applied to total energy benefits for a specific program or sector).

Much of the discussion during workshop three centered around two topics, namely whether to include Participant Impacts and what to include in terms of other Non-Utility System Impacts. Some participants argued that complexities associated with (and contentiousness related to) quantifying NEIs dictated that the MCT should exclude both Participants Costs and Participant Benefits. At least one participant countered this point-of-view by stating that removing Participant Costs could distort BCAs, facilitate programs with large amounts of free riders and lead to promoting marginal energy efficiency measures. Synapse pointed out that, even if Participant Costs and Benefits are removed from the Primary Test that Participant Impacts can be incorporated by using the PCT as a Secondary Test. How the Secondary Test would be incorporated into utility and regulator decision-making would need to be clarified, though, since under current Minnesota CIP practice secondary tests have no practical role.[35]

[35] As mentioned earlier in this Report, Synapse explained in their Straw Proposal (p. 3) that the "purpose of a primary test is to inform whether an IOU's proposed investments in energy efficiency create more benefits than costs and therefore merit approval. The primary test is the main determinant of whether a program should be included in the Triennial Plan. Secondary tests can be developed to help enhance the overall understanding of energy efficiency impacts. The additional information from a secondary test can help to prioritize energy efficiency programs and to inform decisions regarding marginally cost-effective programs and allocation of resources. The secondary test is not intended to undermine the purpose of the primary test and may include a subset of the impacts included in the primary test or additional impacts."

There was also discussion around whether the list of Societal Impacts was sufficiently complete with some arguing that Public Health should also be included. There were also questions about other impacts Synapse excluded from the Straw Proposal, namely Water (Non-Utility System Impact) and Resilience (Societal Impact). Participants were asked to provide written feedback on the Synapse Straw Proposal, specifically regarding areas of agreement and disagreement. The next section discusses CAC member comments on Synapse's Straw Proposal.

4. Comments on the Synapse Straw Proposal

The Department received comments from ten CAC members on Synapse's Straw Proposal.[36] Overall, CAC members supported the Straw Proposal's approach, with the largest areas of disagreement around treatment of Participant Impacts, whether or not Low-Income-specific elements should be included, and whether to include utility performance incentives and Risk, Reliability, and Resilience in Utility System Impacts.

There were items in the Synapse Straw Proposal that received general consensus support among members, mainly related to USIs. Regarding USIs, most participants supported the Straw Proposal approach to including all impacts (other than utility performance incentives), although OTP and Xcel contended that items such as Risk, Reliability, and Resilience were already embedded within other factors. Xcel also questioned including Credit and Risk because it was not clear that energy efficiency has a large impact on credit and collections. Although there were some strong differences of opinion regarding specific Non-Utility System and Societal Impacts to include in the Primary Test, there was general agreement on most components.

A summary of comments from CAC members is provided in Appendix G.

5. Staff Working Group Report

Leading up to meeting five, Staff and The Mendota Group reviewed and summarized Committee comments, developed Staff recommendations for the MCT, and drafted the Minnesota Cost-Effectiveness Advisory Committee Working Group Report (Working Group Report).[37] The Working Group Report provided a summary of the activities of the CAC and identified next steps for the Committee in developing a MCT that could be used as CIP's Primary Test for screening energy efficiency, load management, and efficient fuel-switching programs. The Working Group Report was distributed to the CAC on August 18, 2022 and was the focus of discussion during meeting five.

As discussed in more detail in the Working Group Report, overall, Staff agreed with the impacts that Synapse's Straw Proposal recommended to include in the MCT. Tables 8-11 summarize the Utility and Non-Utility System impacts that Staff recommended be included in the MCT. Those impacts that were included in the Synapse Straw Proposal but Staff recommended removing are reflected by ~~strikeouts~~. Staff did not recommend adding any items to Synapse's list. Generally, Staff's recommended impacts aligned with the Synapse Straw Proposal and the CAC's written comments.

[36] We count Minnesota Energy Resources Corporation in this number although MERC simply responded, "MERC has no comments at this time. However, we appreciate the thoughtful and methodical direction you all have provided, along with the Synapse team, and looking forward to continued participation in the CEAC."
[37] The Working Group Report can be downloaded here: https://mendotagroup.com/mn-cost-effectiveness-ac/#WGReport1

Table 8 - Electric USIs that Staff's Working Group Report Recommended Including in MCT

Category	Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load.
	Environmental Compliance	Actions to comply with environmental regulations. This can include compliance with federal regulations like the Clean Air Act or state or local greenhouse gas emissions mandates.
	Renewable Portfolio Standard Compliance	Actions to comply with renewable portfolio standards or clean energy standards.
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption.
	Ancillary Services	Services required to maintain electric grid stability and power quality (i.e., frequency regulation, voltage regulation, spinning reserves, and operating reserves).
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably.
	Transmission System Losses	Electricity lost through the transmission system.
Distribution	Distribution Costs	Maintaining the availability of the distribution system to transport electricity safely and reliably; includes capacity, O&M, voltage.
	Distribution System Losses	Electricity lost through the distribution system.
General	Program Incentives	Utility financial support to participants or other market actors; typically includes rebates, upstream payments, interest rate buy-down.
	Program Administration Costs	Utility outreach to trade allies, technical training, marketing, payments to third-party consultants, and administration and management of energy efficiency programs.
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of energy efficiency programs.
	Credit and Collection Costs	Utility costs associated with arrearages, disconnections, and reconnections.
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks.
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions.

Table 9 - Gas USIs that Staff's Working Group Report Recommended Including in MCT

Category	Impact	Description
Commodity/ Supply	Fuel	Purchasing gas at specific locations on the gas system and the variable cost of getting the gas where, and when, it will be used.
	Capacity & Storage	The gas and storage capacity required to meet forecasted peak load.
	Environmental Compliance	Actions to comply with environmental regulations.
	Market Price Effects	The decrease (or increase) in wholesale prices as a result of reduced (or increased) customer consumption.
Transportation	Transportation	The transport of gas from delivery points located on interstate and intrastate pipelines to distribution utility city gate.
Delivery	Delivery	Delivery of gas from the city gate to retail customers.
General	General	Same as Electric Utility System Impacts

Table 10 - Non-Utility System Impacts that Staff's Working Group Report Recommended Including in MCT

Type	Participant Impact	Description
~~Participant Energy Impacts~~	~~Participant portion of DER costs~~	~~Costs incurred to install and operate DERs~~
	~~Participant transaction costs~~	~~Other costs incurred to install and operate DERs~~
	~~Risk~~	~~Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER. Should be incremental to that included in Utility System Impacts.~~
	~~Reliability~~	~~The ability to prevent or reduce the duration of host customer outages. Should be incremental to that included in Utility System Impacts.~~
	~~Resilience~~	~~The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions. Should be incremental to that included in Utility System Impacts.~~
	~~Tax incentives~~	~~Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs~~
~~Participant Non-Energy Impacts~~	~~Water~~	~~Changes in water consumption resulting from a DER (e.g., reductions from low-flow showerheads, spray valves, clothes washers)~~

Type	Participant Impact	Description
	~~Asset value~~	~~Changes in the value of a home or business resulting from a DER (e.g., increased building value, improved equipment value, extended equipment life)~~
	~~Productivity~~	~~Changes in a customer's productivity (e.g., changes in labor costs, operational flexibility, O&M costs, reduced waste streams, reduced spoilage)~~
	~~Economic well-being~~	~~Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)~~
	~~Comfort~~	~~Changes in comfort level (e.g., thermal, noise, and lighting impacts)~~
	~~Health & safety~~	~~Changes in customer health or safety (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths)~~
	~~Empowerment & control~~	~~The satisfaction of being able to control one's energy consumption and energy bill~~
	~~Satisfaction & pride~~	~~The satisfaction of helping to reduce environmental impacts (e.g., one of the reasons why residential customers install rooftop PV)~~
Other Fuels	N/A	The impact of other fuels captures the impacts on fuels that are not provided by the relevant utility, for example, electricity (for a gas utility), gas (for an electric utility), oil, propane, gasoline, and wood.
~~Low-Income~~	~~N/A~~	~~Benefits to low-income customers can be separately monetized to include values such as Safety-Related Emergency Calls, Thermal Comfort, Noise Reduction, Home Durability, Equipment Maintenance, Health Benefits, and/or Improved Safety, to cite some examples. Although currently MN Low-Income programs need not pass the Societal Test to be included in utility portfolios, Synapse suggests that the MCT could include Low-Income-specific elements as an alternative to the current approach.~~
~~Water~~[38]	~~N/A~~	~~Investments in energy efficiency can reduce water consumption.~~

[38] Synapse does not include water in its Straw Proposal because there was no clear linkage to Minnesota policy. This item is included definitional purposes.

Table 11 - Societal Impacts that Staff's Working Group Report Recommended Including in MCT

Category	Impact	Description
Societal Impacts	GHG Emissions	Non-embedded GHG emissions. Should be incremental to values included in Utility System impacts.
	Criteria Air Emissions	Emissions of criteria pollutants such as carbon monoxide, lead, nitrogen oxides, ground-level ozone, particulate matter, and sulfur oxides.
	Other Environmental	Catch-all for all other environmental impacts to include other air emissions, solid waste, land, water, and other environmental impacts.
	Economic and Jobs (Macroeconomic)	Incremental economic development and job impacts.
	Energy Security	Reduction in imports of various forms of energy to help inform the goals of energy independence and security.
	Energy Equity	Energy equity requires intentionally designing systems, technology, procedures, and policies that lead to the fair and just distribution of benefits in the energy system.
	~~*Public Health*~~[39]	~~Energy resources can create health impacts for populations impacted by fuel extraction, combustion and transportation.~~
	~~*Resilience*~~	~~Resilience impacts beyond those experienced by utilities or host customers. This resilience is different from Utility System Impact resilience.~~

C. Phase II of CAC Process: Developing Methodologies and Quantifying Impacts (From Proposed Decision)

During Phase II of the CAC process, the Committee focused on identifying methodologies and attempting to quantify Utility System, Non-Utility System, and Societal Impacts that utilities will incorporate into their cost-effectiveness modeling to evaluate programs for the 2024-2026 CIP Triennials. This part of the process also included documenting the methodologies and the sources.

This phase of the CAC required a multi-step approach and prioritization of which impacts would be examined first. The process began by analyzing the USI methods. There was also considerable homework for the CAC between meetings to ensure that the process remained on track.

Below is a summary of the three CAC meetings that were held during Phase II of the process:

- **Meeting #6: September 07, 2022 –** Cost-effectiveness and Program Design, Purpose and Structure of Secondary Tests; Key Takeaways from Homework Assignment #1.
- **Meeting #7: October 14, 2022 –** Draft Utility System Impact Methodology Descriptions, Efficient Fuel-Switching and Load Management Cost-Effectiveness Analysis Guidelines, Plan for Feedback on Utility System Impact Methodologies and Estimating Process, Plan for Developing Other Required Information.

[39] Synapse does not include Public Health or Societal-Impacts associated with Resilience in its Straw Proposal because there was no clear linkage to Minnesota policy. These items are included definitional purposes.

- **Meeting #8: November 18, 2022 –** Utility System Impact Methodology Descriptions (Agreement, Disagreement, Recommendations), Content and Process for Developing Efficient Fuel-Switching and Load Management Guidance, Next Steps on Avoided Electric Energy/Capacity Costs and Updates to BENCOST Values, Next Steps Leading Up to Staff's Proposed Decision Filing.

This phase of the CAC focused on the following key tasks, which are discussed in more detail in the following sections:

- **Task 1: Develop Utility System Impacts**
  - Developing documentation regarding how these factors are calculated and guidance regarding sources that utilities can use to develop estimates and incorporate into their cost-effectiveness modeling.
  - Reviewing utility-proposed 2024-2026 electric avoided costs.
  - Reviewing and updating 2024-2026 gas BENCOST inputs.

- **Task 2: Develop Non-Utility System Impacts**
  - Similar to Utility System Impacts, this task involve developing documentation regarding how the Non-Utility System impacts are calculated and guidance regarding the sources that utilities use to develop estimates and incorporate into their cost-effectiveness modeling.

- **Task 3: Develop Efficient Fuel-Switching and Load Management Cost-Effectiveness Guidance**
  - This applies the approach adopted for the Primary Test to evaluation of Efficient Fuel-Switching and Load Management CIP programs. The Guidance also sought to address EFS/LM-related questions raised by CAC members.

- **Task 4: Determining Discount Rates to Use in Cost-Effectiveness Analyses**
  - Document and estimate the discount rates utilities will use in their cost-effectiveness analyses.

- **Task 5: Secondary Cost-Effectiveness Tests and Program Design**
  - How the secondary tests apply to cost-effectiveness screening and to inform program design decisions.

1. Utility System Impacts

a. Avoided Electric Marginal Energy and Capacity Costs

On August 24, 2022, Staff distributed a homework assignment to the CAC in preparation for CAC meeting six. For full details regarding Staff's request, the homework assignment can be found in Appendix I. As part of the CAC's August 31, 2022, responses to the homework assignment, the CAC provided input related to avoided electric costs. Key takeaways from the homework related to the avoided costs include:

- There were differing views on standardizing electric avoided cost methodologies and Trade Secret designations:
  - Center for Energy and Environment (CEE) and Xcel support standardizing methodologies – MP and OTP prefer using own approaches;

- MP, OTP and Xcel believe Trade Secret must remain for marginal energy and capacity costs – CEE wants more transparency and Xcel says willing to work directly with parties to share, and
- Continued use of the Discrete Approach methodology for transmission and distribution (T&D) avoided costs is acceptable with MP and Xcel, but OTP concerned about the costs required to develop estimates using the Discrete Approach.

On November 7, 2022, Staff requested that the CAC provide additional feedback on avoided electric and marginal energy and capacity costs. Staff's feedback request is provided below for context:

Feedback Requested:

Questions for Electric IOUs

We request that the electric IOUs describe how they can improve the transparency of their avoided electric marginal energy and capacity costs. If CIP's approved electric avoided marginal energy and capacity costs are allowed to be based on the values found in the IOUs' integrated resource plans (IRPs), would the electric IOUs agree to the following:

- Provide their avoided cost data in some level of detail that is not considered Trade Secret? What level of detail would be acceptable to not treat as Trade Secret (hourly, daily, monthly, annually)?
- If a stakeholder requested more detailed avoided marginal or capacity costs that the utility considers Trade Secret, are the electric IOUs willing to sign an NDA with that stakeholder and then share the data with the requesting stakeholder?

Questions for Entire CAC

If the electric IOUs are allowed to use the avoided electric marginal energy and capacity costs from their IRPs for their CIP cost-effectiveness analysis, would the CAC be supportive of the following to improve the transparency of the avoided costs:

- Require that the electric IOUs provide clear documentation of their avoided marginal energy and capacity cost methodology approaches as part of their Triennial Filings, including a description of the following -
    - Data sources;
    - Model runs;
    - A comparison against previously approved avoided costs, how the values changed, and why they changed;
    - Provide a higher level/non-Trade Secret table of their avoided marginal energy and or capacity cost values (see above question to electric IOUs)?

On November 17, 2022, the CAC provided their written feedback related to avoided electric costs. On November 18, 2022, during CAC meeting eight, there was discussion of key takeaways based on the CAC's November 17, 2022, written comments. Notes and takeaways from meeting eight can be found in Appendix I.

b. Utility System Impact Methodology Descriptions

The Mendota Group led the development of draft USI methodology descriptions and estimates for the respective impacts and distributed the information for CAC feedback. Priority was given to those USIs that had higher potential impacts on overall cost-effectiveness results and available data (given the short timeframe available to collect the data). Synapse provided recommendations regarding the USIs likely to have the greatest impact. In compiling the USI methodology descriptions, The Mendota Group generally recommended selecting the more straightforward estimation method based on the belief that overly complex estimation methods would require more time and effort and, ultimately, cost more to produce.

On August 24, 2022, Staff distributed a homework assignment to the CAC in preparation for CAC meeting six. For full details regarding Staff's request, the homework assignment can be found in Appendix I. In the CAC's August 31, 2022, responses to the homework assignment, the CAC provided input related to the USIs. Key takeaways from the homework included:

- General CAC support for list of prioritized USI inputs, with some caveats -
    - Add Risk and Benefits of reducing energy imports (American Council for an Energy-Efficient Economy, ACEEE);
    - Add Credit and collection costs (CPE), and
    - Quantify impacts that are reasonably likely to have a meaningful effect on cost-effectiveness calculations (Xcel).

Given the allotted time available to develop estimates, the approach focused on finding reasonable proxy values for priority USIs. Although the more simplified methods may be less accurate, as this is the first time Minnesota utilities will be including these values in their CIP cost-effectiveness analyses, it is important to have starting point values with an understanding that future triennials can incorporate different methods for developing criteria estimates.

Table 12. List of Utility System Impacts

Electric Utility System Impact	Gas Utility System Impact
Energy*	Fuel*
Capacity*	Capacity & Storage*
<u>Environmental Compliance</u>	<u>Environmental Compliance</u>
<u>Renewable Portfolio Standard Compliance</u>	<u>Market Price Effects</u>
<u>Market Price Effects</u>	Transportation*
<u>Ancillary Services</u>	Delivery*
<u>Utility Performance Incentives</u>	Program Incentives *
Transmission Capacity*	Program Administration Costs*
Transmission System Losses*	<u>Utility Performance Incentives</u>
Distribution Costs*	<u>Credit and Collection Costs</u>
Distribution System Losses*	<u>Risk</u>
Program Incentives*	<u>Reliability</u>
Program Administration Costs*	<u>Resilience</u>
<u>Credit and Collection Costs</u>	
<u>Risk</u>	
<u>Reliability</u>	
<u>Resilience</u>	

Table Key: * Are part of current CIP cost effectiveness analyses. <u>Underlined</u> are new priority impacts.

On October 14, 2022, during CAC meeting seven, The Mendota Group provided an initial overview and discussion of the draft USI methodology descriptions. Notes and takeaways from meeting seven can be found in Appendix I. On October 21, 2022, The Mendota Group distributed the draft USI methodology descriptions to the CAC for review and comment.

On November 18, 2022, during CAC meeting eight, there was discussion around areas of agreement, disagreement, and proposed recommendations, which was based on a synthesis of the CAC's November 1, 2022 written comments on the draft USI methodology descriptions. Notes and takeaways from meeting eight can be found in Appendix I.

c. Gas BENCOST Inputs

The inputs that the Department requires the gas IOUs use to evaluate the cost-effectiveness of their CIPs are found in a regulatory filing document called the Inputs to BENCOST for Gas IOUs. The Department provides a description and the sources for each of the inputs in the BENCOST regulatory filing document.

On August 24, 2022, Staff distributed a homework assignment to the CAC in preparation for CAC meeting six. For full details regarding Staff's request, the homework assignment can be found in Appendix I.

In the CAC's August 31, 2022, responses to the homework assignment, the CAC provided input related to the BENCOST inputs. Key takeaways from the homework included:

- BENCOST inputs should be updated to current values, but some CAC members were interested in revising the input values to reflect price volatility and higher commodity price forecasts (ACEEE, Fresh Energy, CEE);
- Some members believe that transportation and delivery are already incorporated in the current BENCOST model so don't consider these "new"; and
- CEE had several specific suggested changes to inputs.

On November 7, 2022, Staff requested that utility CAC members provide data related to updating the BENCOST's Commodity Cost input and the Non-Gas Fuel Loss Factor input.

On December 1, 2022, the utility CAC members provided the data that Staff needed to update these two BENCOST inputs.

2. Non-Utility System Impacts

On November 7, 2022, Staff requested that the CAC provide feedback on non-utility system impacts. Staff's feedback request is provided below for context:

> **Feedback Requested:**
> We request that the CAC provide any feedback on a methodology to quantify the GHG Emissions Non-Utility System Impact (i.e. non-embedded GHG emissions that should be incremental to values included in Utility System Impacts).
>
> **Context:**
> As noted in the 8/18/2022 "Minnesota CAC Working Group Report v2," below is a list of the non-utility system impacts that CIP Staff recommended be included in the MCT. Non-Utility

System Impacts remain important. However, other than determining a value for GHG Emissions, we will not be able to develop estimates for the other non-utility system impacts as part of this process. This concluding phase of the CAC process requires prioritization in order to complete the currently in progress updates. However, Department CIP Staff view developing the MCT as something that will be refined and built upon going forward.

Table 13. Summary of Non-Utility System Impacts

Type	Participant Impact	Description
~~Participant Energy Impacts~~	~~Participant portion of DER costs~~	~~Costs incurred to install and operate DERs~~
	~~Participant transaction costs~~	~~Other costs incurred to install and operate DERs~~
	~~Risk~~	~~Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER. Should be incremental to that included in Utility System Impacts.~~
	~~Reliability~~	~~The ability to prevent or reduce the duration of host customer outages. Should be incremental to that included in Utility System Impacts.~~
	~~Resilience~~	~~The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions. Should be incremental to that included in Utility System Impacts.~~
	~~Tax incentives~~	~~Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs~~
~~Participant Non-Energy Impacts~~	~~Water~~	~~Changes in water consumption resulting from a DER (e.g., reductions from low-flow showerheads, spray valves, clothes washers)~~
	~~Asset value~~	~~Changes in the value of a home or business resulting from a DER (e.g., increased building value, improved equipment value, extended equipment life)~~
	~~Productivity~~	~~Changes in a customer's productivity (e.g., changes in labor costs, operational flexibility, O&M costs, reduced waste streams, reduced spoilage)~~
	~~Economic well-being~~	~~Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)~~
	~~Comfort~~	~~Changes in comfort level (e.g., thermal, noise, and lighting impacts)~~

Type	Participant Impact	Description
	~~Health & safety~~	~~Changes in customer health or safety (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths)~~
	~~Empowerment & control~~	~~The satisfaction of being able to control one's energy consumption and energy bill~~
	~~Satisfaction & pride~~	~~The satisfaction of helping to reduce environmental impacts (e.g., one of the reasons why residential customers install rooftop PV)~~
Other Fuels	N/A	The impact of other fuels captures the impacts on fuels that are not provided by the relevant utility, for example, electricity (for a gas utility), gas (for an electric utility), oil, propane, gasoline, and wood.
~~**Low-Income**~~	~~N/A~~	~~Benefits to low-income customers can be separately monetized to include values such as Safety-Related Emergency Calls, Thermal Comfort, Noise Reduction, Home Durability, Equipment Maintenance, Health Benefits, and/or Improved Safety, to cite some examples. Although currently MN Low-Income programs need not pass the Societal Test to be included in utility portfolios, Synapse suggests that the MCT could include Low-Income-specific elements as an alternative to the current approach.~~
~~**Water**~~[40]	~~N/A~~	~~Investments in energy efficiency can reduce water consumption.~~

[40] Synapse does not include water in its Straw Proposal because there was no clear linkage to Minnesota policy. This item is included definitional purposes.

Table 14. Summary Societal Impacts

Category	Impact	Description
Societal Impacts	GHG Emissions	Non-embedded GHG emissions. Should be incremental to values included in Utility System impacts.
	Criteria Air Emissions	Emissions of criteria pollutants such as carbon monoxide, lead, nitrogen oxides, ground-level ozone, particulate matter, and sulfur oxides.
	Other Environmental	Catch-all for all other environmental impacts to include other air emissions, solid waste, land, water, and other environmental impacts.
	Economic and Jobs (Macroeconomic)	Incremental economic development and job impacts.
	Energy Security	Reduction in imports of various forms of energy to help inform the goals of energy independence and security.
	Energy Equity	Energy equity requires intentionally designing systems, technology, procedures, and policies that lead to the fair and just distribution of benefits in the energy system.
	~~*Public Health*~~[41]	~~Energy resources can create health impacts for populations impacted by fuel extraction, combustion and transportation.~~
	~~*Resilience*~~	~~Resilience impacts beyond those experienced by utilities or host customers. This resilience is different from Utility System Impact resilience.~~

On December 15, 2022, the CAC provided their written feedback on non-utility system impacts. Staff provided a synthesis of takeaways from the CAC's response below.

Areas of Agreement

MCT and Societal Cost Tests

- Most respondents (CEE, Department Energy Regulation and Planning Staff [ERP Staff], CPE, Fresh Energy, Xcel) agree that utilities should use the Minnesota Public Utilities Commission's [PUC] approved high-end externality values for greenhouse gas emissions (with three exceptions – Synapse, MP, and OTP).
- Xcel points out the importance of aligning the values between gas and electric utilities. They also indicated that they used the high GHG values in their electric 2021-2023 cost-effectiveness calculations.

Areas of Disagreement

GHG Emissions Value

- MP supports the "reference case which is mid-carbon regulation cost starting in 2025" to align with IRPs.[42] MP also points out that these carbon costs generally apply to electric utilities and not gas utilities. They believe the carbon costs should apply to both utility types.

[41] Synapse does not include Public Health or Societal-Impacts associated with Resilience in its Straw Proposal because there was no clear linkage to Minnesota policy. These items are included definitional purposes.

[42] 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs (Docket Nos. E999/CI-07-1199 and E999/DI-19-406). Note that Xcel says that, for their IRP, they used the high range. I'm a bit surprised that the PUC would allow MP to use the mid-range and Xcel to use the high-range. This may require some further investigation.

- OTP does not oppose including the GHG Emissions Non-Utility System Impacts in the MCT and SCT, but "believes it would be appropriate to use a proxy of 0 for these values the 2024-2026 Triennial and adjust once the methodology is developed. However, Otter Tail cautions against adding GHG Emission Non-Utility impacts in a primary test when the utility's Integrate Resource Plan does not include these impacts. Supply-side resources and demand-side resources should use inputs that keep alignment between them for most cost-effective resource selection."
- Synapse argues that the PUC's high externality is too low, pointing to the EPA's Social Cost of Carbon which "has become the 'conventional' source for determining the value of GHG emissions, at least in some states." That value is approximately $195/ton, "which is a lot higher than the $25.76/ton in 2020 from the Commission's January 3, 2018 Order Updating Environmental Cost Values."

Way the GHG Emissions Value is incorporated

- CEE and Fresh Energy emphasize that the avoided cost values should be presented on an annualized basis (vs. a single value with an escalator).

Other Issues

Criteria Pollutants (also termed Criteria Air Emissions)

- The PUC's Order Updating Environmental Cost Values also includes range estimates for criteria pollutants. Some respondents addressed criteria pollutants (in previous discussions about the MCT, Fresh Energy recommended including criteria air pollutants within Public Health). CPE commented that they were anticipating that the methodology for calculating criteria air emissions in BENCOST would not change with this Triennial. MP commented that criteria air emissions, like GHGs, should use the mid-range. OTP stated that they did not oppose including criteria air emissions in the Societal Test but would need guidance regarding calculating it. Xcel indicated that their IRP used high and low values for each of the three geographic regions and that their 2021-2023 used high-end values.

3. Draft Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance

On November 7, 2022, The Mendota Group and Staff distributed a draft version of the Efficient Fuel-Switching (EFS) and Load Management (LM) Cost-Effectiveness Technical Guidance for CAC review. Staff requested that the CAC provide feedback on the draft document, specific to how EFS and LM cost-effectiveness should be evaluated.

Tables 15 and 16 summarize topics that were included in the draft technical guidance and were presented during CAC meeting eight on November 18, 2022:

Table 15. Draft Efficient Fuel-Switching Guidance

Topic	Draft Proposed
Modelling Gas and Electric Projects/Programs	Model as combined gas/electric project or program (vs. modelling gas and electric separately).
Other Costs	SCT and PCT should include ancillary electrification costs such as panel upgrades.
Retail Rates	Include up-to-date and most relevant retail rates in cost-effectiveness modelling.
Shared Utility Projects	Model cost-effectiveness and report based on financial contributions to projects/programs.
Program-Level Filing and Program Information	Programs that combined EFS, LM, EE should report savings for each component separately.
Low-Income Programs	Low-income programs need not be cost-effective per the MCT.
Combination Programs	Utilities can combine EFS, LM, and EE elements into programs; however, for EFS, need to qualify measures based on ECO Act Guidance.

Table 16. Draft Load Management Guidance

Topic	Proposed
Avoided Costs	Use single method for estimating avoided energy and capacity costs.
First-Year and Lifecycle Savings	Use lifetimes that align with equipment to which load management activities apply.
Conservation and Load Management	Utilities can offer load shifting programs but does not qualify as conservation unless has energy savings.
Programs with Load Management Elements	Programs that combine LM with other elements should submit for approval and track results for separable elements.
Natural Gas Load Management Programs	Gas LM programs are permitted; however, likely need to propose different demand reduction factors in BENCOST
Other Cost-Effectiveness Tests	Utilities can use tests other than MNT, SCT, UCT, PCT, and RIM to evaluate programs – however, only the former will be official tests.

On November 17, 2022, the CAC provided their written feedback on the draft technical guidance. On November 18, 2022, during CAC meeting eight, there was discussion of key takeaways from the CAC based on the CAC's November 17, 2022, written comments on the draft technical guidance. Notes from meeting eight can be found in Appendix I.

4. Discount Rates for Cost-Effectiveness Analyses

On August 24, 2022, Staff distributed a homework assignment to the CAC in preparation for CAC meeting six. The homework assignment can be found in Appendix I for full details regarding Staff's request.

In the CAC's August 31, 2022, responses to the homework assignment, the CAC provided input related to discount rates. Key takeaways from the homework assignment include:

- There was general CAC agreement on using Societal Discount Rate in the MCT.
- However, there were differing views on what Societal Discount Rate should be (ACEEE, CEE, Fresh Energy say the value is too high) and differing views on using Societal Discount Rate in secondary tests (ACEEE, CEE, Fresh Energy support including the rate in other tests – CPE, GP, OTP, Xcel recommend not changing current).

On November 7, 2022, Staff requested that the CAC provide additional feedback on discount rates. Staff's feedback request is provided below for context:

> **Feedback Requested:** This feedback request is an opportunity for the CAC to provide additional input on discount rates for consideration.
>
> We request that the CAC provide feedback on what you believe is the appropriate discount rate that should be used in the following secondary cost-effectiveness tests along with justification as to why you think it's appropriate:
> - Societal Cost Test
> - Utility Cost Test
> - Participant Cost Test
> - Ratepayer Impact Measure Test
>
> We also request feedback on whether you are supportive or unsupportive of the Department continuing to use the Societal Discount Rate's historical method that's outlined below, and updating the rate using calendar year 2022 Treasury data. For context, the Societal Discount Rate currently equals 3.17% when updated using YTD 2022 Treasury data.
> - The Societal Discount Rate: The discount rate used in the Societal Cost Test to value, in current dollars, the future stream of societal benefits and costs resulting from a conservation investment. The Societal Discount Rate is calculated using the United States Department of the Treasury's (Treasury) 20-year Constant Maturity (CMT) Rate, which averaged [Final Value TBD] percent between January 03, 2022 through December 31, 2022. The Treasury's 20-year Daily CMT Rate captures the market's expectations regarding inflation, along with a small risk factor. At this time, Staff conclude that a rate including inflation expectations and a small risk factor is a reasonable method for estimating a social discount rate for externalities.

On December 1, 2022, the CAC provided their written feedback on discount rates. Staff provide a synthesis of takeaways from the CAC's response below.

Areas of Agreement

MCT and Societal Cost Test

- No one on the CAC disagreed that the MCT and SCT should use a Societal Discount rate. However, there are differences of opinion regarding what the Societal Discount Rate should be.

Areas of Disagreement

Societal Discount Rate

- *Support for Using Historical Method to Update the Societal Discount Rate* - CPE, OTP, Xcel, and ERP Staff agree with the current method of estimating the Societal Discount Rate. Arguments are generally that this approach has been used historically and it remains the appropriate way to develop the estimate.

- *Support for 2.5%* - CEE, Fresh Energy, ACEEE. CEE and Fresh Energy support 2.5% because this is consistent with the federal Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) report.[43]

Discount Rates Applied to Other Tests

- Generally, the utilities and ERP Staff support the current approach for other tests, as follows:
    - *Utility Cost Test*
        - ERP Staff, Xcel, CPE – Support using the CIP Utility Discount Rates developed as part of Department's Deputy Commissioner February 11, 2020 Decisions in Docket Nos. E999/CIP-18-783 and G999/CIP.
        - OTP – Supports using the utility Weighted Average Cost of Capital (WACC).
    - *Participant Test*

      ERP Staff, Xcel, OTP
        - Residential Customers should use a Societal Discount Rate.
        - Non-Residential Customers should use WACC.
    - *Ratepayer Impact Measure*
        - ERP Staff, Xcel, OTP think should use WACC.
        - CPE think it should be aligned with the value used for UCT.
- CEE, Fresh Energy, and Synapse
    - **All Secondary Tests**
        - CEE, Fresh Energy, and Synapse hold that the secondary tests should all use the Societal Discount rate. CEE echoes the Synapse perspective in stating that the UCT should reflect the regulatory perspective - which is long-term and focused on policy objectives and outcomes for customers. They believe the Societal Discount rate best reflects this perspective.

[43] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

5. Secondary Cost-Effectiveness Tests and Program Design

According to the NPSM for DERs, the Primary Test answers the question: Which resources have benefits that exceed costs and therefore merit utility acquisition or support on behalf of their customers?[44] The distinction between Primary and Secondary tests is that the Primary Test is the test that determines which measures and programs to include the utility's portfolio and how the utility and regulator will decide whether their portfolio is "cost effective".[45] Secondary Tests are also important but tend to answer different questions such as: how much will utility bills on average be reduced (UCT), and how much will cost-effectiveness change if an additional policy goal is added or removed from the Primary Test?

On September 7, 2022, during CAC meeting six, there was discussion around how the secondary tests will apply to cost-effectiveness screening and to inform program design decisions. Notes and takeaways from meeting six can be found in Appendix I.

On November 7, 2022, Staff requested that the CAC provide feedback impacts to include in the secondary cost-effectiveness tests. Staff's feedback request is provided below for context:

> **Feedback Requested:** Please see the table below that includes a proposed list of impacts that would be included in each of the secondary cost-effectiveness tests (i.e. the SCT, UCT, PCT, and RIM tests). The x's in the table signify what would be included in the various tests. Please provide feedback on which impacts you agree should be included in each of the secondary tests, and with impacts you disagree should be included in certain tests and why.

Table 17. List of Cost-effectiveness Test Impacts

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
Utility System	Electric Utility	Generation	Energy Generation*	x	x	x		x
			Capacity*	x	x	x		x
			Environmental Compliance	x	x	x		x
			Renewable Portfolio Standard Compliance	x	x	x		x
			Market Price Effects	x	x	x		x
			Ancillary Services	x	x	x		x
		Transmission	Transmission Capacity*	x	x	x		x
			Transmission System Losses*	x	x	x		x

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

[45] Per historical Department guidance, Minnesota IOU Conservation Improvement Programs must be cost-effective based on the Societal Test at the "segment" level. In other words, individual measures or programs need not be cost-effective but the segments (Residential, Commercial, etc.) into which programs are grouped must be cost-effective.

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
		Distribution	Distribution Costs*	x	x	x		x
			Distribution System Losses*	x	x	x		x
		General	Program Incentives*	x	x	x		x
			Program Administration Costs*	x	x	x		x
			Utility Performance Incentives	x	x	x		x
			Utility Revenue Impacts*					x
			Credit and Collection Costs	x	x	x		x
			Risk	x	x	x		x
			Reliability	x	x	x		x
			Resilience	x	x	x		x
Utility System	Gas Utility	Commodity / Supply	Fuel and Variable O&M*	x	x	x		x
			Capacity and Storage*	x	x	x		x
			Environmental Compliance	x	x	x		x
			Market Price Effects	x	x	x		x
		Transportation	Transportation*	x	x	x		x
		Delivery	Delivery*	x	x	x		x
		General (same as Electric)	Program Incentives *	x	x	x		x
			Program Administration Costs*	x	x	x		x
			Utility Performance Incentives	x	x	x		x
			Credit and Collection Costs	x	x	x		x
			Risk	x	x	x		x
			Reliability	x	x	x		x
			Resilience	x	x	x		x
Non-Utility System	All	Other Fuels	Other Fuels	x	x			
		Participant	Participant Costs*		x		x	
			Participant Benefits*		x		x	
Societal	All		GHG emissions*	x	x			

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
		Societal Impacts	Criteria air emissions*	x	x			
			Other environmental	x	x			
			Economic and Jobs (Macroeconomic)	x	x			
			Energy Security	x	x			
			Energy Equity	x	x			
			*Societal Discount Rate**	x	x		x	

***** Included in current tests. Participant Benefits do not currently include Non-Energy Impacts, although some utilities include customer operation and maintenance savings (and reduction in other fuel usage as part of O&M).

On December 15, 2022, the CAC provided their written feedback on impacts to include in the tests. Staff provide a synthesis of takeaways from the CAC's response below.

Areas of Agreement

- Overall, other than Xcel's suggestion Other Fuels be included in the Participant Cost Test and break-out the Participant impacts in greater detail, there is agreement that the list of elements in the chart is correct. Staff notes that Other Fuels in the table is different from customer operation and maintenance (O&M) savings associated with EE measures. O&M savings, including customer savings from reduced use of other fuels such as propane is included in Participant Benefits.
- CEE, Fresh Energy, CPE, MP, and OTP agreed with the list of items that should be included in the respective tests.
- Nuances include OTP's indication that they do not oppose including the performance incentive in the SCT, UCT, or RIM tests "with the only caveat being that it should not be included in determining the performance incentive."

Areas of Disagreement

- Xcel requested the following:
  - PCT – impacts should include Other Fuels, Rebate benefits, and bill savings;
  - RIM – impacts should include bill savings but not necessarily all Participant benefits (see comments below regarding more granularity for this test), and
  - UCT – should not include performance incentives due to circularity.

Other Considerations

- CEE provided input regarding what the secondary tests should include with an emphasis on the PCT. CEE maintains that it will be important for the PCT to consider both costs and benefits. CEE also requests that utilities use the most appropriate and applicable rates for estimating participant impacts for EFS programs.
- Representing the Sustainable Buildings 2030 project team, Russ Landry from CEE emphasizes the role that cost-effectiveness plays in that program (the program has statutory requirements related to cost-effectiveness). He indicates that the PCT is a critical factor in the program, and requests that the test "be as clearly defined as possible" and "for the inputs into this analysis to be based on the best, most updated

information available from utilities and to regulators about each of the input values, including expected escalation rates and discount rate(s).”

- MP highlighted that they continue to believe that Risk, Reliability, and Resilience are already embedded in other utility system costs. They also mention that Credit and Collections, Other environmental, Economic and Jobs, Energy and Security, and Energy Equity have not yet been quantified (they do not seem aware that we have deferred these for now).
- OTP provided a table with commentary on each of the elements included in each test. Many of the lines state that “Otter Tail believes this is already included as part of our IRP” (e.g. Risk, Reliability, and Resilience).
- Xcel said they will continue to use secondary tests to inform various aspects of their program and portfolio design. Xcel will use the PCT, UCT, and SCT to inform both EE and EFS programming. Xcel also states they will use RIM to analyze load management program cost-effectiveness. Xcel also requests that the participant impacts be broken into greater detail to provide more insight into whether an impact is upfront as opposed to ongoing. Xcel also recommended separating the impacts by fuel. Finally, Xcel provided an example of how they think the information can be reported. “The intent is to provide a format which allows a simultaneous consideration of multiple tests and the impacts on multiple fuels – the latter being particularly important when considering EFS measures.”

D. Staff Recommendations (From Proposed Decision)

Staff appreciate insights that The Mendota Group, Synapse, and the CAC provided, and carefully considered the different points of view expressed regarding updates to CIP’s current cost-effectiveness tests.

This section presents Staff’s key recommended cost-effectiveness methodology updates for the 2024-2026 CIP Triennials for screening energy efficiency, load management, and efficient fuel-switching programs.

1. Minnesota Test as CIP’s Primary Cost-Effectiveness Test

As mentioned earlier in this Proposed Decision, the Department created the CAC to act as a forum for discussing how to update components of cost-effectiveness models and integrate these into the CIP process.

A key activity of the CAC during 2022 was to proceed through the NSPM for DERs[46] 5-step process to develop the Primary Test that Minnesota IOUs will use to evaluate their 2024-2026 CIPs. According to the NPSM for DERs, the 5-step process is designed to produce a Primary Test that answers the question: Which resources have benefits that exceed costs and therefore merit utility acquisition or support on behalf of their customers?[47] Synapse assisted the CAC by conducting workshops to walk through the 5-step process for developing a primary cost-effectiveness test.

[46] 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.

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

Staff recommend that the Deputy Commissioner approve the MCT as CIP's primary cost-effectiveness test that the gas and electric IOUs shall use to screen their energy efficiency, load management, and efficient fuel-switching programs for the 2024-2026 triennial period. The other cost-effectiveness tests (SCT, UCT, PCT, RIM) should serve as CIP's secondary tests.

Staff recommend that the Deputy Commissioner continue to allow approval of cost-effectiveness at the segment-level (as has been done historically), so that the IOUs are responsible for ensuring that each segment, rather than individual program, is cost-effective by CIP standards. Approving at the segment-level recognizes that individual programs are often linked together and not intended to operate in isolation.

Based on the extensive feedback from the CAC, Table 18 summarizes the impacts that Staff recommend be included in the new MCT. Table 18 also outlines which impacts are and are not currently quantified in the MCT. An * indicates impacts that are currently quantified to estimate cost-effectiveness and should be included in the IOUs' 2024-2026 CIP cost-effectiveness analyses using the MCT. As part of this current CAC update process, there was not enough time to quantify all of the impacts that have been identified for inclusion in the MCT. However, Staff view developing the MCT as something that will be refined and built upon going forward. Impacts in Table 18 that do not have an * symbol are not currently quantified as part of the MCT and/or do not have an approved estimation methodology. These impacts should be assigned a value equal to 0 for the IOUs' 2024-2026 CIP cost-effectiveness analyses using the MCT.

Table 18. Staff Recommended MCT Impacts

Type	Utility	Category	Impact
Utility System	Electric Utility	Generation	Energy Generation*
			Capacity*
			Environmental Compliance
			Renewable Portfolio Standard Compliance
			Market Price Effects*
			Ancillary Services*
		Transmission	Transmission Capacity*
			Transmission System Losses*
		Distribution	Distribution Costs*
			Distribution System Losses*
		General	Program Incentives*
			Program Administration Costs*
			Utility Performance Incentives*
			Credit and Collection Costs
			Risk
			Reliability
			Resilience
	Gas Utility	Commodity / Supply	Fuel*
			Capacity and Storage*

Type	Utility	Category	Impact
			Environmental Compliance*
			Market Price Effects
		Transportation	Transportation*
		Delivery	Delivery*
		General (same as Electric)	(see electric section)
Non-Utility System	Both	Other Fuels	Other Fuels
Societal	Both	Societal Impacts	GHG emissions*
			Criteria air emissions*
			Other environmental
			Economic and Jobs (Macroeconomic)
			Energy Security
			Energy Equity

Additionally, during CAC meeting six on September 7, 2022, there was discussion around how cost-effectiveness can inform program design decisions, and Staff recommended adopting the following general guidelines for the 2024-2026 triennial period:

- Cost-effectiveness and program design are separate, but related concepts. Program design and portfolio development involve many considerations;
- Cost-effectiveness evaluations can help inform program design but should not be the primary basis for program design;
- Just because a program is cost-effective does not mean that the utility should include it in its portfolio and, by extension, just because a program is not cost-effective does not mean that it should be automatically eliminated; and
- It is the utility's responsibility to design a program (including measure mix, incentives, etc.) that is attractive to customers, is deliverable in a practical sense, and (generally) is cost-effective under the primary test used to evaluate programs.

2. Secondary Cost-Effectiveness Tests and Program Design

As stated earlier, Staff recommend the new MCT be used as CIP's primary cost-effectiveness test, and that the other cost-effectiveness tests (SCT, UCT, PCT, RIM) serve as CIP secondary cost-effectiveness tests.

Staff further recommend adopting Synapse's approach to primary and secondary cost-effectiveness tests, as presented in Synapse's June 8, 2022 Straw Proposal (see Appendix F). Specifically, as described in Synapse's Straw Proposal:

> The primary test is the main determinant of whether a program should be included in the Triennial Plan. Secondary tests can be developed to help enhance the overall understanding of energy efficiency impacts. The additional information from a secondary test can help to prioritize energy efficiency programs and to inform decisions regarding marginally cost-effective programs and allocation of resources. The secondary test is not intended to undermine the

purpose of the primary test and may include a subset of the impacts included in the primary test or additional impacts.

During CAC meeting six on September 7, 2022, there was discussion about how the secondary tests will apply to CIP cost-effectiveness screening and how they can inform program design decisions. As presented during that meeting, Staff recommend that the following general guidelines be adopted regarding the purpose of the secondary tests for the 2024-2026 triennial period:

- MN Statutes require the calculation of results according to UCT, SCT, PCT, and RIM tests. These will be the Secondary tests.
- Secondary tests can help to:
    - Inform decisions on how to prioritize programs (based on constraints or objectives).
    - Inform how a program affect different parties (e.g., all customers, host customers, society).
    - Inform decisions regarding marginally cost-effective programs.
- Any impact that is included in more than one test (e.g. avoided energy) should be treated consistently across all the tests (e.g., using the same $/MWh or $/Dth value).
- When IOUs present cost-effectiveness results in Triennial Plans and Status Reports, they should:
    - Describe the cost-effectiveness results by program using the Minnesota Test,
    - Describe any key cost-effectiveness issues that were considered in program design, and
    - Describe any programs where secondary tests played a role in decision-making.

Table 19 summarizes the impacts that Staff recommend be included in the MCT and the secondary tests. For 2024-2026 CIP cost-effectiveness analyses using the secondary tests, utilities can include estimates for impacts that are not currently quantified or do not have an approved methodology, but utilities should clearly outline all the assumptions and methodology details regarding how those impacts were estimated as part of their CIP Status Report and Triennial Filings.

Table 19. List of Cost-effectiveness Test Impacts

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
Utility System	Electric Utility	Generation	Energy Generation	x	x	x		x
			Capacity	x	x	x		x
			Environmental Compliance	x	x	x		x
			Renewable Portfolio Standard Compliance	x	x	x		x
			Market Price Effects	x	x	x		x
			Ancillary Services	x	x	x		x
		Transmission	Transmission Capacity	x	x	x		x
			Transmission System Losses	x	x	x		x
		Distribution	Distribution Costs	x	x	x		x
			Distribution System Losses	x	x	x		x

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
		General	Program Incentives	x	x	x		x
			Program Administration Costs	x	x	x		x
			Utility Performance Incentives	x	x	x		x
			Utility Revenue Impacts					x
			Credit and Collection Costs	x	x	x		x
			Risk	x	x	x		x
			Reliability	x	x	x		x
			Resilience	x	x	x		x
Utility System	Gas Utility	Commodity / Supply	Fuel and Variable O&M	x	x	x		x
			Capacity and Storage	x	x	x		x
			Environmental Compliance	x	x	x		x
			Market Price Effects	x	x	x		x
		Transportation	Transportation	x	x	x		x
		Delivery	Delivery	x	x	x		x
		General (same as Electric	Program Incentives	x	x	x		x
			Program Administration Costs	x	x	x		x
			Utility Performance Incentives	x	x	x		x
			Credit and Collection Costs	x	x	x		x
			Risk	x	x	x		x
			Reliability	x	x	x		x
			Resilience	x	x	x		x
Non-Utility System	All	Other Fuels	Other Fuels	x	x			
		Participant	Participant Costs		x		x	
			Participant Benefits		x		x	
Societal	All	Societal Impacts	GHG emissions	x	x			
			Criteria air emissions	x	x			
			Other environmental	x	x			

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
			Economic and Jobs (Macroeconomic)	x	x			
			Energy Security	x	x			
			Energy Equity	x	x			
			Societal Discount Rate	x	x		x	

3. Utility System Impact Methodologies

Staff recommend that the Deputy Commissioner require the IOUs to use the USI methodology descriptions included in Appendix K. Below are hyperlinks to the full methodology descriptions, a general description of the methods, and the proposed values for each of the new impacts for the 2024-2026 triennial period:

A. Electric Impacts

1. **Ancillary Services (Electric)**
   - Methodology Description Link
   - Impact Description: Ancillary services are those services required to maintain electric grid stability. They typically include frequency regulation, voltage regulation, spinning reserves, and operating reserves. The Midwest Independent System Operator's (MISO) three main ancillary services products are regulation, spinning reserves, and supplemental reserves. A DER's net effect on ancillary services depends on its load shape and what the real-time system conditions are at the time of its operation. As the MTR points out, even if a DER's operation is not directly in response to a signal to provide ancillary services, it may nevertheless create an impact. A DER that reduces energy consumption would create a benefit by avoiding the average ancillary service price, whereas a DER that increases usage would create a cost equal to the average price.
   - Proposed Values:
     - The proposed value for the 2024-2026 Triennial for Ancillary Services is a 1 percent adder, calculated against both electric energy and capacity for all years.
     - Where we were able to obtain data, we found a wide range of values. Impacts on ancillary services, though, were considerably lower than, for example, market effects. The numbers suggest that a 1 percent adder to both electric energy and capacity is a reasonable starting point until further analyses can be conducted.

2. **Environmental Compliance (Electric)**
   - Methodology Description Link
   - Impact Description: Current and future environmental compliance requirements that impact utility rates; environmental compliance impacts already included in the cost of the relevant energy resource should not be included in this category of impacts to avoid double-counting. In this context, Environmental Compliance does not include utility

system costs associated with GHGs (these will be included as a Non-Utility System impact).

- Proposed Value:
  - The proposed value for the 2024-2026 Triennial for Electric Environmental Compliance Costs is zero.
  - The zero value is based on the challenge of estimating non-GHG environmental compliance costs in the time available. This does not preclude the opportunity for the factor to be updated at a future time if it is determined that there are identifiable and calculable environmental compliance costs. Environmental Compliance will remain a category within the MCT and serve as a placeholder to capture any future compliance costs that are not embedded in other utility system impacts.

3. Generating Capacity (Electric)

- Methodology Description Link

- Impact Description: Generating capacity is the amount of installed capacity (i.e., kW) required to meet the forecasted peak load, which typically includes an additional reserve margin. A utility either needs to build generating capacity or procure it to ensure it has sufficient generating capacity to meet planning requirements. DERs that decrease or increase loads impact generating capacity needs. Minnesota utilities use different approaches – all consider generating capacity data Trade Secret.

- Proposed Value:
  - The proposed Generating Capacity value for the 2024-2026 Triennial is based on MISO's Local Resource Zone 1 Cost of New Entry.[48] 2023/2024 - $104.17/kW-year.
  - The MISO CONE value for the Local Resource Zone that includes most of Minnesota serves as a good proxy value for estimates of capacity costs avoided (or increased) by CIP Distributed Energy Resources as it represents the value of a generating unit that could be constructed to meet marginal capacity requirements. The value has the added benefit of being a publicly available number that all Minnesota electric utilities can use in their BCAs.

4. Marginal Energy (Electric)

- Methodology Description Link

- Impact Description: Energy generation costs consist of the fuel and variable O&M costs from the production or procurement of energy (i.e. kWh) from generation resources. Energy generation costs can vary significantly by season and time of day.

- Proposed Value:
  - Staff recommend that utilities use Minnesota values from the National Renewable Energy Laboratory's (NREL) Cambium model. NREL's Cambium data

[48] "Filing of the Midcontinent Independent System Operator, Inc. Regarding Local Resource Zone CONE Calculation",
Attachment B, September 30, 2022,
https://cdn.misoenergy.org/MISO%202022%20Annual%20CONE%20filing626484.pdf

sets are sets of simulated hourly emission, cost, and operational data for a range of modeled futures of the U.S. electric sector that are updated and released annually.

- Staff believe that consistency in the manner by which utilities estimate marginal energy to include in BCAs is important and the NREL approach facilitates regular updates (e.g. using IRP data may be outdated at the time of a Triennial filing) and enables the information to be shared publicly.
- The data also can be readily incorporated into the BENCOST model for Input 7 – Non-Gas Fuel Cost.

o The following table summarizes data from NREL's Cambium model for 2024-2050 in 2023($):[49]

Year	$/MWh
2024	$30.67
2026	$28.63
2028	$27.49
2030	$26.77
2032	$26.86
2034	$26.17
2036	$25.70
2038	$24.38
2040	$25.13
2042	$24.99
2044	$24.34
2046	$23.43
2048	$23.15
2050	$21.60

5. Market Price Effects (Electric)

o Methodology Description Link

o Impact Description: In jurisdictions with competitive wholesale electricity markets, wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers at any given instant. When DERs reduce (or increase) the demand for electricity, they reduce (or increase) the wholesale market prices. This change creates benefits (or costs) for all customers participating in the wholesale market at that time. This effect is sometimes referred to as demand reduction induced price effect (DRIPE). It's also called wholesale price suppression effect. As Load Serving Entities (LSEs), Minnesota electric utilities participate in MISO competitive wholesale energy and operating reserves markets. Reductions in utility energy and capacity requirements

[49] Standard Scenarios 2021 Mid-Case, Busbar costs, $/MWh, energy_cost_busbar (column BO) – Minnesota. Obtained from the Standard Scenario Viewer and Data Downloader, accessible at: https://www.nrel.gov/analysis/standard-scenarios.html

through energy efficiency and load management, in turn, impact the MISO wholesale electricity and reserves markets as described above.

- Proposed Value:
  - The proposed value for the 2024-2026 Triennial for Electric Market Price Effects is 1 percent, applied to both energy and capacity values for all years.
  - Given the limited time frame available to the Working Group for estimating values for electric market effects, and the challenges that utilities would face in developing electric market effects estimates to use in cost-effectiveness analyses, using a very modest proxy value of 1% is prudent. Future evaluations of Electric Market Price Effects should consider the degree to which individual utilities are net importers or exporters and possibly apply the factor differentially to utilities on this basis.

6. Renewable Portfolio Standard Compliance (Electric)

- Methodology Description Link

- Impact Description: In jurisdictions that have adopted a renewable portfolio standard (RPS) or similar regulatory mechanisms, DERs can impact the cost of compliance. DERs can reduce compliance costs either by reducing the target (lowering overall electricity energy and demand requirements) or increasing the level of qualified renewable or clean energy generation. Alternatively, if a DER increases electricity requirements (e.g., electrification), it will require additional renewable purchases and, therefore, increase the compliance costs of meeting the standard. Minnesota very recently adopted changes to its previous Renewable Energy Objective, which set requirements for the amount of electricity utilities must obtain from renewable resources to serve Minnesota customers. The new law (SF4), increases utility requirements to serve customers with renewable-energy produced electricity to 55 percent by 2035 and further requires that utilities generate or procure sufficient electricity from carbon-free energy technologies to serve 100 percent of their Minnesota customers' needs by 2040.[50]

- Proposed Value:
  - The RPS Compliance value for the 2024-2026 Triennial will be set to 0.
  - The zero value is based on the fact that Minnesota's electric utilities are currently exceeding Minnesota's Renewable Energy Objective and this is considered to persist through the Triennial period. Although SF4 will require changes to the way utilities generate and procure electricity in the future, such changes will need to be addressed at a later date when more information is available. The zero value can be revisited if it is later determined that estimates of DER impacts on utility selection of renewables to meet the new requirements are relevant to include in BCAs.

[50] The Renewable Energy Objective had required that, by 2025, Otter Tail Power and Minnesota Power obtain 25 percent and Xcel Energy obtain 30 percent of their electricity from renewable resources. See SF 4 text - https://www.revisor.mn.gov/bills/text.php?number=SF4&version=1&session=ls93&session_year=2023&session_number=0

B. Gas Impacts

7. Environmental Compliance (Gas)

- Methodology Description Link

- Impact Description: Current and future environmental compliance requirements that impact utility rates; environmental compliance impacts already included in the cost of the relevant energy resource should not be included in this category of impacts to avoid double-counting. In this context, Environmental Compliance does not include utility system costs associated with GHGs (these will include as a Non-Utility System impact).

- Proposed Value:
  - The proposed value for the 2024-2026 Triennial for Gas Environmental Compliance Impacts is 1.40% of the $/MCF commodity cost for 2024 – 2045.
  - The initial value is based solely on proposed federal methane emissions standards that the EPA anticipates finalizing in 2024. All other gas environmental compliance factors are assumed to be 0 for this Triennial. We derived the 1.40% estimate based on the EPA's Regulatory Impact Analysis (RIA) for the proposed regulations. The RIA estimates natural gas commodity price impacts for the 2023-2035 period. As the analysis provides estimated impacts for five discrete years (2023, 2025, 2026, 2030, 2035), we used this data to extrapolate annual values for the 2023-2035 period. The 1.40% is a simple average of this period. Extrapolating values out to 2045 (the period covered by the BENCOST model) had a minimal impact on this estimate (1.38%) and, therefore, we suggest using the 1.40% as it is based on the time period included in the EPA analysis.

8. Market Price Effects (Gas)

- Methodology Description Link

- Impact Description: Wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers. When DERs reduce the demand for gas, they reduce (or increase) the wholesale market prices, which creates benefits for all customers participating in the wholesale market at that time. Even a very small perturbation of the market price can have large impacts when applied across all wholesale customers.

- Proposed Value:
  - The proposed value for the 2024-2026 Triennial for Gas Market Price Effects is zero.
  - The considerable uncertainty about whether Gas Market Price Effects exist in Minnesota led to the recommendation to include a zero value for the variable for the upcoming Triennial.

C. Electric and Gas Impacts

9. Utility Performance Incentives (Electric and Gas)

- Methodology Description Link

- Impact Description: IOUs are offered financial incentives for meeting specific performance metrics related to the success of their CIP programs. Minnesota utility performance incentives (shareholder incentives) are a form of shared savings mechanism, with the utility and ratepayers sharing in the net benefits from CIP. Currently, electric IOUs cannot include net benefits associated with their Efficient Fuel-Switching programs in cost-effectiveness calculations while natural gas IOUs can. Although authorized in statute,[51] there is not a separate performance incentive for load management.

- Proposed Value:
  - This is a methodological approach. Please see the methodology description in Appendix K.
  - The tests that include utility administrative costs should also include performance incentives as they are utility costs (that get passed on to ratepayers).

4. Low-Income Impacts

Many CIP low-income programs (most of which by design are intended to exclusively serve the needs of low-income customers) have, historically, not been cost-effective. However, in recognition of their importance in serving this customer group, the Department has allowed non-cost-effective low-income programs to be included in utility CIP portfolios. This practice is based on the premise that the benefits of offering low-income programs outweigh the costs.

Staff recommend maintaining the current policy that does not require that low-income programs pass CIP's primary cost-effectiveness test and not including in tests specific impacts that would apply to low-income programs.

5. Electric Avoided Costs and Transparency

Regarding the electric IOU's avoided transmission and distribution (T&D) costs, Staff recommend that electric IOUs can either choose to update their avoided T&D costs using the approved Discrete Approach methodology, or they can continue to use the Discrete Approach avoided T&D cost values that were approved previously for the 2021-2023 Triennial period.[52]

For reference, the Discrete Approach methodology is the standardized methodology for estimating electric utility avoided T&D costs as part of CIP Triennial Plan cycles. The Discrete Approach follows the six general steps outlined below to estimate avoided T&D costs:

1. Start with a forecast of the load reductions each electric IOU's CIP would provide over the study period.
2. Calculate the present value of the costs (revenue requirement) of load-growth driven T&D investments that are needed in the future to provide a reliable system under normal operating conditions.

[51] Minn. Stat. §216B.241, subd. 13(d)(3).
[52] *Deputy Commissioner's Decision – CIP Electric Utilities Cost-Effectiveness Review*, Docket No. E999/CIP-18-783, May 20, 2019.

3. Allocate the projected load reductions due to projected CIP achievements to the transmission and distribution systems on a proportional basis based on percentage of system load share.
4. Calculate the present value of the costs of load-growth driven T&D investments that are needed in the future, after load reductions, to provide a reliable system under normal operating conditions.
5. Calculate the differences in the present value of costs (revenue requirement) before and after DSM investments (under the discrete method, there will be no difference if the projected CIP load reductions were not large enough to defer T&D investments).
6. Divide the difference in projected T&D deferred costs ($) by the average annual projected CIP load reductions (kW per year) to obtain a $/kW-yr estimate of T&D deferral benefit.

Historically, Minnesota's electric utilities have treated avoided capacity costs and marginal energy costs as Trade Secret. Per the Deputy Commissioner's February 11, 2020 Decision approving the 2021-2023 CIP cost-effectiveness inputs, "The Deputy Commissioner determines that improvements to the transparency of electric avoided costs be included as one of the priority cost-effectiveness issues to explore leading up to the 2024-2026 CIP Triennials."

Regarding avoided capacity and marginal energy costs, Staff recommend that the electric IOUs use the methodologies and estimates described in Appendix K. Staff believe these proposed methodologies address the Deputy Commissioner's directive for Staff to recommend ways to improve the transparency of electric avoided costs. Based on the feedback Staff received from the CAC, Staff recognize that there are pros and cons of using public data to derive the electric IOUs' avoided marginal energy and capacity costs versus using utility-specific avoided cost data (i.e. through their IRPs). Staff believe that the proposed methods in Appendix K are more transparent and still maintain the accuracy of the IOUs' avoided cost estimates.

6. 2024-2026 Gas BENCOST Inputs

Staff, with technical assistance from The Mendota Group, have incorporated the MCT and the other updated inputs into the BENCOST updates.

Staff recommend that the Deputy Commissioner approve the Inputs to BENCOST for Gas IOUs' 2024-2026 CIP Triennium, which is included in Appendix L.

Staff recommend that the gas IOUs work with their electric utility counterparts determine ways to model EFS measures and programs outside of the standardized BENCOST model.

7. Proposed Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance

This Proposed Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance (CE Technical Guidance) supplements the Department's March 15, 2022, Technical Guidance (ECO Act Technical Guidance) related to implementing the ECO Act.[53] The CE Technical Guidance is intended to

[53] "In the Matter of Technical Guidance for the Inclusion of Efficient Fuel-Switching, Load Management, and Pre-Weatherization Measures in CIP" (Docket E,G999/CIP-21-837), Commissioner Decision, Minnesota Department of

help Minnesota's electric and gas IOUs conduct cost-effectiveness evaluations of their EFS and LM programs.

The CE Technical Guidance covers a range of topics raised by CAC members. The document seeks to clarify how IOUs will conduct cost-effectiveness evaluations of EFS and LM programs per ECO Act and ECO Act Technical Guidance requirements. CAC members also provided comments on the November 7, 2022, Draft of the CE Technical Guidance. The Department and The Mendota Group revised the document to address these comments.

Staff include the full CE Technical Guidance in Appendix J and ask that stakeholders refer to the details contained in that section.

As presented in the CE Technical Guidance, Staff propose that IOUs will be required to submit the following in their Triennial Plan and Status Report filings:

- Demonstration that the overall portfolio and designated segments are cost-effective based on the MCT;[54]
- Presentation of portfolio, segment, and program cost-effectiveness results based on the MCT and the secondary tests (SCT, UCT, PCT, RIM);
- Creation of an EFS segment that contains only EFS measures;
- For EFS improvements, consideration of cost-effectiveness at the program level based on the Minnesota Test, the SCT, UCT, and the PCT (natural gas utilities also include RIM);
- For LM programs and programs that include LM elements, consideration of cost-effectiveness at the program level based on the MCT, the SCT, UCT, PCT, and RIM;
- Methods for allocating costs for EFS, LM, and EE measures to programs that include multiple program types, and
- How the utility evaluated cost-effectiveness for programs that include LM and EE or EFS elements based on each of the program types associated with the program.

8. Discount Rates for Cost-Effectiveness Analyses

a. Societal Discount Rate Method

Staff believe the federal Treasury rate remains a good proxy to value, in current dollars, the future stream of societal benefits and costs resulting from a conservation investment. Staff updated the Societal Discount Rate using the United States Department of the Treasury's (Treasury) 20-year Constant Maturity (CMT) Rate, which averaged 3.3 percent between January 3, 2022 and December 30, 2022. The Treasury's 20-year Daily CMT Rate captures the market's expectations regarding inflation, along with a small risk factor. Staff conclude that a rate including inflation expectations and a small risk factor is a reasonable method for estimating a social discount rate for externalities. Staff also find that it is important to have a consistent way that the Societal Discount Rate can be updated for each Triennial period. Therefore, Staff recommend that the Deputy Commissioner require the gas and electric IOUs to use a 3.3% Societal Discount rate in the MCT and the SCT, and for residential programs in the PCT.

Commerce, March 15, 2022, Appendix A. The ECO Act is the Minnesota Energy Conservation and Optimization Act of 2021.

[54] The Low-Income segment is excluded from this requirement. Utilities need not demonstrate that the segment is cost-effective. See third bullet related to the EFS segment.

b. Discount Rates for the Primary and Secondary Tests

Staff point out that each cost-effectiveness test is designed to analyze conservation investments from a different perspective. This ensures that regulators have a complete picture of who is actually better off and who might be worse off as a result of a CIP investment. For the tests to be meaningful, each test should use the appropriate discount rate that reflects the time value of future benefits from the perspective of the entity who is making the investment. Therefore, Staff recommend that the Deputy Commissioner require the gas and electric IOUs to use the following discount rates in their cost-effectiveness tests:

<u>Primary Cost-Effectiveness Test</u>

- **Minnesota Test – 3.3% Societal Discount Rate**

  The discount rate used to value, in current dollars, the future stream of societal benefits and costs resulting from a conservation investment. The Treasury rate is a good proxy for the way society discounts the future value of benefits. Staff updated the Societal Discount Rate using the United States Department of the Treasury's (Treasury) 20-year Constant Maturity (CMT) Rate, which averaged 3.3 percent between January 03, 2022 through December 30, 2022. The Treasury's 20-year Daily CMT Rate captures the market's expectations regarding inflation, along with a small risk factor. Staff conclude that a rate including inflation expectations and a small risk factor is a reasonable method for estimating a social discount rate for externalities.

<u>Secondary Cost-Effectiveness Tests</u>

- **Societal Cost Test – 3.3% Societal Discount Rate**

  The discount rate used to value, in current dollars, the future stream of societal benefits and costs resulting from a conservation investment. The Treasury rate is a good proxy for the way society discounts the future value of benefits. Staff updated the Societal Discount Rate using the United States Department of the Treasury's (Treasury) 20-year Constant Maturity (CMT) Rate, which averaged 3.3 percent between January 03, 2022 through December 30, 2022. The Treasury's 20-year Daily CMT Rate captures the market's expectations regarding inflation, along with a small risk factor. Staff conclude that a rate including inflation expectations and a small risk factor is a reasonable method for estimating a social discount rate for externalities.

- **Utility Cost Test – CIP Utility Discount Rate**

  The discount rate used in the UCT to value, in current dollars, the future stream of utility system benefits and costs (excluding benefits resulting from avoided environmental damage) resulting from a conservation investment. The CIP Utility Discount Rate is based on the theory that CIP investments are funded by both the utility and the ratepayers that participate in CIP. Utilities invest money in CIP programs and customer participants pay incremental costs. The future benefits of energy savings come from the avoided costs resulting from the customer and utility investments.

Staff recommend that the Deputy Commissioner require the electric and gas IOUs to apply the following CIP Utility Discount Rates in the UCT for 2024-2026 CIP cost-effectiveness testing:

Xcel Electric: 5.38 percent
Xcel Gas: 5.34 percent
CenterPoint: 5.39 percent
MN Energy Resources: 5.57 percent
Minnesota Power: 5.41 percent
Otter Tail: 5.61 percent
Greater MN Gas: 5.61 percent
Great Plains: 5.79 percent

These are unchanged from the previous Triennial. For details about how the CIP Utility Discount Rate is calculated, see pages 21-22 of the *Deputy Commissioner's Decision – In the Matter of CIP Gas and Electric Utilities 2021-2023 Cost-Effectiveness Review.* February 11, 2020. Docket Nos. G999/CIP-18-782, E999/CIP-18-783.

- **Participant Cost Test – Societal Discount Rate for Residential Programs and CIP Utility Discount Rate for Non-Residential Programs**

The Participant Discount Rate for residential customers should equal the Societal Discount Rate of 3.3%. Such a discount rate would reflect a residential customer's likely opportunity costs (i.e., the return on investment that a residential customer would likely give up in order to invest in CIP).

The Participant Discount Rate for commercial and industrial customers is equal to the CIP Utility Discount Rate. Although this discount rate may be lower than the actual discount rate for a particular commercial/industrial customer, it represents an attempt to reflect in a simple manner a reasonable estimate of a business customer's opportunity costs and creates symmetry with the UCT's discount rate and the RIM's discount rate.

- **Ratepayer Impact Measure Test – CIP Utility Discount Rate**

RIM attempts to evaluate what would happen to customer rates due to changes in utility revenues, combined with the costs incurred by the utility to run the program, and avoided costs. It is similar to the UCT in that it is looking at investments through the utility's lens. The RIM indicates cost shifts between participants and non-participants. The RIM indicates cost shifts between participants and non-participants. Similar to the UCT, it is looking at investments from the utility perspective. Therefore, it is recommended that the RIM Test also used the CIP Utility Discount Rate.

Test	Societal Discount Rate	CIP Utility Discount Rate
Minnesota	x	
Societal	x	
Utility		x
Participant – Residential Customer	x	
Participant – Non-Residential Customer		x
Ratepayer Impact Measure		x

9. Non-Utility System Impacts

a. Greenhouse Gases

Staff find that there seems to be general agreement among CAC members that both gas and electric utilities should use the PUC's high externality value to estimate the environmental damage factor.

Per the MN PUC's January 3, 2018 Order in docket number CI-14-643, environmental externalities are calculated using the "*damage-cost* method, which attempts to place an economic value on the net damage to the environment caused by power-plant emissions."[55]

The Table 20 comes from the MN PUC's January 3, 2018, Order and includes the amounts in 2015 $/ton that constitute the high externality values for CO_2.

Table 20. Environmental Cost Values for CO2 (2017–2050)[50] (2015 dollars per net short ton)

Year	Low	High	Year	Low	High
2017	$8.44	$39.76	2034	$11.92	$55.07
2018	$8.64	$40.66	2035	$12.12	$55.97
2019	$8.85	$41.56	2036	$12.33	$56.87
2020	$9.05	$42.46	2037	$12.53	$57.77
2021	$9.25	$43.36	2038	$12.74	$58.67
2022	$9.46	$44.26	2039	$12.94	$59.58
2023	$9.66	$45.16	2040	$13.15	$60.48
2024	$9.87	$46.06	2041	$13.35	$61.38
2025	$10.07	$46.96	2042	$13.56	$62.28
2026	$10.28	$47.86	2043	$13.76	$63.18
2027	$10.48	$48.77	2044	$13.97	$64.08
2028	$10.69	$49.67	2045	$14.17	$64.98
2029	$10.89	$50.57	2046	$14.38	$65.88
2030	$11.10	$51.47	2047	$14.58	$66.78

[55] Order Updating Environmental Cost Values, "In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3", Docket No. E-999/CI-14-643, January 3, 2018, p. 6.

Year	Low	High	Year	Low	High
2031	$11.30	$52.37	2048	$14.79	$67.68
2032	$11.51	$53.27	2049	$14.99	$68.58
2033	$11.71	$54.17	2050	$15.20	$69.48

Staff have incorporated these high CO_2 externality values into the Gas Environmental Damage Factor and the Non-Gas Environmental Damage Factor described in the 2024-2026 Gas BENCOST Inputs section of this Proposed Decision.

Staff recommend that the Deputy Commissioner require both the gas and electric IOUs to use the updated Gas and Non-Gas Environmental Damage Factors for their 2024-2026 cost-effectiveness analyses.

b. Criteria Pollutants

Similarly, Staff recommend that utilities should use the high-end value for criteria air emissions in the updated Gas and Non-Gas Environmental Damage Factors components of cost-effectiveness analyses. For reference, Table 21 comes from the MN PUC's January 3, 2018, Order and includes the amounts in $/ton values for criteria air pollutants. The relevant values are the High column within Metropolitan Fringe.

Table 21. Updated Environmental Cost Values for NO_x, SO_2, and $PM_{2.5}$

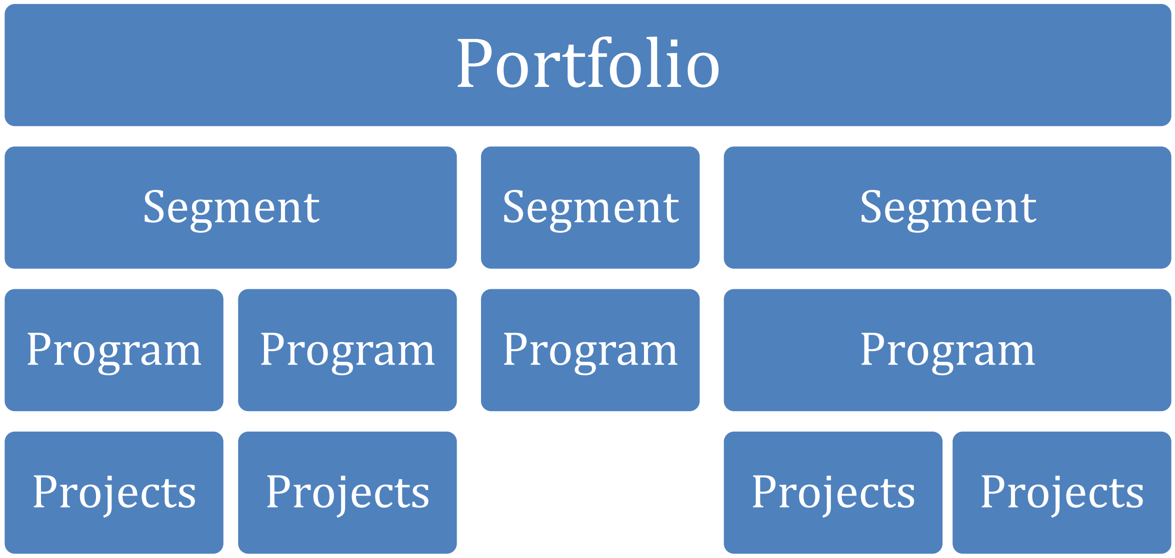
	Rural			Metropolitan Fringe			Urban		
	Low	Median	High	Low	Median	High	Low	Median	High
PM2.5	3,437	6,220	8,441	6,450	11,724	16,078	10,063	18,305	25,137
NO_x	1,985	4,762	6,370	2,467	5,352	7,336	2,760	5,755	7,893
SO2	3,427	6,159	8,352	4,543	8,245	11,317	5,753	10,439	14,382

10. Reporting Guidelines

Below is a high-level outline of proposed reporting guidelines that the IOUs should meet when submitting their CIP Triennial Plans and Status reports to the Department.

As background regarding the various reporting levels, please see Figure 1. The terms "programs" and "projects" refer to different aspects of utility CIPs. "Projects" refers to individual Custom projects or projects within a program that relies on deemed savings (for example, a residential program that provides incentives for customer projects to install air source heat pumps). Custom projects are also part of a program. Programs are included in segments. Together, the various segments make up a utility's CIP Portfolio.

Figure 1. CIP Reporting Levels Example



<u>Future Practice: 2024-2026 Triennial Period</u>

- The MCT is the primary test used to determine utility CIP cost-effectiveness, reviewed and approved at the segment-level.
- Secondary cost-effectiveness tests include the SCT, UCT, RIM, and PCT.

<u>Planning: 2024-2026 Triennial Plans</u>

- Utilities run cost-effectiveness estimates for measures, programs, segments, and portfolio based on MCT, SCT, UCT, RIM, and PCT.
    - Utilities report their cost-effectiveness results at the program, segment, and portfolio level.
    - Cost-effectiveness will be reviewed/approved by the Department at the segment-level based on the MCT.
    - Utilities should also report secondary test results for informational purposes.

- When IOUs present cost-effectiveness results in Triennial Plans and Status Reports, they should:
    - Describe the cost-effectiveness results by program using the MCT.
    - Describe any key cost-effectiveness issues that were considered in program design.
    - Describe any programs where secondary tests played a role in decision-making.

<u>Actuals: 2024-2026 Status Reports</u>

- Using actual information from prior years, utilities run cost-effectiveness results for measures, programs, segments, and portfolio based on MCT, SCT, UCT, RIM, and PCT.
    - Utilities report their cost-effectiveness results at the program, segment, and portfolio level.
    - Cost-effectiveness will be reviewed/approved by the Department at the segment-level based on the MCT.
    - Utilities should also report secondary test results for informational purposes.

- When IOUs present cost-effectiveness results in Triennial Plans and Status Reports, they should:
    - Describe the cost-effectiveness results by program using the MCT.

- Describe any key cost-effectiveness issues that were considered in program design.
- Describe any programs where secondary tests played a role in decision-making.

a. Transparent Reporting

When IOUs present cost-effectiveness results in Triennial Plan and Status Report filings, they should clearly and transparently report the results using the following guidance.

Cost-Effectiveness Ratios Table

- The filings should include a summary table that provides the calculated cost-effectiveness ratios for programs, segments, and portfolio.
- Below is an example of what the table generally should look like (please note that the cost-effectiveness ratios in the example table are illustrative):

Table 22. Cost-Effectiveness Table Example

Program	Minnesota Test	Societal Cost Test	Utility Cost Test	Participant Cost Test	Ratepayer Impact Measure Test
Residential Program #1	3.50	2.51	3.41	3.19	0.59
Residential Program #2	3.50	4.76	3.06	N/A	0.58
Residential Program #3	3.50	0.96	2.13	1.27	0.54
Residential Segment	**3.50**	**2.08**	**2.45**	**3.09**	**0.55**
Low-Income Program #1	0.75	0.73	0.43	N/A	0.27
Low-Income Program #2	0.75	0.58	0.44	2.86	0.27
Low-Income Program #3	0.75	0.22	0.15	N/A	0.13
Low-Income Segment	**0.75**	**0.69**	**0.43**	**3.87**	**0.28**
C/I Program #1	3.00	1.30	2.80	1.20	0.60
C/I Program #2	3.00	1.31	2.84	1.28	0.69
C/I Program #3	3.00	1.63	1.21	4.45	0.52
C/I Segment	**3.00**	**3.01**	**5.96**	**2.73**	**0.80**
Other Program #1	3.25	1.30	2.80	1.20	0.60
Other Program #2	3.25	1.31	2.84	1.28	0.69
Other Program #3	3.25	1.63	1.21	4.45	0.52
Other Segment	**3.25**	**3.01**	**5.96**	**2.73**	**0.80**
Total Portfolio	**3.30**	**2.30**	**2.94**	**2.74**	**0.65**

Narrative Details

- The filings should include narratives accompanying the cost-effectiveness ratios table and describe:
  - The cost-effectiveness results by program using the MCT.
  - Any key cost-effectiveness issues that were considered in program design.
  - Any programs where secondary tests played a role in decision-making.

Methods and Impacts Reporting

- The filings should (either in the main body of the filing or as part of a technical appendix) clearly show where and how IOUs incorporated the required cost-effectiveness impacts and methods into their cost-effectiveness calculations.

E. Comments by Interested Parties

By the end of the comment period on March 6, 2023, the Department received comments on Staff's Proposed Decision from Center for Energy and Environment, CenterPoint Energy, City of Minneapolis and City St. Louis Park, Fresh Energy, Minnesota Energy Resources Corporation, Midwest Energy Efficiency Alliance, Minnesota Power, Otter Tail Power, and Xcel Energy.

The comments received by the Department are summarized below along with the Deputy Commissioner's determinations.

1. Center for Energy and Environment (CEE)

a. Areas of Support

CEE generally supports the Department's Proposed Decision. CEE considers the updated cost-effectiveness framework to be a significant step in the effort to modernize the State's utility energy efficiency, efficient fuel switching, and load management programs.

CEE believes that the Department's proposed primary Minnesota cost-effectiveness test will help to ensure that utilities build programs and portfolios that advance our State's ambitious energy policy goals.

b. Areas of Non-Support

i. Commodity Cost of Natural Gas - Inputs to BENCOST for Natural Gas IOU's 2024-2026 CIP Triennium

The natural gas commodity cost input is intended to reflect the current cost that natural gas utilities incur, and then pass along to customers, to purchase natural gas. This input can be challenging to estimate given the variability in natural gas costs. This is particularly true right now, given the changing market conditions and significant price increases in natural gas over the last two years.

Page 219 of Staff's Proposed Decision provides the proposed commodity cost of natural gas of $4.98 per dekatherm to be used in cost-effectiveness testing for ECO in 2024 through 2026.

CEE is concerned that Staff's proposed methodology for estimating the natural gas commodity cost does not reflect the current gas market. While using the weighted average of Minnesota's natural gas utilities' purchased gas adjustment (PGA) data has worked well over the last two CIP trienniums, during which the natural gas market was relatively stable, this retrospective methodology is not a good match for the current natural gas market. Natural gas prices have increased substantially over the last two years due to a variety of factors, including inflation, demand, export markets, and ongoing geo-political events. Averaging past prices of natural gas purchases over that period, blunts the effects of those market changes and underestimates current natural gas prices.

CEE provided an analysis of Minnesota utilities purchased gas price data. CEE states that the analysis shows sustained inflation over 24 months, resulting in significant increases in natural gas prices for Minnesota's utilities. Averaging, of course, picks a midpoint. In this case, averaging natural gas prices over these 24 months of inflation, picks a natural gas price that is most reflective of gas prices at the end of 2021. It omits significant inflation in natural gas prices throughout 2022 and provides a base commodity cost for natural gas that is not reflective of today's prices.

CEE reviewed natural gas costs from recent Minnesota utility bills. Though these data points are limited, they provide an up-to-date glimpse of where Minnesota utilities' natural gas prices are today. From January 2023 to February 2023, Minnesota's two largest natural gas utilities reported commodity costs from $7.99 per dekatherm to $8.67 per dekatherm on customer bills. These data points generally support the upward trajectory of natural gas prices as shown from the analysis above. They are both significantly higher than the commodity cost of natural gas included in the Proposed Decision.

CEE also analyzed U.S. Energy Information Administration (EIA) data for natural gas prices in Minnesota at the citygate. This EIA data is publicly available with state-specific natural gas prices that correspond to the prices Minnesota's natural gas utilities pay to take gas from interstate natural gas pipelines. EIA defines the citygate as, "[a] point or measuring station at which a distributing gas utility receives gas from a natural gas pipeline company or transmission system." Over the most recent 12-month period for which data is available, Minnesota natural gas citygate prices averaged $7.45 per Mcf. Over the 24-month period from November 2020 to October 2022, the same time period used to calculate the commodity cost in the Proposed Decision, Minnesota's average citygate price was $6.79 per Mcf, 36% higher than the natural gas commodity cost included in the Proposed Decision.

CEE's Recommendations: CEE recommends that the Department use the 12-month average of EIA's Minnesota-specific citygate prices to determine the commodity cost of natural gas for cost-effectiveness testing for the 2024-2026 ECO triennium. The average citygate natural gas price in Minnesota for the most recently available 12-month period (December 2021 to November 2022) is $7.45 per Mcf. Alternatively, the Department could adopt the most recently available 12-month weighted average gas cost from Minnesota utilities' PGA filings. From November 2021 to October 2022, the weighted average natural gas cost from Minnesota utilities' PGA filings is $6.46 per Mcf. While CEE prefers to use EIA data because it matches the data source proposed for the gas escalation rate, either of these two options represents a better match to current natural gas prices than the 24-month average of Minnesota utilities PGA data, as included in the Proposed Decision.

Deputy Commissioner's Determinations:

The Deputy Commissioner appreciates CEE's analysis of the different natural gas commodity prices and the organization's concern that historical prices do not accurately reflect the current gas market.

Ideally, the commodity cost of natural gas BENCOST input would accurately reflect forecasted costs that Minnesota's utilities would expect to pay for gas. Unfortunately, other than EIA projections, my Staff have not identified any publicly available dataset for Minnesota utility forecasted natural gas costs. The published EIA forecasted values that the Department used to create the rate at which the commodity costs are escalated are for the West Central Region which includes a seven-state portion of the upper Midwest. Although, as CEE points out, EIA publishes historical citygate natural gas prices, Staff's analysis of published historical values dating back to January 2020 shows that the EIA values are both considerably higher than utility PGA costs and reflect month-to-month volatility not evident in utility PGA costs. Although two-year historical PGA values may reflect lower prices than the current natural gas market and a one-year historical look might more closely resemble current gas prices, it is entirely possible that a future Triennial, if using one-year historical values, would have the opposite result with low one-year historical prices that are inconsistent with higher prevailing prices in the Triennial filing year. Using two years of historical PGA values helps smooth out year-to-year changes.

The Deputy Commissioner does not believe there is sufficient reason to deviate from historical practice in using prior two-year weighted-average PGA costs from the state's gas utilities as the starting commodity cost value. As described in response to CPE's written comments, the Deputy Commissioner does agree with CPE's proposed mathematical refinement, which effectively develops an average PGA cost for each utility over the two-year period and then weights each utility's average price by the utility's proportion of total sales to non-exempt customers. The Deputy Commissioner finds that this is a more accurate way of producing these estimates. The Commodity Cost value has been updated and the description of how the value is calculated has also been updated in "Appendix L: Inputs to BENCOST for Natural Gas Investor-Owned Utilities' 2024-2026 Conservation Improvement Program Triennium."

For future triennials, the Deputy Commissioner directs Staff to evaluate if there is an accurate, publicly available data source for Minnesota forecasted natural gas prices as a possible replacement for historical utility PGA costs.

ii. Gas Escalation Rate - Inputs to BENCOST for Natural Gas IOU's 2024-2026 CIP Triennium

The escalation rate applied to natural gas costs over the term of an analysis reflects expected trajectory of future gas costs over the life of the energy efficiency measures analyzed. Estimating the appropriate gas escalation rate is always challenging due to inherent uncertainty in the natural gas market. Estimating the appropriate gas escalation rate right now is especially difficult, at a time with changing market conditions.

On page 218 of the Proposed Decision, Staff propose a gas escalation rate of 2.61 percent and explain, "Staff calculated the Annual Escalation Rates using the projected average percent changes in the price of natural gas from 2023 through 2043 (20-year period) to all users in the West North Central Region as estimated in the Energy Information Administration's 2022 Annual Energy Outlook."

Importantly, applying a gas escalation rate of 2.61 percent to cost-effectiveness tests in ECO, effectively predicts that natural gas prices will go down over time. This is because the proposed escalation rate is lower than the proposed societal discount rate and utility discount rate, the two discount rates applied to ECO cost-effectiveness tests. Over the term of a cost-effectiveness analysis, natural gas costs will simultaneously be escalated and discounted. Anytime a discount rate is higher than the corresponding escalation rate, the overall value of the input will go down over time.

CEE does not agree that it is reasonable to predict that natural gas costs will decrease over time. CEE believes that there is a great deal of uncertainty in natural gas markets and some market factors may put upward pressure on prices, including the U.S. liquefied natural gas (LNG) export market and natural gas demand in Europe. However, any expectation that natural gas prices in the U.S. will stabilize or decline is predicated on the inflation experienced in the natural gas market over the last two years. In other words, one might expect that the market will adjust and prices will plateau or decline in large part because prices are so high today.

EIA estimates inflation of the natural gas market going forward within the context of the inflation experienced in the natural gas market in the past. Embedded within the base price of EIA's natural gas price forecast is past inflation. For example, while not a perfect match for prices incurred by Minnesota's natural gas utilities, EIA's average price to all users of natural gas in the West North Central region has a 2022 base price of $6.55 per Mcf.

CEE's Recommendation: CEE recommends that the Department adopt a gas escalation rate for cost-effectiveness testing for ECO for 2024-2026 based on the average of the escalation rate associated with the reference case EIA natural gas price forecast for all users in the West North Central Region (which was used to calculate the proposed gas escalation rate in the Proposed Decision) with the EIA forecast for the low oil and gas supply scenario for natural gas prices to all users in the West North Central Region, as estimated in the Energy Information Administration's 2022 Annual Energy Outlook. EIA's low oil and gas supply scenario forecasts gas prices if natural gas supply is lower than expected or if natural gas demand, including demand from the international LNG export market, is higher than expected. While it is impossible to predict natural gas market conditions in the future, CEE believes that it is at least equally likely that gas prices will increase over time due to increased demand and other inflationary pressures as it is that prices will decrease. CEE believes that the escalation rate associated with the average of these two forecasts is more reasonable than the escalation rate associated with the base EIA forecast for all users in the West North Central region, which predicts sustained decreases in natural gas prices over the next 20 years.

> **Deputy Commissioner's Determinations:** The Deputy Commissioner appreciates CEE's analysis of the rate Staff uses to escalate the commodity cost of natural gas, which is based on the average price to all users in the West North Central region. CEE points out that benefit-cost analyses in which the discount rate exceeds the escalation rate effectively means that the factor (in this case, commodity natural gas costs) will decrease over the relevant time period. CEE further states that the organization does not believe it is reasonable to predict that natural gas costs will decrease over time. The Deputy Commissioner does not have a view on whether natural gas costs are likely to increase or decrease over time and, therefore, does not agree with selecting forecasting methods based on their consistency with the belief that natural gas costs will increase. The Deputy Commissioner finds that Staff's approach is reasonable. As noted in the previous section, if in future triennials Staff can identify a publicly available data source for Minnesota forecasted natural gas prices that can serve as a possible replacement for historical utility PGA costs, then the costs will not require a separate escalation rate.

iii. *Lifetime Assumptions for Building Shell Energy Efficiency Measure - Inputs to BENCOST for Natural Gas IOU's 2024-2026 CIP Triennium*

On page 223 of the Proposed Decision, Staff provide guidance on the expected lifetime of energy conservation measures, as follows:

> The project life used in the BENCOST model is based on specific energy conservation measures. Projects with expected lives shorter than 20 years use lower figures. Each utility must show the reasonableness of its expected lifetime for a particular energy conservation measure or project. In most cases, the maximum life used is limited to 20 years for the following reasons:
>
> 1. benefits are more uncertain the further out in time the model is extended;
> 2. benefit streams diminish further out in time and have lesser effects on cost-effectiveness than more current years;
> 3. the further out in time the model is extended, the more uncertain it becomes that current ratepayers, who are funding CIP, receive the full benefits of CIP; and
> 4. if a project cannot pay for itself within 20 years, ratepayers should instead be funding other, more cost effective projects.

CEE appreciates Staff's openness to utilities proposing appropriate measure lifetimes in their triennial filings. CEE also appreciates Staff's description of why most energy efficiency measures should have an expected lifetime of no greater than 20 years for cost-effectiveness testing.

However, many energy efficiency measures, including building shell energy efficiency measures like insulation and air sealing, remain in place, effective, and provide significant benefits well beyond 20 years. Utility bill savings for these measures typically surpass the cost of the measure within 20 years. Nonetheless, by artificially limiting the effective lifetime of these measures in cost-effectiveness tests, it underestimates the benefits that these technologies provide.

Accurately representing the useful lifetime of energy efficiency measures in cost-effectiveness testing is important and impactful because utilities use cost-effectiveness testing to build and shape their energy efficiency portfolios. By underestimating the benefits of building shell energy efficiency measures and other long lasting energy efficiency measures, those measures may not be prioritized or funded appropriately, which will lead to a less durable energy efficiency resource and therefore higher costs on the utility system and for customers.

CEE recommended, in their December 29, 2022 Comments in Docket Number E,G999/CIP-18-694, that the Department update the lifetime assumption for insulation and air sealing measures in the Technical Reference Manual ("TRM") 4.0 to 50 years to more appropriately reflect the effective useful life of insulation and air sealing materials. In addition to the long effective useful life of insulation and air sealing materials, CEE also provided support for their recommendation to extend the lifetime of air sealing and insulation measures based on observations from CEE's own fieldwork. While not included in CEE's December 29, 2022 Comments, CEE also recommends a lifetime assumption for efficient windows of more than 20 years.

CEE's Recommendation: Given the longevity of building shell energy efficiency measures and importance of those measures to Minnesota's energy goals, including efficiency, affordability, greenhouse gas emissions reductions, and reliability, CEE believes that it is important for the Department to encourage or require utilities to use a lifetime assumption for building shell energy efficiency measures that reflects the actual term over which those measures will provide benefits. CEE recommends that the Department direct utilities to use a 50-year measure life for insulation and air sealing measures and use a 40-year measure life for high performance windows.

Deputy Commissioner's Determinations:
The Project Lifetime input described in the Inputs to BENCOST for Natural Gas IOUs' 2024-2026 CIP Triennium, is an input that varies from project to project.

The Deputy Commissioner notes that the BENCOST already provides some flexibility in the project lifetime used for specific measures in stating, "The project life used in the BENCOST model is based on specific energy conservation measures. Projects with expected lives shorter than 20 years use lower figures. Each utility must show the reasonableness of its expected lifetime for a particular energy conservation measure or project. In most cases, the maximum life used is limited to 20 years."

For cost-effectiveness analyses, the Deputy Commissioner is open to allowing project lifetimes that are greater than 20 years in cases that reasonably align with measure lifetimes that are approved in the most recent TRM. Additionally, the Deputy Commissioner is open to Staff reviewing custom measures and projects on a case-by-case basis when a utility proposes that a specific project's lifetime is greater than 20 years.

However, the Deputy Commissioner does not want to create an inconsistency between this cost-effectiveness Decision and approved lifetimes for prescriptive measures based on the most recent updates to the TRM. The Deputy Commissioner encourages CEE to continue to participate in the Technical Reference Manual Advisory Committee as that is the appropriate forum to discuss potential modifications to individual prescriptive measure technical assumptions.

The Deputy Commissioner also instructs Staff to revisit measure lifetimes in the next TRM cycle to determine what, if any, adjustments could be made to increase expected lifetime for prescriptive measure assumptions beyond 20 years.

2. CenterPoint Energy (CPE)

a. Areas of Support

i. Cost-Effectiveness Discount Rate

CPE supports Department Staff's proposed discount rates for cost-effectiveness testing.

ii. Cost-Effectiveness Requirements for Efficient Fuel-Switching Low-Income Programs

CPE supports Staff's recommendation to relax cost-effectiveness requirements for CIP efficient fuel-switching low-income programs. CIP's benefits to low-income households outweigh the costs, even if not all benefits are quantified and accounted for.

b. Areas of Mixed Support and Non-Support

i. Participant Costs and Benefits

CPE is neutral on whether to include or exclude participant costs and benefits from the primary cost-effectiveness test (the MCT). However, excluding participant impacts may result in primary cost-effectiveness estimates that do not fully and accurately reflect CIP's impacts on customers. For this reason, CPE raises questions about Department Staff's recommendation to remove participant impacts from the MCT. CPE frames its questions in the context of the NSPM for DERs' principles used to develop the proposed cost-effectiveness methodologies.

For example, CPE notes that in addition to the energy benefits associated with energy efficiency and conservation measures, CIP also delivers NEBs to program participants. NEBs can include increased comfort and productivity for CIP participants as well as improved health and economic outcomes. CPE recognizes that NEBs are difficult to quantify, and that it may, therefore, be tempting to exclude all participant impacts (both benefits and costs) from the MCT to ensure symmetry across CIP costs and benefits. However, doing so would appear to violate the NSPM's third principle, "account for relevant, material impacts…even if they are difficult to quantify and monetize."

Deputy Commissioner's Determinations:
The Deputy Commissioner appreciates CPE's feedback as it relates to the MCT.

The CAC adopted a MCT that excludes participant impacts as a way to address the NSPM's principle of ensuring symmetry across the primary test's costs and benefits. Symmetry can be achieved for participant impacts by either removing both participant costs and benefits from the primary test, or including them both. Thus, the decision to remove participant impacts from the primary test (which was based on extensive feedback from the CAC), achieves the NSPM for DER's principal of symmetry.

Additionally, as presented in this Decision, the utilities are still required to report results from programs using the RIM (ratepayers), UCT (utility), PCT (participants), and SCT (society) as CIP's secondary tests. As Staff noted in their Proposed Decision, the key purpose of the primary MCT is to determine "which resources have benefits that exceed costs and, therefore, merit utility acquisition or support on behalf of their customers" while the secondary tests "tend to answer different questions such as: how much will utility bills on average be reduced (UCT), and how much will cost-effectiveness change if an additional policy goal is added or removed from the Primary Test."

As outlined in the Deputy Commissioner's Decision section, for 2024-2026 CIP cost-effectiveness analyses using the secondary tests, utilities may include estimates for impacts that are not currently quantified or do not have an approved methodology (such as some participant impacts), but utilities should clearly outline all the assumptions and methodology details regarding how those impacts were estimated as part of their CIP Status Report and Triennial Filings.

ii. Utility Performance Incentives

CPE has concerns about Department Staff's proposed methodological approach for including the utility performance incentive in the MCT as part of 2024-2026 Triennial Plans and future CIP Status Reports. CPE is unsure how it will be applied in practice and why the proposed approach for Triennial Planning would produce different results than the proposed approach for CIP Status Reports.

CPE believes that Department Staff's description of how to apply the utility financial incentive to 2024-2026 Triennial Plans is the only method in the *Proposed Decision* that seems relatively clear. CPE understands the proposed approach (beginning at the end of pg. 214 of the Proposed Decision) to be:

- Running a portfolio cost-effectiveness model to produce results (e.g., net economic benefits from the utility test under the current financial incentive mechanism)
- These results are used in utility financial incentive calculation algorithms to calculate the utility's incentive for the year
- The incentive is allocated across the portfolio segment and program levels as a cost based either on annual or lifetime savings.

CPE is supportive of this approach and believes it reflects the consensus reached by CAC members.

CPE recommends against the financial incentive calculation process described for CIP Status reports in pg. 215 of the *Proposed Decision*. The process as described is not feasible unless cost-benefit and financial incentive mechanism algorithms are fully integrated to create the circularity for Microsoft Excel to process. To date, CPE is unaware of plans for doing this. If there is a long-term plan for this integration, CPE sees another problem. The approach for estimating financial incentive costs for Triennial Planning produces a different result than the process described for CIP Status Reports. This result can be seen in the following example from pg. 212 of the Proposed Decision:

- Total Benefits: $407,000,000
- Total Costs: $105,000,000
- 2021-2023 Triennial Period/Proposal for 2024—2026 Triennial Plans
    - Net Benefits: $302,000,000
    - Ten percent of net Benefits: = $30.2 million
- New Approach for CIP Status Reports:
    - Net Benefits = $274,545,455
    - Ten percent of net benefits = $27,454,545

CPE opposes integrating the utility financial incentive as a cost in a way that leads to incremental reductions in the incentive for better performance.

CPE respectfully recommends that the proposed approach for the 2024-2026 Triennial Plans also be used for the CIP Status Reports.

Deputy Commissioner's Determinations:
The Deputy Commissioner recognizes that utilities have remaining concerns about the way utility performance incentives will be calculated and incorporated into cost-effectiveness analyses.

As documented in the Proposed Decision, the NSPM for DERs indicates that financial incentives related to CIP performance should be treated as a utility system impact (cost) because it is a program administrative cost that is recovered from ratepayers. Staff's proposed method for incorporating utility performance incentives into cost-effectiveness analyses for both utility triennial and status report filings is appropriate.

This Decision does not address revisions to the way the CIP Shared Savings Incentive Mechanism itself is calculated, as it is outside the scope of this CIP cost-effectiveness update process.

The Deputy Commissioner directs utilities to use the finalized methodology for Utility Performance Incentives that is included in Appendix K.

iii. Applying Cost-Effectiveness Testing to Efficient Fuel Switching

CPE seeks clarification about how the MCT will be applied to EFS and standard CIP programs as summarized in the Proposed Decision. CPE interprets this guidance as requiring evaluation of the EFS segment separately from CIP segments and then evaluation of the whole portfolio, but not evaluation of individual programs or customer segments that offer both EFS and CIP measures. However, the method for allocating administrative costs between EFS and CIP segments should be documented as relevant.

Deputy Commissioner's Determinations: The Deputy Commissioner interprets Staff's Proposed Decision recommendations differently than CPE. CPE states that Staff's guidance does not recommend evaluating cost-effectiveness for individual programs or customer segments that offer both EFS and non-EFS measures. Staff indicate that utilities should propose an EFS-only segment to ensure that the EFS portion of utility CIP portfolios are cost-effective and to enable accurate accounting of EFS activities. As stated in Appendix A of the Commissioner's March 15, 2022 Final Decision, "Utilities implementing EFS measures shall create an EFS segment within their CIP portfolios. Utilities can opt to bundle EFS measures into programs. Similarly, these programs can be included in the CIP segment that the utility deems most appropriate. However, to ensure that EFS improvements can be assessed and tracked separately from other aspects of utilities' CIP programming, utilities will also, as part of their CIP plans and annual reports, present efficient fuel-switching improvements separately."[56]

c. Areas of Non-Support

i. *Gas Commodity Costs*

CPE recommends revising Staff's proposed gas commodity cost of $4.98 per Dth. The method in the proposed BENCOST model uses an average of averages approach to calculate an average commodity cost for each utility before further averaging these rates. CPE does not believe that it is analytically correct to average two years of commodity costs for each utility rather than calculating monthly commodity costs ($) for all utilities, summing those costs, and then dividing total costs by the total gas sales from nonexempt customers. CPE calculates a commodity cost of $4.52 per Dth using the data provided by Department Staff. See row 33 in Exhibit A included with CPE's filing.

Deputy Commissioner's Determinations: The Deputy Commissioner agrees with CPE's approach, which effectively develops an average PGA cost for each utility over the two-year period and then weights each utility's average price by the utility's proportion of total sales to non-exempt customers. The Deputy Commissioner finds that this is a more accurate way of producing these estimates. The Commodity Cost value has been updated and the description of how the value is calculated has also been updated in "Appendix L: Inputs to BENCOST for Natural Gas Investor-Owned Utilities' 2024-2026 Conservation Improvement Program Triennium."

3. City of Minneapolis and St. Louis Park (The Cities)

a. Areas of Support

The Cities support the Proposed Decision with a few important modifications. Staff recommendations include critical changes to evolve CIP into ECO to support energy efficiency, load management, and fuel switching in utility programs. The Cities believe this proposed cost-effectiveness framework will make a significant step to achieving the ambitious energy goals of both the State and our Cities. The Cities also strongly support Staff's recommendation to maintain the current policy not requiring low-income programs to pass the CIP primary cost-effectiveness test.

b. Areas of Non-Support

i. Assumptions regarding lifetime of building shell measures

The Proposed Decision references TRM 4.0, which includes technology specifications that are used in cost effectiveness tests. Among those TRM specifications are lifetime assumptions for residential building shell measures, including insulation and air sealing. The lifetime assumption given for air sealing

[56] In the Matter of Technical Guidance for the Inclusion of Efficient Fuel-Switching, Load Management, and Pre-Weatherization Measures in CIP" (Docket E,G999/CIP-21-837), Commissioner Decision, Minnesota Department of Commerce, March 15, 2022, Appendix A, p. 46.

and insulation is 20 years and is based on the 2008 Database of Energy Efficiency Resources, which is maintained by the California Public Utilities Commission. The Cities find that the 20-year lifetime assumption underestimates actual lifetime based on our experience in home inspection programs in St. Louis Park and Minneapolis, including Truth in Sale of Housing.

The Cities Recommendation: The Cities recommend that the lifetime assumption for insulation and air sealing measures in the TRM 4.0 be updated to reflect their effective useful life more accurately.

Deputy Commissioner's Determinations:
The Project Lifetime input described in the Inputs to BENCOST for Natural Gas IOUs' 2024-2026 CIP Triennium, is an input that varies from project to project.

The Deputy Commissioner notes that the BENCOST already provides some flexibility in the project lifetime used for specific measures in stating, "The project life used in the BENCOST model is based on specific energy conservation measures. Projects with expected lives shorter than 20 years use lower figures. Each utility must show the reasonableness of its expected lifetime for a particular energy conservation measure or project. In most cases, the maximum life used is limited to 20 years."

For cost-effectiveness analyses, the Deputy Commissioner is open to allowing project lifetimes that are greater than 20 years in cases that reasonably align with measure lifetimes that are approved in the most recent TRM. Additionally, the Deputy Commissioner is open to Staff reviewing custom measures and projects on a case-by-case basis when a utility proposes that a specific project's lifetime is greater than 20 years.

However, the Deputy Commissioner does not want to create an inconsistency between this cost-effectiveness Decision and approved lifetimes for prescriptive measures based on the most recent updates to the TRM. The Deputy Commissioner encourages The Cities to participate in the Technical Reference Manual Advisory Committee as that is the appropriate forum to discuss potential modifications to individual prescriptive measure technical assumptions.

The Deputy Commissioner also instructs Staff to revisit measure lifetimes in the next TRM cycle to determine what, if any, adjustments could be made to increase expected lifetime for prescriptive measure assumptions beyond 20 years.

ii. *Natural gas commodity cost inputs* - Inputs to BENCOST for Natural Gas IOU's 2024-2026 CIP Triennium

The Proposed Decision recommends using natural gas commodity costs of $4.98 per dekatherm for cost effectiveness tests from 2024 through 2026. The Department used a 24-month average weighted by utility gas sales for the commodity calculation. This was appropriate in the past two trienniums during relatively stable gas prices. However, inflation, geopolitical events, and other variables have made gas prices less stable, requiring a new approach to developing cost assumptions for the coming triennium.

The Cities reviewed utility cost of gas data from municipal facility utility bills over the past three Januarys and found significant increases across rate classes. The average change in the cost of gas over two years was an increase of 125%. Over a one-year span, the average change in the cost of gas was much less, at only 54%.

Averaging the price of natural gas over a long period- especially one with high inflation- removes much of that inflation. The Cities' analysis indicates the relative impact of comparing today's cost of gas to that from two years ago. The Cities are concerned that the proposed commodity cost of $4.98 per dekatherm is too low and does not reflect current or expected market conditions.

The Cities Recommendation: The Cities recommend reducing that retrospective period from 24 to 12 months for gas commodity costs for the coming Triennium.

> **Deputy Commissioner's Determinations:** As discussed in more depth in response to CEE's written comments, the Deputy Commissioner does not believe there is sufficient reason to deviate from historical practice in using prior two-year weighted-average PGA costs from the state's gas utilities as the starting commodity cost value.
>
> As described in response to CPE's written comments, the Deputy Commissioner does agree with CPE's proposed mathematical refinement, which effectively develops an average PGA cost for each utility over the two-year period and then weights each utility's average price by the utility's proportion of total sales to non-exempt customers. The Deputy Commissioner finds that this is a more accurate way of producing these estimates. The Commodity Cost value has been updated and the description of how the value is calculated has also been updated in "Appendix L: Inputs to BENCOST for Natural Gas Investor-Owned Utilities' 2024-2026 Conservation Improvement Program Triennium."
>
> For future triennials, the Deputy Commissioner directs Staff to evaluate if there is an accurate, publicly available data source for Minnesota forecasted natural gas prices as a possible replacement for historical utility PGA costs.

4. Fresh Energy

a. Areas of Support

i. MCT as Primary CIP Cost-Effectiveness Test

Fresh Energy supports using the MCT as the primary cost- effectiveness test for CIP. The societal perspective and discount rate employed in the MCT better reflect and are more consistent with Minnesota's energy efficiency policy objectives because they place a higher value on the long-term net benefits to customers and society, rather than utility or utility shareholders.

ii. Proposal to incorporate high-end values for greenhouse gas and criteria air emissions into the environmental damage factor inputs.

Fresh Energy supports Staff's proposed updates to the Gas and Non-Gas Fuel Environmental Damage Factors (BENCOST Inputs 9 and 10), which is to modify the environmental damage factor methodology for the 2024-2026 triennium to incorporate the high-end value for criteria air emissions and the PUC's approved high-end externality values for greenhouse gas emissions for each year of a cost-effectiveness analysis period.

Fresh Energy noted what it believes is an inconsistency in the recommended methodology for incorporating the value for criteria air emissions into the environmental damage factor: on page 53 of the Proposed Decision, Staff recommend that utilities use the high-end value for criteria air emissions, but in Appendix L detailing the BENCOST inputs (pages 220-221), Inputs 9 and 10 state that the median of the range for criteria air emissions was used. As stated above, Fresh Energy supports the use of the high-end values for criteria air emissions.

> **Deputy Commissioner's Determinations:** The Deputy Commissioner agrees with Fresh Energy and Staff that utilities should use the high-end value for criteria emissions, and finds, as Fresh Energy observed, that the language in the Proposed Decision's Appendix L was inconsistent with this recommendation. This Decision includes the corrected language and associated values in Appendix L and the BENCOST model spreadsheet.

b. Areas of Non-Support

i. The MCT should use a lower societal discount rate that is more in line with federal and state law and policy.

Fresh Energy believes the societal discount rate used in the MCT should be a range of 1.5 to 2.5 percent with 2 percent utilized as the central estimate, which is more in line with federal and state law and policy. This is lower than the current value (from the 2021-2023 Triennial) of 3.02 percent, and also lower than Staff's proposed value of 3.3 percent for the 2024- 2026 Triennial. Calculating the societal discount rate using the United States Department of the Treasury's 20-year Constant Maturity Rate results in a much higher discount rate than what is currently recommended by experts.

The most current analysis of the social cost of carbon from the federal IWG determined that the consumption rate of interest (rather than the social rate of return on capital) is the appropriate discount rate to estimate the intergenerational impacts of climate change. Specifically, "a consideration of discount rates below 3 percent, including 2 percent and lower, are warranted when discounting intergenerational impacts." The IWG found it appropriate as an interim recommendation that agencies may consider conducting additional sensitivity analysis using discount rates below 2.5 percent. Other jurisdictions are also considering discount rates applied in valuing social cost of carbon, including 2 percent in Massachusetts, 2 percent in Vermont, 2 percent in New York, and 2.5 percent in Washington state.

Further, the societal discount rate should align with Minnesota's recently-enacted 100 percent carbon-free electricity requirement. This law amends Sec. 18. Minnesota Statutes 2022, section 216B.2422, subdivision 3 to read:

> **Subd. 3. Environmental costs.** (a) The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.
>
> (b) The commission shall provisionally adopt and apply the draft cost of greenhouse gas emissions valuations presented in the United States Environmental Protection Agency's EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, released in September 2022, including the time horizon, global estimates of damages, and the full range of discount rates from 2.5 to 1.5 percent, with two percent as the central estimate. The commission shall adopt the estimates contained in the final version of the external review draft report when it becomes available.

c) If, at any time, the estimates adopted by the commission under paragraph (a) are exceeded by estimates released by the federal Interagency Working Group on the Social Cost of Greenhouse Gases or its successors, the commission shall adopt the working group estimates.

(d) The commission shall establish interim environmental cost values associated with each method of electricity generation by March 1, 1994. These values expire on the date the commission establishes environmental cost values under paragraph (a).

Fresh Energy Recommendations: Fresh Energy recommends that the Department employ a societal discount rate within the range of 2.5 to 1.5 percent, with 2 percent as the central estimate, in keeping with the work of the EPA, IWG, and Minnesota legislature.

Deputy Commissioner's Determinations: The Deputy Commissioner agrees with Staff's recommendation that the federal Treasury rate remains a good proxy to value, in current dollars, the future stream of societal benefits and costs resulting from a conservation investment. This approach has been used historically and it remains an appropriate way to develop the estimate. Since we are dealing with a Societal Discount Rate, it is not intended to only focus on the GHG/externality aspect of the way society discounts the future value of benefits from CIP activities. From this perspective, the Deputy Commissioner finds that the Treasury rate represents an appropriate proxy for the way society discounts the future value of benefits of CIP.

ii. The societal discount rate should be used across all secondary tests.

Synapse's 2018 CARD report recommend that the societal discount rate currently used in Minnesota for some cost-effectiveness tests be used for all tests—including secondary tests. Synapse found that the societal discount rate is appropriate for all tests because it is consistent with the policies in Minnesota that require consideration of societal impacts. Further, these policies place relatively high priority on long-term impacts. Using the societal discount rate across all tests also allows for more direct comparison of results across the different tests. The societal discount rate better reflects and is more consistent with Minnesota's energy efficiency policy objectives because it places a higher value on the long-term benefits and time preference that maximizes the net benefits to customers and society, rather than utility or utility shareholders. The goal of the cost-effectiveness analyses, including the Utility Cost Test, should be to maximize the net benefits to customers and to society, not just to maximize investor value. Therefore, the discount rate should be consistent with the time preference that regulators consider to achieve those policy goals. The proposed utility discount rates are too high.

Fresh Energy Recommendations: The societal discount rate be used for all secondary cost-effectiveness tests, in addition to use in the MCT.

Deputy Commissioner's Determinations: The Deputy Commissioner agrees with Staff's recommendation regarding the discount rates that are appropriate for each cost-effectiveness test. Each cost-effectiveness test is designed to analyze conservation investments from a different perspective. This ensures that regulators have a complete picture of who is actually better off and who might be worse off as a result of a CIP investment. For the tests to be meaningful, each test should use the appropriate discount rate that reflects the time value of future benefits from the perspective of the entity who is making the investment.

iii. The MCT should use a higher commodity cost of gas and gas escalation rate.

The commodity cost (BENCOST Input 3) of $4.98/Dth and gas escalation rate of 2.61% in the Proposed Decision are not representative the of current cost of natural gas and fail to accurately capture the outlook of the cost of natural gas. The Department should instead use a higher commodity cost and gas escalation rate. Underestimation of the cost of natural gas would be detrimental to Minnesota's electrification and energy efficiency goals, especially given that efficient fuel-switching is now allowed in ECO.

Fresh Energy Recommendations: Fresh Energy understand that CEE will be proposing specific values and sources for the commodity cost and gas escalation rate to use in the MCT and Fresh Energy supports the proposed higher commodity cost and gas escalation rate that are presented in their analysis.

> **Deputy Commissioner's Determinations:**
> As discussed in more depth in response to CEE's written comments, the Deputy Commissioner does not believe there is sufficient reason to deviate from historical practice in using prior two-year weighted-average PGA costs from the state's gas utilities as the starting commodity cost value.
>
> As described in response to CPE's written comments, the Deputy Commissioner does agree with CPE's proposed mathematical refinement, which effectively develops an average PGA cost for each utility over the two-year period and then weights each utility's average price by the utility's proportion of total sales to non-exempt customers. The Deputy Commissioner finds that this is a more accurate way of producing these estimates. The Commodity Cost value has been updated and the description of how the value is calculated has also been updated in "Appendix L: Inputs to BENCOST for Natural Gas Investor-Owned Utilities' 2024-2026 Conservation Improvement Program Triennium."
>
> For future triennials, the Deputy Commissioner directs Staff to evaluate if there is an accurate, publicly available data source for Minnesota forecasted natural gas prices as a possible replacement for historical utility PGA costs.

iv. Estimation of low-income impacts should be prioritized for the next Triennial.

Fresh Energy Recommendations: Fresh Energy looks forward to working with Department to estimate the cost-effectiveness of low-income programs moving forward. This is important to appropriately value these programs. Fresh Energy is interested in working to assign values to the benefits of these programs that are currently assumed to pencil out. Fresh Energy supports the current assumption that the benefits to these programs outweigh the costs, but is also interested in refining this analysis with real values to more effectively serve this important group. Fresh Energy recommends that this topic be prioritized in ongoing discussions in the CIP Low-Income Plus working group convened by the Department.

> **Deputy Commissioner's Determinations:** The Deputy Commissioner applauds Fresh Energy's dedication and commitment to underserved communities. Specific to the scope of the current cost-effectiveness regulatory process, impacts on low-income customers are not explicitly included in the MCT's approved structure for the 2024-2026 triennium. The Deputy

Commissioner appreciates Fresh Energy's support of the 2024-2026 approach that recognizes CIP's importance to low-income customers by extending current CIP policy of not requiring that low-income programs pass CIP's primary cost-effectiveness test. The Deputy Commissioner also appreciates Fresh Energy's leadership in the development of the CIP Low-income Plus working group and looks forward to ongoing and future stakeholder discussions around how CIP programs can best meet the needs of Minnesota's under-resourced customers.

v. Estimation of societal impacts should be prioritized for the next Triennial

Fresh Energy Recommendations: Fresh Energy looks forward to continuing to work with the Department and the CAC to develop estimates for important societal impacts including economic and jobs, other environmental, energy security, energy equity, and public health, in addition to revisiting utility impacts such as environmental compliance. Fresh Energy asks that these societal impacts be prioritized leading into the next Triennial. Fresh Energy is disappointed that discussion of these impacts was not prioritized during the CAC stakeholder process as originally envisioned, but Fresh Energy looks forward to discussing the impacts leading into the next Triennial.

Deputy Commissioner's Determinations: The Deputy Commissioner understands Fresh Energy's concerns but also recognizes the challenges Staff faced in substantially modifying the overall cost-effectiveness framework in time for utilities to develop their 2024-2026 Triennial filings which are due June 1, 2023. Staff and the CAC accomplished a great deal in a short period of time. The Deputy Commissioner views developing the MCT as something that will be built upon going forward, and looks forward to Staff determining the most appropriate timing for discussing continued refinements leading up to the 2027-2029 triennials.

5. Minnesota Energy Resources Corporation (MERC)

a. Areas of Support

MERC appreciates the Department's willingness to engage with stakeholders through the CAC. In general, MERC is supportive of the Department's recommendations described in the Proposed Decision.

b. Areas of Non-Support

i. Utility Performance Incentive Impact

The utility performance incentive for the 2024-2026 Triennial Plan is currently under development as part of a separate docket and is not expected to be finalized until after the 2024-2026 Triennial Plan filing deadline. As such, MERC believes it is premature to determine the methodology for how the incentive is incorporated into the cost-effectiveness analysis for the plan. However, MERC will proceed to meet the June 1, 2023, filing deadline using the best available information with documentation describing the methodologies, inputs, and assumptions.

Staff offers guidance on how to incorporate Utility Performance Incentives in cost-effectiveness analysis starting on page 211 of the Proposed Decision. The guidance notes that including the utility performance incentive as a cost in the cost-effectiveness analysis causes a circular reference error, since the incentive amount is dependent on the result of the cost-effectiveness analysis. Although the Proposed Decision offers additional guidance aimed at avoiding this error, it is unclear how the utility performance incentive should be incorporated in actual practice as part of the 2024-2026 Triennial Plans and Status Reports.

MERC Recommendations: MERC encourages the Department to update the Proposed Decision to clarify the guidance related to the utility performance incentive. MERC looks forward to continued dialogue with the Department and other utilities and stakeholders on this topic.

> **Deputy Commissioner's Determinations:** The scope of the guidance provided in the Cost-Effectiveness Proposed Decision and this Decision is intended to describe how the Utility Performance Incentive should be incorporated as an impact in the cost-effectiveness tests. In Triennial filings, utilities should use the current Utility Performance Incentive mechanism to estimate the costs that will be included in cost-effectiveness tests. The guidance is not intended to describe how the 2024-2026 Shared Savings financial incentive mechanism is calculated. The Deputy Commissioner looks forward to continued discussions about the 2024-2026 Shared Savings financial incentive as part of that separate proceeding.
>
> The Deputy Commissioner directs utilities to use the finalized methodology for Utility Performance Incentives that is included in Appendix K.

6. Midwest Energy Efficiency Alliance (MEEA)

a. Areas of Support

MEEA support of Staff's Proposed Decision. MEEA has been a partner of the National Energy Screening Project (NESP) since 2018, helping to promote the use of the NSPM for DERs in the Midwest. MEEA commends Staff on the stakeholder process - in which MEEA participated from the beginning - that led to the Proposed Decision. Staff and their consultants kept stakeholders well informed and conducted effective, productive meetings. Participation from local and national experts, utilities and energy advocates was strong, and all parties had ample opportunities to provide input on issues. Staff followed the five-step framework laid out in the *NSPM for DERs* and held well to the NSPM principles. Robust discussion from participants and well-organized homework assignments informed the process throughout its course, and MEEA is happy to see the results of the stakeholder consensus in this Proposed Decision.

Staff's Proposed Decision, its appendices and your upcoming Decision in this docket will not only play key roles in BCA testing for the CIP plans, but also serve as important references regionally and nationally. The well-executed and transparently documented activities of Staff and the CAC are a case study in how the authors and promoters of the *NSPM for DERs* expect the process to work. The outcomes are meaningful, straightforward and actionable. MEEA believes that implementation of Staff's recommendations will lead to strong positive outcomes for CIP and continue Minnesota's leadership in the Midwest.

> **Deputy Commissioner's Determinations:** The Deputy Commissioner greatly appreciates MEEA's letter of support and all of the insights that MEEA contributed as a member of the Committee. The expertise that MEEA brought to the CAC was valuable to this cost-effectiveness update process.

7. Minnesota Power (MP)

a. Areas of Support

MP largely supports the proposed decision with a few exceptions.

i. Minnesota Cost Test as CIP's Primary Cost-Effectiveness Test

MP supports the proposed transition to using the new MCT as the primary cost-effectiveness test that utilities use to screen their energy efficiency, LM, and EFS programs for the 2024-2026 triennial period. MP also supports the continuation of allowing approval of cost-effectiveness at the segment-level and supports the proposed impacts to be included in the MCT as included in Table 18 of the Proposed Decision.

ii. Secondary Cost-Effectiveness Tests and Program Design

MP has no concerns with the proposed use of and impacts included in the secondary cost-effectiveness tests.

iii. Utility System Impact Methodologies

MP is supportive of the inclusion of and values assigned to the Utility System impacts detailed in the Proposed Decision with the exception of the Electric Marginal Energy costs and Utility Performance Incentives.

iv. Low-Income Impacts

MP agrees with the Department's proposal to maintain the current policy, which does not require that low-income programs pass CIP's primary cost- effectiveness test and does not include specific impacts that would apply to low-income programs in the tests. There are many valuable impacts and benefits associated with low-income programs that are not currently captured in existing impacts but would be very difficult to quantify. Meanwhile, given the existing impacts in the cost-effectiveness tests, low-income programs often will not pass despite the significant value they bring to participants and communities alike. As such, MP agrees it is important to maintain this flexibility for low-income cost-effectiveness.

v. Electric Avoided Costs and Transparency

MP supports the Department's proposal to allow electric IOUs to choose to update their avoided T&D costs using the approved Discrete Approach methodology, or continue to use the Discrete Approach avoided T&D cost values that were approved previously for the 2021-2023 Triennial period.

vi. Discount Rates for Cost-Effectiveness Analyses

MP supports the discount rates proposed to be used in each of the cost- effectiveness tests.

b. Areas of Non-Support

i. Avoided Marginal Energy Costs

MP understands the desire for increased transparency around cost-effectiveness inputs. However, by moving away from utility specific avoided marginal energy costs, the resulting net-benefits will not reflect the true value of demand side management programs to MP customers. MP has a unique avoided cost profile that will not be reflected through the cambium model data set. MP has high amounts of renewables in its resource mix and a system with a high load factor, and ultimately this unique generation portfolio and customer mix will not be represented by a regional model. However, MP supports the use of the Cambium model by Non-Electric utilities for marginal energy cost assumptions.

> **Deputy Commissioner's Determinations:** The Deputy Commissioner notes that several stakeholders (MP, OTP, and Xcel) raised concerns about the Proposed Decision's recommendation to use Minnesota values from the NREL Cambium model for avoided marginal energy costs.
>
> Based on the concerns raised, namely the Cambium model's lack of consistency with utility IRP data, uncertainties about which Cambium scenario best matches utility futures, and how utilities will effectively integrate Cambium data into their cost-effectiveness analyses, the Deputy Commissioner finds it prudent to modify Staff's recommendation. Rather than require use of Cambium data, the Deputy Commissioner will allow electric IOUs to use internally-provided marginal energy data, presumed to be the most up-to-date forecasts that would be used for Resource Plan modeling. The Deputy Commissioner directs utilities to use the finalized methodology for Marginal Energy that is included in Appendix K.
>
> The Deputy Commissioner also remains concerned about the lack of transparency regarding the marginal energy values electric IOUs use in their cost-effectiveness analyses. With this in mind, the Deputy Commissioner requires that as part of their 2024-2026 triennial plan filings, the electric IOUs should:
>
> - describe the methods used to estimate their avoided marginal energy cost values;
> - share avoided marginal energy cost data in a form that is not considered Trade Secret (e.g. monthly, seasonal, or annual values, by daytype and season, etc.), **AND/OR** provide a clear and simplified way for interested parties to receive the Trade Secret avoided marginal energy cost data (e.g. through a non-disclosure agreement with the utility).
>
> For future triennials, the Deputy Commissioner directs Staff to explore establishing estimation methods for avoided marginal energy costs that both facilitate using the most up-to-date information possible and that enable this data to be shared publicly.
>
> Lastly, this Decision updates Input 7 – Non-Gas Fuel Costs in Appendix L's Inputs to BENCOST for Natural Gas IOUs to replace the Cambium annual marginal energy data with the method used in the previous triennial to estimate these costs. However, for gas IOU EFS projects and programs, gas IOUs should work with their electric counterparts to obtain more detailed marginal energy data than the standard data included in the BENCOST model. This approach will help ensure that evaluation of EFS projects and programs remain consistent with the approach adopted in the Commissioner's March 15, 2022 ECO Act Technical Guidance.

ii. Utility Performance Incentives

MP could support inclusion of the utility performance incentive in the net-benefit calculations, but opposes the iterative recalculation proposed in Appendix K of Staff's Proposed Decision. While the proposal addresses the mathematical issue of circularity it does not change the fact that conceptually this method is circular in nature. The shared savings incentive is intended to allow the utilities to earn a portion of the net benefits that were created as a direct result of the implementation of their programs. This iterative method would result in utilities earning some amount less than the allowed percent of net benefits created by these programs. For example, if a utility is allowed to earn 10 percent of net benefits as their financial incentive, by including the incentive as a cost in the calculation of net benefits, this calculation will result in a roughly 9 percent reduction in financial incentive compared to using net benefits achieved through program performance when considering only the costs associated with delivering the programs.

MP's Recommendation: MP's preferred approach would be to calculate net benefits without any consideration of the performance incentive and base the financial incentive off of that result (as has been done historically). Then, apply that financial incentive amount to the initial net benefits to arrive at the final net benefits accounting for the performance incentive. This method removes the circular nature of including the incentive in the calculation of the incentive but still allows the final net benefits to reflect the costs of the performance incentive.

However, if the PUC approves the iterative approach to including the performance incentive in net benefits, MP recommends the Department provide a table of factors for each potential percent of net benefits that could be awarded that can simply be multiplied by the initial net benefits to arrive at the financial incentive. This financial incentive amount could then be subtracted from the net benefits (or added to the costs component of net benefits) to arrive at the final net benefits which now includes the performance incentive. This removes the need for utilities to run the iterative calculation, reduces potential for errors in configuring the iterative calculation, and increases transparency by allowing anyone to easily complete the calculation. The factors can easily be created because the iterative process will always converge on the same number for a given percent awarded. Attachment A demonstrates this and creates a table of factors that correspond to the existing net benefits awarded by achievement level table from the template for the current mechanism. Factors could easily be calculated for any percent of net benefits that could potentially be awarded in the 2024-2026 triennial period.

MP could support the requirement to apply the performance incentive at the segment level but recommends against applying it at the program level. Doing so skews the benefit/cost (B/C) ratios making it more difficult to tell the difference in value between the really high performing segments and low performing segments because the high performing program B/C ratios are more heavily impacted than lower performing programs.

Finally, MP recommends a simpler approach to allocating the performance incentive to segments. Rather than basing the allocation on lifetime savings, MP recommends applying the financial incentive factor approach described above at the segment level. Or, under the approach that does not use the iterative method, simply multiply segment level net benefits by one minus the percent awarded. Both of these approaches remove the need for additional calculations involving lifetime savings because net benefits already reflect lifetime savings. Since the financial incentive is directly tied to net benefits, allocating the financial incentive in this way is the most accurate way to attribute the financial incentive "cost" to the segments. Attachment A demonstrates this application based on MP's 2021 cost-effectiveness results.

Deputy Commissioner's Determinations:
The scope of the guidance provided in the Cost-Effectiveness Proposed Decision and this Decision is intended to describe how the Utility Performance Incentive should be incorporated as an impact in the cost-effectiveness tests. The guidance is not intended to describe how the 2024-2026 Shared Savings financial incentive mechanism is calculated. The Deputy Commissioner looks forward to continued discussions about the 2024-2026 Shared Savings financial incentive as part of that separate proceeding.

MP also recommends against applying the Utility Performance Incentive at the program level in triennial filings and allocating the Utility Performance Incentive as a cost based on segment and program lifetime savings. The Deputy Commissioner supports Staff's Proposed Decision recommendation to apply Utility Performance Incentives to the portfolio, segments, and programs in utility triennial filings because this will provide more complete information about program-level cost-effectiveness. The Deputy Commissioner also supports Staff's recommendation to allocate Utility Performance Incentives to segments and programs based on the allocation on program and segment percentage of portfolio lifetime savings.

The Deputy Commissioner directs utilities to use the finalized methodology for Utility Performance Incentives that is included in Appendix K.

iii. Proposed Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance

MP has no comments on the CE Technical Guidance at this time. The uncertainty and significant resources required to work through the four-step evaluation process for EFS has presented significant challenges for moving forward with EFS in the immediate future.

MP would urge that EFS guidelines be reevaluated regularly and that the Department leave room for flexibility. For example, similar to how the guidelines for other pieces of the evaluation process allow for utilities to propose alternative approaches as they begin to bring EFS proposals forward, MP recommends that there also be flexibility in this component as well.

Deputy Commissioner's Determinations: The Deputy Commissioner appreciates the continued collective efforts of Staff and stakeholders to provide clarity around the ECO statutory requirements, and encourages Staff and the IOUs to continue to identify and communicate areas of uncertainty and evaluate whether updates to current regulatory policy guidance are needed. Additionally, the Department's March 15, 2022, ECO Act Technical Guidance provides utilities with the opportunity to propose alternative methods in meeting the EFS criteria. Utilities should refer to the step-by-step process included in the ECO Act Technical Guidance for more information regarding custom proposals that can be submitted as part of utility CIP triennial plan filings or CIP program modifications for the Department's review.[57]

[57] "In the Matter of Technical Guidance for the Inclusion of Efficient Fuel-Switching, Load Management, and Pre-Weatherization Measures in CIP" (Docket E,G999/CIP-21-837), Commissioner Decision, Minnesota Department of Commerce, March 15, 2022, Appendix A.

iv. Non-Utility System Impacts

Staff proposed using the high environmental cost values for greenhouse gasses and criteria pollutants to estimate the environmental damage factor for the 2024-2026 cost-effectiveness analyses. MP recommends using the mid values to align with what MP uses in the IRP as the reference case. The High case is included as a sensitivity.

> **Deputy Commissioner's Determinations:** The Deputy Commissioner understands that there was general consensus from the CAC and Staff that both gas and electric utilities should use the MN PUC's January 3, 2018 Order's high externality values for CO_2 and criteria emissions to estimate the environmental damage factors. The Deputy Commissioner agrees with the arguments presented in support for adopting the high externality values for the purposes of CIP cost-effectiveness.

8. Otter Tail Power (OTP)

a. Areas of Support

OTP mostly supports the Proposed Decision but does have a couple items with which it disagrees.

i. Minnesota Test as CIP's Primary Cost-Effectiveness Test

OTP has no concerns at this time for the Primary Test being the MCT and the other cost-effectiveness tests (SCT, UCT, PCT, RIM) becoming secondary tests.

OTP agrees with the recommendation to continue to allow approval of cost-effectiveness at the segment level which allows utilities to have more flexibility when offering programs. This also allows for the ability to follow the general guidelines recommended in Staff's Proposed Decision, which are as follows:

- Cost-effectiveness and program design are separate, but related concepts. Program design and portfolio development involve many considerations;
- Cost-effectiveness evaluations can help inform program design but should not be the primary basis for program design;
- Just because a program is cost-effective does not mean that the utility should include it in its portfolio and, by extension, just because a program is not cost-effective does not mean that it should be automatically eliminated; and
- It is the utility's responsibility to design a program (including measure mix, incentives, etc.) that is attractive to customers, is deliverable in a practical sense, and (generally) is cost-effective under the primary test used to evaluate programs.

OTP agrees with Staff's recommendation to include the MCT Impacts listed within Table 18 of the Proposed Decision, but only quantifying those marked with an asterisk that have previously been quantified or have approved estimation methodology. If the MCT were to be used for the Utility Performance Incentive calculation, however, that impact should be removed from the test prior to computing the incentive to avoid a circular reference.

ii. Secondary Cost-Effectiveness Tests and Program Design

OTP agrees with Staff's recommendation to continue to use the other cost-effectiveness tests (UCT, SCT, PCT, RIM) as secondary tests and with their recommended guidelines on page 40 of Staff's Proposed Decision, which are as follows:

- MN Statutes require the calculation of results according to UCT, SCT, PCT, and RIM tests. These will be the Secondary tests.
- Secondary tests can help to:
  - Inform decisions on how to prioritize programs (based on constraints or objectives).
  - Inform how a program affect different parties (e.g., all customers, host customers, society).
  - Inform decisions regarding marginally cost-effective programs.
- Any impact that is included in more than one test (e.g. avoided energy) should be treated consistently across all the tests (e.g., using the same $/MWh or $/Dth value).
- When IOUs present cost-effectiveness results in Triennial Plans and Status Reports, they should:
  - Describe the cost-effectiveness results by program using the Minnesota Test,
  - Describe any key cost-effectiveness issues that were considered in program design, and
  - Describe any programs where secondary tests played a role in decision-making.

OTP agrees with Staff's recommendation that the selected impacts be included in the corresponding tests as found in Table 19 on pages 40-42 of the Proposed Decision. OTP also agrees with Staff's recommendation that for the 2024-2026 Triennial, only include the impacts that are currently quantified or have an approved methodology are included, unless the assumptions and methodology used is clearly outlined. OTP opposes the Utility Performance Incentive being included in any applicable test for the purposes of calculating the Utility Performance Incentive.

iii. Utility System Impact Methodologies

<u>Ancillary Services (Electric)</u>
OTP supports a 1 percent adder on the energy and capacity to reflect ancillary services.

<u>Environment Compliance (Electric)</u>
The only environmental compliance costs that should be included are the same ones that have been included in utility IRP filings. Environmental requirements that have not yet been established should not be included in benefit/cost analysis unless also included in IRP modeling. OTP will need to further analyze what environmental costs are utility costs and what new environmental costs are societal costs and then which of these are not included in the Company's IRP modeling. OTP supports a value of $0 for the 2024-2026 Triennial plans.

<u>Generating Capacity (Electric)</u>
OTP agrees with Staff that MISO's Local Resource Zone 1 Cost of New Entry be used for Generating Capacity.

<u>Market Price Effects (Electric)</u>
OTP does not oppose the 1 percent adder for the 2024-2026 Triennial and supports the proposal for further evaluation of this input.

Renewable Portfolio Standard Compliance (Electric)
OTP agrees with a value of $0 for the 2024-2026 Triennial.

iv. Low-Income Impacts

OTP agrees with Staff's recommendation to maintain the current policy that does not require that low-income programs pass CIP's primary cost- effectiveness test and not including it in tests that would apply to low-income programs. Many of the benefits to these programs are hard to quantify and could unintentionally exclude projects that are highly beneficial to everyone involved.

v. Electric Avoided Costs and Transparency

OTP agrees with Staff's recommendation to continue to use the Discrete Approach avoided T&D cost values that were approved previously for the 2021-2023 Triennial period or update them if they choose.

vi. Discount Rates for Cost-Effectiveness Analyses

OTP agrees with Staff's recommendations regarding the discount rates used for each of the cost-effectiveness tests, and OTP also agrees with Staff's proposal to use the United States Department of the Treasury's 20-year Constant Maturity Rate to update the Societal Discount Rate's value.

vii. Reporting Guidelines

OTP does not oppose Staff's recommendation to use the MCT as the primary cost-effectiveness test and the SCT, UCT, RIM and PCT as the secondary cost-effectiveness test. OTP believes the recommended reporting guidelines for the 2024-2026 Triennial plan and 2024-2026 Status Reports seem reasonable. However, as explained elsewhere in OTP's comments, the Utility Performance Incentives (Electric and Gas), the program level cost-effectiveness results should not include the Utility Performance Incentive for the MCT, UCT, RIM and SCT.

b. Areas of Non-Support

i. Utility System Impact Methodologies

Marginal Energy (Electric)
OTP disagrees with Staff's recommendation to use the NREL Cambium model for Marginal Energy pricing. OTP supports the Cambium model for Marginal Energy pricing to be used by Non-Electric Utilities to calculate electric marginal energy; however, if an electric utility is using the avoided costs in the IRP to evaluate the selection of Supply Side energy resources, the same values should be used to evaluate Demand Side management. If there is a difference, it could result in a less cost-effective resource being chosen over a more cost-effective resource due to the misalignment. Thus, OTP believes that similar to how the TRM is applied, Utilities should be able to either use the NREL Cambium model, or if available, their own trade secret avoided costs that are in alignment with the companies' IRP.

> **Deputy Commissioner's Determination:** The Deputy Commissioner notes that several stakeholders (MP, OTP, and Xcel) raised concerns about the Proposed Decision's recommendation to use Minnesota values from the NREL Cambium model for avoided marginal energy costs.

As discussed in more detail in response to MP, rather than require use of Cambium data, the Deputy Commissioner will allow electric IOUs to use internally-provided marginal energy data, presumed to be the most up-to-date forecasts that would be used for Resource Plan modeling. The Deputy Commissioner directs utilities to use the finalized methodology for Marginal Energy that is included in Appendix K.

The Deputy Commissioner also remains concerned about the lack of transparency regarding the marginal energy values electric IOUs use in their cost-effectiveness analyses. With this in mind, the Deputy Commissioner requires that as part of their 2024-2026 triennial plan filings, the electric IOUs should:

- describe the methods used to estimate their avoided marginal energy cost values;
- share avoided marginal energy cost data in a form that is not considered Trade Secret (e.g. monthly, seasonal, or annual values, by daytype and season, etc.), **AND/OR** provide a clear and simplified way for interested parties to receive the Trade Secret avoided marginal energy cost data (e.g. through a non-disclosure agreement with the utility).

For future triennials, the Deputy Commissioner directs Staff to explore establishing estimation methods for avoided marginal energy costs that both facilitate using the most up-to-date information possible and that enable this data to be shared publicly.

Lastly, this Decision updates Input 7 – Non-Gas Fuel Costs in Appendix L's Inputs to BENCOST for Natural Gas IOUs to replace the Cambium annual marginal energy data with the method used in the previous triennial to estimate these costs. However, for gas IOU EFS projects and programs, gas IOUs should work with their electric counterparts to obtain more detailed marginal energy data than the standard data included in the BENCOST model. This approach will help ensure that evaluation of EFS projects and programs remain consistent with the approach adopted in the Commissioner's March 15, 2022 ECO Act Technical Guidance.

Utility Performance Incentives (Electric and Gas)

OTP is comfortable including the Utility Performance Incentive (Incentive) within the MCT, UCT, SCT and RIM cost-effectiveness test evaluations; however, OTP does not agree with including the Incentive in the Net Benefit calculation for purposes of calculating the Utility Performance Incentive. This essentially penalizes the utilities for having higher achievements.

The solution to "Enable Iteration Calculations" within Excel proposed within Section 9. Methodology Description: Utility Performance Incentives (Electric and Gas) portion of Appendix K does allow the formulas to resolve removing the circular reference. However, using the same example with the Incentive being 10 percent of the MCT Net Benefits, the calculation will diverge by lowering the Incentive roughly 9.1 percent. If the reduction in the Incentive is not factored into the calculation to determine the Incentive, it could have unintended consequences.

In addition, OTP does not agree with including the Incentive in the Net Benefit calculation at the program level. ECO cost-effectiveness at the segment level is a requirement. Cost-effectiveness at the program level is not a requirement. Therefore, adding the incentive at the program level is counterintuitive and does not aid in program design. The Incentive is currently evaluated at the portfolio level and is currently approved to be the lesser of up to 35 percent of program spend or 10 percent of Net Benefits. This evaluation would still need to be completed at the portfolio level prior to establishing what the Incentive for the segments and programs would be. This does add to the administrative process as it creates iterations into the evaluation process; however, it would be less burdensome if it were only added to the segment level. This would allow the Incentive to be calculated and the appropriate portion to be included into its own program within the segments. Then only the Incentive programs would need to be evaluated and included into the segment level analysis. This would only increase the amount of evaluation time by the number of segments rather than the number of programs and still include the Incentive within the segment level where the cost-effectiveness is being evaluated.

OTP would propose to run the cost-effectiveness tests without the Incentive being included, calculate the Incentive, include the Incentive at the segment level and then evaluate the segment and portfolio level with the Incentive included and the result would give the cost-effectiveness of the segment and portfolio including the Incentive.

Deputy Commissioner's Determinations:
The scope of the guidance provided in the Cost-Effectiveness Proposed Decision and this Decision is intended to describe how the Utility Performance Incentive should be incorporated as an impact in the cost-effectiveness tests. The guidance is not intended to describe how the 2024-2026 Shared Savings financial incentive mechanism is calculated. The Deputy Commissioner looks forward to continued discussions about the 2024-2026 Shared Savings financial incentive as part of that separate proceeding.

As discussed in response to written comments from MP, the Deputy Commissioner supports Staff's Proposed Decision recommendation to apply Utility Performance Incentives to the portfolio, segments, and programs in utility triennial filings because this will provide more complete information about program-level cost-effectiveness. The Deputy Commissioner also supports Staff's recommendation to allocate Utility Performance Incentives to segments and programs based on the allocation on program and segment percentage of portfolio lifetime savings.

The Deputy Commissioner directs utilities to use the finalized methodology for Utility Performance Incentives that is included in Appendix K.

ii. Proposed Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance

OTP has reviewed the Proposed Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance provided in Appendix J and believes it is mostly reasonable. However, OTP would like to call out a couple concerns.

In regard to EFS and the consideration of Other Costs, OTP agrees that using a rule of thumb to discount the average upgrade costs by 50 to 95 percent. However, when calculating the actual projects, it is not always known if an upgrade was necessary for the project to be completed unless the customer also submits receipts for the work done by the electrician in addition to the installation of the measure. Since we may not hear about all the work needed, it may be hard to establish accurate estimates on the percentage of projects that need upgrades and the average cost of those upgrades that would be attributed to other benefits to the customer and would recommend that if there is not enough evidence to support these percentages to apply to the customer's costs as outlined in the example that a proxy of 50 percent be applied to the customer's other costs. OTP will work with the information available to estimate the upgrade costs when they are known.

Also, in regards to the "incentive competition" section in bullet point number four in the Instructions and Guidance Section of Attachment B – Reporting Information from ECO Act Technical Guidance, as stated in our feedback comments on this section during the stakeholder process, although OTP agrees that this would be helpful to reduce customer confusion and "incentive competition," service territories overlap very often and it is nearly impossible for OTP to have consistent rebate levels with the dozens of different natural gas companies (Municipal, Cooperative, and IOU) that serve its communities. OTP considers customer confusion when setting rebate levels, and tries to work with other utilities, when possible, but also wants stakeholders to be aware of the difficulty in providing consistent rebates when many natural gas providers also provide service in our communities.

> **Deputy Commissioner's Determinations:** The Deputy Commissioner appreciates Staff's interest in capturing in cost-effectiveness analyses non-equipment incremental costs customers may incur to switch from fossil-fueled equipment, as these costs could pose real barriers to adoption. If utilities use customer costs as a guide for setting incentive levels, factoring these additional costs can be important because it facilitates utilities providing incentives to offset these costs.
>
> However, the Deputy Commissioner recognizes that estimating these increased customer costs will be difficult, and has modified the language in the Other Costs part of Appendix J to indicate that the TRMAC could examine if it is appropriate to include these costs in cost-effectiveness evaluations but that, in the interim, utilities are encouraged (but not required) to use the guidance to develop estimates of Other Costs to include in programs.
>
> With respective to incentive competition, the Deputy Commissioner agrees with Staff that utilities should actively seek to coordinate with utilities with which their service territories overlap. Given that the ECO Act explicitly authorizes both natural gas and electric utilities to offer EFS programs, utilities in overlapping service territories could offer incentives for the same measure. Staff's language in Attachment B repeats language in the Commissioner's March 15, 2022 Decision (p. 47) and remains relevant. The Deputy Commissioner continues to encourage utilities to coordinate efforts with other utilities to the greatest degree possible.

iii. Non-Utility System Impacts

Greenhouse Gases

OTP does not oppose the recommendation to use the High Environmental Cost Values for CO_2 (2027-2050) in Table 20 for the Environmental Damage Factor for the 2024-2026 Triennial. However, OTP cautions against adding GHG Emission Non-Utility impacts in a primary test when the utility's IRP does not include these impacts. Supply-side resources and demand-side resources should use inputs that keep alignment between them for most cost-effective resource selection.

Criteria Pollutants

OTP does not oppose the recommendation to use the High Metropolitan Fringe Values in Table 21 for Criteria pollutants. However, OTP cautions against adding Criteria Pollutants to Non-Utility impacts in a primary test when the utility's IRP does not include these impacts. Again, supply-side resources and demand-side resources should use inputs that keep alignment between them for most cost-effective resource selection.

> **Deputy Commissioner's Determinations:** The Deputy Commissioner appreciates OTP's feedback. The Deputy Commissioner recognizes that there might not be complete alignment between IRP and CIP modelling and notes that the UCT is the cost-effectiveness test that will most closely align with IRP modeling. Adopting the MCT as the primary test necessarily creates a

divergence between IRP modeling and CIP cost-effectiveness analyses because the MCT aims to more broadly capture utility system, non-utility system and societal impacts. Although the scenarios utilities run for IRP purposes consider some of the factors included in the proposed revisions to CIP cost-effectiveness tests (such as environmental damage factors), they do not include all of the factors from Table 19 (and, to be sure, IRP modeling includes many factors that cost-effectiveness modeling does not include). Therefore, the Deputy Commissioner believes it is appropriate and acceptable to include high externality values in the cost-effectiveness tests.

9. Xcel Energy (Xcel)

a. Areas of Support

Xcel appreciates the actionable guidance provided by Staff in their Proposed Decision and the intention of providing reasonable inputs into the cost-effectiveness test utilized for the 2024-2026 Triennial plan. Many of the changes discussed by the CAC and included in the Proposed Decision are beneficial and will support continued progress in the development of customer programs that benefit all Minnesotans.

That said, Xcel has concerns with certain aspects of the Proposed Decision, some of which it has expressed previously during the CAC process and others which arise from the novel introduction of the Cambium datasets as part of the Proposed Decision.

b. Areas of Non-Support

i. General Comments on the Minnesota Cost Test

Generally, Xcel is supportive of using the MCT as recommended in the Proposed Decision. However, Xcel continues to have concerns with the adoption of a Primary Test that does not include participant impacts, particularly if applied at granular level.

Minnesota Statutes specify that in determining cost-effectiveness, consideration is to be given to "the costs and benefits to ratepayers, the utility, participants, and society." Historically, this has been interpreted as a reference to the four traditional tests that are designed to reflect each of these perspectives. The MCT, however, does not reflect any of these perspectives. Rather, being a Jurisdiction-Specific Test, it is designed to reflect the regulatory perspective. Xcel does not believe that statute inherently prevents the MCT from being adopted as a Primary Test simply because it reflects the regulatory perspective. However, Xcel does have concerns with a Primary Test that explicitly omits costs (and benefits) that statute specifically identifies for consideration. Including participant impacts in the MCT would position the test as a single analysis that incorporates all four of the perspectives named in statute, rather than omitting one of them.

Xcel urges the Deputy Commissioner to carefully consider whether omitting participant impacts from the Primary Test may create a risk that future policymakers will interpret use of the MCT without participant impacts as a violation of statute and potentially put CIP as a whole in jeopardy. Xcel is particularly concerned that the language of the Proposed Decision could be used to support an argument that, in adopting the MCT as the Primary Test, the Department has elevated the regulatory perspective above the perspectives specified in statute. Xcel emphasizes here that it does not believe that such an argument has merit. Rather, Xcel is concerned about future risks to CIP as political winds shift over time. Political arguments need not have merit to be effective, and care should be taken to avoid undermining the long-term viability of Minnesota's successful energy efficiency framework.

Turning from the design of the MCT to its application, Xcel notes that the most useful and informative application of the MCT is at a higher level, such as the portfolio and segment levels. This is because it is intended to identify which resources merit acquisition. “Resources” in this context refers broadly to potential energy resources, such as energy efficiency or demand response, rather than the specific measures or programmatic activities by which those resources are acquired. As the test is applied more granularly to the program and particularly the measure level, it becomes less informative. This is to be expected: because it represents the regulatory perspective, the MCT is well-suited to identify whether a portfolio represents an overall cost-effective set of energy efficiency resource acquisition strategies, but it is neither intended nor designed to identify whether tankless water heaters (for example) should be included in a program.

There is thus a tension between the Proposed Decision’s recommendation that the MCT be calculated down to the measure level and Staff’s recommended guideline that “It is the utility's responsibility to design a program (including measure mix, incentives, etc.) that is attractive to customers, is deliverable in a practical sense, and (generally) is cost-effective under the primary test[.]” Given that Staff’s guidelines call for cost-effectiveness in Triennial Plans and Status Reports to be presented at the program level and above, and that “cost-effectiveness will be reviewed/approved by the Department at the segment level,” Xcel suggests that application of the MCT (and other tests) at the measure level may be excessive. If measure-level calculations are not reported and if the measure mix is the utility’s responsibility, it is unclear what purpose the measure-level calculations serve.

Similarly, Xcel notes the tension between the Proposed Decision’s guidance on the one hand that “Just because a program is cost-effective does not mean that the utility should include it in its portfolio” and its endorsement on the other hand of Synapse’s recommendation that “The primary test is the main determinant of whether a program should be included in the Triennial Plan.”

Finally, Xcel notes that historically, custom efficiency projects have been required to pass the Societal Cost Test, and in some cases also to meet criteria to ensure the project does not have excessively short or long customer payback periods. The Proposed Decision does not provide guidance on whether the MCT (or another test) should replace these requirements for custom projects. Xcel requests clarity with regard to how custom projects should be assessed for cost-effectiveness.

Deputy Commissioner’s Determinations:
The Deputy Commissioner appreciates Xcel’s feedback as it relates to the MCT and traditional cost-effectiveness tests.

As Xcel observes, Minnesota Statutes specify that, “in determining cost-effectiveness, the commissioner shall consider: (1) the costs and benefits to ratepayers, the utility, participants, and society.”[58] However, importantly, statute does not prohibit the use of another test to evaluate CIP cost-effectiveness, nor does statute specify which test must serve as the primary test. Additionally, as presented in this Decision, the utilities are still required to report results from programs using the RIM (ratepayers), UCT (utility), PCT (participants), and SCT (society) as CIP’s secondary tests.

Xcel also expresses concern about how the MCT removes participant costs and benefits. The CAC adopted a MCT that excludes participant impacts as a way to address the NSPM’s principle of ensuring symmetry across the primary test’s costs and benefits. Symmetry can be achieved

[58] MN Statutes, §216B.241, subd. 1c (e). Similar language is repeated in subd. 12 (for gas utilities), subd. 13 (for load management programs),

for participant impacts by either removing both participant costs and benefits from the primary test, or including them both. Thus, the decision to remove participant impacts from the primary test (which was based on extensive feedback from the CAC), achieves the NSPM for DER's principal of symmetry.

As Staff noted in their Proposed Decision, the key purpose of the primary MCT is to determine "which resources have benefits that exceed costs and, therefore, merit utility acquisition or support on behalf of their customers" while the secondary tests "tend to answer different questions such as: how much will utility bills on average be reduced (UCT), and how much will cost-effectiveness change if an additional policy goal is added or removed from the Primary Test." Utilities effectively will be meeting statutory requirements in determining cost-effectiveness by considering, analyzing, and reporting the costs and benefits across the primary test and the secondary tests.

Xcel also raises a concern about the Proposed Decision's recommendation that the MCT be calculated down to the measure level. The Deputy Commissioner does not believe that Staff intended to require that utilities necessarily conduct cost-effectiveness analyses at the measure-level. Language in the Reporting Guidelines section has been updated to clarify this issue.

The Deputy Commissioner also clarifies that CIP custom projects should be screened using the MCT as the primary test.

ii. Cost-Effectiveness Inputs: Utility System Impacts

Staff recommends utilizing the estimates described in Appendix K for utility system impacts.

The Proposed Decision suggests the IOUs utilize the Cambium dataset as an alternative to the traditional IRP modeling approach for utility system impacts. This recommendation in the Proposed Decision departs from the discussions at the CAC and is the first opportunity the Company has had to review and comment on the use of the Cambium data as provided by NREL. This has made review of this aspect of the Proposed Decision especially difficult.

Xcel does not support using an alternative methodology for utility system impacts for CIP. Xcel believes it is important to use the same assumptions for energy efficiency, LM, and EFS regardless of which filing it is being analyzed in. The recommendation to utilize Cambium versus Xcel's specific utility system impacts creates tension between CIP and the IRP and with the EFS statute. For example, Xcel is unclear how to meet Minn. Stat. 216B.241 Subd. 11(d)(2) which explicitly states the following comparison for efficient fuel switching:

> (2) results in a net reduction of statewide greenhouse gas emissions as defined in section 216H.01, subdivision 2, over the lifetime of the improvement. For an efficient fuel-switching improvement installed by an electric utility, the reduction in emissions must be measured based on the hourly emission profile of the electric utility, using the hourly emissions profile in the most recent resource plan approved by the commission under section 216B.2422;

Xcel appreciates the concerns on the part of stakeholders, including the Department, about using trade secret data to calculate utility avoided costs in CIP. Historical practice has been to use the same hourly data for modeling CIP avoided costs as used in utility IRPs, in order to have the cost assumptions in each proceeding be as consistent as possible. Because Xcel believes it is important that its hourly information from the IRP remain trade secret, increasing transparency in CIP assumptions necessarily involves a tradeoff with consistency between CIP and other proceedings.

As noted, the Company's preference is to use consistent modeling assumptions between CIP and the IRP. If a different set of assumptions is to be used for CIP in the interest of transparency, the Company believes two principles should be applied: first, the assumptions used in the 2024-2026 Triennial portfolios should be consistent within the portfolios (rather than using differing assumptions between different customer-side resources such as energy efficiency, load management, and efficient fuel switching). Second, the data used for Triennial planning should reflect (as closely as possible) the electric system of the utility it is applied to.

If the Deputy Commissioner sees fit to approve the methodology for the 2024-2026 Triennial, Xcel offers suggestions to moderating the data to better fit the electric system here in Minnesota in the remainder of this section.

<u>Clarification Necessary to Utilize Cambium</u>
If IOUs are to use the Cambium data for their Triennial Plans, there are several details for which clarity is needed but which are not addressed in the Proposed Decision. These are described below, along with the Company's recommended approach for each.

> **Marginal Energy:** The marginal energy cost, identified in the Cambium data, only considers avoided fuel costs associated with the marginal generation. This does not reflect the true cost of renewable generation. Energy efficiency can delay the need for new wind and solar resources as well as fossil-fuel resources, so the avoided cost of renewable marginal energy is better represented as the levelized cost of energy of new renewable generation. To do this Xcel suggests the load balancing area that best represents the geographical region that a utility serve is used. Xcel recommends the use Load Balancing area 4314 because the Load Balancing areas identify the marginal unit that is serving the area. Since Xcel knows the type of unit that is serving the marginal load, Xcel can better assign the levelized cost of renewables on an hourly basis.
>
> **Resource Mix :** Xcel believes that, in the short term, Xcel's resource mix is dissimilar to that of the whole state. For example, the Cambium data for 2024 estimates that nuclear generation represents about 16 percent of the annual electric energy in Minnesota while Xcel's IRP modeling for 2024 estimates it at 24 percent of Xcel's annual generation. Cambium also overestimates the amount of coal on Xcel's system at 19 percent where Xcel estimates about 10 percent. Xcel is unclear how to address this discrepancy utilizing the Cambium data.
>
> **Scenarios:** Staff has not provided guidance on which of the ten different Cambium scenarios to use. Xcel recommends that IOUs be given latitude to determine which scenario best fits their systems. In this case, utilities can clearly state which scenario is being utilized. For example, after Xcel's initial review, Xcel believes that the mid-case, with 95% decarbonization by 2050, may be the most reasonable and realistic Cambium scenario to use for modeling Xcel's system given current resource plans.
>
> **Unmodeled Years** ***:*** The most recent release of Cambium only provides hourly data for eight years (2024, 2026, 2028, 2030, 2035, 2040, 2045, and 2050). Xcel recommends that linear interpolation on an annual basis is the simplest (and possibly only) option to bridge these gaps. This approach smooths out changes between modeled years which may not properly account

for resource retirement or new build, but it is not immediately clear that a better alternative exists. Absent alternative guidance from the Department, this is the approach Xcel would apply.

Weather: An important component of forecasting load and therefore marginal energy price is weather. The Cambium data set only uses a single year of weather data (2012) in its underlying models. Xcel believes it is important to have symmetry between the weather data used in the marginal energy data (Cambium) and the end use load shapes Xcel applies to that data. Ideally, the savings calculations that are applied to those load shapes would use the same weather data. Both Xcel's own energy savings calculations and the measure definitions in the Minnesota TRM are generally based on Typical Meteorological Year (TMY) data. It is unclear how important this discrepancy will be in modeling energy savings and cost-effectiveness in practice, and Xcel is thus not prepared to provide any recommendations related to weather data sets at this time. However, Xcel believes it is an issue worth recognizing, and if the Cambium dataset is to be used, Xcel recommends that the topic be explored in detail through the TRMAC.

Deputy Commissioner's Determinations: The Deputy Commissioner notes that several stakeholders (MP, OTP, and Xcel) raised concerns about the Proposed Decision's recommendation to use Minnesota values from the NREL Cambium model for avoided marginal energy costs.

As discussed in more detail in response to MP, rather than require use of Cambium data, the Deputy Commissioner will allow electric IOUs to use internally-provided marginal energy data, presumed to be the most up-to-date forecasts that would be used for Resource Plan modeling. The Deputy Commissioner directs utilities to use the finalized methodology for Marginal Energy that is included in Appendix K.

The Deputy Commissioner also remains concerned about the lack of transparency regarding the marginal energy values electric IOUs use in their cost-effectiveness analyses. With this in mind, the Deputy Commissioner requires that as part of their 2024-2026 triennial plan filings, the electric IOUs should:

- describe the methods used to estimate their avoided marginal energy cost values;
- share avoided marginal energy cost data in a form that is not considered Trade Secret (e.g. monthly, seasonal, or annual values, by daytype and season, etc.), **AND/OR** provide a clear and simplified way for interested parties to receive the Trade Secret avoided marginal energy cost data (e.g. through a non-disclosure agreement with the utility).

For future triennials, the Deputy Commissioner directs Staff to explore establishing estimation methods for avoided marginal energy costs that both facilitate using the most up-to-date information possible and that enable this data to be shared publicly.

Lastly, this Decision updates Input 7 – Non-Gas Fuel Costs in Appendix L's Inputs to BENCOST for Natural Gas IOUs to replace the Cambium annual marginal energy data with the method used in the previous triennial to estimate these costs. However, for gas IOU EFS projects and programs, gas IOUs should work with their electric counterparts to obtain more detailed marginal energy data than the standard data included in the BENCOST model. This approach will help ensure that evaluation of EFS projects and programs remain consistent with the approach adopted in the Commissioner's March 15, 2022 ECO Act Technical Guidance.

iii. Cost-Effectiveness Inputs: Greenhouse Gases

The Proposed Decision suggests that NREL's Cambium data set should be used to determine the magnitude of emissions for this Triennial. Appendix A goes on to explain, "Using Cambium marginal energy pricing data for Minnesota offers multiple benefits including publicly available data set, hourly updates, state-specific data, and complementary information related to GHG emission." Xcel assumes that the Proposed Decision intended to define the cost values on page 52 and 53 and utilize the Cambium data to provide a method for determining the magnitude of these pollutants. Xcel continues to recommend that each utility utilize the modeled data from their resource plans to define how to determine the magnitude of the pollutants for simplicity and consistency across filings.

> **Deputy Commissioner's Determinations:** As noted above, this Decision modifies the avoided marginal energy cost methodology compared to what was included in the Proposed Decision. The Deputy Commissioner directs utilities to use the finalized methodology for Marginal Energy that is included in Appendix K.

Environmental Cost Values
Xcel appreciates the Department providing guidance on which dollar per ton values to use as a benefit for avoided carbon but would rather the values be provided on the as the nominal inputs rather than the escalated yearly values. These nominal values provide further transparency into what is utilized in the cost-effectiveness tests themselves.

> **Deputy Commissioner's Determinations:** The Deputy Commission points out that the forecasted CO_2 environmental cost values in the BENCOST model (Input 9) are taken directly from the PUC's 2018 Order Updating Environmental Cost values, updated to 2023$. This detail is shown in the Input 9 tab of the BENCOST spreadsheet.

Avoided Carbon Values
Xcel would appreciate further guidance on calculating the avoided carbon for electricity. Carbon will be a big part of the cost benefit analysis as well as screening of EFS measures, so it is important to have a standardized approach to quantifying avoided GHGs. Currently, the Department has provided guidance for calculating GHGs for EFS as part of Appendix A of the Commissioner Decision for Docket E,G999/CIP-21-837. In this approved methodology, Xcel is required to use hourly CO2e emissions (identified from the new hourly GHG emission values identified using system load) and compare theses to the hourly CO2e emissions for the most recently approved expansion plan. This is consistent with Minn. Stat. 216B.241 Subd. 11(d)(2) which requires a reduction in emissions using the hourly emissions profile of the most recent resource plan but differs from the Proposed Decision guidance.

First, Xcel continues to disagree with this methodology as described in Appendix A of the Commissioner Decision for Docket E,G999/CIP-21-837 as it produces unreliable results including many hours of negative GHG intensity. Xcel believes a suitable methodology for estimating GHG impacts is to use system average hourly emissions from our IRP modeling until modeling software can better determine the marginal unit and such the marginal emissions rate, Xcel's intention was to propose an alternative method for Department consideration.

Second, if the Department suggests that the Cambium data can satisfy Minnesota Statute, Xcel requests clarification regarding which emissions methodology to use. Within the Cambium data there are 36 emissions rates covering a range of methodologies including: system average emissions in the region, system average emissions serving customer load, short run marginal Emissions, and long run marginal emissions. For each of these four Cambium provides the emissions rates for CO2, N2O, CH4, and CO2e as well as combustion, pre-combustion, and total emissions. If Xcel must use the Cambium data as the source, Xcel suggests that it use the long run marginal emissions rate in CO2e at combustion (lrmer_co2e_c in the data set.) Xcel suggests that this rate is used for both determining the GHG cost ben inputs as well as screening EFS measures.

> **Deputy Commissioner's Determinations:** As discussed elsewhere in this Decision, the Cambium data is not used for purposes of forecasting marginal energy costs or in the BENCOST model. Additionally, per Appendix A of the Commissioner's March 15, 2022 Decision in Docket E,G999/CIP-21-837, Xcel and other utilities are permitted to propose alternative methodologies for Department review, either as program modifications or as part of their Triennial filings.

Criteria Pollutants

Xcel has traditionally calculated the criteria pollutant benefit using the output of our production costing run that is used to calculate the marginal energy benefit. The values provided on page 53 of the Proposed Decision only provides the value of these pollutants but does not provide a method for determining the magnitude of these pollutants.

Further, the Cambium data set does not include any information related to criteria pollutants. If Xcel is required to use the Cambium data set, Xcel is concerned that there is no symmetrical data set for the criteria pollutants so Xcel would be forced to use dissimilar data to calculate impacts. Consistent with Xcel's proposal to use IRP values, Xcel proposes that annual system average values from Xcel's electric generation system be used to determine the criteria pollutants on a lb/kWh basis. These values can then be applied to the cost value of each criterion as determined in resource planning modelling. The resulting $/kWh for Criteria pollutants can be derived from these values which are publicly available in each utility's most recent IRP.

> **Deputy Commissioner's Determinations:** The Deputy Commissioner agrees with Staff's Proposed Decision to require the utilities to use the high-end value for criteria air emissions in the updated Gas and Non-Gas Environmental Damage Factors components of cost-effectiveness analyses. The Deputy Commissioner asks that Xcel refer to the Deputy Commissioner's Decision section for additional guidance regarding criteria pollutants.

Source Energy Conversion

Xcel recognizes that screening of EFS measures is outside the scope of this Docket but given the interconnected nature of these decisions Xcel would like to provide some comments on source energy conversions for EFS measures. Xcel would prefer to use Xcel's own system's heat rate to determine the source energy impacts of EFS measures as those will better reflect the reality of these measures. If Xcel must use the Cambium data set, Xcel feels it is best to not use the data set for the whole state, but rather use the load balancing area that best represents the geographical region that a utility serves. Xcel would use Load balancing area 4319. The reason Xcel suggests is because the Load balancing areas identify the marginal unit that is serving the area. Since Xcel knows the type of unit that is serving the region, Xcel can estimate the heat rate for those units. See Attachment A of Xcel's full comments for a table of proposed heat rates.

> **Deputy Commissioner's Determinations:** As discussed elsewhere, the Decision no longer directs utilities to use Cambium data.

F. Deputy Commissioner's Decision

The Deputy Commissioner supports Staff's analysis and appreciates their efforts during the review of the cost-effectiveness methodology updates for the 2024-2026 CIP Triennials. The Deputy Commissioner also greatly appreciates the significant contributions that Committee members provided as part of this process and the technical assistance and meeting facilitation provided by The Mendota Group and Synapse.

The Deputy Commissioner approves the CIP cost-effectiveness methodology updates for the 2024-2026 CIP Triennials with the following specific determinations:

1. Minnesota Test as CIP's Primary Cost-Effectiveness Test

a. The Deputy Commissioner approves the MCT as CIP's primary cost-effectiveness test that the gas and electric IOUs shall use to screen their energy efficiency, load management, and efficient fuel-switching programs. The Deputy Commissioner also requires that CIP custom projects should be screened using the MCT as the primary test.

b. The Deputy Commissioner will allow approval of cost-effectiveness at the segment-level, so that the IOUs are responsible for ensuring that each segment, rather than individual program, is cost-effective by CIP standards.

c. The Deputy Commissioner approves the following general guidelines regarding cost-effectiveness and program design decisions:
   i. Cost-effectiveness and program design are separate, but related concepts. Program design and portfolio development involve many considerations;
   ii. Cost-effectiveness evaluations can help inform program design but should not be the primary basis for program design;
   iii. Just because a program is cost-effective does not mean that the utility should include it in its portfolio and, by extension, just because a program is not cost-effective does not mean that it should be automatically eliminated; and
   iv. It is the utility's responsibility to design a program (including measure mix, incentives, etc.) that is attractive to customers, is deliverable in a practical sense, and (generally) is cost-effective under the primary test used to evaluate programs.

d. Table 23 summarizes the impacts that are part of the new MCT's framework. An * indicates impacts that are currently quantified to estimate cost-effectiveness and should be included in the IOUs' 2024-2026 CIP cost-effectiveness analyses using the MCT. Impacts that do not have an * symbol are not currently quantified as part of the MCT and/or do not have an approved estimation methodology. These impacts should be assigned a value equal to 0 for the IOUs' 2024-2026 CIP cost-effectiveness analyses using the MCT.

Table 23. MCT Impacts

Type	Utility	Category	Impact
Utility System	Electric Utility	Generation	Energy Generation*

Type	Utility	Category	Impact
			Capacity*
			Environmental Compliance
			Renewable Portfolio Standard Compliance
			Market Price Effects*
			Ancillary Services*
		Transmission	Transmission Capacity*
			Transmission System Losses*
		Distribution	Distribution Costs*
			Distribution System Losses*
		General	Program Incentives*
			Program Administration Costs*
			Utility Performance Incentives*
			Credit and Collection Costs
			Risk
			Reliability
			Resilience
	Gas Utility	Commodity / Supply	Fuel*
			Capacity and Storage*
			Environmental Compliance*
			Market Price Effects
		Transportation	Transportation*
		Delivery	Delivery*
		General (same as Electric)	(see electric section)
Non-Utility System	Both	Other Fuels	Other Fuels
Societal	Both	Societal Impacts	GHG emissions*
			Criteria air emissions*
			Other environmental
			Economic and Jobs (Macroeconomic)
			Energy Security
			Energy Equity

2. Secondary Cost-Effectiveness Tests and Program Design

a. The Deputy Commissioner approves the SCT, UCT, PCT, and RIM as CIP's secondary cost-effectiveness tests.

b. The Deputy Commissioner approves the following approach to primary and secondary cost-effectiveness tests, as presented in Synapse's June 8, 2022 Straw Proposal (see Appendix F):

The primary test is the main determinant of whether a program should be included in the Triennial Plan. Secondary tests can be developed to help enhance the overall understanding of energy efficiency impacts. The additional information from a secondary test can help to prioritize energy efficiency programs and to inform decisions regarding marginally cost-effective programs and allocation of resources. The secondary test is not intended to undermine the purpose of the primary test and may include a subset of the impacts included in the primary test or additional impacts.

c. The Deputy Commissioner approves the following general guidelines regarding the purpose of the secondary tests:
    i. Secondary tests can help to:
        - Inform decisions on how to prioritize programs (based on constraints or objectives).
        - Inform how a program affect different parties (e.g., all customers, host customers, society).
        - Inform decisions regarding marginally cost-effective programs.
    ii. Any impact that is included in more than one test (e.g. avoided energy) should be treated consistently across all the tests (e.g., using the same $/MWh or $/Dth value).
    iii. When IOUs present cost-effectiveness results in their Triennial Plans and Status Reports, they should:
        - Describe the cost-effectiveness results by program using the Minnesota Test,
        - Describe any key cost-effectiveness issues that were considered in program design, and
        - Describe any programs where secondary tests played a role in decision-making.

d. Table 24 summarizes the impacts that the Deputy Commissioner approves for the MCT's and the secondary tests' frameworks. For 2024-2026 CIP cost-effectiveness analyses using the secondary tests, utilities may include estimates for impacts that are not currently quantified or do not have an approved methodology, but utilities should clearly outline all the assumptions and methodology details regarding how those impacts were estimated as part of their CIP Status Report and Triennial Filings.

Table 24. List of Cost-effectiveness Test Impacts

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
Utility System	Electric Utility	Generation	Energy Generation	x	x	x		x
			Capacity	x	x	x		x
			Environmental Compliance	x	x	x		x
			Renewable Portfolio Standard Compliance	x	x	x		x
			Market Price Effects	x	x	x		x
			Ancillary Services	x	x	x		x

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
		Transmission	Transmission Capacity	x	x	x		x
			Transmission System Losses	x	x	x		x
		Distribution	Distribution Costs	x	x	x		x
			Distribution System Losses	x	x	x		x
		General	Program Incentives	x	x	x		x
			Program Administration Costs	x	x	x		x
			Utility Performance Incentives	x	x	x		x
			Utility Revenue Impacts					x
			Credit and Collection Costs	x	x	x		x
			Risk	x	x	x		x
			Reliability	x	x	x		x
			Resilience	x	x	x		x
Utility System	Gas Utility	Commodity / Supply	Fuel and Variable O&M	x	x	x		x
			Capacity and Storage	x	x	x		x
			Environmental Compliance	x	x	x		x
			Market Price Effects	x	x	x		x
		Transportation	Transportation	x	x	x		x
		Delivery	Delivery	x	x	x		x
		General (same as Electric	Program Incentives	x	x	x		x
			Program Administration Costs	x	x	x		x
			Utility Performance Incentives	x	x	x		x
			Credit and Collection Costs	x	x	x		x
			Risk	x	x	x		x
			Reliability	x	x	x		x
			Resilience	x	x	x		x
Non-Utility System	All	Other Fuels	Other Fuels	x	x			
		Participant	Participant Costs		x		x	
			Participant Benefits		x		x	

Type	Utility	Category	Impact	MN Test	Societal Test	Utility Cost Test	Participant Test	RIM
Societal	All	Societal Impacts	GHG emissions	x	x			
			Criteria air emissions	x	x			
			Other environmental	x	x			
			Economic and Jobs (Macroeconomic)	x	x			
			Energy Security	x	x			
			Energy Equity	x	x			
			Societal Discount Rate	x	x		x	

3. Utility System Impact Methodologies

a. The Deputy Commissioner requires the IOUs to use the USI methodology descriptions included in Appendix K. Below are hyperlinks to the full methodology descriptions, a general description of the methods, and values for each of the new impacts:

Electric Impacts

i. Ancillary Services (Electric)

- Method Description Link
- Required Values: The required value for the 2024-2026 Triennial for Ancillary Services is a 1 percent adder, calculated against both electric energy and capacity for all years.

ii. Environmental Compliance (Electric)

- Method Description Link
- Required Value: The required value for the 2024-2026 Triennial for Electric Environmental Compliance Costs is zero.

iii. Generating Capacity (Electric)

- Method Description Link
- Required Value: The required Generating Capacity value for the 2024-2026 Triennial is based on MISO's Local Resource Zone 1 Cost of New Entry.[59] 2023/2024 - $104.17/kW-year.

iv. Marginal Energy (Electric)

- Method Description Link

[59] "Filing of the Midcontinent Independent System Operator, Inc. Regarding Local Resource Zone CONE Calculation",
Attachment B, September 30, 2022,
https://cdn.misoenergy.org/MISO%202022%20Annual%20CONE%20filing626484.pdf

- Required Value: The Deputy Commissioner will allow electric IOUs to use internally-provided marginal energy data, presumed to be the most up-to-date forecasts that would be used for Resource Plan modeling. The Deputy Commissioner requires that as part of their 2024-2026 triennial plan filings, the electric IOUs should: 1) describe the methods used to estimate their avoided marginal energy cost values; 2) share avoided marginal energy cost data in a form that is not considered Trade Secret (e.g. monthly, seasonal, or annual values, by daytype and season, etc.), **AND/OR** provide a clear and simplified way for interested parties to receive the Trade Secret avoided marginal energy cost data (e.g. through a non-disclosure agreement with the utility). For future triennials, the Deputy Commissioner directs Staff to explore establishing estimation methods for avoided marginal energy costs that both facilitate using the most up-to-date information possible and that enable this data to be shared publicly.

v. Market Price Effects (Electric)

- Method Description Link

- Required Value: The required value for the 2024-2026 Triennial for Electric Market Price Effects is 1 percent, applied to both energy and capacity values for all years.

vi. Renewable Portfolio Standard Compliance (Electric)

- Method Description Link

- Required Value: The required RPS Compliance value for the 2024-2026 Triennial will be set to 0.

Gas Impacts

vii. Environmental Compliance (Gas)

- Method Description Link

- Required Value: The required value for the 2024-2026 Triennial for Gas Environmental Compliance Impacts is 1.40% of the $/MCF commodity cost for 2024 – 2045.

viii. **Market Price Effects (Gas)**

- Method Description Link

- Required Value: The required value for the 2024-2026 Triennial for Gas Market Price Effects is zero.

Electric and Gas Impacts

ix. **Utility Performance Incentives (Electric and Gas)**

- Method Description Link

- Required Value: This is a methodological approach. Please see the methodology description in Appendix K.

4. Low-Income Impacts

a. The Deputy Commissioner will not require that low-income programs pass CIP's primary cost-effectiveness test. Many CIP low-income programs (most of which by design are intended to exclusively serve the needs of low-income customers) have, historically, not been cost-effective. However, in recognition of their importance in serving this customer group, the Department has allowed non-cost-effective low-income programs to be included in utility CIP portfolios. This practice is based on the premise that the benefits of offering low-income programs outweigh the costs.

b. Utilities should not include in tests specific impacts that would apply to low-income programs.

5. Electric Avoided Costs and Transparency

a. Regarding the electric IOU's avoided transmission and distribution (T&D) costs, the Deputy Commissioner will allow the electric IOUs to either choose to update their avoided T&D costs using the approved Discrete Approach methodology, or they can continue to use the Discrete Approach avoided T&D cost values that were approved previously for the 2021-2023 Triennial period.[60]

b. Regarding avoided capacity and marginal energy costs, the Deputy Commissioner requires the electric IOUs to use the methodologies and estimates described in Appendix K.

c. The Deputy Commissioner remains concerned about the lack of transparency regarding the marginal energy values electric IOUs use in their cost-effectiveness analyses. With this in mind, the Deputy Commissioner requires that as part of their 2024-2026 triennial plan filings, the electric IOUs should: 1) describe the methods used to estimate their avoided marginal energy cost values; 2) share avoided marginal energy cost data in a form that is not considered Trade Secret (e.g. monthly, seasonal, or annual values, by daytype and season, etc.), **AND/OR** provide a clear and simplified way for interested parties to receive the Trade Secret avoided marginal energy cost data (e.g. through a non-disclosure agreement with the utility).

[60] *Deputy Commissioner's Decision – CIP Electric Utilities Cost-Effectiveness Review*, Docket No. E999/CIP-18-783, May 20, 2019.

d. For future triennials, the Deputy Commissioner directs Staff to explore establishing estimation methods for avoided marginal energy costs that both facilitate using the most up-to-date information possible and that enable this data to be shared publicly.

6. 2024-2026 Gas BENCOST Inputs

a. The Deputy Commissioner requires the gas IOUs to use the approved Inputs to BENCOST for Gas IOUs' 2024-2026 CIP Triennium, which is included in Appendix L.

b. The Deputy Commissioner directs the gas IOUs work with their electric utility counterparts to determine ways to model EFS measures and programs outside of the standardized BENCOST model.

c. Related to the Commodity Cost input, for future triennials, the Deputy Commissioner directs Staff to evaluate if there is an accurate, publicly available data source for Minnesota forecasted natural gas prices as a possible replacement for historical utility PGA costs.

d. Related to the Project Lifetime input, as part of the TRMAC, the Deputy Commissioner instructs Staff to revisit measure lifetimes in the next TRM cycle to determine what, if any, adjustments could be made to increase expected lifetime for prescriptive measure assumptions beyond 20 years.

7. Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance

a. The Deputy Commissioner requires the IOUs to implement the Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance (CE Technical Guidance) contained in Appendix J. The CE Technical Guidance supplements the Department's March 15, 2022, Technical Guidance related to implementing the ECO Act.[61] The CE Technical Guidance is intended to help Minnesota's electric and gas IOUs conduct cost-effectiveness evaluations of their EFS and LM programs.

8. Discount Rates for Cost-Effectiveness Analyses

a. Societal Discount Rate Method: The Deputy Commissioner finds that the federal Treasury rate remains a good proxy to value, in current dollars, the future stream of societal benefits and costs resulting from a conservation investment. My Staff updated the Societal Discount Rate using the United States Department of the Treasury's (Treasury) 20-year Constant Maturity (CMT) Rate, which averaged 3.3 percent between January 3, 2022 and December 30, 2022.

b. Each cost-effectiveness test is designed to analyze conservation investments from a different perspective. This ensures that regulators have a complete picture of who is

[61] "In the Matter of Technical Guidance for the Inclusion of Efficient Fuel-Switching, Load Management, and Pre-Weatherization Measures in CIP" (Docket E,G999/CIP-21-837), Commissioner Decision, Minnesota Department of Commerce, March 15, 2022, Appendix A. The ECO Act is the Minnesota Energy Conservation and Optimization Act of 2021.

actually better off and who might be worse off as a result of a CIP investment. For the tests to be meaningful, each test should use the appropriate discount rate that reflects the time value of future benefits from the perspective of the entity who is making the investment. Therefore, the Deputy Commissioner requires the gas and electric IOUs to use the following discount rates in their cost-effectiveness tests:

i. **Minnesota Cost Test – 3.3% Societal Discount Rate**

ii. **Societal Cost Test – 3.3% Societal Discount Rate**

iii. **Utility Cost Test – CIP Utility Discount Rates**
- Xcel Electric: 5.38 percent
- Xcel Gas: 5.34 percent
- CenterPoint: 5.39 percent
- MN Energy Resources: 5.57 percent
- Minnesota Power: 5.41 percent
- Otter Tail: 5.61 percent
- Greater MN Gas: 5.61 percent
- Great Plains: 5.79 percent

iv. **Participant Cost Test**
- Societal Discount Rate for Residential Programs
- CIP Utility Discount Rate for Non-Residential Programs

v. **Ratepayer Impact Measure Test – CIP Utility Discount Rates**
- Xcel Electric: 5.38 percent
- Xcel Gas: 5.34 percent
- CenterPoint: 5.39 percent
- MN Energy Resources: 5.57 percent
- Minnesota Power: 5.41 percent
- Otter Tail: 5.61 percent
- Greater MN Gas: 5.61 percent
- Great Plains: 5.79 percent

9. Non-Utility System Impacts

a. Greenhouse Gases: The Deputy Commissioner finds that both gas and electric utilities should use the PUC's high externality value to estimate the environmental damage factor. Table 25 comes from the MN PUC's January 3, 2018, Order and includes the amounts in 2015 $/ton that constitute the high externality values for CO2. My Staff have incorporated these high CO2 externality values into the Gas Environmental Damage Factor and the Non-Gas Environmental Damage Factor described in the 2024-2026 Gas BENCOST Inputs section of this Decision. The Deputy Commissioner requires both the gas and electric IOUs to use the updated Gas and Non-Gas Environmental Damage Factors for their 2024-2026 cost-effectiveness analyses.

Table 25. Environmental Cost Values for CO2 (2017–2050)[50] (2015 dollars per net short ton)

Year	Low	High	Year	Low	High
2017	$8.44	$39.76	2034	$11.92	$55.07
2018	$8.64	$40.66	2035	$12.12	$55.97
2019	$8.85	$41.56	2036	$12.33	$56.87
2020	$9.05	$42.46	2037	$12.53	$57.77
2021	$9.25	$43.36	2038	$12.74	$58.67
2022	$9.46	$44.26	2039	$12.94	$59.58
2023	$9.66	$45.16	2040	$13.15	$60.48
2024	$9.87	$46.06	2041	$13.35	$61.38
2025	$10.07	$46.96	2042	$13.56	$62.28
2026	$10.28	$47.86	2043	$13.76	$63.18
2027	$10.48	$48.77	2044	$13.97	$64.08
2028	$10.69	$49.67	2045	$14.17	$64.98
2029	$10.89	$50.57	2046	$14.38	$65.88
2030	$11.10	$51.47	2047	$14.58	$66.78
2031	$11.30	$52.37	2048	$14.79	$67.68
2032	$11.51	$53.27	2049	$14.99	$68.58
2033	$11.71	$54.17	2050	$15.20	$69.48

b. Criteria Pollutants: The Deputy Commissioner requires the utilities to use the high-end value for criteria air emissions in the updated Gas and Non-Gas Environmental Damage Factors components of cost-effectiveness analyses. For reference, Table 26 comes from the MN PUC's January 3, 2018, Order and includes the amounts in $/ton values for criteria air pollutants. The relevant values are the High column within Metropolitan Fringe.

Table 26. Updated Environmental Cost Values for NO_x, SO_2, and $PM_{2.5}$

	Rural			Metropolitan Fringe			Urban		
	Low	**Median**	**High**	**Low**	**Median**	**High**	**Low**	**Median**	**High**
PM2.5	3,437	6,220	8,441	6,450	11,724	16,078	10,063	18,305	25,137
NO_x	1,985	4,762	6,370	2,467	5,352	7,336	2,760	5,755	7,893
SO2	3,427	6,159	8,352	4,543	8,245	11,317	5,753	10,439	14,382

10. Reporting Requirements

a. As part of the 2024-2026 CIP Triennial Plan and Status Report filings, the Deputy Commissioner directs the IOUs to clearly and transparently report cost-effectiveness results using the following guidance:

i. Triennial Plans

- Utilities run cost-effectiveness estimates based on the MCT, SCT, UCT, RIM, and PCT.
  - Utilities report their cost-effectiveness results at the program, segment, and portfolio level.

- Cost-effectiveness will be reviewed/approved by the Department at the segment-level based on the MCT.
- Utilities should also report secondary test results for informational purposes.

ii. Status Reports

- Using actual information from prior years, utilities run cost-effectiveness results based on the MCT, SCT, UCT, RIM, and PCT.
  - Utilities report their cost-effectiveness results at the program, segment, and portfolio level.
  - Cost-effectiveness will be reviewed/approved by the Department at the segment-level based on the MCT.
  - Utilities should also report secondary test results for informational purposes.

iii. Cost-Effectiveness Ratios Table

- The filings should include a summary table that provides the calculated cost-effectiveness ratios for programs, segments, and portfolio.
- Below is an example of what the table generally should look like (please note that the cost-effectiveness ratios in the example table are illustrative):

Table 27. Cost-Effectiveness Table Example

Program	Minnesota Test	Societal Cost Test	Utility Cost Test	Participant Cost Test	Ratepayer Impact Measure Test
Residential Program #1	3.50	2.51	3.41	3.19	0.59
Residential Program #2	3.50	4.76	3.06	N/A	0.58
Residential Program #3	3.50	0.96	2.13	1.27	0.54
Residential Segment	**3.50**	**2.08**	**2.45**	**3.09**	**0.55**
Low-Income Program #1	0.75	0.73	0.43	N/A	0.27
Low-Income Program #2	0.75	0.58	0.44	2.86	0.27
Low-Income Program #3	0.75	0.22	0.15	N/A	0.13
Low-Income Segment	**0.75**	**0.69**	**0.43**	**3.87**	**0.28**
C/I Program #1	3.00	1.30	2.80	1.20	0.60
C/I Program #2	3.00	1.31	2.84	1.28	0.69
C/I Program #3	3.00	1.63	1.21	4.45	0.52
C/I Segment	**3.00**	**3.01**	**5.96**	**2.73**	**0.80**
Other Program #1	3.25	1.30	2.80	1.20	0.60
Other Program #2	3.25	1.31	2.84	1.28	0.69
Other Program #3	3.25	1.63	1.21	4.45	0.52
Other Segment	**3.25**	**3.01**	**5.96**	**2.73**	**0.80**
Total Portfolio	**3.30**	**2.30**	**2.94**	**2.74**	**0.65**

iv. Narrative Details

- The filings should include narrative accompanying the cost-effectiveness ratios table that describes:
  - o The cost-effectiveness results by program using the MCT.
  - o Any key cost-effectiveness issues that were considered in program design.
  - o Any programs where secondary tests played a role in decision-making.

v. Methods and Impacts Reporting

- The filings should (either in the main body of the filing or as part of a technical appendix) clearly show where and how IOUs incorporated the required cost-effectiveness impacts and methods into their cost-effectiveness calculations.

BY ORDER OF THE DEPUTY COMMISSIONER

Michelle Joy Gransee

Michelle Gransee
Deputy Commissioner,
Minnesota Department of Commerce,
Division of Energy Resources

Appendix A - Members of the Cost-Effectiveness Advisory Committee

Name	Organization	Name	Organization
Adam Zoet	MN Dept. of Commerce	Karl Shlanta	Xcel Energy
Adway De	MN Dept. of Commerce	Kathy Baerlocher	Great Plains Natural Gas
Amalia Hicks	Cadmus	Katie O'Rourke	Minnesota Energy Resources Corp
Andy Bahn	MN Dept. of Commerce	Kevin Lawless	The Forward Curve
Anna Roberts	Otter Tail Power	Kimberley Lillyblad	Minnesota Municipal Power Agency
Anthony Fryer	MN Dept. of Commerce	Kristin Berkland*	Office of Minnesota Attorney General
Audrey Partridge	Center for Energy and Environment	Kristine Anderson	Greater Minnesota Gas
Baishali Bakshi	MN Pollution Control Agency	Kurt Hauser	Missouri River Energy Services
Becky Billings	Xcel Energy	Kyle Schleis	Connexus Energy
Brian Edstrom	Citizens Utility Board of Minnesota	Laura Silver	MN Dept. of Commerce
Caitlin Eichten	Fresh Energy	Lauren Sweeney	MN Dept of Commerce
Chris Baker	Willdan	Lisa Beckner	Minnesota Power
Christopher Davis	MN Dept. of Commerce	Lloyd Kass	Franklin Energy Group
Cory Hetchler	Connexus Energy	Maddie Koolbeck	Slipstream
Courtney Lane	Synapse Energy Economics	Martin Kapsch	CenterPoint Energy
David Bael	MN Pollution Control Agency	Martin Kushler	American Council for an Energy-Efficient Economy
David Siddiqui	Oracle Corporation	Matt Wisnefske	Cadmus
Ethan Warner	CenterPoint Energy	Michael Hinde	Minnesota Valley Electric Cooperative
Gregory Ehrendreich	Midwest Energy Efficiency Alliance	Michelle Rosier	Minnesota Public Utilities Commission
Grey Staples	The Mendota Group	Nadia Mezic	Minnesota Public Utilities Commission
Jamie Fitzke	Center for Energy and Environment	Nick Mark	Xcel Energy
Jamie Stallman	Great River Energy	Nick Minderman	Xcel Energy
Jason Grenier	Otter Tail Power	Natalie Fortman	E4TheFuture
Jeremy Petersen	Xcel Energy	Nicholas VanDuzee, Jr.	CenterPoint Energy
Jessica Burdette	MN Dept. of Commerce	Peter Scholtz*	Office of Minnesota Attorney General
Jessica Peterson	Xcel Energy	Rachel Sours-Page	The Mendota Group
Jill Eide	Great River Energy	Russ Landry	Center for Energy and Environment
John O'Neil	Southern Minnesota Municipal Power Agency	Tim Woolf	Synapse Energy Economics
Jon Vesta	Frontier Energy	Tom Sagstetter	Elk River Municipal Utilities
Joseph Dammel	Fresh Energy	Will Nissen	MN Dept. of Commerce
Joseph Reilly	Minnesota Energy Resources Corp	Wyatt Miller	Minnesota Power
Josh Mason	Rochester Public Utilities	Zach Froio	Minnesota Energy Resources Corp
Julie Michals	E4TheFuture	Zach Klabo	Minnesota-Dakota Utilities Company

* Participated as an observer and did not provide written comments.

Appendix B – Initial Scope of Cost-Effectiveness Issues for Department Stakeholder Process to Address (From Proposed Decision)

Excerpt from Deputy Commissioner's February 20, 2020 Decision.

Section VI.

C. DEPUTY COMMISSIONER'S FINDINGS AND DETERMINATIONS

The Deputy Commissioner approves the following initial scope of cost-effectiveness issues that the Department will explore in coordination with a Cost-Effectiveness Advisory Committee leading up to the 2024-2026 CIP Triennials.

<u>What:</u> Cost-effectiveness issues to explore leading up to the 2024-2026 CIP Triennials, and the general process and timeline for the 2024-2026 cost-effectiveness review process.

<u>Who:</u> Establish a Cost-Effectiveness Advisory Committee to help determine a final list of priority issues, and to act as a forum to discuss potential cost-effectiveness methodology updates.

<u>When:</u> Quarterly advisory committee meetings from 2020-2022 with a Final Decision by January 2023:

2020 Meeting Schedule: Meeting #1 - September 2020, Meeting #2 - December 2020.

2021 Meeting Schedule: Meeting #3 - March 2021, Meeting #4 - June 2021, Meeting #5 - September 2021, Meeting #6 - December 2021.

2022 Meeting Schedule Meeting #7 - March 2022, Meeting #8 - June 2022, Meeting #9 - September 2022, Meeting #10 - December 2022.

Cost-Effectiveness 2024-2026 Proposed Decisions: November 2022.

Cost-Effectiveness 2024-2026 Decisions: January 2023.

2024-2026 Triennials: June 1, 2023.

<u>How:</u>

1) Commerce reaches out to individuals to serve on the advisory committee, and individuals can request to serve on the committee.
2) Advisory committee meets to determine final list of CIP cost-effectiveness issues to explore for the 2024-2026 Triennials.
3) Advisory committee meets to discuss who, what, where why, when, and how to implement agreed to methodology updates.
4) Commerce develops informal documents for committee feedback, and ultimately issues formal Proposed and Final Decisions with the approved 2024-2026 cost-effectiveness assumptions.
5) Initial list of ideas include:

A. Synapse's Summary of Priority Recommendations[62]

- Establishing the "Minnesota Test."
- Decide whether to include participant impacts in primary test (e.g., NEBs).

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[62] Slide 62 of "Stakeholder Presentation - Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota." < https://www.synapse-energy.com/sites/default/files/MN-NSPM-Presentation-17-094.pdf>.

- Decide whether to include other fuel impacts in primary test.
- Include missing elements of the Utility Cost test.

B. Additional Ideas from This Stakeholder Process

- Examine discount rates used in the CIP cost-effectiveness tests.
  - Ways to improve transparency of avoided electric marginal energy and capacity costs, including:
    - o Transparency of the data inputs and sources.
    - o Transparency of the methodologies and software.
    - o Transparency of the resulting avoided cost values.
- Examine updates to the Gas BENCOST model spreadsheet.
- Identify ways to improve the symmetry across the cost-effectiveness tests' costs and benefits.
- Examine whether there is a modified version of the "Minnesota Test" that stakeholders would find more agreeable than the version that Synapse proposed.
- Advisory Committee and process ideas:
  - o It would be helpful if the Department presents objectives and priorities for the advisory committee to react to.
  - o It would be good to have more diversity in terms of the organizations represented on the advisory committee.
  - o Should discuss possible unintended consequences that any proposed changes could have between CIP and other areas.

C. Core 2024-2026 Electric and Gas Cost-Effectiveness Review

- Review of the electric utilities' proposed 2024-2026 avoided electric costs.
  - Review and updates to the 2024-2026 gas BENCOST inputs.

<u>Why:</u>

1) *Consistent with the Department's Role in Regulating CIP:*

- Ensuring that cost-effective energy savings are being procured systematically, aggressively, and accurately.
- Establishing technical assumptions for quantifying the cost-effectiveness of utility energy efficiency programs.

Subd. 1d.Technical assistance: (a) The commissioner shall evaluate energy conservation improvement programs on the basis of cost-effectiveness and the reliability of the technologies employed. The commissioner shall, by order, establish, maintain, and update energy-savings assumptions that must be used when filing energy conservation improvement programs . . . .

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Appendix C – Minnesota Energy Policy Inventory (From Proposed Decision)

COMMERCE DEPARTMENT
ENERGY RESOURCES

Draft Minnesota Energy Policy Inventory

CIP Cost-Effectiveness Advisory Committee

May 17, 2022

I. Minnesota Energy Policy Summary Tables

Table 1. Statewide Policy Goals

Policy	Citation	Policy Impacts Reflected in Policies															
						Societal											
		Participant	Other Fuels	Water	Low-Income	GHG	Air	Waste	Water	Land	Other Environ	Health	Economic	Security	Equity	Resilience	Other
Statewide Policy Goal (ECO 2021), Energy savings and optimization policy goal	Minn. Stat. § 216B.2401		X			X							X	X			X
Statewide Policy Goal (NGEA 2007), Energy planning	Minn. Stat. § 216C.05, Subd 1	X									X		X	X		X	
Statewide Policy Goal (NGEA 2007), Energy policy goals	Minn. Stat. § 216C.05, Subd 2										X			X			X
Statewide Policy Goal (NGEA 2007), GHG emissions-reduction goal	Minn. Stat. § 216H.02, Subd. 1					X											

Table 2. Other Policies

Policy	Citation	Policy Impacts Reflected in Policies															
						Societal											
		Participant	Other Fuels	Water	Low-Income	GHG	Air	Waste	Water	Land	Other Environ	Health	Economic	Security	Equity	Resilience	Other
Other Policies (NGIA 2021), Definitions	Minn. Stat. § 216B.2427, Subd 1		X			X											
Other Policies (NGIA 2021), Innovation Plans	Minn. Stat. § 216B.2427, Subd 2		X		X	X		X			X		X				
Other Policies (NGIA 2021), Limitations on utility customer costs	Minn. Stat. § 216B.2427, Subd 3		X														
Other Policies (NGIA 2021), Throughput goal	Minn. Stat. § 216B.2427, Subd 10		X								X						
Other Policies (NGIA 2021), Lifecycle GHG Emissions Accounting Framework; Cost-Benefit Test for Innovative Resources	Minn. Stat. § 216B.2428		X			X					X		X				

Table 3. CIP Statutes

Policy	Citation	Policy Impacts Reflected in Policies															
						Societal											
		Participant	Other Fuels	Water	Low-Income	GHG	Air	Waste	Water	Land	Other Environ	Health	Economic	Security	Equity	Resilience	Other
CIP COUs, Energy savings goal	Minn. Stat. § 216b.2403, Subd 2		X														
CIP COUs, Energy conservation and optimization plans	Minn. Stat. § 216b.2403, Subd 3					X											X
CIP COUs, Energy conservation programs for low-income households	Minn. Stat. § 216b.2403, Subd 5				X						X				X		
CIP COUs, Criteria for efficient fuel-switching improvements	Minn. Stat. § 216b.2403, Subd 8		X			X											
CIP IOUs, Energy-saving goals	Minn. Stat. § 216b.241, Subd 1c		X			X											X
CIP IOUs, Technical assistance	Minn. Stat. § 216b.241, Subd 1d		X														
CIP IOUs, Applied research and development grants.	Minn. Stat. § 216b.241, Subd 1e					X											

Policy	Citation	Policy Impacts Reflected in Policies															
CIP IOUs, Energy conservation and optimization plans	Minn. Stat. § 216b.241, Subd 2				X	X									X		X
CIP IOUs, Efficient lighting program	Minn. Stat. § 216b.241, Subd 5										X						
CIP IOUs, Biomethane purchases	Minn. Stat. § 216b.241, Subd 5b							X									
CIP IOUs, Low-income programs	Minn. Stat. § 216b.241, Subd 7		X		X										X		
CIP IOUs, Building performance standards; Sustainable Building 2030	Minn. Stat. § 216b.241, Subd 9					X											
CIP IOUs, Programs for efficient fuel-switching improvements; electric utilities	Minn. Stat. § 216b.241, Subd 11		X			X											
CIP IOUs, Programs for efficient fuel-switching improvements; gas utilities	Minn. Stat. § 216b.241, Subd 12		X			X											
CIP IOUs, Minnesota efficient technology accelerator	Minn. Stat. § 216b.241, Subd 14	X				X							X		X		

Table 4. PUC Statutes

Policy	Citation	Policy Impacts Reflected in Policies															
						Societal											
		Participant	Other Fuels	Water	Low-Income	GHG	Air	Waste	Water	Land	Other Environ	Health	Economic	Security	Equity	Resilience	Other
PUC (Rates), Reasonable rate	Minn. Stat. § 216B.03														X		
PUC (IRPs), Long-range emission reduction planning	Minn. Stat. § 216B.2422, Subd. 2c					X											
PUC (IRPs), Environmental costs	Minn. Stat. § 216B.2422, Subd. 3(a)					X	X						X				
PUC (IRPs), Preference for renewable energy facility	Minn. Stat. § 216B.2422, Subd. 4					X											

I. Statewide Policy Goals

Energy Conservation & Optimization Act of 2021, MN Statute 216B.2401, ENERGY SAVINGS AND OPTIMIZATION POLICY GOAL.

(a) The legislature finds that energy savings are an energy resource, and that cost-effective energy savings are preferred over all other energy resources. In addition, the legislature finds that optimizing the timing and method used by energy consumers to manage energy use provides significant benefits to the consumers and to the utility system as a whole. The legislature further finds that cost-effective energy savings and load management programs should be procured systematically and aggressively in order to reduce utility costs for businesses and residents, improve the competitiveness and profitability of businesses, create more energy-related jobs, reduce the economic burden of fuel imports, and reduce pollution and emissions that cause climate change. Therefore, it is the energy policy of the state of Minnesota to achieve annual energy savings equivalent to at least 2.5 percent of annual retail energy sales of electricity and natural gas through multiple measures, including but not limited to:

(1) cost-effective energy conservation improvement programs and efficient fuel-switching utility programs under sections 216B.2402 to 216B.241;

(2) rate design;

(3) energy efficiency achieved by energy consumers without direct utility involvement;

(4) advancements in statewide energy codes and cost-effective appliance and equipment standards;

(5) programs designed to transform the market or change consumer behavior;

(6) energy savings resulting from efficiency improvements to the utility infrastructure and system; and

(7) other efforts to promote energy efficiency and energy conservation.

(b) A utility is encouraged to design and offer to customers load management programs that enable: (1) customers to maximize the economic value gained from the energy purchased from the customer's utility service provider; and (2) utilities to optimize the infrastructure and generation capacity needed to effectively serve customers and facilitate the integration of renewable energy into the energy system.

(c) The commissioner must provide a reasonable estimate of progress made toward the statewide energy-savings goal under paragraph (a) in the annual report required under section 216B.241, subdivision 1c, and make recommendations for administrative or legislative initiatives to increase energy savings toward that goal. The commissioner must also annually report on the energy productivity of the state's economy by estimating the ratio of economic output produced in the most recently completed calendar year to the primary energy inputs used in that year.

Next Generation Energy Act of 2007, MN Statute 216C.05 FINDINGS AND PURPOSE.

Subdivision 1.**Energy planning.**

The legislature finds and declares that continued growth in demand for energy will cause severe social and economic dislocations, and that the state has a vital interest in providing for: increased efficiency in energy consumption, the development and use of renewable energy resources wherever possible, and the creation of an effective energy forecasting, planning, and education program.

The legislature further finds and declares that the protection of life, safety, and financial security for citizens during an energy crisis is of paramount importance.

Therefore, the legislature finds that it is in the public interest to review, analyze, and encourage those energy programs that will minimize the need for annual increases in fossil fuel consumption by 1990 and the need for additional electrical generating plants, and provide for an optimum combination of energy sources and energy conservation consistent with environmental protection and the protection of citizens.

The legislature intends to monitor, through energy policy planning and implementation, the transition from historic growth in energy demand to a period when demand for traditional fuels becomes stable and the supply of renewable energy resources is readily available and adequately utilized.

The legislature further finds that for economic growth, environmental improvement, and protection of citizens, it is in the public interest to encourage those energy programs that will provide an optimum combination of energy resources, including energy savings.

Therefore, the legislature, through its committees, must monitor and evaluate progress toward greater reliance on cost-effective energy efficiency and renewable energy and lesser dependence on fossil fuels in order to reduce the economic burden of fuel imports, diversify utility-owned and consumer-owned energy resources, reduce utility costs for businesses and residents, improve the competitiveness and profitability of Minnesota businesses, create more energy-related jobs that contribute to the Minnesota economy, and reduce pollution and emissions that cause climate change.

Subd. 2.**Energy policy goals.**

It is the energy policy of the state of Minnesota that:

(1) annual energy savings equal to at least 1.5 percent of annual retail energy sales of electricity and natural gas be achieved through cost-effective energy efficiency;

(2) the per capita use of fossil fuel as an energy input be reduced by 15 percent by the year 2015, through increased reliance on energy efficiency and renewable energy alternatives;

(3) 25 percent of the total energy used in the state be derived from renewable energy resources by the year 2025; and

(4) retail electricity rates for each customer class be at least five percent below the national average.

Next Generation Energy Act of 2007, MN Statute 216H.02, GREENHOUSE GAS EMISSIONS CONTROL.

Subdivision 1.**Greenhouse gas emissions-reduction goal.**

It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050. The levels shall be reviewed based on the climate change action plan study.

Subd. 2.**Climate change action plan.**

By February 1, 2008, the commissioner of commerce, in consultation with the commissioners of the Pollution Control Agency, the Housing Finance Agency, and the Departments of Natural Resources, Agriculture, Employment and Economic Development, and Transportation, and the chair of the Metropolitan Council, shall submit to the legislature a climate change action plan that meets the requirements of this section.

Subd. 3.**Stakeholder process.**

The plan required by subdivision 2 must be developed through a structured, broadly inclusive stakeholder-based review of potential policies and initiatives that will reduce statewide greenhouse gas emissions from a broad range of sources and activities. The commissioner shall engage a nationally recognized independent expert entity to conduct the stakeholder process. The report of the stakeholder process must form the basis for the plan submitted by the commissioner under subdivision 2.

Subd. 4.**General elements of the plan.**

The plan must:

(1) estimate 1990 and 2005 greenhouse gas emissions in the state and make projections of emissions in 2015, 2025, and 2050;

(2) identify, evaluate, and integrate a broad range of statewide greenhouse gas reduction options for all emission sectors in the state;

(3) assess the costs, benefits, and feasibility of implementing the options;

(4) recommend an integrated set of reduction options and strategies for implementing the options that will achieve the goals in subdivision 1, including analysis of the associated costs and benefits to Minnesotans;

(5) estimate the statewide greenhouse gas emissions reductions anticipated from implementation of existing state policies;

(6) recommend a system to require the reporting of statewide greenhouse gas emissions, identifying which facilities must report, and how emission estimates should be made; and

(7) evaluate the option of exempting a project from the prohibitions contained in section 216H.03, subdivision 3, if the project contributes a specified fee per ton of carbon dioxide emissions emitted annually by the project, the proceeds of which would be used to fund permanent, quantifiable, verifiable, and enforceable reductions in greenhouse gas emissions that would not otherwise have occurred.

Subd. 5.**Specific plan requirements.**

(a) The plan must evaluate and recommend interim goals as steps to achieve the goals in subdivision 1.

(b) The plan must determine the feasibility, assess the costs and benefits, and recommend how the state could adopt a regulatory system that imposes a cap on the aggregate air pollutant emissions of a group of sources, requires those subject to the cap to own an allowance for each ton of the air pollutant emitted, and allows for market-based trading of those allowances. The evaluation must contain an analysis of the state implementing a cap and trade system alone, in coordination with other states, and as a requirement of federal law applying to all states. The plan must recommend the parameters of a cap and trade system that includes a cap that would prevent significant increases in greenhouse gas emissions above current levels with a schedule for lowering the cap periodically to achieve the goals in subdivision 1 and interim goals recommended under paragraph (a). The plan must consider cost savings and cost increases on energy consumers in the state.

(c) The plan must include recommendations for improvements in the emissions inventory and recommend whether the state should require greenhouse gas emissions reporting from specific sources and, if so, which sources should be required to report. The plan must also evaluate options for an emissions registry after reviewing registries in other states and recommend a registry that will insure the greatest opportunity for Minnesota entities to obtain marketable credits.

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Subd. 6.**Regional activities.**

The state must, to the extent possible, with other states in the Midwest region, develop and implement a regional approach to reducing greenhouse gas emissions from activities in the region, including consulting on a regional cap and trade system. The commissioner of commerce shall coordinate Minnesota's regional activities under this subdivision and report to the legislative committees in the senate and house of representatives with jurisdiction over energy and environmental policy by February 1, 2008, and February 1, 2009, on the progress made and recommendations for further action. The commissioner of commerce, as part of the activities required under this subdivision, must meet with responsible officials from bordering states, other states in the Midwest region, and states in other regions of the country to:

(1) determine whether other states are interested in establishing and cooperating in a multistate or regional greenhouse gas cap and trade allowance program;

(2) identify and prepare an inventory of greenhouse gas reduction resources available to support a multistate or regional greenhouse gas cap and trade allowance program;

(3) seek cooperation on a regional inventory of greenhouse gas emission sources; and

(4) prepare an inventory of available renewable energy resources within a state or region.

The commissioner of commerce must develop a definition of scope of this regional activity that is in addition to the components described in clauses (1) to (4). The commissioner must report on the additional scoping definitions to the chairs and ranking minority members of the legislative committees with jurisdiction over energy and environmental finance and policy on or before the commencement of the 2008 regular legislative session.

II. Other Policies

Natural Gas Innovation Act of 2021, MN Statutes 216B.2427, NATURAL GAS UTILITY INNOVATION PLANS.

Subdivision 1. **Definitions.**

(a) For the purposes of this section and section 216B.2428, the following terms have the meanings given.

(b) "Biogas" means gas produced by the anaerobic digestion of biomass, gasification of biomass, or other effective conversion processes.

(c) "Carbon capture" means the capture of greenhouse gas emissions that would otherwise be released into the atmosphere.

(d) "Carbon-free resource" means an electricity generation facility whose operation does not contribute to statewide greenhouse gas emissions, as defined in section 216H.01, subdivision 2.

(e) "District energy" means a heating or cooling system that is solar thermal powered or that uses the constant temperature of the earth or underground aquifers as a thermal exchange medium to heat or cool multiple buildings connected through a piping network.

(f) "Energy efficiency" has the meaning given in section 216B.241, subdivision 1, paragraph (f), but does not include energy conservation investments that the commissioner determines could reasonably be included in a utility's conservation improvement program.

(g) "Greenhouse gas emissions" means emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride emitted by anthropogenic sources within Minnesota and from the generation of electricity imported from outside the state and consumed in Minnesota, excluding carbon dioxide that is injected into geological formations to prevent its release to the atmosphere in compliance with applicable laws.

(h) "Innovative resource" means biogas, renewable natural gas, power-to-hydrogen, power-to-ammonia, carbon capture, strategic electrification, district energy, and energy efficiency.

(i) "Lifecycle greenhouse gas emissions" means the aggregate greenhouse gas emissions resulting from the production, processing, transmission, and consumption of an energy resource.

(j) "Lifecycle greenhouse gas emissions intensity" means lifecycle greenhouse gas emissions per unit of energy delivered to an end user.

(k) "Nonexempt customer" means a utility customer that has not been included in a utility's innovation plan under subdivision 3, paragraph (f).

(l) "Power-to-ammonia" means the production of ammonia from hydrogen produced via power-to-hydrogen using a process that has a lower lifecycle greenhouse gas intensity than does natural gas produced from conventional geologic sources.

(m) "Power-to-hydrogen" means the use of electricity generated by a carbon-free resource to produce hydrogen.

(n) "Renewable energy" has the meaning given in section 216B.2422, subdivision 1.

(o) "Renewable natural gas" means biogas that has been processed to be interchangeable with, and that has a lower lifecycle greenhouse gas intensity than, natural gas produced from conventional geologic sources.

(p) "Solar thermal" has the meaning given to qualifying solar thermal project in section 216B.2411, subdivision 2, paragraph (d).

(q) "Strategic electrification" means the installation of electric end-use equipment in an existing building in which natural gas is a primary or back-up fuel source, or in a newly constructed building in which a customer receives natural gas service for one or more end-uses, provided that the electric end-use equipment:

(1) results in a net reduction in statewide greenhouse gas emissions, as defined in section 216H.01, subdivision 2, over the life of the equipment when compared to the most efficient commercially available natural gas alternative; and

(2) is installed and operated in a manner that improves the load factor of the customer's electric utility.

Strategic electrification does not include investments that the commissioner determines could reasonably be included in the natural gas utility's conservation improvement program under section 216B.241.

(r) "Total incremental cost" means the calculation of the following components of a utility's innovation plan approved by the commission under subdivision 2:

(1) the sum of:

(i) return of and on capital investments for the production, processing, pipeline interconnection, storage, and distribution of innovative resources;

(ii) incremental operating costs associated with capital investments in infrastructure for the production, processing, pipeline interconnection, storage, and distribution of innovative resources;

(iii) incremental costs to procure innovative resources from third parties;

(iv) incremental costs to develop and administer programs; and

(v) incremental costs for research and development related to innovative resources;

(2) less the sum of:

(i) value received by the utility upon the resale of innovative resources or innovative resource by-products, including any environmental credits included with the resale of renewable gaseous fuels or value received by the utility when innovative resources are used as vehicle fuel;

(ii) cost savings achieved through avoidance of purchases of natural gas produced from conventional geologic sources, including but not limited to avoided commodity purchases and avoided pipeline costs; and

(iii) other revenues received by the utility that are directly attributable to the utility's implementation of an innovation plan.

(s) "Utility" means a public utility, as defined in section 216B.02, subdivision 4, that provides natural gas sales or natural gas transportation services to customers in Minnesota.

Subd. 2. **Innovation plans.**

(a) A natural gas utility may file an innovation plan with the commission. The utility's plan must include, as applicable, the following components:

(1) the innovative resource or resources the utility plans to implement to contribute to meeting the state's greenhouse gas and renewable energy goals, including those established in section 216C.05, subdivision 2, clause (3), and section 216H.02, subdivision 1, within the requirements and limitations set forth in this section;

(2) research and development investments related to innovative resources the utility plans to undertake;

(3) total lifecycle greenhouse gas emissions that the utility projects are reduced or avoided through implementing the plan;

(4) a comparison of the estimate in clause (3) to total emissions from natural gas use by utility customers in 2020;

(5) a description of each pilot program included in the plan that is related to the development or provision of innovative resources, and an estimate of the total incremental costs to implement each pilot program;

(6) the cost-effectiveness of innovative resources calculated from the perspective of the utility, society, the utility's nonparticipating customers, and the utility's participating customers compared to other innovative resources that could be deployed to reduce or avoid the same greenhouse gas emissions targeted for reduction by the utility's proposed innovative resource;

(7) for any pilot program not previously approved as part of the utility's most recent innovation plan, a third-party analysis of:

(i) the lifecycle greenhouse gas emissions intensity of the proposed innovative resources; and

(ii) the forecasted lifecycle greenhouse gas emissions reduced or avoided if the proposed pilot program is implemented;

(8) an explanation of the methodology used by the utility to calculate the lifecycle greenhouse gas emissions avoided or reduced by each pilot program included in the plan,

including descriptions of how the utility's method deviated, if at all, from the carbon accounting frameworks established by the commission under section 216B.2428;

(9) a discussion of whether the plan supports the development and use of alternative agricultural products, waste reduction, reuse, or anaerobic digestion of organic waste, and the recovery of energy from wastewater, and, if it does, a description of the geographic areas of the state in which the benefits are realized;

(10) a description of third-party systems and processes the utility plans to use to:

(i) track the innovative resources included in the plan so that environmental benefits produced by the plan are not claimed for any other program; and

(ii) verify the environmental attributes and greenhouse gas emissions intensity of innovative resources included in the plan;

(11) projected local job impacts resulting from implementation of the plan and a description of steps the utility and the utility's energy suppliers and contractors are taking to maximize the availability of construction employment opportunities for local workers;

(12) a description of how the utility proposes to recover annual total incremental costs of the plan;

(13) steps the utility has taken or proposes to take to reduce the expected cost of the plan on low- and moderate-income residential customers and to ensure that low- and moderate-income residential customers benefit from innovative resources included in the plan;

(14) a report on the utility's progress toward implementing the utility's previously approved innovation plan, if applicable;

(15) a report of the utility's progress toward achieving the cost-effectiveness objectives established by the commission with respect to the utility's previously approved innovation plan, if applicable; and

(16) collections of pilot programs that the utility estimates would, if implemented, provide approximately 50 percent, 150 percent, and 200 percent of the greenhouse gas reduction or avoidance benefits of the utility's proposed plan.

(b) The commission must approve, modify, or reject a plan. The commission must not approve an innovation plan unless the commission finds:

(1) the size, scope, and scale of the plan produces net benefits under the cost-benefit framework established by the commission in section 216B.2428;

(2) the plan promotes the use of renewable energy resources and reduces or avoids greenhouse gas emissions at a cost level consistent with subdivision 3;

(3) the plan promotes local economic development;

(4) the innovative resources included in the plan have a lower lifecycle greenhouse gas intensity than natural gas produced from conventional geologic sources;

(5) the systems used to track and verify the environmental attributes of the innovative resources included in the plan are reasonable, considering available third-party tracking and verification systems;

(6) the costs and revenues projected under the plan are reasonable in comparison to other innovative resources the utility could deploy to reduce greenhouse gas emissions, considering other benefits of the innovative resources included in the plan;

(7) the total amount of estimated greenhouse gas emissions reduction or avoidance to be achieved under the plan is reasonable considering the state's greenhouse gas and renewable energy goals, including those established in section 216C.05, subdivision 2, clause (3), and section 216H.02, subdivision 1; customer cost; and the total amount of greenhouse gas emissions reduction or avoidance achieved under the utility's previously approved plans, if applicable; and

(8) any renewable natural gas purchased by a utility under the plan that is produced from the anaerobic digestion of manure is certified as being produced at an agricultural livestock production facility that has not and does not increase the number of animal units at the facility solely or primarily to produce renewable natural gas for the plan.

(c) In seeking to recover costs under a plan approved by the commission under this section, the utility must demonstrate to the satisfaction of the commission that the actual total incremental costs incurred to implement the approved innovation plan are reasonable. Prudently incurred costs under an approved plan, including prudently incurred costs to obtain the third-party analysis required in paragraph (a), clauses (6) and (7), are recoverable either:

(1) under section 216B.16, subdivision 7, clause (2), via the utility's purchased gas adjustment;

(2) in the utility's next general rate case; or

(3) via annual adjustments, provided that after notice and comment the commission determines that the costs included for recovery through rates are prudently incurred. Annual adjustments must include a rate of return, income taxes on the rate of return, incremental property taxes, incremental depreciation expense, and incremental operation and maintenance expenses. The rate of return must be at the level approved by the commission in the utility's last general rate case, unless the commission determines that a different rate of return is in the public interest.

(d) The commission may not approve a utility's initial plan filed under this section unless:

(1) 50 percent or more of the utility's costs approved by the commission for recovery under the plan are for the procurement and distribution of renewable natural gas, biogas, hydrogen produced via power-to-hydrogen, and ammonia produced via power-to-ammonia; and

(2) the utility's costs approved by the commission for recovery for any pilot program to facilitate the development, expansion, or modification of district energy systems, as required under subdivision 9, represent no more than 20 percent of the total costs approved by the commission for recovery under the plan.

(e) Upon approval of a utility's plan, the commission shall establish cost-effectiveness objectives for the plan based on the cost-benefit test for innovative resources developed under section 216B.2428. The cost-effectiveness objective for each plan must demonstrate incremental progress from the previously approved plan's cost-effectiveness objective.

(f) A utility operating under an approved plan must file annual reports to the commission on work completed under the plan, including:

(1) costs incurred;

(2) lifecycle greenhouse gas emissions reductions or avoidance achieved;

(3) a description of the processes used to track and verify the innovative resources and to retire the associated environmental attributes;

(4) an assessment of the degree to which the lifecycle greenhouse gas accounting methodology is consistent with current science;

(5) the economic impact of the plan, including job creation;

(6) the utility's progress toward achieving the cost-effectiveness objectives established by the commission; and

(7) modifications to elements of the plan proposed by the utility.

(g) When evaluating a utility's annual report, the commission may:

(1) approve the continuation of a pilot program included in the plan, with or without modifications;

(2) require the utility to file a new or modified pilot program or plan; or

(3) disapprove the continuation of a pilot program or plan.

(h) An innovation plan has a term of five years. A subsequent innovation plan must be filed no later than four years after the previous plan was approved by the commission so that, if approved, the new plan takes effect immediately upon expiration of the previous plan.

(i) For purposes of this section and the commission's lifecycle carbon accounting framework and cost-benefit test for innovative resources under section 216B.2428, any required analysis of lifecycle greenhouse gas emissions reductions or avoidance, or lifecycle greenhouse gas intensity:

(1) must include but is not limited to estimates of:

(i) avoided or reduced greenhouse gas emissions attributable to utility operations;

(ii) avoided or reduced greenhouse gas emissions from the production, processing, and transmission of fuels prior to receipt by the utility; and

(iii) avoided or reduced greenhouse gas emissions at the point of end use;

(2) must not count any unit of greenhouse gas emissions avoidance or reduction more than once; and

(3) may, where direct measurement is not technically or economically feasible, rely on emissions factors, default values, or engineering estimates from a publicly accessible source accepted by a federal or state government agency, provided that the emissions factors, default values, or engineering estimates can be demonstrated to the satisfaction of the commission to produce a reasonable estimate of greenhouse gas emissions reductions, avoidance, or intensity.

(j) Strategic electrification implemented in a plan approved by the commission under this section is not eligible for a financial incentive under section 216B.241, subdivision 2c. Electric end-use equipment installed under a plan approved by the commission under this section is the exclusive property of the building owner.

Subd. 3. **Limitations on utility customer costs.**

(a) Except as provided in paragraph (b), the first innovation plan submitted to the commission by a utility must not propose, and the commission must not approve, annual total incremental costs exceeding the lesser of:

(1) 1.75 percent of the utility's gross operating revenues from natural gas service provided in Minnesota at the time of plan filing; or

(2) $20 per nonexempt customer, based on the proposed annual total incremental costs for each year of the plan divided by the total number of nonexempt utility customers.

(b) The commission may approve additional annual costs up to the lesser of:

(1) an additional 0.25 percent of the utility's gross operating revenues from service provided in Minnesota at the time of plan filing; or

(2) $5 per nonexempt customer, based on the proposed annual total incremental costs for each year of the plan divided by the total number of nonexempt utility customers of incremental costs.

The commission may approve the additional costs under this paragraph only if the commission determines that the additional costs are associated exclusively with the purchase of renewable natural gas produced from:

(i) food waste diverted from a landfill;

(ii) a municipal wastewater treatment system; or

(iii) an organic mixture that includes at least 15 percent, by volume, sustainably harvested native prairie grasses or locally appropriate cover crops, as determined by a local soil and water conservation district or the United States Department of Agriculture, Natural Resources Conservation Service.

(c) Unless the commission determines that paragraph (d) applies, if the commission determines that the utility has successfully achieved the cost-effectiveness objectives established in the utility's most recently approved innovation plan, the next subsequent plan filed by the utility under this section is subject to the provisions of paragraphs (a) and (b), except that:

(1) the cap on total incremental costs in paragraph (a) with respect to the second plan is the lesser of:

(i) 2.75 percent of the utility's gross operating revenues from natural gas service in Minnesota at the time of the plan's filing; or

(ii) $35 per nonexempt customer; and

(2) the cap on additional costs in paragraph (b) is the lesser of:

(i) an additional 0.75 percent of the utility's gross operating revenues from natural gas service in Minnesota at the time of the plan's filing; or

(ii) $10 per nonexempt customer.

(d) If the commission determines that the utility has successfully achieved the cost-effectiveness objectives established in two of the same utility's previously approved innovation plans, all subsequent plans filed by the utility under this section are subject to paragraphs (a) and (b), except that:

(1) the cap on total incremental costs in paragraph (a) with respect to the third or subsequent plan is the lesser of:

(i) four percent of the utility's gross operating revenues from natural gas service in Minnesota at the time of the plan's filing; or

(ii) $50 per nonexempt customer; and

(2) the cap on additional costs in paragraph (b) is the lesser of:

(i) an additional 1.5 percent of the utility's gross operating revenues from natural gas service in Minnesota at the time of the plan's filing; or

(ii) $20 per nonexempt customer.

(e) For purposes of paragraphs (a) to (d), the limits on annual total incremental costs must be calculated at the time the innovation plan is filed as the average of the utility's forecasted total incremental costs over the five-year term of the plan.

(f) A large customer facility that the commissioner of commerce has exempted from a utility's conservation improvement program under section 216B.241, subdivision 1a, paragraph (b), is exempt from the utility's innovation plan offerings and must not be charged any costs incurred to implement an approved innovation plan unless the large customer facility files a request with the commissioner to be included in a utility's innovation plan. The commission may prohibit large customer facilities exempt from innovation plan costs from participating in innovation plans.

(g) A utility filing an innovation plan may include annual spending and investments on research and development of up to ten percent of the proposed total incremental costs related to innovative plans, subject to the limitations in paragraphs (a) to (e).

(h) For purposes of this subdivision, gross operating revenues do not include revenues from large customer facilities exempt from innovation plan costs.

Subd. 4. **Innovative resources procured outside of an innovation plan.**

(a) Without filing an innovation plan, a natural gas utility may propose and the commission may approve cost recovery for:

(1) innovative resources acquired to satisfy a commission-approved green tariff program that allows customers to choose to meet a portion of the customers' energy needs through innovative resources; or

(2) utility expenditures for innovative resources procured at a cost that is within five percent of the average of Ventura and Demarc index prices for natural gas produced from conventional geologic sources at the time of the transaction per unit of natural gas that the innovative resource displaces.

(b) An approved green tariff program must include provisions to ensure that reasonable systems are used to track and verify the environmental attributes of innovative resources included in the program, taking into account any available third-party tracking or verification systems.

(c) For the purposes of this subdivision, "Ventura and Demarc index prices" means the daily index price of wholesale natural gas sold at the Northern Natural Gas Company's Ventura trading hub in Hancock County, Iowa, and its demarcation point in Clifton, Kansas.

Subd. 5. **Power-to-ammonia.**

When determining whether to approve a power-to-ammonia pilot program as part of an innovative plan, the commission must consider:

(1) the risk of exposing any person to unhealthy concentrations of ammonia;

(2) the risk that any home or business might be affected by ammonia odors;

(3) whether the greenhouse gas emissions addressed by the proposed power-to-ammonia project could be more efficiently addressed using power-to-hydrogen; and

(4) whether the power-to-ammonia project achieves lifecycle greenhouse gas emissions reductions in the agricultural sector more effectively than power-to-hydrogen.

Subd. 6. **Thermal energy audits.**

The first innovation plan filed under this section by a utility with more than 800,000 customers must include a pilot program to provide thermal energy audits to small- and medium-sized businesses in order to identify opportunities to reduce or avoid greenhouse gas emissions from natural gas use. The pilot program must provide incentives for businesses to implement recommendations made by the audit. The utility must develop criteria to identify businesses that achieve significant emissions reductions by implementing audit recommendations and must recognize the businesses as thermal energy leaders.

Subd. 7 **Innovative resources for certain industrial processes.**

The first innovation plan filed under this section by a utility with more than 800,000 customers must include a pilot program to provide innovative resources to industrial facilities whose manufacturing processes, for technical reasons, are not amenable to electrification. A large customer facility exempt from innovation plan offerings under subdivision 3, paragraph (f), is not eligible to participate in the pilot program under this subdivision.

Subd. 8. **Electric cold climate air-source heat pumps.**

(a) The first innovation plan filed under this section by a utility with more than 800,000 customers must include a pilot program that facilitates deep energy retrofits and the installation of cold climate electric air-source heat pumps in existing residential homes that have natural gas heating systems.

(b) For purposes of this subdivision, "deep energy retrofit" means the installation of any measure or combination of measures, including air sealing and addressing thermal bridges, that under normal weather and operating conditions can reasonably be expected to reduce a building's calculated design load to ten or fewer British Thermal Units per hour per square foot of conditioned floor area. Deep energy retrofit does not include the installation of photovoltaic electric generation equipment, but may include the installation of a solar thermal energy project.

Subd. 9. **District energy.**

The first innovation plan filed under this section by a utility with more than 800,000 customers must include a pilot program to facilitate the development, expansion, or modification of district energy systems in Minnesota. This subdivision does not require the utility to propose, construct, maintain, or own district energy infrastructure.

Subd. 10. **Throughput goal.**

It is the goal of the state of Minnesota that through the Natural Gas Innovation Act and Conservation Improvement Program, utilities reduce the overall amount of natural gas produced from conventional geologic sources delivered to customers.

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Subd. 11. **Utility system report and forecasts.**

(a) A public utility filing an innovation plan shall concurrently submit a report to the commission containing the following information:

(1) the volume of methane gas emissions attributed to venting or leakage across the utility's system, including emissions information reported to the Environmental Protection Agency and gas leaks considered to be hazardous or nonhazardous, and a narrative description of the utility's expectations regarding the cost and performance of the utility's leakage reduction programs over the next five years;

(2) total system greenhouse gas emissions and greenhouse gas emissions projected to be reduced or avoided through innovative resource investments and energy conservation investments, and a narrative description of the costs required to achieve the reductions over the next five years through investments in innovative resources and energy conservation;

(3) the quantity of pipe in service in the utility's natural gas network in Minnesota, by material, size, coating, operating pressure, and decade of installation, based on utility information reported to the United States Department of Transportation;

(4) a narrative description of other significant equipment owned and operated by the utility through which gas is transported or stored, including regulator stations and storage facilities, a discussion of the function of the equipment, how the equipment is maintained, and utility efforts to prevent leaks from the equipment;

(5) a five-year forecast of fuel prices and anticipated purchases including, as available, natural gas produced from conventional geologic sources, renewable natural gas, and alternative fuels;

(6) a five-year forecast of potential capital investments by the utility in existing infrastructure and new infrastructure for natural gas produced from conventional geologic sources and for innovative resources; and

(7) an inventory of the utility's current financial incentive programs for natural gas, including rebates and incentives offered for new and existing buildings and a description of the utility's projected changes in incentives the utility is likely to implement over the next five years.

(b) Information filed under this subdivision is intended to be used by the commission to evaluate a utility's innovation plan in the context of the utility's other planned investments and activities with respect to natural gas produced from conventional geologic sources. Information filed under this subdivision must not be used by the commission to set or limit utility rate recovery.

216B.2428 LIFECYCLE GREENHOUSE GAS EMISSIONS ACCOUNTING FRAMEWORK; COST-BENEFIT TEST FOR INNOVATIVE RESOURCES.

By June 1, 2022, the commission shall, by order, issue frameworks the commission must use to calculate lifecycle greenhouse gas emissions intensities of each innovative resource, as follows:

(1) a general framework to compare the lifecycle greenhouse gas emissions intensities of power-to-hydrogen, strategic electrification, renewable natural gas, district energy, energy efficiency, biogas, carbon capture, and power-to-ammonia; and

(2) a cost-benefit analytic framework to be applied to innovative resources and innovation plans filed under section 216B.2427 that the commission must use to compare the cost-effectiveness of those resources and plans. This analytic framework must take into account:

(i) the total incremental cost of the plan or resource and the lifecycle greenhouse gas emissions avoided or reduced by the innovative resource or plan, using the framework developed under clause (1);

(ii) additional economic costs and benefits, programmatic costs and benefits, additional environmental costs and benefits, and other costs or benefits that may be expected under a plan; and

(iii) baseline cost-effectiveness criteria against which an innovation plan should be compared. When establishing baseline criteria, the commission must take into account options available to reduce lifecycle greenhouse gas emissions from natural gas end uses and the goals in section 216C.05, subdivision 2, clause (3), and section 216H.02, subdivision 1. To the maximum reasonable extent, the cost-benefit framework must be consistent with environmental cost values established under section 216B.2422, subdivision 3, and other calculations of the social value of greenhouse gas emissions reductions used by the commission. The commission may update frameworks established under this section as necessary.

III. CIP COU Statutory Requirements

MN Statute 216B.2403 CONSUMER-OWNED UTILITIES; ENERGY CONSERVATION AND OPTIMIZATION.

Subdivision 1. **Applicability.**

This section applies to:

(1) a cooperative electric association that provides retail service to more than 5,000 members;

(2) a municipality that provides electric service to more than 1,000 retail customers; and

(3) a municipality with more than 1,000,000,000 cubic feet in annual throughput sales to natural gas retail customers.

Subd. 2. **Consumer-owned utility; energy-savings goal.**

(a) Each individual consumer-owned utility subject to this section has an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales, to be met with a minimum of energy savings from energy conservation improvements equivalent to at least 0.95 percent of the consumer-owned utility's gross annual retail energy sales. The balance of energy savings toward the annual energy-savings goal may be achieved only by the following consumer-owned utility activities:

(1) energy savings from additional energy conservation improvements;

(2) electric utility infrastructure projects, as defined in section 216B.1636, subdivision 1, that result in increased efficiency greater than would have occurred through normal maintenance activity;

(3) net energy savings from efficient fuel-switching improvements that meet the criteria under subdivision 8, which may contribute up to 0.55 percent of the goal; or

(4) subject to department approval, demand-side natural gas or electric energy displaced by use of waste heat recovered and used as thermal energy, including the recovered thermal energy from a cogeneration or combined heat and power facility.

(b) The energy-savings goals specified in this section must be calculated based on weather-normalized sales averaged over the most recent three years. A consumer-owned utility may elect to carry forward energy savings in excess of 1.5 percent for a year to the next three years, except that energy savings from electric utility infrastructure projects may be carried forward for five years. A particular energy savings can only be used to meet one year's goal.

(c) A consumer-owned utility subject to this section is not required to make energy conservation improvements that are not cost-effective, even if the improvement is necessary to attain the energy-savings goal. A consumer-owned utility subject to this section must make reasonable efforts to implement energy conservation improvements that exceed the minimum level established under this subdivision if cost-effective opportunities and funding are available, considering other potential investments the consumer-owned utility intends to make to benefit customers during the term of the plan filed under subdivision 3.

(d) Notwithstanding any provision to the contrary, until July 1, 2026, spending by a consumer-owned utility subject to this section on efficient fuel-switching improvements implemented to meet the annual energy savings goal under this section must not exceed 0.55 percent per year, averaged over a three-year period, of the consumer-owned utility's gross annual retail energy sales.

Subd. 3. **Consumer-owned utility; energy conservation and optimization plans.**

(a) By June 1, 2022, and at least every three years thereafter, each consumer-owned utility must file with the commissioner an energy conservation and optimization plan that describes the programs for energy conservation, efficient fuel-switching, load management, and other measures the consumer-owned utility intends to offer to achieve the utility's energy savings goal.

(b) A plan's term may extend up to three years. A multiyear plan must identify the total energy savings and energy savings resulting from energy conservation improvements that are projected to be achieved in each year of the plan. A multiyear plan that does not, in each year of the plan, meet both the minimum energy savings goal from energy conservation improvements and the total energy savings goal of 1.5 percent, or lower goals adjusted by the commissioner under paragraph (k), must:

(1) state why each goal is projected to be unmet; and

(2) demonstrate how the consumer-owned utility proposes to meet both goals on an average basis over the duration of the plan.

(c) A plan filed under this subdivision must provide:

(1) for existing programs, an analysis of the cost-effectiveness of the consumer-owned utility's programs offered under the plan, using a list of baseline energy- and capacity-savings assumptions developed in consultation with the department; and

(2) for new programs, a preliminary analysis upon which the program will proceed, in parallel with further development of assumptions and standards.

(d) The commissioner must evaluate a plan filed under this subdivision based on the plan's likelihood to achieve the energy-savings goals established in subdivision 2. The commissioner may make recommendations to a consumer-owned utility regarding ways to increase the effectiveness of the consumer-owned utility's energy conservation activities and programs under this subdivision. The commissioner may recommend that a consumer-owned utility implement a cost-effective energy conservation program, including an energy conservation program suggested by an outside source such as a political subdivision, nonprofit corporation, or community organization.

(e) Beginning June 1, 2023, and every June 1 thereafter, each consumer-owned utility must file: (1) an annual update identifying the status of the plan filed under this subdivision, including: (i) total expenditures and investments made to date under the plan; and (ii) any intended changes to the plan; and (2) a summary of the annual energy-savings achievements under a plan. An annual filing made in the last year of a plan must contain a new plan that complies with this section.

(f) When evaluating the cost-effectiveness of a consumer-owned utility's energy conservation programs, the consumer-owned utility and the commissioner must consider the costs and benefits to ratepayers, the utility, participants, and society. The commissioner must also consider the rate at which the consumer-owned utility is increasing energy savings and expenditures on energy conservation, and lifetime energy savings and cumulative energy savings.

(g) A consumer-owned utility may annually spend and invest up to ten percent of the total amount spent and invested on energy conservation improvements on research and development projects that meet the definition of energy conservation improvement.

(h) A generation and transmission cooperative electric association or municipal power agency that provides energy services to consumer-owned utilities may file a plan under this subdivision on behalf of the consumer-owned utilities to which the association or agency provides energy services and may make investments, offer conservation programs, and otherwise fulfill the energy-savings goals and reporting requirements of this subdivision for those consumer-owned utilities on an aggregate basis.

(i) A consumer-owned utility is prohibited from spending for or investing in energy conservation improvements that directly benefit a large energy facility or a large electric customer facility the commissioner has exempted under section 216B.241, subdivision 1a.

(j) The energy conservation and optimization plan of a consumer-owned utility may include activities to improve energy efficiency in the public schools served by the utility. These activities may include programs to:

(1) increase the efficiency of the school's lighting and heating and cooling systems;

(2) recommission buildings;

(3) train building operators; and

(4) provide opportunities to educate students, teachers, and staff regarding energy efficiency measures implemented at the school.

(k) A consumer-owned utility may request that the commissioner adjust the consumer-owned utility's minimum goal for energy savings from energy conservation improvements under subdivision 2, paragraph (a), for the duration of the plan filed under this subdivision. The request must be made by January 1 of the year when the consumer-owned utility must file a plan under this subdivision. The request must be based on:

(1) historical energy conservation improvement program achievements;

(2) customer class makeup;

(3) projected load growth;

(4) an energy conservation potential study that estimates the amount of cost-effective energy conservation potential that exists in the consumer-owned utility's service territory;

(5) the cost-effectiveness and quality of the energy conservation programs offered by the consumer-owned utility; and

(6) other factors the commissioner and consumer-owned utility determine warrant an adjustment.

The commissioner must adjust the energy savings goal to a level the commissioner determines is supported by the record, but must not approve a minimum energy savings goal from energy conservation improvements that is less than an average of 0.95 percent per year over the consecutive years of the plan's duration, including the year the minimum energy savings goal is adjusted.

(l) A consumer-owned utility filing a conservation and optimization plan that includes an efficient fuel-switching program to achieve the utility's energy savings goal must, as part of the filing, demonstrate by a comparison of greenhouse gas emissions between the fuels that the requirements of subdivision 8 are met, using a full fuel-cycle energy analysis.

Subd. 4. **Consumer-owned utility; energy savings investment.**

(a) Except as otherwise provided, a consumer-owned utility that the commissioner determines falls short of the minimum energy savings goal from energy conservation improvements established in subdivision 2, paragraph (a), for three consecutive years during which the utility has annually spent on energy conservation improvements less than 1.5 percent of the utility's gross operating revenues for an electric utility or less than 0.5 percent of the utility's gross operating revenues for a natural gas utility, must spend no less than the following amounts for energy conservation improvements:

(1) for a municipality, 0.5 percent of the municipality's gross operating revenues from the sale of gas and 1.5 percent of the municipality's gross operating revenues from the sale of electricity, excluding gross operating revenues from electric and gas service provided in Minnesota to large electric customer facilities; and

(2) for a cooperative electric association, 1.5 percent of the association's gross operating revenues from service provided in the state, excluding gross operating revenues from service provided in Minnesota to large electric customers facilities indirectly through a distribution cooperative electric association.

(b) The commissioner may not impose the spending requirement under this subdivision if the commissioner has determined that the utility has followed the commissioner's recommendations, if any, provided under subdivision 3, paragraph (d).

(c) Upon request of a consumer-owned utility, the commissioner may reduce the amount or duration of the spending requirement imposed under this subdivision, or both, if the commissioner determines that the consumer-owned utility's failure to maintain the minimum energy savings goal is the result of:

(1) a natural disaster or other emergency that is declared by the executive branch through an emergency executive order that affects the consumer-owned utility's service area;

(2) a unique load distribution experienced by the consumer-owned utility; or

(3) other factors that the commissioner determines justifies a reduction.

(d) Unless the commissioner reduces the duration of the spending requirement under paragraph (c), the spending requirement under this subdivision remains in effect until the consumer-owned utility has met the minimum energy savings goal for three consecutive years.

Subd. 5. **Energy conservation programs for low-income households.**

(a) A consumer-owned utility subject to this section must provide energy conservation programs to low-income households. The commissioner must evaluate a consumer-owned utility's plans under this section by considering the consumer-owned utility's historic spending on energy conservation programs directed to low-income households, the rate of customer participation in and the energy savings resulting from those programs, and the number of low-income persons residing in the consumer-owned utility's service territory. A municipal utility that furnishes natural gas service must spend at least 0.2 percent of the municipal utility's most recent three-year average gross operating revenue from residential customers in Minnesota on energy conservation programs for low-income households. A consumer-owned utility that furnishes electric service must spend at least 0.2 percent of the consumer-owned utility's gross operating revenue from residential customers in Minnesota on energy conservation programs for low-income households. The requirement under this paragraph applies to each generation and transmission cooperative association's aggregate gross operating revenue from the sale of electricity to residential customers in Minnesota by all of the association's member distribution cooperatives.

(b) To meet all or part of the spending requirements of paragraph (a), a consumer-owned utility may contribute money to the energy and conservation account established in section 216B.241, subdivision 2a. An energy conservation optimization plan must state the amount of contributions the consumer-owned utility plans to make to the energy and conservation account. Contributions to the account must be used for energy conservation programs serving low-income households, including renters, located in the service area of the consumer-owned utility making the contribution. Contributions must be remitted to the commissioner by February 1 each year.

(c) The commissioner must establish energy conservation programs for low-income households funded through contributions to the energy and conservation account under paragraph (b). When establishing energy conservation programs for low-income households, the commissioner must consult political subdivisions, utilities, and nonprofit and community organizations, including organizations providing energy and weatherization assistance to low-income households. The commissioner must record and report expenditures and energy savings achieved as a result of energy conservation programs for low-income households funded through the energy and conservation account in the report required under section 216B.241, subdivision 1c, paragraph (f). The commissioner may contract with a political subdivision, nonprofit or community organization, public utility, municipality, or consumer-owned utility to implement low-income programs funded through the energy and conservation account.

(d) A consumer-owned utility may petition the commissioner to modify the required spending under this subdivision if the consumer-owned utility and the commissioner were unable to expend the amount required for three consecutive years.

(e) The commissioner must develop and establish guidelines for determining the eligibility of multifamily buildings to participate in energy conservation programs provided to low-income households. Notwithstanding the definition of low-income household in section 216B.2402, a consumer-owned utility or association may apply the most recent guidelines published by the department for purposes of determining the eligibility of multifamily buildings to participate in low-income programs. The commissioner must convene a stakeholder group to review and update these guidelines by August 1, 2021, and at least once every five years thereafter. The stakeholder group must include but is not limited to representatives of public utilities; municipal electric or gas utilities; electric cooperative associations; multifamily housing owners and developers; and low-income advocates.

(f) Up to 15 percent of a consumer-owned utility's spending on low-income energy conservation programs may be spent on preweatherization measures. A consumer-owned utility is prohibited from claiming energy savings from preweatherization measures toward the consumer-owned utility's energy savings goal.

(g) The commissioner must, by order, establish a list of preweatherization measures eligible for inclusion in low-income energy conservation programs no later than March 15, 2022.

(h) A Healthy AIR (Asbestos Insulation Removal) account is established as a separate account in the special revenue fund in the state treasury. A consumer-owned utility may elect to contribute money to the Healthy AIR account to provide preweatherization measures for households eligible for weatherization assistance from the state weatherization assistance program in section 216C.264. Remediation activities must be executed in conjunction with federal weatherization assistance program services. Money contributed to the account by a consumer-owned utility counts toward: (1) the minimum low-income spending requirement under paragraph (a); and (2) the cap on preweatherization measures under paragraph (f). Money in the account is annually appropriated to the commissioner of commerce to pay for Healthy AIR-related activities.

Subd. 6. **Recovery of expenses.**

The commission must allow a cooperative electric association subject to rate regulation under section 216B.026 to recover expenses resulting from: (1) a plan under this section; and (2) assessments and contributions to the energy and conservation account under section 216B.241, subdivision 2a.

Subd. 7. **Ownership of preweatherization measure or energy conservation improvement.**

(a) A preweatherization measure or energy conservation improvement installed in a building under this section, excluding a system owned by a consumer-owned utility that is designed to turn off, limit, or vary the delivery of energy, is the exclusive property of the building owner, except to the extent that the improvement is subject to a security interest in favor of the consumer-owned utility in case of a loan to the building owner for the improvement.

(b) A consumer-owned utility has no liability for loss, damage, or injury directly or indirectly caused by a preweatherization measure or energy conservation improvement, unless a consumer-owned utility is determined to have been negligent in purchasing, installing, or modifying a preweatherization measure or energy conservation improvement.

Subd. 8. **Criteria for efficient fuel-switching improvements.**

(a) A fuel-switching improvement is deemed efficient if, applying the technical criteria established under section 216B.241, subdivision 1d, paragraph (e), the improvement, relative to the fuel being displaced:

(1) results in a net reduction in the amount of source energy consumed for a particular use, measured on a fuel-neutral basis;

(2) results in a net reduction of statewide greenhouse gas emissions, as defined in section 216H.01, subdivision 2, over the lifetime of the improvement. For an efficient fuel-switching improvement installed by an electric consumer-owned utility, the reduction in emissions must be measured based on the hourly emissions profile of the consumer-owned utility or the utility's electricity supplier, as reported in the most recent resource plan approved by the commission under section 216B.2422. If the hourly emissions profile is not available, the commissioner must develop a method consumer-owned utilities must use to estimate that value;

(3) is cost-effective, considering the costs and benefits from the perspective of the consumer-owned utility, participants, and society; and

(4) is installed and operated in a manner that improves the consumer-owned utility's system load factor.

(b) For purposes of this subdivision, "source energy" means the total amount of primary energy required to deliver energy services, adjusted for losses in generation, transmission, and distribution, and expressed on a fuel-neutral basis.

Subd. 9. **Manner of filing and service.**

(a) A consumer-owned utility must submit the filings required under this section to the department using the department's electronic filing system. The commissioner may approve an exemption from this requirement if an affected consumer-owned utility is unable to submit filings via the department's electronic filing system. All other interested parties must submit filings to the department via the department's electronic filing system whenever practicable but may also file by personal delivery or by mail.

(b) The submission of a document to the department's electronic filing system constitutes service on the department. If a department rule requires service of a notice, order, or other document by the department, a consumer-owned utility, or an interested party upon persons on a service list maintained by the department, service may be made by personal delivery, mail, or electronic service. Electronic service may be made only to persons on the service list that have previously agreed in writing to accept electronic service at an e-mail address provided to the department for electronic service purposes.

Subd. 10. **Assessment.**

The commission or department may assess consumer-owned utilities subject to this section to carry out the purposes of section 216B.241, subdivisions 1d, 1e, and 1f. An assessment under this subdivision must be proportionate to a consumer-owned utility's gross operating revenue from sales of gas or electric service in Minnesota during the previous calendar year, as applicable. Assessments under this subdivision are not subject to the cap on assessments under section 216B.62 or any other law.

IV. CIP IOU Statutory Requirements,

MN Statutes 216B.241, PUBLIC UTILITIES; ENERGY CONSERVATION AND OPTIMIZATION.

Subdivision 1. MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 1a. **Large customer facility.**

(a) The owner of a large customer facility may petition the commissioner to exempt both electric and gas utilities serving the large customer facility from contributing to investments and expenditures made under an energy and conservation optimization plan filed under subdivision 2 or section 216B.2403, subdivision 3, with respect to retail revenues attributable to the large customer facility. The filing must include a discussion of the competitive or economic pressures facing the owner of the facility and the efforts taken by the owner to identify, evaluate, and implement energy conservation and efficiency improvements. A filing submitted on or before October 1 of any year must be approved within 90 days and become effective January 1 of the year following the filing, unless the commissioner finds that the owner of the large customer facility has failed to take reasonable measures to identify, evaluate, and implement energy conservation and efficiency improvements. If a facility qualifies as a large customer facility solely due to its peak electrical demand or annual natural gas usage, the exemption may be limited to the qualifying utility if the commissioner finds that the owner of the large customer facility has failed to take reasonable measures to identify, evaluate, and implement energy conservation and efficiency improvements with respect to the nonqualifying utility. Once an exemption is approved, the commissioner may request the owner of a large customer facility to submit, not more often than once every five years, a report demonstrating the large customer facility's ongoing commitment to energy conservation and efficiency improvement after the exemption filing. The commissioner may request such reports for up to ten years after the effective date of the exemption, unless the majority ownership of the large customer facility changes, in which case the commissioner may request additional reports for up to ten years after the change in ownership occurs. The commissioner may, within 180 days of receiving a report submitted under this paragraph, rescind any exemption granted under this paragraph upon a determination that the large customer facility is not continuing to make reasonable efforts to identify, evaluate, and implement energy conservation improvements. A large customer facility that is, under an order from the commissioner, exempt from the investment and expenditure requirements of paragraph (a) as of December 31, 2010, is not required to submit a report to retain its exempt status, except as otherwise provided in this paragraph with respect to ownership changes. No exempt large customer facility may participate in a utility conservation improvement program unless the owner of the facility submits a filing with the commissioner to withdraw its exemption.

(b) A commercial gas customer that is not a large customer facility and that purchases or acquires natural gas from a public utility having fewer than 600,000 natural gas customers in Minnesota may petition the commissioner to exempt gas utilities serving the commercial gas customer from contributing to investments and expenditures made under an energy and conservation optimization plan filed under subdivision 2 or section 216B.2403, subdivision 3, with respect to retail revenues attributable to the commercial gas customer. The petition must be supported by evidence demonstrating that the commercial gas customer has acquired or can reasonably acquire the capability to bypass use of the utility's gas distribution system by obtaining natural gas directly from a supplier not regulated by the commission. The commissioner shall grant the exemption if the commissioner finds that the petitioner has made the demonstration required by this paragraph.

(c) 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.

(d) Notwithstanding paragraph (a), a large customer facility or commercial gas customer that is exempt from the investment and expenditure requirements of this section pursuant to an order from the commissioner as of December 31, 2020, is not required to submit additional documentation to maintain the exemption and must not be assessed any costs related to any energy conservation and optimization plan filed under this section or section 216B.2403, including but not limited to costs, incentives, or rates of return associated with investments in programs for efficient fuel-switching improvements.

(e) A public utility is prohibited from spending for or investing in energy conservation improvements that directly benefit a large energy facility or a large electric customer facility the commissioner has issued an exemption to under this section.

Subd. 1b.

MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 1c. **Public utility; energy-saving goals.**

(a) The commissioner shall establish energy-saving goals for energy conservation improvements and shall evaluate an energy conservation improvement program on how well it meets the goals set.

(b) A public utility providing electric service has an annual energy-savings goal equivalent to 1.75 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (c). A public utility providing natural gas service has an annual energy-savings goal equivalent to one percent of gross annual retail energy sales, which cannot be lowered by the commissioner. The savings goals must be calculated based on the most recent three-year weather-normalized average. A public utility providing electric service may elect to carry forward energy savings in excess of 1.75 percent for a year to the succeeding three calendar years, except that savings from electric utility infrastructure projects allowed under paragraph (d) may be carried forward for five years. A public utility providing natural gas service may elect to carry forward energy savings in excess of one percent for a year to the succeeding three calendar years. A particular energy savings can only be used to meet one year's goal.

(c) In its energy conservation and optimization plan filing, a public utility may request the commissioner to adjust its annual energy-savings percentage goal based on its historical conservation investment experience, customer class makeup, load growth, a conservation potential study, or other factors the commissioner determines warrants an adjustment.

(d) The commissioner may not approve a plan of a public utility that provides for an annual energy-savings goal of less than one percent of gross annual retail energy sales from energy conservation improvements.

The balance of the 1.75 percent annual energy savings goal may be achieved through energy savings from:

(1) additional energy conservation improvements;

(2) electric utility infrastructure projects approved by the commission under section 216B.1636 that result in increased efficiency greater than would have occurred through normal maintenance activity; or

(3) subject to department approval, demand-side natural gas or electric energy displaced by use of waste heat recovered and used as thermal energy, including the recovered thermal energy from a cogeneration or combined heat and power facility.

(e) A public utility is not required to make energy conservation investments to attain the energy-savings goals of this subdivision that are not cost-effective even if the investment is necessary to attain the energy-savings goals. For the purpose of this paragraph, in determining cost-effectiveness, the commissioner shall consider: (1) the costs and benefits to ratepayers, the utility, participants, and society; (2) the rate at which a public utility is increasing both its energy savings and its expenditures on energy conservation; and (3) the public utility's lifetime energy savings and cumulative energy savings.

(f) On an annual basis, the commissioner shall produce and make publicly available a report on the annual energy and capacity savings and estimated carbon dioxide reductions achieved by the programs under this section and section 216B.2403 for the two most recent years for which data is available. The report must also include information regarding any annual energy sales or generation capacity increases resulting from efficient fuel-switching improvements. The commissioner shall report on program performance both in the aggregate and for each entity filing an energy conservation improvement plan for approval or review by the commissioner, and must estimate progress made toward the statewide energy-savings goal under section 216B.2401.

(g) Notwithstanding any provision to the contrary, until July 1, 2026, spending by a public utility subject to this section on efficient fuel-switching improvements to meet energy savings goals under this section must not exceed 0.35 percent per year, averaged over three years of the public utility's gross annual retail energy sales.

Subd. 1d. **Technical assistance.**

(a) The commissioner shall evaluate energy conservation improvement programs filed under this section and section 216B.2403 on the basis of cost-effectiveness and the reliability of the technologies employed. The commissioner shall, by order, establish, maintain, and update energy-savings assumptions that must be used by utilities when filing energy conservation improvement programs. The department must track a public utility's or consumer-owned utility's lifetime energy savings and cumulative lifetime energy savings reported in plans submitted under this section and section 216B.2403.

(b) The commissioner shall establish an inventory of the most effective energy conservation programs, techniques, and technologies, and encourage all Minnesota utilities to implement them, where appropriate. The commissioner shall describe these programs in sufficient detail to provide a utility reasonable guidance concerning implementation. The commissioner shall prioritize the opportunities in order of potential energy savings and in order of cost-effectiveness.

(c) The commissioner may contract with a third party to carry out any of the commissioner's duties under this subdivision, and to obtain technical assistance to evaluate the effectiveness of any conservation improvement program.

(d) The commissioner may assess up to $850,000 annually for the purposes of this subdivision. The assessments must be deposited in the state treasury and credited to the energy and conservation account created under subdivision 2a. An assessment made under this subdivision is not subject to the cap on assessments provided by section 216B.62, or any other law.

(e) The commissioner must work with stakeholders to develop technical guidelines that public utilities and consumer-owned utilities must use to:

~~(1)~~ determine whether deployment of a fuel-switching improvement meets the criteria established in subdivision 11, paragraph (d); subdivision 12, paragraph (a); or section 216B.2403, subdivision 8, as applicable; and

(2) calculate the amount of energy saved due to the deployment of a fuel-switching improvement.

The guidelines must be issued by the commissioner by order no later than March 15, 2022, and must be updated as the commissioner determines is necessary.

Subd. 1e. **Applied research and development grants.**

(a) The commissioner may, by order, approve and make grants for applied research and development projects of general applicability that identify new technologies or strategies to maximize energy savings, improve the effectiveness of energy conservation programs, or document the carbon dioxide reductions from energy conservation programs. When approving projects, the commissioner shall consider proposals and comments from utilities and other interested parties. The commissioner may assess up to $3,600,000 annually for the purposes of this subdivision. The assessments must be deposited in the state treasury and credited to the energy and conservation account created under subdivision 2a. An assessment made under this subdivision is not subject to the cap on assessments provided by section 216B.62, or any other law.

(b) The commissioner, as part of the assessment authorized under paragraph (a), shall annually assess and grant up to $500,000 for the purpose of subdivision 9.

(c) The commissioner, as part of the assessment authorized under paragraph (a), each state fiscal year shall assess $500,000 for a grant to the partnership created by section 216C.385, subdivision 2. The grant must be used to exercise the powers and perform the duties specified in section 216C.385, subdivision 3.

(d) By February 15 annually, the commissioner shall report to the chairs and ranking minority members of the committees of the legislature with primary jurisdiction over energy policy and energy finance on the assessments made under this subdivision for the previous calendar year and the use of the assessment. The report must clearly describe the activities supported by the assessment and the parties that engaged in those activities.

Subd. 1f. **Facilities energy efficiency.**

(a) The commissioner of administration and the commissioner of commerce shall maintain and, as needed, revise the sustainable building design guidelines developed under section 16B.325.

(b) The commissioner of administration and the commissioner of commerce shall maintain and update the benchmarking tool developed under Laws 2001, chapter 212, article 1, section 3, so that all public buildings can use the benchmarking tool to maintain energy use information for the purposes of establishing energy efficiency benchmarks, tracking building performance, and measuring the results of energy efficiency and conservation improvements.

(c) The commissioner shall require that utilities include in their conservation improvement plans programs that facilitate professional engineering verification to qualify a building as Energy Star-labeled, Leadership in Energy and Environmental Design (LEED) certified, or Green Globes-certified.

(d) The commissioner may assess up to $500,000 annually for the purposes of this subdivision. The assessments must be deposited in the state treasury and credited to the energy and conservation account created under subdivision 2a. An assessment made under this subdivision is not subject to the cap on assessments provided by section 216B.62, or any other law.

Subd. 1g. **Manner of filing and service.**

(a) A public utility shall submit filings to the department via the department's electronic filing system. The commissioner may approve an exemption from this requirement in the event a public utility is unable to submit filings via the department's electronic filing system. All other interested parties shall submit filings to the department via the department's electronic filing system whenever practicable but may also file by personal delivery or by mail.

(b) Submission of a document to the department's electronic filing system constitutes service on the department. Where department rule requires service of a notice, order, or other document by the department, public utility, or interested party upon persons on a service list maintained by the department, service may be made by personal delivery, mail, or electronic service, except that electronic service may only be made upon persons on the service list who have previously agreed in writing to accept electronic service at an electronic address provided to the department for electronic service purposes.

Subd. 2. **Public utility; energy conservation and optimization plans.**

(a) The commissioner may require a public utility to make investments and expenditures in energy conservation improvements, explicitly setting forth the interest rates, prices, and terms under which the improvements must be offered to the customers.

(b) A public utility shall file an energy conservation and optimization plan by June 1, on a schedule determined by order of the commissioner, but at least every three years. As provided in subdivisions 11 to 13, plans may include programs for efficient fuel-switching improvements and load management. An individual utility program may combine elements of energy conservation, load management, or efficient fuel-switching. The plan must estimate the lifetime energy savings and cumulative lifetime energy savings projected to be achieved under the plan. A plan filed by a public utility by June 1 must be approved or approved as modified by the commissioner by December 1 of that same year.

(c) The commissioner shall evaluate the plan on the basis of cost-effectiveness and the reliability of technologies employed. The commissioner's order must provide to the extent practicable for a free choice, by consumers participating in an energy conservation program, of the device, method, material, or project constituting the energy conservation improvement and for a free choice of the seller, installer, or contractor of the energy conservation improvement, provided that the device, method, material, or project seller, installer, or contractor is duly licensed, certified, approved, or qualified, including under the residential conservation services program, where applicable.

(d) The commissioner may require a utility subject to subdivision 1c to make an energy conservation improvement investment or expenditure whenever the commissioner finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of new supply of energy.

(e) Each public utility subject to this subdivision may spend and invest annually up to ten percent of the total amount spent and invested on energy conservation improvements under this section by the public utility on research and development projects that meet the definition of energy conservation improvement.

(f) The commissioner shall consider and may require a public utility to undertake an energy conservation program suggested by an outside source, including a political subdivision, a nonprofit corporation, or community organization.

(g) A public utility, a political subdivision, or a nonprofit or community organization that has suggested an energy conservation program, the attorney general acting on behalf of consumers and small business interests, or a public utility customer that has suggested an energy conservation program and is not represented by the attorney general under section 8.33 may petition the commission to modify or revoke a department decision under this section, and the commission may do so if it determines that the energy conservation program is not cost-effective, does not adequately address the residential conservation improvement needs of low-income persons, has a long-range negative effect on one or more classes of customers, or is otherwise not in the public interest. The commission shall reject a petition that, on its face, fails to make a reasonable argument that an energy conservation program is not in the public interest.

(h) The commissioner may order a public utility to include, with the filing of the public utility's annual status report, the results of an independent audit of the public utility's conservation improvement programs and expenditures performed by the department or an auditor with experience in the provision of energy conservation and energy efficiency services approved by the commissioner and chosen by the public utility. The audit must specify the energy savings or increased efficiency in the use of energy within the service territory of the public utility that is the result of the public utility's spending and investments. The audit must evaluate the cost-effectiveness of the public utility's conservation programs.

(i) The energy conservation and optimization plan of each public utility subject to this section must include activities to improve energy efficiency in public schools served by the utility. As applicable to each public utility, at a minimum the activities must include programs to increase the efficiency of the school's lighting and heating and cooling systems, and to provide for building recommissioning, building operator training, and opportunities to educate students, teachers, and staff regarding energy efficiency measures implemented at the school.

(j) The commissioner may require investments or spending greater than the amounts proposed in a plan filed under this subdivision or section 216C.17 for a public utility whose most recent advanced forecast required under section 216B.2422 projects a peak demand deficit of 100 megawatts or more within five years under midrange forecast assumptions.

(k) A public utility filing a conservation and optimization plan that includes an efficient fuel-switching program to achieve the utility's energy savings goal must, as part of the filing, demonstrate by a comparison of greenhouse gas emissions between the fuels that the requirements of subdivisions 11 or 12 are met, as applicable, using a full fuel-cycle energy analysis.

Subd. 2a. **Energy and conservation account.**

The energy and conservation account is established in the special revenue fund in the state treasury. The commissioner must deposit money assessed or contributed under subdivisions 1d, 1e, 1f, and 7 in the state treasury and credit it to the energy and conservation account in the special revenue fund. Money in the account is appropriated to the commissioner for the purposes of subdivisions 1d, 1e, 1f, and 7. Interest on money in the account accrues to the account.

Subd. 2b. **Recovery of expenses.**

(a) The commission shall allow a public utility to recover expenses resulting from an energy conservation and optimization plan approved by the department under this section and contributions and assessments to the energy and conservation account, unless the recovery would be inconsistent with a financial incentive proposal approved by the commission.

(b) A public utility may file annually, or the Public Utilities Commission may require the public utility to file, and the commission may approve, rate schedules containing provisions for the automatic adjustment of charges for utility service in direct relation to changes in the expenses of the public utility for real and personal property taxes, fees, and permits, the amounts of which the public utility cannot control. A public utility is eligible to file for adjustment for real and personal property taxes, fees, and permits under this subdivision only if, in the year previous to the year in which it files for adjustment, it has spent or invested at least 1.75 percent of its gross revenues from provision of electric service, excluding gross operating revenues from electric service provided in the state to large electric customer facilities for which the commissioner has issued an exemption under subdivision 1a, paragraph (b), and 0.6 percent of its gross revenues from provision of gas service, excluding gross operating revenues from gas services provided in the state to large electric customer facilities for which the commissioner has issued an exemption under subdivision 1a, paragraph (b), for that year for energy conservation improvements under this section.

Subd. 2c.

MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 3. **Ownership of preweatherization measure or energy conservation improvement.**

(a) A preweatherization measure or energy conservation improvement made to or installed in a building in accordance with this section, except systems owned by a public utility and designed to turn off, limit, or vary the delivery of energy, are the exclusive property of the owner of the building except to the extent that the improvement is subjected to a security interest in favor of the public utility in case of a loan to the building owner.

(b) A public utility has no liability for loss, damage or injury caused directly or indirectly by a preweatherization measure or energy conservation improvement except for negligence by the utility in purchasing, installing, or modifying a preweatherization measure or energy conservation improvement.

Subd. 4.

MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 5. **Efficient lighting program.**

(a) Each public utility and consumer-owned utility that provides electric service to retail customers and is subject to subdivision 1c or section 216B.2403 shall include as part of its conservation improvement activities a program to strongly encourage the use of LEDs. The program must include at least a public information campaign to encourage use of LEDs and proper management of spent lamps and LEDs by all customer classifications.

(b) A public utility that provides electric service at retail to 200,000 or more customers shall establish, either directly or through contracts with other persons, including lamp manufacturers, distributors, wholesalers, and retailers and local government units, a system to collect for delivery to a reclamation or recycling facility spent fluorescent and high-intensity discharge lamps from households and from small businesses as defined in section 645.445 that generate an average of fewer than ten spent lamps per year.

(c) A collection system must include establishing reasonably convenient locations for collecting spent lamps from households and financial incentives sufficient to encourage spent lamp generators to take the lamps to the collection locations. Financial incentives may include coupons for purchase of new LEDs, a cash back system, or any other financial incentive or group of incentives designed to collect the maximum number of spent lamps from households and small businesses that is reasonably feasible.

(d) A public utility that provides electric service at retail to fewer than 200,000 customers or a consumer-owned utility that provides electric service at retail to customers may establish a collection system under paragraphs (b) and (c) as part of conservation improvement activities required under this section.

(e) The commissioner of the Pollution Control Agency may not, unless clearly required by federal law, require a public utility or consumer-owned utility that establishes a household fluorescent and high-intensity discharge lamp collection system under this section to manage the lamps as hazardous waste as long as the lamps are managed to avoid breakage and are delivered to a recycling or reclamation facility that removes mercury and other toxic materials contained in the lamps prior to placement of the lamps in solid waste.

(f) If a public utility or consumer-owned utility contracts with a local government unit to provide a collection system under this subdivision, the contract must provide for payment to the local government unit of all the unit's incremental costs of collecting and managing spent lamps.

(g) All the costs incurred by a public utility or consumer-owned utility to promote the use of LEDs and to collect LEDs under this subdivision are conservation improvement spending under this section.

(h) For the purposes of this subdivision, "LED" means a light-emitting diode bulb or lighting product.

Subd. 5a. **Qualifying solar energy project.**

(a) A utility or association may include in its conservation plan programs for the installation of qualifying solar energy projects as defined by section 216B.2411 to the extent of the spending allowed for generation projects by section 216B.2411. The cost-effectiveness of a qualifying solar energy project may be determined by a different standard than for other energy conservation improvements under this section if the commissioner determines it is in the public interest to do so to encourage solar energy projects. Energy savings from qualifying solar energy projects may not be counted toward the minimum energy-savings goal of at least one percent for energy conservation improvements required under subdivision 1c, but may, if the conservation plan is approved:

(1) be counted toward energy savings above that minimum percentage; and

(2) be eligible for a performance incentive under section 216B.16, subdivision 6c, or 216B.241, subdivision 2c, that is distinct from the incentive for energy conservation and is based on the competitiveness and cost-effectiveness of solar projects in relation to other potential solar projects available to the utility.

(b) Qualifying solar energy projects may not be considered when establishing demand-side management targets under section 216B.2422, 216B.243, or any other section of this chapter.

Subd. 5b. **Biomethane purchases.**

(a) A natural gas utility may include in its conservation plan purchases of biomethane, and may use up to five percent of the total amount to be spent on energy conservation improvements under this section for that purpose. The cost-effectiveness of biomethane purchases may be determined by a different standard than for other energy conservation improvements under this section if the commissioner determines that doing so is in the public interest in order to encourage biomethane purchases. Energy savings from purchasing biomethane may not be counted toward the minimum energy-savings goal of at least one percent for energy conservation improvements required under subdivision 1c, but may, if the conservation plan is approved:

(1) be counted toward energy savings above that minimum percentage; and

(2) be considered when establishing performance incentives under subdivision 2c.

(b) For the purposes of this subdivision, "biomethane" means biogas produced through anaerobic digestion of biomass, gasification of biomass, or other effective conversion processes, that is cleaned and purified into biomethane that meets natural gas utility quality specifications for use in a natural gas utility distribution system.

Subd. 5c. **Large solar electric generating plant.**

(a) For the purpose of this subdivision:

(1) "project" means a solar electric generation project consisting of arrays of solar photovoltaic cells with a capacity of up to two megawatts located on the site of a closed landfill in Olmsted County owned by the Minnesota Pollution Control Agency; and

(2) "cooperative electric association" means a generation and transmission cooperative electric association that has a member distribution cooperative association to which it provides wholesale electric service in whose service territory a project is located.

(b) A cooperative electric association may elect to count all of its purchases of electric energy from a project toward only one of the following:

(1) its energy-savings goal under subdivision 1c; or

(2) its energy objective or standard under section 216B.1691.

(c) A cooperative electric association may include in its conservation plan purchases of electric energy from a project. The cost-effectiveness of project purchases may be determined by a different standard than for other energy conservation improvements under this section if the commissioner determines that doing so is in the public interest in order to encourage solar energy. The kilowatt hours of solar energy purchased by a cooperative electric association from a project may count for up to 33 percent of its one percent savings goal under subdivision 1c or up to 22 percent of its 1.5 percent savings goal under that subdivision. Expenditures made by a cooperative association for the purchase of energy from a project may not be used to meet the revenue expenditure requirements of subdivisions 1a and 1b.

Subd. 5d. **On-bill repayment programs.**

(a) For the purposes of this subdivision:

(1) "utility" means a public utility, municipal utility, or cooperative electric association subject to subdivision 1c that provides electric or natural gas service to retail customers; and

(2) "on-bill repayment program" means a program in which a utility collects on a customer's bill repayment of a loan to the customer by an eligible lender to finance the customer's investment in eligible energy conservation or renewable energy projects, and remits loan repayments to the lender.

(b) A utility may include as part of its conservation improvement plan an on-bill repayment program to enable a customer to finance eligible projects with installment loans originated by an eligible lender. An eligible project is one that is either an energy conservation improvement, or a project installed on the customer's site that uses an eligible renewable energy source as that term is defined in section 216B.2411, subdivision 2, paragraph (b), but does not include mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste. An eligible renewable energy source also includes solar thermal technology that collects the sun's radiant energy and uses that energy to heat or cool air or water, and meets the requirements of section 216C.25. To be an eligible lender, a lender must:

(1) have a federal or state charter and be eligible for federal deposit insurance;

(2) be a government entity, including an entity established under chapter 469, that has authority to provide financial assistance for energy efficiency and renewable energy projects;

(3) be a joint venture by utilities established under section 452.25; or

(4) be licensed, certified, or otherwise have its lending activities overseen by a state or federal government agency.

The commissioner must allow a utility broad discretion in designing and implementing an on-bill repayment program, provided that the program complies with this subdivision.

(c) A utility may establish an on-bill repayment program for all customer classes or for a specific customer class.

(d) A public utility that implements an on-bill repayment program under this subdivision must enter into a contract with one or more eligible lenders that complies with the requirements of this subdivision and contains provisions addressing capital commitments, loan origination, transfer of loans to the public utility for on-bill repayment, and acceptance of loans returned due to delinquency or default.

(e) A public utility's contract with a lender must require the lender to comply with all applicable federal and state laws, rules, and regulations related to lending practices and consumer protection; to conform to reasonable and prudent lending standards; and to provide businesses that sell, maintain, and install eligible projects the ability to participate in an on-bill repayment program under this subdivision on a nondiscriminatory basis.

(f) A public utility's contract with a lender may provide:

(1) for the public utility to purchase loans from the lender with a condition that the lender must purchase back loans in delinquency or default; or

(2) for the lender to retain ownership of loans with the public utility servicing the loans through on-bill repayment as long as payments are current.

The risk of default must remain with the lender. The lender shall not have recourse against the public utility except in the event of negligence or breach of contract by the utility.

(g) If a public utility customer makes a partial payment on a utility bill that includes a loan installment, the partial payment must be credited first to the amount owed for utility service, including taxes and fees. A public utility may not suspend or terminate a customer's utility service for delinquency or default on a loan that is being serviced through the public utility's on-bill repayment program.

(h) An outstanding balance on a loan being repaid under this subdivision is a financial obligation only of the customer who is signatory to the loan, and not to any subsequent customer occupying the property associated with the loan. If the public utility purchases loans from the lender as authorized under paragraph (f), clause (1), the public utility must return to the lender a loan not repaid when a customer borrower no longer occupies the property.

(i) Costs incurred by a public utility under this subdivision are recoverable as provided in section 216B.16, subdivision 6b, paragraph (c), including reasonable incremental costs for billing system modifications necessary to implement and operate an on-bill repayment program and for ongoing costs to operate the program. Costs in a plan approved by the commissioner may be counted toward a utility's conservation spending requirements under subdivisions 1a and 1b.

Energy savings from energy conservation improvements resulting from this section may be counted toward satisfying a utility's energy-savings goals under subdivision 1c.

(j) This subdivision does not require a utility to terminate or modify an existing financing program and does not prohibit a utility from establishing an on-bill financing program in which the utility provides the financing capital.

(k) A municipal utility or cooperative electric association that implements an on-bill repayment program shall design the program to address the issues identified in paragraphs (d) through (h) as determined by the governing board of the utility or association.

Subd. 6.

MS 2008 [Expired]

Subd. 7.**Low-income programs.**

(a) The commissioner shall ensure that each public utility subject to subdivision 1c provides energy conservation and efficient fuel-switching programs to low-income households. When approving spending and energy-savings goals for low-income programs, the commissioner shall consider historic spending and participation levels, energy savings achieved by low-income programs, and the number of low-income persons residing in the utility's service territory. Beginning January 1, 2022, a public utility furnishing gas service must spend at least one percent of its most recent three-year average gross operating revenue from residential customers in the state on low-income programs. A public utility that furnishes electric service must spend at least 0.4 percent of its gross operating revenue from residential customers in the state on low-income programs. Beginning in 2024, a public utility that furnishes electric service must spend 0.6 percent of the public utility's gross operating revenue from residential customers in the state on low-income programs.

(b) To meet the requirements of paragraph (a), a public utility may contribute money to the energy and conservation account established under subdivision 2a. An energy conservation improvement plan must state the amount, if any, of low-income energy conservation improvement funds the public utility will contribute to the energy and conservation account. Contributions must be remitted to the commissioner by February 1 of each year.

(c) The commissioner shall establish low-income energy conservation programs to utilize contributions made to the energy and conservation account under paragraph (b). In establishing low-income programs, the commissioner shall consult political subdivisions, utilities, and nonprofit and community organizations, especially organizations providing energy and weatherization assistance to low-income households. Contributions made to the energy and conservation account under paragraph (b) must provide programs for low-income households, including low-income renters, in the service territory of the public utility providing the money. The commissioner shall record and report expenditures and energy savings achieved as a result of low-income programs funded through the energy and conservation account in the report required under subdivision 1c, paragraph (f). The commissioner may contract with a political subdivision, nonprofit or community organization, public utility, or consumer-owned utility to implement low-income programs funded through the energy and conservation account.

(d) A public utility may petition the commissioner to modify its required spending under paragraph (a) if the utility and the commissioner have been unable to expend the amount required under paragraph (a) for three consecutive years.

(e) Representatives of each public utility must participate in the stakeholder group on multifamily building eligibility for low-income energy conservation programs, as provided under section 216B.2403, subdivision 5, paragraph (e). Notwithstanding the definition of low-income household under section 216B.2402, a public utility may apply the most recent guidelines for eligibility of multifamily buildings to participate in low-income energy conservation programs published by the commissioner under section 216B.2403, subdivision 5, paragraph (e).

(f) Up to 15 percent of a public utility's spending on low-income programs may be spent on preweatherization measures. A public utility is prohibited from claiming energy savings from preweatherization measures toward the public utility's energy savings goal.

(g) The commissioner must, by order, establish a list of preweatherization measures eligible for inclusion in low-income programs no later than March 15, 2022.

(h) A public utility may elect to contribute money to the Healthy AIR account under section 216B.2403, subdivision 5, paragraph (h), to provide preweatherization measures to households eligible for weatherization assistance under section 216C.264. Remediation activities must be executed in conjunction with federal weatherization assistance program services. Money contributed to the account counts toward: (1) the minimum low-income spending requirement in paragraph (a); and (2) the cap on preweatherization measures under paragraph (f).

(i) The 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.

Subd. 8. **Assessment.**

The commission or department may assess public utilities subject to this section to carry out the purposes of subdivisions 1d, 1e, and 1f. An assessment under this subdivision must be proportionate to a public utility's gross operating revenue from sales of gas or electric service within Minnesota during the last calendar year, as applicable. Assessments made under this subdivision are not subject to the cap on assessments provided by section 216B.62, or any other law.

Subd. 9. **Building performance standards; Sustainable Building 2030.**

(a) The purpose of this subdivision is to establish cost-effective energy-efficiency performance standards for new and substantially reconstructed commercial, industrial, and institutional buildings that can significantly reduce carbon dioxide emissions by lowering energy use in new and substantially reconstructed buildings. For the purposes of this subdivision, the establishment of these standards may be referred to as Sustainable Building 2030.

(b) The commissioner shall contract with the Center for Sustainable Building Research at the University of Minnesota to coordinate development and implementation of energy-efficiency performance standards, strategic planning, research, data analysis, technology transfer, training, and other activities related to the purpose of Sustainable Building 2030. The commissioner and the Center for Sustainable Building Research shall, in consultation with utilities, builders, developers, building operators, and experts in building design and technology, develop a Sustainable Building 2030 implementation plan that must address, at a minimum, the following issues:

(1) training architects to incorporate the performance standards in building design;

(2) incorporating the performance standards in utility conservation improvement programs; and

(3) developing procedures for ongoing monitoring of energy use in buildings that have adopted the performance standards.

The plan must be submitted to the chairs and ranking minority members of the senate and house of representatives committees with primary jurisdiction over energy policy by July 1, 2009.

(c) Sustainable Building 2030 energy-efficiency performance standards must be firm, quantitative measures of total building energy use and associated carbon dioxide emissions per square foot for different building types and uses, that allow for accurate determinations of a building's conformance with a performance standard. Performance standards must address energy use by electric vehicle charging infrastructure in or adjacent to buildings as that infrastructure begins to be made widely available. The energy-efficiency performance standards must be updated every three or five years to incorporate all cost-effective measures. The performance standards must reflect the reductions in carbon dioxide emissions per square foot resulting from actions taken by utilities to comply with the renewable energy standards in section 216B.1691. The performance standards should be designed to achieve reductions equivalent to the following reduction schedule, measured against energy consumption by an average building in each applicable building sector in 2003: (1) 60 percent in 2010; (2) 70 percent in 2015; (3) 80 percent in 2020; and (4) 90 percent in 2025. A performance standard must not be established or increased absent a conclusive engineering analysis that it is cost-effective based upon established practices used in evaluating utility conservation improvement programs.

(d) The annual amount of the contract with the Center for Sustainable Building Research is up to $500,000. The Center for Sustainable Building Research shall expend no more than $150,000 of this amount each year on administration, coordination, and oversight activities related to Sustainable Building 2030. The balance of contract funds must be spent on substantive programmatic activities allowed under this subdivision that may be conducted by the Center for

Sustainable Building Research and others, and for subcontracts with not-for-profit energy organizations, architecture and engineering firms, and other qualified entities to undertake technical projects and activities in support of Sustainable Building 2030. The primary work to be accomplished each year by qualified technical experts under subcontracts is the development and thorough justification of recommendations for specific energy-efficiency performance standards. Additional work may include:

(1) research, development, and demonstration of new energy-efficiency technologies and techniques suitable for commercial, industrial, and institutional buildings;

(2) analysis and evaluation of practices in building design, construction, commissioning and operations, and analysis and evaluation of energy use in the commercial, industrial, and institutional sectors;

(3) analysis and evaluation of the effectiveness and cost-effectiveness of Sustainable Building 2030 performance standards, conservation improvement programs, and building energy codes;

(4) development and delivery of training programs for architects, engineers, commissioning agents, technicians, contractors, equipment suppliers, developers, and others in the building industries; and

(5) analysis and evaluation of the effect of building operations on energy use.

(e) The commissioner shall require utilities to develop and implement conservation improvement programs that are expressly designed to achieve energy efficiency goals consistent with the Sustainable Building 2030 performance standards. These programs must include offerings of design assistance and modeling, financial incentives, and the verification of the proper installation of energy-efficient design components in new and substantially reconstructed buildings. A utility's design assistance program must consider the strategic planting of trees and shrubs around buildings as an energy conservation strategy for the designed project. A utility making an expenditure under its conservation improvement program that results in a building meeting the Sustainable Building 2030 performance standards may claim the energy savings toward its energy-savings goal established in subdivision 1c.

(f) The commissioner shall report to the legislature every three years, beginning January 15, 2010, on the cost-effectiveness and progress of implementing the Sustainable Building 2030 performance standards and shall make recommendations on the need to continue the program as described in this section.

Subd. 10.

MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 11. **Programs for efficient fuel-switching improvements; electric utilities.**

(a) A public utility providing electric service at retail may include in the plan required under subdivision 2 programs to implement efficient fuel-switching improvements or combinations of energy conservation improvements, fuel-switching improvements, and load management. For each program, the public utility must provide a proposed budget, an analysis of the program's cost-effectiveness, and estimated net energy and demand savings.

(b) The department may approve proposed programs for efficient fuel-switching improvements if the department determines the improvements meet the requirements of paragraph (d). For fuel-switching improvements that require the deployment of electric technologies, the department must also consider whether the fuel-switching improvement can be operated in a manner that facilitates the integration of variable renewable energy into the electric system. The net benefits from an efficient fuel-switching improvement that is integrated with an energy efficiency program approved under this section may be counted toward the net benefits of the energy efficiency program, if the department determines the primary purpose and effect of the program is energy efficiency.

(c) A public utility may file a rate schedule with the commission that provides for annual cost recovery of reasonable and prudent costs to implement and promote efficient fuel-switching programs. The commission may not approve a financial incentive to encourage efficient fuel-switching programs operated by a public utility providing electric service.

(d) A fuel-switching improvement is deemed efficient if, applying the technical criteria established under section 216B.241, subdivision 1d, paragraph (e), the improvement meets the following criteria, relative to the fuel that is being displaced:

(1) results in a net reduction in the amount of source energy consumed for a particular use, measured on a fuel-neutral basis;

(2) results in a net reduction of statewide greenhouse gas emissions as defined in section 216H.01, subdivision 2, over the lifetime of the improvement. For an efficient fuel-switching improvement installed by an electric utility, the reduction in emissions must be measured based on the hourly emission profile of the electric utility, using the hourly emissions profile in the most recent resource plan approved by the commission under section 216B.2422;

(3) is cost-effective, considering the costs and benefits from the perspective of the utility, participants, and society; and

(4) is installed and operated in a manner that improves the utility's system load factor.

(e) For purposes of this subdivision, "source energy" means the total amount of primary energy required to deliver energy services, adjusted for losses in generation, transmission, and distribution, and expressed on a fuel-neutral basis.

Subd. 12. **Programs for efficient fuel-switching improvements; natural gas utilities.**

(a) As part of a public utility's plan filed under subdivision 2, a public utility that provides natural gas service to Minnesota retail customers may propose one or more programs to install electric technologies that reduce the consumption of natural gas by the utility's retail customers as an energy conservation improvement. The commissioner may approve a proposed program if the commissioner, applying the technical criteria developed under section 216B.241, subdivision 1d, paragraph (e), determines that:

~~(1)~~ the electric technology to be installed meets the criteria established under section 216B.241, subdivision 11, paragraph (d), clauses (1) and (2); and

(2) the program is cost-effective, considering the costs and benefits to ratepayers, the utility, participants, and society.

(b) If a program is approved by the commission under this subdivision, the public utility may count the program's energy savings toward its energy savings goal under section 216B.241, subdivision 1c. Notwithstanding section 216B.2402, subdivision 4, efficient fuel-switching achieved through programs approved under this subdivision is energy conservation.

(c) A public utility may file rate schedules with the commission that provide annual cost-recovery for programs approved by the department under this subdivision, including reasonable and prudent costs to implement and promote the programs.

(d) The commission may approve, modify, or reject a proposal made by the department or a utility for an incentive plan to encourage efficient fuel-switching programs approved under this subdivision, applying the considerations established under section 216B.16, subdivision 6c, paragraphs (b) and (c). The commission may approve a financial incentive mechanism that is calculated based on the combined energy savings and net benefits that the commission has determined have been achieved by a program approved under this subdivision, provided the commission determines that the financial incentive mechanism is in the ratepayers' interest.

(e) A public utility is not eligible for a financial incentive for an efficient fuel-switching program under this subdivision in any year in which the utility achieves energy savings below one percent of gross annual retail energy sales, excluding savings achieved through fuel-switching programs.

Subd. 13. **Cost-effective load management programs.**

(a) A public utility may include in the utility's plan required under subdivision 2 programs to implement load management activities, or combinations of energy conservation improvements, fuel-switching improvements, and load management activities. For each program the public utility must provide a proposed budget, cost-effectiveness analysis, and estimated net energy and demand savings.

~~(b)~~ The commissioner may approve a proposed program if the commissioner determines the program is cost-effective, considering the costs and benefits to ratepayers, the utility, participants, and society.

(c) A public utility providing retail electric service to Minnesota customers may file rate schedules with the commission that provide for annual cost recovery of reasonable and prudent costs incurred to implement and promote cost-effective load management programs approved by the department under this subdivision.

(d) The commission may approve, modify, or reject a proposal made by the department or a public utility for an incentive plan to encourage investments in load management programs. The commission may approve a proposal that the commission determines:

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

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

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

(e) The commission may structure an incentive plan to encourage cost-effective load management programs as an asset on which a public utility earns a rate of return at a level the commission determines is reasonable and in the public interest.

(f) 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 216B.16, subdivision 6c, if the department determines the primary purpose of the load management activity is energy efficiency.

(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 programs.

(h) The commission may include net benefits from a particular load management activity in an incentive plan under this subdivision or section 216B.16, subdivision 6c, but not both.

Subd. 14. **Minnesota efficient technology accelerator.**

(a) A nonprofit organization with extensive experience implementing energy efficiency programs in Minnesota and conducting efficient technology research in the state may file a proposal with the commissioner of commerce for a program to accelerate deployment and reduce the cost of emerging and innovative efficient technologies and approaches and lead to lower energy costs for Minnesota consumers. Accelerator activities include strategic initiatives with technology manufacturers to improve the efficiency and performance of products, as well as with equipment installers and other key actors in the technology supply chain. Benefits of activities expected from the accelerator include cost effective energy savings for Minnesota utilities, bill savings for Minnesota utility consumers, enhanced employment opportunities in Minnesota, and avoidance of greenhouse gas emissions.

(b) Prior to developing and filing a proposal, the nonprofit must submit to the commissioner of commerce a notice of intent to file a proposal under this subdivision. The notice of intent must describe the nonprofit's qualifications and eligibility to file a proposal under this subdivision. The commissioner must review the notice of intent and issue a determination of eligibility within 30 days if the commissioner determines the nonprofit meets the required qualifications.

(c) Upon receiving the determination by the commissioner under paragraph (b), the nonprofit organization must engage with interested stakeholders on at least the following attributes required of a program proposal under this subdivision:

(1) a proposed budget and operational guidelines for the accelerator;

(2) a proposed energy savings attribution, evaluation, and allocation methodology that includes a method for calculating net benefits from activities under the program. Energy savings

and net benefits from activities under the program must be allocated to participating utilities and be considered when determining cost-effectiveness of achieved energy savings and related incentives;

(3) a process to ensure that the technologies that are selected for the program benefit electric and natural gas utility customers in proportion to the funds each utility sector contributes to the program and address residential, commercial, and industrial building energy use; and

(4) a process for identifying and tracking performance metrics for each technology selected against which progress can be measured, including one or more methods for evaluating cost-effectiveness.

(d) No earlier than 180 days from the date of the commissioner's eligibility determination under paragraph (b), the nonprofit may file a program proposal under this subdivision. The filing must describe how the proposal addresses each of the required attributes listed in paragraph (c), clauses (1) to (4), and how the proposal addresses the recommendations and concerns identified in the stakeholder engagement process required under paragraph (c).

(e) Within ten days of receiving the proposal, the commissioner must provide public notice of the proposal and solicit feedback from interested parties for a period of not less than ten business days.

(f) Within 90 days of the filing of the proposal, the commissioner must approve, modify, or reject a proposal under this subdivision. In making a determination, the commissioner must consider public comments, the expected costs and benefits of the program from the perspectives of ratepayers, the participating utilities, and society, and the expected costs and benefits relative to other energy conservation programming authorized under this section.

(g) The initial program term may be up to five years. At the request of the nonprofit, the commissioner may renew a program approved under paragraph (d) for up to five years at a time. The nonprofit must submit to the commissioner a request to renew the program no later than 180 days prior to the end of the term of the program approved or renewed under this subdivision. When making a request to renew and determination on renewal, the nonprofit and commissioner must follow the process established under this subdivision, except that a qualified nonprofit is not required to seek eligibility under paragraph (b).

(h) Upon approval, each public utility with over 30,000 customers must participate in the program and contribute to the approved budget of the program by depositing annually in the energy and conservation account under subdivision 2a an amount that is proportional to the utility's gross operating revenue from sales of gas or electric service in Minnesota, excluding revenues from large customer facilities exempted under subdivision 1a. A participating utility must not be required to contribute more than the following percentages of the utility's spending approved by the commission in the plan filed under subdivision 2: (1) two percent in the program's initial two years; (2) 3.5 percent in the program's third and fourth years; and (3) five percent thereafter. Other utilities may elect to participate in the accelerator program. Costs incurred by a public utility under this subdivision are recoverable under subdivision 2b as an assessment to the energy and conservation account. Amounts provided to the account under this subdivision are not subject to the cap on assessments in section 216B.62. The commissioner may make expenditures from the account for the purposes of this subdivision, including amounts necessary to cover administrative costs incurred by the department under this subdivision. Costs for research projects under this subdivision that the commissioner determines may be duplicative to projects that would be eligible for funding under subdivision 1e, paragraph (a), may be deducted from the assessment under subdivision 1e for utilities participating in the accelerator.

(i) The commissioner must not approve more than one program to be implemented or in operation at any given time under this subdivision.

(j) At least once during the term of a program that is approved or renewed, the commissioner must contract for an independent review of the program to determine if it meets the objectives and requirements of this section and any criteria established by the department as a condition of approval. The review may not be conducted by an entity or person that acted as a stakeholder or interested party, or otherwise participated in the program preparation, filing, or review process. Upon completion, the reviewer must prepare a report detailing findings and recommendations, and the commissioner must transmit a copy of the report to the chairs and ranking minority members of the house of representatives and senate committees with jurisdiction over energy policy. Money required to conduct the review and prepare the report must be deducted from the total contribution amount under paragraph (h).

V. PUC Statutes

Rates, MN Statute 216B.03, REASONABLE RATE.

Every rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers. To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05. Any doubt as to reasonableness should be resolved in favor of the consumer. For rate-making purposes a public utility may treat two or more municipalities served by it as a single class wherever the populations are comparable in size or the conditions of service are similar.

IRPs, MN Statute 216B.2422, RESOURCE PLANNING; RENEWABLE ENERGY.

Subdivision 1. **Definitions.**

(a) For purposes of this section, the terms defined in this subdivision have the meanings given them.

(b) "Utility" means an entity with the capability of generating 100,000 kilowatts or more of electric power and serving, either directly or indirectly, the needs of 10,000 retail customers in Minnesota. Utility does not include federal power agencies.

(c) "Renewable energy" means electricity generated through use of any of the following resources:

(1) wind;

(2) solar;

(3) geothermal;

(4) hydro;

(5) trees or other vegetation;

(6) landfill gas; or

(7) predominantly organic components of wastewater effluent, sludge, or related by-products from publicly owned treatment works, but not including incineration of wastewater sludge.

(d) "Resource plan" means a set of resource options that a utility could use to meet the service needs of its customers over a forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs. These resource options include using, refurbishing, and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy conservation.

(e) "Refurbish" means to rebuild or substantially modify an existing electricity generating resource of 30 megawatts or greater.

Subd. 2. **Resource plan filing and approval.**

A utility shall file a resource plan with the commission periodically in accordance with rules adopted by the commission. The commission shall approve, reject, or modify the plan of a public utility, as defined in section 216B.02, subdivision 4, consistent with the public interest. In the resource plan proceedings of all other utilities, the commission's order shall be advisory and the order's findings and conclusions shall constitute prima facie evidence which may be rebutted by substantial evidence in all other proceedings. With respect to utilities other than those defined in section 216B.02, subdivision 4, the commission shall consider the filing requirements and decisions in any comparable proceedings in another jurisdiction. As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.

Subd. 2a. **Historical data and advance forecast.**

Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.

Subd. 2b.**Optional integrated resource plan compliance for certain cooperatives.**

For the purposes of this subdivision, a "cooperative" means a generating and transmission cooperative electric association that has at least 80 percent of its member distribution cooperatives located outside of Minnesota and that provides less than four percent of the electricity annually sold at retail in the state of Minnesota. A cooperative may, in lieu of filing a resource plan under subdivision 2, elect to file a report to the commission under this subdivision. The report must include projected demand levels for the next 15 years and generation resources to meet any projected generation deficiencies. To supply the information required in a report under this subdivision, a cooperative may use reports submitted under section 216C.17, subdivision 2, reports to regional reliability organizations, or similar reports submitted to other state utility commissions. A report must be submitted annually by July 1, but the commission may extend the time if it finds the extension in the public interest. Presentation of the annual report shall be done in accordance with procedures established by the commission. Data in a report under this subdivision may be aggregate data and need not be separately reported for individual distribution cooperative members of the cooperative. The commission may take whatever action in response to a report under this subdivision that it could take with respect to a report by a cooperative under subdivision 2.

Subd. 2c. **Long-range emission reduction planning.**

Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.

Subd. 3. **Environmental costs.**

(a) The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.

(b) The commission shall establish interim environmental cost values associated with each method of electricity generation by March 1, 1994. These values expire on the date the commission establishes environmental cost values under paragraph (a).

Subd. 4. **Preference for renewable energy facility.**

The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f.

Subd. 5. **Bidding; exemption from certificate of need proceeding.**

(a) A utility may select resources to meet its projected energy demand through a bidding process approved or established by the commission. A utility shall use the environmental cost estimates determined under subdivision 3 in evaluating bids submitted in a process established under this subdivision.

(b) Notwithstanding any other provision of this section, if an electric power generating plant, as described in section 216B.2421, subdivision 2, clause (1), is selected in a bidding process approved or established by the commission, a certificate of need proceeding under section 216B.243 is not required.

(c) A certificate of need proceeding is also not required for an electric power generating plant that has been selected in a bidding process approved or established by the commission, or such other selection process approved by the commission, to satisfy, in whole or in part, the wind power mandate of section 216B.2423 or the biomass mandate of section 216B.2424.

Subd. 6. **Consolidation of resource planning and certificate of need.**

A utility shall indicate in its resource plan whether it intends to site or construct a large energy facility. If the utility's resource plan includes a proposed large energy facility and construction of that facility is likely to begin before the utility files its next resource plan, the commission shall conduct the resource plan proceeding consistent with the requirements of section 216B.243 with respect to the proposed facility. If the commission approves the proposed facility in the resource plan, a separate certificate of need proceeding is not required.

Appendix D – Cost-Effectiveness Advisory Committee Preliminary Votes on Non-Utility System Impacts to Include in Primary Test and Maps to Policy (From Proposed Decision)

Type	Impact	Yes	No	Maybe	Maps to Policy?
Participant	Participant costs	7	1	4	✓
	Participant benefits	5	1	6	✓
Other Fuels	Other fuels	9	0	3	✓
Water	Water	7	3	2	▪
Low-Income	Low-income	7	1	3	✓
Societal	GHG emissions	12	0	0	✓
	Criteria air emissions	6	0	5	✓
	Solid waste	1	5	6	✓
	Water impacts	4	3	5	
	Land impacts	1	5	6	
	Other environmental	1	3	8	✓
	Public health	3	2	7	
	Macroeconomic	1	3	7	✓
	Energy security	6	3	3	✓
	Energy equity	5	1	6	✓
	Resilience	4	1	6	✓

The color coding corresponds to the number of "votes" each category received from members with green signifying more votes and red signifying fewer votes

Appendix E – IOU List of Utility System Impacts Currently Included in Their CIP Cost-Effectiveness Tests (From Proposed Decision)

Electric

Type	Impact	Minnesota Power	Otter Tail	Xcel
Generation	**Energy**	Yes	Yes	Marginal Energy
	Capacity	Yes	Yes	Peak Load Capacity
	Environmental Compliance		Yes, through IRP approval	Embedded in Energy and Capacity
	RPS Compliance		Yes, through IRP approval	Embedded in Energy and Capacity
	Market Price Effects		Yes	No, but could be included if marginal energy cost measured @ load w/o EE
	Ancillary Services		Yes	Yes, in Capacity
Transmission	**Capacity**	Yes	Yes	Yes
	Losses	Yes	Yes	Yes
Distribution	**Capacity**	Yes	Yes	Yes
	Losses	Yes	Yes	Yes
General	**Financial Incentives**	Yes	If customer rebates, then yes	Yes
	Program Administration	Yes	Yes	Yes
	Utility Performance Incentives		Yes	No – can be quantified in incentive mechanism
	Credit and Collections		No	No
	Risk		No	No
	Reliability		Part of IRP/IDP	No
	Resilience		Part of IRP/IDP	No

Gas

Type	Impact	CenterPoint	MERC	Xcel
Commodity / Supply	**Fuel**	Yes	Yes	Yes
	Capacity & Storage	Unsure, probably partially captured in commodity costs	Yes, insofar as this is captured in the PGA for the demand cost (input 4)	Yes
	Environmental Compliance	Unsure, probably partially captured in commodity costs	No. Env. damage factor represents the social cost of carbon.	Yes
	Market Price Effects	Unsure of definition		Maybe
Transportation	**Transportation**	If this is O&M then yes	No	No
Delivery	**Delivery**	If this is O&M then yes	No	No
General	**Financial Incentives**	Yes	No	Yes
	Program Administration	Yes	Yes	Yes
	Utility Performance Incentives	Shown in net benefits in status reports. Not used in BENCOST	Yes	No
	Credit and Collections	No	No	No
	Risk	No	No	No
	Reliability	No	No	No
	Resilience	No	No	No
Other (Specify)	**Non-energy benefits adder**		Yes	
	Variable O&M		Yes	
	Bill/Revenue impacts		Yes	
	Incremental measure costs		Yes	

Appendix F – Synapse Straw Proposal (From Proposed Decision)

Cost-Effectiveness Test for Minnesota Conservation Improvement Programs

Straw Proposal for the Primary Test

Prepared for the Minnesota Cost-Effectiveness Advisory Committee

June 8, 2022

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Contents

EXECUTIVE SUMMARY

Synapse Energy Economics, Inc. (Synapse) is assisting the Minnesota Department of Commerce (DOC) with guiding the Conservation Improvement Program (CIP) Cost-Effectiveness Advisory Committee (CAC) through *the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*[63] (NSPM for DERs) process to develop a primary cost effectiveness test for Minnesota through a series of workshops.

The goal of the workshops is to develop a primary jurisdiction-specific cost-effectiveness test for Minnesota, the MN Test, for use by the Investor-owned utilities (IOUs) in their upcoming 2024-2026 Triennial Plans. While the purpose of the workshops is to develop a test for assessing the cost-effectiveness of energy efficiency, the MN Test should ideally be applied to all types of DERs.

The workshops cover the NSPM for DERs five-step process for developing a primary test:

Step 1. Articulate Applicable Policy Goals.
Step 2. Include All Utility System Impacts.
Step 3. Decide Which Non-Utility System Impacts to Include.
Step 4. Ensure that Benefits and Costs are Properly Addressed.
Step 5. Establish Comprehensive, Transparent Documentation.

Each step in the process is guided by the eight principles of the NSPM for DERs:

Principle 1: Treat DERs as a Utility System Resource. DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.

Principle 2: Align with Policy Goals. Utilities invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the state's applicable policy goals and objectives.

Principle 3: Ensure Symmetry. Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.

Principle 4: Account for Relevant, Material Impacts. Cost-effectiveness tests should include all relevant (according to applicable policy goals) material impacts including those that are difficult to quantify or monetize.

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

Principle 5: Conduct Forward-Looking, Long-term, Incremental Analyses. Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.

Principle 6: Avoid Double-Counting Impacts. Cost-effectiveness analyses present a risk of double-counting benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double-counting.

Principle 7: Ensure Transparency. Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.

Principle 8: Conduct BCAs Separately from Rate Impact Analyses. Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses, and therefore should be conducted separately from rate impact analyses.[64]

Thus far, the CAC has discussed the first three-steps in the NSPM process over the course of two workshops. Based on verbal input from CAC stakeholders, written comments, and the draft list of applicable policy goals developed by the DOC, Synapse developed a MN Test straw proposal for stakeholder consideration.

The MN Test is intended to be the primary test. The purpose of a primary test is to inform whether an IOU's proposed investments in energy efficiency create more benefits than costs and therefore merit approval. The primary test is the main determinant of whether a program should be included in the Triennial Plan. Secondary tests can be developed to help enhance the overall understanding of energy efficiency impacts. The additional information from a secondary test can help to prioritize energy efficiency programs and to inform decisions regarding marginally cost-effective programs and allocation of resources. The secondary test is not intended to undermine the purpose of the primary test and may include a subset of the impacts included in the primary test or additional impacts.

Table 1 shows the impacts that we recommend be included the MN Test, based on our interpretation of the Minnesota policy goals and the stakeholder input to date. Stakeholders are encouraged to provide comments on this straw proposal to ensure it is consistent with their interpretation of Minnesota policy goals. Each impact will be discussed in more detail within the remainder of this report.

[64] NSPM for DERs, pg. iv.

Table 1 indicates which impacts should be included in the MN Test as the primary cost-effectiveness test for the IOUs next Triennial Plan. These impacts should be monetized for inclusion in future benefit-cost assessments to the extent practical. Even if an impact is deemed too difficult to quantify and monetize it should be included by other means. This can include discussing the potential positive or negative impacts in a qualitative manner or using proxies or percentage adders, which are discussed in more detail below.

Table 1. MN Test Straw Proposal

	Category	Impact	Include in MN Test
Utility System	Electric Utility System	All	✓
	Gas Utility System	All	✓
Non-Utility System	Other Fuels	Other Fuels	✓
	Water	Water	-
	Participant	Participant Costs	✓
		Participant Benefits	✓
	Low-Income	Low-Income	✓
Societal	Societal Impacts	Greenhouse Gas Emissions	✓
		Criteria Air Emissions	✓
		Solid Waste	Included in Other Environmental
		Water Impacts	Included in Other Environmental
		Land Impacts	Included in Other Environmental
		Other Environmental	✓
		Public Health	-
		Economic and Jobs	✓
		Energy Security	✓
		Energy Equity	✓
		Resilience	-

UTILITY SYSTEM IMPACTS

All Utility System Impacts Included

Step 2 of the NSPM for DERs indicates that al utility system impacts should be included in cost-effectiveness tests. Utility system impacts are defined as the elements of the electricity or gas system required to deliver service to utility customers. For electric utilities, this includes generation, transmission, distribution, and utility operations. For gas utilities, this includes transportation, delivery, fuel, and utility operations.

It is important to include all elements of utility system impacts in a cost-effectiveness test for several reasons. It allows for DERs like energy efficiency to be treated consistently with other utility resources and ensures that at a minimum the cost-effectiveness test will show whether total utility system costs are reduced or increased by the investment in energy efficiency.

Table 2 and Table 3 provide a list of the electric and gas utility system impacts for inclusion in the MN Test. Based on the comments submitted by the MN IOUs, some of the below impacts are not currently included in cost-effectiveness. It therefore may not be feasible for all new impacts to be quantified and monetized for inclusion on the MN Test for the upcoming Triennial Plan. However, this does not indicate that these impacts should not be included in the MN Test. Such impacts could be addressed through a proxy or adder or discussed qualitatively. How these impacts are valued should be the subject of future workshops.

Table 2. Proposed Electric Utility System Impacts

Category	Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load.
	Environmental Compliance	Actions to comply with environmental regulations. This can include compliance with federal regulations like the Clean Air Act or state or local greenhouse gas emissions mandates.
	Renewable Portfolio Standard Compliance	Actions to comply with renewable portfolio standards or clean energy standards.
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption.
	Ancillary Services	Services required to maintain electric grid stability and power quality (i.e., frequency regulation, voltage regulation, spinning reserves, and operating reserves).
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably.
	Transmission System Losses	Electricity lost through the transmission system.
Distribution	Distribution Costs	Maintaining the availability of the distribution system to transport electricity safely and reliably; includes capacity, O&M, voltage.
	Distribution System Losses	Electricity lost through the distribution system.
General	Program Incentives	Utility financial support to participants or other market actors; typically includes rebates, upstream payments, interest rate buy-down.
	Program Administration Costs	Utility outreach to trade allies, technical training, marketing, payments to third-party consultants, and administration and management of energy efficiency programs.
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of energy efficiency programs.
	Credit and Collection Costs	Utility costs associated with arrearages, disconnections, and reconnections.
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks.
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions.

Table 3. Proposed Gas Utility System Impacts

Category	Impact	Description
Commodity/ Supply	Fuel	Purchasing gas at specific locations on the gas system and the variable cost of getting the gas where, and when, it will be used.
	Capacity & Storage	The gas and storage capacity required to meet forecasted peak load.
	Environmental Compliance	Actions to comply with environmental regulations.
	Market Price Effects	The decrease (or increase) in wholesale prices as a result of reduced (or increased) customer consumption.
Transportation	Transportation	The transport of gas from delivery points located on interstate and intrastate pipelines to distribution utility city gate.
Delivery	Delivery	Delivery of gas from the city gate to retail customers.
General	Same as Electric Utility System Impacts	

Additional Guidance

Environmental Compliance

There was significant stakeholder discussion around the treatment of greenhouse gas (GHG) emissions, criteria air pollutants, and the regulatory cost of carbon as to whether these are utility system or societal impacts.

It is important that anything considered a regulatory cost or mandated cost be included as a utility system cost. If the cost of such regulations or mandates are currently or anticipated to be paid by ratepayers over the BCA study period, then it is considered a utility system cost. If the social cost of carbon (SCC) is also included as a societal benefit, the GHG and carbon values already included in the utility system costs should be subtracted out to avoid double counting.

Risk, Reliability, and Resilience

No parties oppose the inclusion of risk, reliability, and resilience impacts in the MN Test. However, the question for how to account for these impacts remains. Based on feedback from the CAC, the impacts of risk, reliability, and resilience may already be embedded in other utility system impacts through the Integrated Resource Plan (IRP) and Integrated Distribution Plan (IDP) process. For the sake of transparency, the utilities should document in which utility system impacts these are included and adjust definitions accordingly. If after review, these impacts are not included, they should be included individually within the appropriate utility system impact category.

NON-UTILITY SYSTEM IMPACTS

Policy goals

The decision for which non-utility system impacts to include should be based upon Minnesota's applicable policy goals.[65] As part of the CAC workshops, stakeholders submitted homework indicating whether the impacts of participant Impacts, other fuels, water, and low-income should be included in the primary test. The DOC and Synapse also reviewed applicable policy goals and mapped those to each impact. Based on these responses and discussions during the workshops, we propose the below non-utility system impacts for the straw proposal.

Participant Impacts

Participant impacts are those impacts pertaining to a utility customer that participates in a program. The decision to include participant impacts is a policy decision and should be based on the applicable policy goals of Minnesota. Based on the initial review of Minnesota policies, there is a relatively weak link to participants, primarily in relation to cost-effectiveness as described in Minn. Stat. § 216C.05, Subd 1 and Minn. Stat. § 216b.241, Subd 14. However, most CAC stakeholders indicated these impacts should be included, as long as participant costs and benefits are treated symmetrically.

For these reasons, we recommend that participant costs and benefits be included in the MN Test. This will ensure the MN Tests adheres to Principle 3 of the NSPM for DERs by creating symmetry and avoiding unintended bias in the assessment of energy efficiency resources.

Table 4 below provides a proposed initial list of participant impacts for inclusion in the MN Test.

[65] NSPM for DERs, page 3-7.

Table 4. Participant Impacts

Type	Participant Impact	Description
Participant Energy Impacts	Participant portion of DER costs	Costs incurred to install and operate DERs
	Participant transaction costs	Other costs incurred to install and operate DERs
	Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER. Should be incremental to that included in Utility System Impacts.
	Reliability	The ability to prevent or reduce the duration of host customer outages. Should be incremental to that included in Utility System Impacts.
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions. Should be incremental to that included in Utility System Impacts.
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
Participant Non-Energy Impacts	Water	Changes in water consumption resulting from a DER (e.g., reductions from low-flow showerheads, spray valves, clothes washers)
	Asset value	Changes in the value of a home or business resulting from a DER (e.g., increased building value, improved equipment value, extended equipment life)
	Productivity	Changes in a customer's productivity (e.g., changes in labor costs, operational flexibility, O&M costs, reduced waste streams, reduced spoilage)
	Economic well-being	Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)
	Comfort	Changes in comfort level (e.g., thermal, noise, and lighting impacts)
	Health & safety	Changes in customer health or safety (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths)
	Empowerment & control	The satisfaction of being able to control one's energy consumption and energy bill
	Satisfaction & pride	The satisfaction of helping to reduce environmental impacts (e.g., one of the reasons why residential customers install rooftop PV)

It may not be realistic to quantify all NEIs listed in Table 4 by the next triennial plan. Therefore, we recommend prioritizing the NEIs that are likely to have the most significant impacts on cost-effectiveness. Table 5 provides the relative impact of NEIs to total benefits by program for Rhode Island's 2022 energy efficiency programs. Programs with measures related to weatherization, such as retrofit programs, typically have the largest NEIs.

Within the residential programs, NEIs related to comfort, health and safety, and asset value have the largest impact and for C&I programs operation and maintenance NEIs are the largest. It would therefore make sense to start with an examination of these NEI values for similar programs in Minnesota.

Table 5. NEI Benefits as a Percentage of Total Benefits

Sector	Program	NEIs as % of Total Benefits
Residential	New Construction	2%
	HVAC	3%
	Single-Family Retrofit	8%
	Multi-Family Retrofit	31%
	Behavioral	0%
	Products	0%
Low-Income	Single-Family Retrofit	44%
	Multi-Family Retrofit	47%
Commercial & Industrial	New Construction	-5%
	Retrofit	14%
	Small Business	15%

Other Fuels Impacts

The impact of other fuels captures the impacts on fuels that are not provided by the relevant utility, for example, electricity (for a gas utility), gas (for an electric utility), oil, propane, gasoline, and wood.

The impact of other fuels should be included in the MN Test. There is a clear policy mandate for the inclusion of other fuels within the MN Test. There is mention of other fuels within 13 policies as included in the Summary of MN Energy Policies as included as an attachment to this straw proposal. For example, the Energy Conservation & Optimization Act of 2021 specifically includes language related to other fuels and Strategic Electrification.

Low-Income Impacts

Impacts related to low-income customers should be included in the MN Test. There are several Minnesota policies that specifically mention the importance of providing programs to low-income customers and ensuring their protection, including Minn. Stat. § 216B.2427, Subd 2, Minn. Stat. § 216b.2403, Subd 5, and Minn. Stat. § 216b.241, Subd 7 as included in the attached Summary of MN Energy Policies.

Furthermore, current cost-effectiveness practice indicates that low-income programs do not have to be cost-effective for inclusion in the IOUs' CIPs. This practice is based on the premise that the benefits of offering low-income programs outweigh the costs, but those benefits are not monetized.

IOUs could continue this practice as a means to include low-income benefits in the MN Test. In the future, these benefits could also be monetized for inclusion in the benefit-cost assessments. Low-income benefits will be similar to many of the participant NEIs but may have a greater magnitude due to the baseline of housing stock for this subset of customers. Table 6 provides a summary of low-income single-family NEIs as currently included in Rhode Island's energy efficiency programs. The table provides the monetized value and the measure group it is applied to within the cost-effectiveness test.

Table 6. Rhode Island Natural Gas Measure NEIs

Low-Income Benefits	Description	Measure Categories	Annual Value
Safety-Related Emergency Calls	Financial savings to the utility as a result of fewer safety related emergency calls being made.	Heating System	$8.43
Thermal Comfort	Greater participant-perceived comfort in home.	Insulation	$30.13
		Air Sealing	$35.89
		Heating System	$33.24
Noise Reduction	Less participant-perceived noise in the home.	Insulation	$13.56
		Air Sealing	$16.39
Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials.	Insulation	$8.76
		Air Sealing	$10.61
		Heating System	$27.43
Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliances.	Heating System	$9.72
Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home.	Insulation	$17.40
		Air Sealing	$230.08
		Heating System	$213.13
Improved Safety	Reduced risk of fire and fire-related property damage.	Insulation	$17.40
		Air Sealing	$2.24
		Heating System	$18.87

Source: National Grid Rhode Island Technical Reference Manual: 2022 Program Year. Appendix B: Non-Energy Impacts.

SOCIETAL IMPACTS

Policy Goals

This category captures the impacts of energy efficiency to society, incremental to what may already be embedded in utility system impacts. These impacts are often referred to as externalities. The decision of whether to include societal impacts should be based on Minnesota's policy goals. The impacts included in Table 7 should be included in the MN Test due to their strong linkage to Minnesota policy goals.

Table 7. Societal Impacts

Category	Impact	Description
Societal Impacts	GHG Emissions	Non-embedded GHG emissions. Should be incremental to values included in utility system impacts.
	Criteria Air Emissions	Emissions of criteria pollutants.
	Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts.
	Economic and Jobs	Incremental economic development and job impacts.
	Energy Security	Reduction in imports of various forms of energy to help inform the goals of energy independence and security.
	Energy Equity	Energy equity requires intentionally designing systems, technology, procedures, and policies that lead to the fair and just distribution of benefits in the energy system.

GHG Emissions

Societal GHG emissions are considered externalities because they are not included in the cost of electricity and gas. This impact is meant to capture the additional cost of GHG emissions after environmental compliance regulations have been met.

It is important that any environmental compliance costs associated with the reduction of GHG emissions that are already included in Utility System Impacts be subtracted from this impact to avoid double counting.

We recommend including this impact in the MN Test because reducing GHG emissions is identified in 12 policies as described in the attached Summary of MN Energy Policies. Specifically, the Energy Conservation & Optimization Act of 2021, indicates the need to reduce pollution and emissions that cause climate change.

Criteria Air Emissions

Under the federal Clean Air Act, the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for six common air pollutants, commonly referred to as "criteria air pollutants", that contribute to environmental and health problems. These include carbon monoxide, lead, nitrogen oxides, ground-level ozone, particle matter, and sulfur oxides.[66] To the extent the impacts from these emissions are not included in the cost of electricity and gas, it would be accounted for here as a societal impact. This impact is meant to capture the additional costs associated with criteria air emissions after environmental compliance regulations have been met.

We recommend including this impact in the MN Test because reducing criteria air emissions is identified in MN Statute 216B.03 on page 55 of the attached Summary of MN Energy Policies.

There is potential for this impact to overlap with the environmental compliance impacts within the utility system impacts, thus care should be taken to avoid double-counting.

Other Environmental

This impact is intended to be a catch-all for all other environmental impacts. This could include air emissions, solid waste, land, water, and other environmental impacts that are not already embedded in environmental compliance costs that are included in the utility system impacts.

We recommend including this impact in the MN Test because reducing other environmental impacts is identified in Minnesota statutes as a policy goal. Specifically, the Next Generation Energy Act of 2007 describes the importance of environmental protection[67], Natural Gas Innovation Act of 2021 discusses reductions in waste[68], and the CIP IOU statutory requirements detail disposal of LEDs.[69]

Economic and Jobs

Investment in energy efficiency resources will result in additional jobs and economic development in several ways. There are jobs associated with managing and delivering the efficiency programs and jobs associated with the companies that implement the programs (such as contractors, vendors, product manufacturers, etc.). Further,

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[66] https://www.epa.gov/criteria-air-pollutants/naaqs-table
[67] Summary of MN Energy Policies, pg. 9.
[68] Id., pg. 15.
[69] Id., pg. 40.

efficiency savings provide consumers with more disposable income, which helps creates jobs and spurs economic development.

The NSPM for DERs states that economic development can be shown as changes to employment (in job-years), gross domestic product (in $), personal income (in $), or state tax revenues (in $).[70] The economic indicators are interrelated and cannot be added together. Further, the monetary values of economic development cannot be added to the monetary cost-effectiveness analysis results because that would result in double-counting. Therefore, the estimates of economic development impacts should be presented alongside the rest of the results of the BCA. Synapse recommends that the number of job-years be used to represent economic development, because job growth is easily understood and relatively easy to isolate from the other indicators.

There is a clear policy linkage in Minnesota to economic and job benefits. It is mentioned in five policies in the attached summary, most notably the Energy Conservation & Optimization Act of 2021 states the need to "improve the competitiveness and profitability of businesses, create more energy-related jobs."[71]

We recommend including this impact in the MN Test because reducing economic development is identified in several statutes as a policy goal for Minnesota.

Energy Security

Energy efficiency can sometimes reduce imports of fossil fuels that are used to generate electricity, heat buildings, or power industries in Minnesota. Reducing imports of fossil fuels can help advance the goals of energy independence and security.

We recommend including this impact in the MN Test because reducing fossil fuel consumption, specifically fuel imports, is identified in three policies within the attached Summary of MN Energy Policies. Specifically, the Energy Conservation & Optimization Act of 2021 state the need to "reduce the economic burden of fuel imports"[72] and the Next Generation Energy Act of 2007 "finds and declares that the protection of life, safety, and financial security for citizens during an energy crisis is of paramount importance".[73]

There is potential for this impact to overlap with the utility system impacts of reliability and risk, thus care should be taken to avoid double-counting.

Energy Equity

While there are multiple definitions of energy equity, Pacific Northwest National Laboratory defines it as:

> "An equitable energy system is one where the economic, health, and social benefits of participation extend to all levels of society, regardless of ability, race, or socioeconomic status. Achieving energy equity requires intentionally designing systems, technology,

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[70] NSPM for DERs, pg.4-22.
[71] Summary of MN Energy Policies, pg. 8.
[72] Summary of MN Energy Policies, pg. 8.
[73] Id., pg. 9.

procedures, and policies that lead to the fair and just distribution of benefits in the energy system."[74]

We recommend including this impact in the MN test. The attached Summary of MN Energy Policies includes five energy policies with mention of equity. While there is not a direct linkage to the definition of equity provided here, the policies note the need to provide energy efficiency to all utility customers and utility sectors. In addition, the stakeholders noted that this is an important, emerging policy goal for Minnesota.

EXCLUDED IMPACTS

There are three impacts we exclude from the straw proposal. These include the non-utility system impact of water and the societal Impacts of public health and resilience. We provide a definition of these impacts and reasons for exclusion below.

Water

Investments in energy efficiency can reduce water consumption.

We recommend excluding this impact from the MN Test because there is no link to Minnesota's policy goals and this value would likely be accounted for as a participant benefit from the installation of energy efficiency measures that also produce water savings.

Public Health

Investments in energy resources can create health impacts for populations impacted by fuel extraction, combustion, and transportation. This can lead to impacts on the level of societal investment required in medical facility infrastructure and economic productivity.

We recommend excluding this impact from the MN Test because there is no link to Minnesota's policy goals and this impact could be accounted for anyway in either criteria air pollutants or participant and low-income NEIs.

Resilience (Societal)

This impact is meant to reflect resilience impacts beyond those experienced by utilities or participants.

We recommend excluding this from the MN Test because of CAC stakeholder comments that this may be accounted for within the utility system impacts.

[74] Pacific Northwest. n.d. (PNNL Energy Equity). Pnnl.com website. https://www.pnnl.gov/projects/energyequity#:~:text=What%20is%20energy%20equity%3F,energy%2Defficient%20housing%20and%20transportation

Appendix G – Cost-Effectiveness Advisory Committee Comments Side-by-Sides (From Proposed Decision)

The following pages includes summaries of comments by Cost Effectiveness Advisory Committee Members to the Synapse Straw Proposal. The first two sheets relate the same information but are split into two sheets to show comments from all parties on the proposal's recommendations related to Utility System Impacts, Non-Utility System Impacts and Societal Impacts. The third sheet includes comments from parties on Participant impacts to include (for those entities who expressed points-of-view regarding specific Participant impacts). The fourth sheet includes CAC member comments on Electric Utility System Impacts while the fifth sheet includes comments on Gas Utility System Impacts.

First column for individual commenters reflects whether the individual/organization supports or does not support including the item (? Indicates not clear whether or not support)

Type	Category	Impact	Straw Proposal Includes	Marty Kushler	Rationale / Comments	CenterPoint	Rationale / Comments	CEE	Rationale / Comments	CUB	Rationale / Comments
General Comments			N/A				CenterPoint Energy is generally supportive of the proposed straw proposal for Minnesota's primary cost-effectiveness test. The Company agrees it is worthwhile to explore the inclusion of other effects of energy efficiency such as on economics and the environment effects, as long as the additional effects are empirically based, consistently applied, and not overly administratively burdensome		CEE generally supports the Straw Proposal. The Straw Proposal reflects Minnesota's relevant policies as well as CAC stakeholders' feedback to date.		I disagree somewhat (or at least suggest an addition) with Table 4 (Participant Impacts table). Though I think bill savings is a participant benefit inherently considered in several categories included in the straw proposal, I think it could/should be called out more specifically as its own category Though bill savings is inherently related to "participant portion of DER costs" and "Participant transaction costs" I think it is broader and somewhat distinguishable from those two categories, too. Also, though I see "economic well-being" beyond bill savings, I think the actual bill savings are the more immediate, tangible benefit that should be considered. Could "bill impacts" be its own row/category in Table 4? Or is it already addressed elsewhere, in your opinion?
Utility System	Electric Utility System	All	✓								
	Gas Utility System	All	✓								
Non-Utility System	Participant	Participant Costs	✓	No	I disagree with including participant impacts. Including participant impacts in the MN Test will greatly increase the amount of work needed and also the amount of disagreement. & ultimately would very likely result in an 'unbalanced' test, where participant benefits are not adequately quantified. (Based on Synapse observed "weak link" in policy to include participant impacts) I believe the link is weak enough that participant impacts could certainly be omitted from the 'primary test'. & I believe they should be omitted for 2 key reasons: (1) the result will inevitably be 'unbalanced', due to the difficulty of identifying and quantifying all the varied participant benefits; and (2) there would be a lot more work (and argument) involved in deciding what benefits to include and what quantitative values to include. Excluding participant impacts from the primary test will save a lot of time, resources, and disputes. However, if participant impacts are to be included at this point, I recommend that parties make that approval 'tentative', and state that any final decision on inclusion of participant impacts would depend upon how adequately the quantification of participant impacts (particularly participant benefits) is ultimately operationalized.	Yes	CPE supports including both participant costs and benefits in a primary cost-effectiveness test for Minnesota. Risks aassociated with removing participant costs are more significant than challenges to quantify. Including societal benefits okay but may be difficult to do before next Triennial. The Company agrees that including participant costs in the primary test is the right approach in the near-term, at minimum.	No	CEE does not support including participant costs and benefits in the primary CIP cost-effectiveness test. Instead, we recommend using the participant cost test as a secondary cost-effectiveness test to evaluate cost-effectiveness from the participant perspective and inform program design. First, CEE does not believe there is a strong policy argument to include participant costs in the primary cost-effectiveness test based on Minnesota policy and the NSPM process. Additionally, after the robust conversations in the CAC stakeholder meetings, we believe it is unclear whether most CAC stakeholders still favor inclusion of participant costs and benefits. Second, while participant costs, which include the costs to install or implement an energy efficiency or fuel-switching project, are relatively simple to quantify, participant benefits are not. We do not believe it is a good use of time and resources to develop interim or longer-term proxies and adders to estimate participant benefits for the primary cost-effectiveness test. Importantly, including only participant costs, which are easy to quantify, in the primary cost- effectiveness test will result in asymmetry and unreasonably reduce cost-effectiveness of energy efficiency and fuel-switching programs. We believe that the participant cost test is much better suited to evaluate cost-effectiveness for participants.		
	Participant	Participant Benefits	✓	No		Yes		No			
	Other Fuels	Other Fuels	✓	Yes	A key question is: will this be monetized at the 'utility cost' level? Or the participant (i.e., retail prices) level? Or the societal cost level? (I'd suggest the latter, to include associated impacts on GHG & other criteria pollutants, etc.)						
	Low-Income	Low-Income	✓	No	Minnesota should continue the practice of not requiring that low-income programs be cost-effective.			Yes	CEE supports including low-income impacts in the primary cost-effectiveness test. Quantifying and monetizing the non-energy impacts of energy efficiency for low-income customers should be a high priority for the Department and the CAC. These impacts are unique, significant, and more easily quantifiable than traditional, market rate participant non-energy impacts.		
	Water	Water	No	No	Agree in terms of a broad societal metric. But should be able to quantify any direct water saving impacts from EE measures. Or could be quantified as a 'non-utility impact' the way that "other fuels" are quantified…if participant impacts are not included in the primary test.			Yes	To the extent that water savings occur as a result of CIP and ECO projects, we recommend that water savings be included in "Other Environmental Impacts" under the proposed inputs for Societal Impacts.		
Societal	Societal Impacts	GHG emissions	✓	Yes	To clarify my thoughts on that last sentence (CEE Comments - "it would not be appropriate to use both an externality value and a regulatory cost of carbon together for the same emission""), if the regulatory tax or fee was less than the appropriate full externality cost of the emissions, then it would be appropriate to add to the cost of the tax or fee additional costs such that the full externality cost of the carbon emissions was included in the primary test calculation. Given the potential for that cost gap, and the great uncertainty regarding any regulatory tax or fee, for the time being, I agree with CEE's recommendation that "…it is reasonable to continue using greenhouse gas externality values to estimate the avoided costs of greenhouse gas emissions."			Yes	CEE supports including GHG emissions as a societal impact in the primary CIP cost-effectiveness test. We believe this is well-supported through Minnesota's energy policy. Simply using the full externality value to reflect greenhouse gas emissions would be simpler and, based on our understanding, would not change the overall value of emissions included in the primary cost-effectiveness test (it would only change the category in which the impacts are reported).		
		Criteria air emissions	✓	Yes	Same as comment on GHGs.						
		Solid Waste	In Other Environmental								
		Water Impacts									
		Land Impacts									
		Other environmental	✓		Realistically, these impacts would be very difficult to quantify, and not likely to be large from CIP. & if they are not really going to be quantified, it would be misleading to say the MN Test "includes them".						
		Economic and Jobs (Macroeconomic)	✓	Yes	I disagree with that. e.g., the economic value of reducing the dollar drain from imported fuels would not be captured in the other dimensions of the BCA. *In response to: "Further, the monetary values of economic development cannot be added to the monetary cost-effectiveness analysis results because that would result in double-counting."* However, if the decision is to treat this as a sidebar, then there should NOT be claim that the "MN Test" includes jobs and economic impacts! Some metrics expressed in dollars should also be reported, because dollars are also an easily understood metric. e.g., the reduction in dollar drain for imported fuels…which would be very difficult to express in job years.						
		Energy Security	✓	No	The reduction in energy imports should be assessed as an economic benefit, resulting from reduced dollar drain from the MN economy. Treating this as "energy independence" or "security" is far too nebulous. There are widely used 'economic multiplier' methodologies that could put a dollar (and jobs) value on that reduced dollar drain from the state. This is much too vague and weakly stated. It's not "sometimes". Minnesota imports essentially 100% of the fossil fuels it consumes, at a cost of billions of dollars a year. That fact should be stated as part of the rationale for a metric relating to imported fossil fuels. This statute directly refers to "the economic burden of fuel imports". Treat the reduced energy imports impact as a direct economic metric. Any overlap with reliability and risk would only relate to supply availability and disruption…which is a tiny factor and not really worth bothering with.			Yes	CEE recommends that this input be re-defined as "Reduced Economic Burden of Fuel Imports." We agree with Synapse that Minnesota policy clearly states that reducing the economic burden of fuel imports is an objective of energy conservation and optimization. We do not know of any relevant Minnesota policy that describes "energy security." Therefore, we recommend changing this input to "Reduced Economic Burden of Fuel Imports," defined and quantified as the economic impact of reduced dollars flowing out of Minnesota to purchase fuels from other states. Minnesota produces no fossil fuels in the state.		
		Energy Equity	✓		That's very popular these days, but be advised that will be hugely difficult to quantify and monetize… & likely a source of much argument.						
		Public health	No		I'm ok with that in terms of a broad societal impact. Participant direct health benefits could be captured, particularly for low-income programs.			No	We generally agree that public health impacts of energy are included in the externality values for criteria pollutants, which is included in the Straw Proposal under Societal Impacts. We note that any additional public health impacts specific to low-income participants should be included in the Low-Income Impacts in the Non-Utility Impacts.		
		Resilience	No		I really don't see how utility system impacts (as typically defined) will capture that. But I'm ok excluding it as it would be very difficult to quantify & likely not that substantial.						

First column for individual commenters reflects whether the individual/organization supports or does not support including the item (? Indicates not clear whether or not support)

Type	Category	Impact	Straw Proposal Includes	Fresh Energy	Rationale / Comments	MEEA	Rationale / Comments	Minnesota Power	Rationale / Comments	Otter Tail Power	Rationale / Comments	Xcel Energy	Rationale/Comments
General Comments			N/A						Overall Minnesota Power is on board with the categories included in the proposed MN test and has no areas of strong disagreement. However, the Company has some concerns regarding the level of new inputs to be explored and quantified and concerns over the ability to quantify many of these categories with any level of accuracy, especially in a timeline that will still allow utilities to evaluate programs (which will likely look quite different than normal) for the new triennials. Furthermore, Minnesota Power thinks it will be important to balance the need for symmetry with making sure inputs are meaningful. There are many many new inputs that have never been quantified before in Minnesota, a lot of which are very difficult to quantify, especially within the participant impacts. Only incorporating meaningful inputs that are based on sound information should be prioritized over attempting to include as many inputs as possible through utilization of erroneous adders.		Otter Tail agrees with the list of eight principles listed by Synapse as guide for determining the process for what benefits and what costs to include in a new Primary Test. The first principle listed by Synapse is as follows: Principle 1: Treat DERs as a Utility System Resource. DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions. Otter Tail verbally supported Principle 1 in the virtual stakeholder meetings and believes DERs should be evaluated similarly to supply-side resources which are thoroughly vetted through the Integrated Resource Plan (IRP) process. Otter Tail stresses the importance of including the same benefits and costs in choosing demand-side utility investments and supply-side investments. Any asymmetry in benefits or costs when evaluating these resources will create non-cost-effective resource selection for customers.		The Company strongly agrees with the straw proposal that suggests participant impacts should remain part of the Primary cost-effectiveness tests. Without this factor as part of cost-effectiveness, Program Administrators' ability to manage programs that reduce electric bills could be at risk. We also acknowledge the wide variety of non-energy impacts realized by participants but suggest careful consideration regarding which of these benefits to include for CIP programs.
Utility System	Electric Utility System	All	✓										
	Gas Utility System	All	✓										
Non-Utility System	Participant	Participant Costs	✓	No	In general, those stakeholders who expressed concern raised several points. First, that participant NEIs can be difficult to quantify and could lead to an unbalanced result, with easier-to- quantify costs outweighing difficult-to-quantify benefits. Second, some stakeholders note that there is not a strong statutory connection to support inclusion of participant NEIs. We understand that of the stakeholders who expressed concern, the primary recommendation is to exclude both participant costs and benefits, but, if participant costs are included in the MN Test, that participant benefits should also be calculated and included. We are persuaded that participant NEIs should not be included in the MN Test at this time given the concerns raised by stakeholders. We agree that if participant costs are included in the MN Tests, benefits should be as well, but our primary recommendation is to not include either in the MN Test. At this time, however, the better evaluative test to consider participant NEIs is the Participant Cost Test (PCT). We recommend that future workshops of this committee include discussion on a full suite of participant NEIs in the context of the PCT and we recommend that future work be done to address possible valuation of these NEIs.	Yes	it makes sense to focus on the NEIs that have the largest impacts & the programs that are most impacted by NEIs I like the approach of Table 6 - defined NEI annual values - rather than having each utility work through the methodology and everything on their own it makes more sense to do it once for everyone and supply the values to use (perhaps with a caveat of "if these are wrong for you, provide another value showing all of your work")		Minnesota Power believes there is justification for the participant impacts to be included or excluded but understands the Departments hesitation to remove them. As such the Company agrees with the inclusion of these impacts but believes there is significant potential to bias the test or reduce the meaningfulness of the evaluation through inclusion of too many impacts that need to be very roughly estimated or applied through generic adders. It will be important to prioritize which impacts to include, ideally based on level of impact and ability to accurately quantify the impacts and ideally in a way that still allows for symmetry within the impact category.	No	Participant Impacts should not be included in the Minnesota Primary Test but instead should be included in a separate Participant Test. Including Participant benefits and cost within the Primary test is not in alignment with the IRP process and opposes Principal 1. Including Participant benefits and costs could distort the cost-effectiveness of demand-side investments when comparing to supply-side investments.	Yes	Participant Impacts should remain a part of the primary cost-effectiveness tests. We believe that participant impacts, both benefits and costs, can still be quantified and are useful in screening out measures or technologies that CIP programs cannot cost- effectively incentivize. Removing participant impacts from the primary tests limits the program administrators' ability to effectively manage the programs. Specifically, it is important the transparency be retained in CIP reporting regarding customer motivations. Removing participant cost and benefit data would erode the ability to demonstrate that the activities supported by CIP are incremental to the naturally occurring adoption.
	Participant	Participant Benefits	✓	No		Yes				No		Yes	Inclusion of broadly-applied Participant Non-Energy Impacts will also cause risk in delivering cost-effective programs for a couple of reasons. First, if a technology requires non-energy benefits to pass the test because the energy benefits are too small relative to participant costs, the probability that CIP support can motivate the customer decreases as the share of the participant cost covered by rebates and energy savings decreases. The Company does not believe that the alternative of paying rebates that exceed the energy benefits is appropriate unless a specific objective (e.g. Low Income CIPs) directs where that practice is in the public interest. To remove this risk in the event that broadly applied Participant Non-Energy Impacts are included, the Company proposes an additional requirement to the primary test. This requirement would be that the benefits from Utility System Impacts must exceed a minimum percentage of the Participant Energy Impacts, plus the quantified non-energy impacts from Water and Productivity.
	Other Fuels	Other Fuels	✓										
	Low-Income	Low-Income	✓	Yes	Fresh Energy agrees that low-income impacts should be included in the MN Test. We are interested in working to monetize the benefits of these programs that are currently assumed to pencil out. Valuation of these non-energy benefits could help policymakers, utilities, and stakeholders design and implement low-income CIP programs that can more effectively serve participants' needs. We are supportive of the current assumption that the benefits to these programs outweigh the costs—we strongly believe that they do—but we are also interested in refining this analysis with real values to more effectively serve this important group.			No	Minnesota Power's preference is to continue the existing practice of allowing LI programs to not be cost-effective, therefore assuming the benefits to LI outweigh the costs without the need to spend significant resources on quantifying those benefits.	No	Otter Tail believes the inclusion of benefits and costs from low-income programming in the Primary Test would be out of alignment with the IRP process. Similar to participant impacts, including low-income benefits and cost within the Primary test is not in alignment with the IRP process and opposes Principle 1. Otter Tail recommends a better place to include non-energy impacts could be in a separate low-income test to prove the value of low-income programs.	?	LI programs should not be driven around these NEI's because they are so hard to quantify. The Company suggests that a targeted approach may make the most sense, focusing NEIs on specific measures where literature indicates NEIs may be highest (e.g. insulation and air sealing) rather than a blanket adder. The Company also suggests that LI Spend requirements are more effective in maximizing the cost-effectiveness of LI Spend, rather than a primary cost-effectiveness test that dictates the measures and spend levels for LI programs.
	Water	Water	No	Yes	If water is not treated as a participant impact (or if participant impacts are not considered in the MN Test, as we recommend), then water should be included as a non-utility system impact and treated similarly to impacts from other fuels. In the Straw Proposal, Synapse recommended excluding this impact from the MN Test because it would likely be accounted for as a participant benefit from the installation of energy efficiency measures that also produce water savings. But if participant benefits are not included in the MN Test, we this impact should be included to account for reduced water consumption due to investments in energy efficiency.								
Societal	Societal Impacts	GHG emissions	✓	Yes	Fresh Energy agrees with the proposal to include this impact in the MN Test. We agree that double counting values would violate NSPM principles and we look forward to future discussion about any possible overlap between regulatory costs and societal costs of carbon. There should be very little overlap in the values that both approaches attempt to capture, but we do not oppose an exercise to attempt to identify any overlapping costs.	Yes	In general agreement A lot of this is stuff that has potential overlap with the system impacts and therefore has to avoid double counting. The straw proposal doesn't really get into the "how to" of things which gives me a little bit of concern - it's easy to say to just account for the part that is incremental to the previously counted, but from a practical standpoint is it going to be straightforward to do so? in some states where EE is less supported than in MN, the public health NEIs might be more important in demonstrating that there is non-participant value. Minnesota doesn't seem to have that political problem, so sticking with participant health and/or value of reduced criteria pollutants in the utility system is fine with me.	Yes	MP agrees the emissions categories are very important and are a policy focus. Time should be spent clarifying how these are captured.				
		Criteria air emissions	✓	Yes (combine with Public Health)	We recommend combining criteria air emissions within the public health impact, as discussed during workshop #3. Health problems caused by criteria air emissions will therefore be captured in the "Public Health" impact, which we recommend including in the MN Test (see below for discussion). Environmental impacts caused by criteria air emissions should be captured in the "Other Environmental" impact.	Yes		Yes					
		Solid Waste	In Other Environmental			Yes		Yes					
		Water Impacts				Yes		Yes					
		Land Impacts				Yes		Yes					
		Other environmental	✓			Yes		Yes					
		Economic and Jobs (Macroeconomic)	✓	Yes	Fresh Energy agrees with the proposal to include this impact in the MN Test and we are interested to discuss how economic and workforce development will be valued in future committee discussions.	Yes		Yes	MP agrees Economic and Jobs impacts are important and have become a larger policy focus in recent years.	No	Including benefits from Economic and Jobs, Energy Security, and Energy Equity, while important are not included in the IRP's vetting of new resources so they cannot be included in a Primary Test. Including these benefits would oppose Principle 1		
		Energy Security	✓			Yes		Yes		No			
		Energy Equity	✓	Yes	Fresh Energy agrees with the proposal to include this impact in the MN Test. As the Straw Proposal notes, there are multiple definitions of energy equity and the proposal provides a definition from the Pacific Northwest National Laboratory. The Department should establish a definition of energy equity (and the resulting metrics) that seek to rectify historical inequitable disparities that frontline, under-resourced, and BIPOC communities currently face.	Yes		Yes	MP agrees Energy Equity is an important factor. Finding ways to recognize and quantify this would align BAC results better with the MN priority of energy equity, making it easier to design and offer an equitable portfolio of programs.	No			
		Public health	No	Yes (Combine with Criteria Air Pollutants)	In accordance with our recommendation that criteria pollutant impacts be folded into public health impacts, we recommend that public health impacts be included in societal impacts. We recommend combining the criteria air emissions impact within the public health impact, and including this combined impact in the MN Test. The public health impact should capture reductions in the frequency and/or severity of health problems of populations due to reductions in criteria air emissions and waste, and improved indoor air quality. We believe it is especially important to include public health impacts in the MN Test if participant NEIs (and therefore the health & safety subcategory) are excluded from the MN Test.	No		No					
		Resilience	No			No		No					

First column for individual commenters reflects whether the individual/organization supports or does not support including the item (? Indicates not clear whether or not support)

Category	Impact	Description	Marty Kushler	Rationale / Comments	CEE	Rationale / Comments	MEEA	Rationale / Comments	Minnesota Power	Rationale / Comments	Otter Tail Power	Rationale / Comments	Xcel Energy	Rationale / Comments
General Comments														We agree with the majority of Synapse's recommendations for the Proposed Electric Utility System Impacts. However, the Company believes that the cost effectiveness standard should be guided by the objectives of the Conservation Improvement Program (CIP). CIP is part of Minnesota's strategy for most effectively meeting the state's energy needs at a reasonable cost to customers. It provides funding for utility-led programs that clears pathways for customers to cut their utility bills and energy waste while simultaneously contributing to Minnesota's growing low-carbon economy. The ability to produce customer bill savings, as promised by CIP, is reduced if CIP program costs rise faster than the energy savings that spend produces, becoming less cost-effective.
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers		I'm assuming that this would include the cost of maintaining whatever 'reserve margin' is required? (If not, would those costs be included below under 'reliability'?)			Yes				Yes			
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load.					Yes				Yes			
	Environmental Compliance	Actions to comply with environmental regulations. This can include compliance with federal regulations like the Clean Air Act or state or local greenhouse gas emissions mandates.		I don't see where the overlap with 'utility costs' would be. This will need to be watched carefully.	Yes	CEE supports including environmental compliance costs as a utility system impact in the primary CIP cost-effectiveness test. The Straw Proposal notes that environmental compliance costs can include costs associated with compliance with federal regulations or state or local greenhouse gas goals. CEE recommends that the Department and the CAC consider incorporating the long-term incremental energy system costs associated with meeting Minnesota's greenhouse gas emissions reduction goal.	Yes		Yes	It will be important to clarify how and where the environmental and emissions related impacts are being calculated and applied so that the appropriate costs and avoided costs are both being captured and so that double counting is not occurring between the different components (mostly utility and societal).	Yes			
	Renewable Portfolio Standard Compliance	Actions to comply with renewable portfolio standards or clean energy standards.					Yes		Yes		Yes		No	Already implicitly included in other impacts that are derived from resource planning and market forecasting tools.
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption.					Yes		Yes		Yes		No	Already implicitly included in other impacts that are derived from resource planning and market forecasting tools.
	Ancillary Services	Services required to maintain electric grid stability and power quality (i.e., frequency regulation, voltage regulation, spinning reserves, and operating reserves).					Yes		Yes		Yes			
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably.					Yes		Yes		Yes			
	Transmission System Losses	Electricity lost through the transmission system.					Yes		Yes		Yes			
Distribution	Distribution Costs	Maintaining the availability of the distribution system to transport electricity safely and reliably; includes capacity, O&M, voltage.					Yes		Yes		Yes			
	Distribution System Losses	Electricity lost through the distribution system.					Yes		Yes		Yes			
General	Program Incentives	Utility financial support to participants or other market actors; typically includes rebates, upstream payments, interest rate buy-down.					Yes	In general agreement with what has been proposed	Yes		Yes		Yes	Program Incentives should be included as both a benefit and a cost and, therefore, cancel out in the assessment of overall cost-effectiveness. While this treatment can help identify whether a program is cost-effective, the Company notes that it means the Minnesota Test would not be informative in assessing the proper level of Program Incentive for a given measure. That is, the test could indicate whether a certain measure should be incentivized, but not whether a given level of incentive is reasonable; other analyses would be required to answer that question.
	Program Administration Costs	Utility outreach to trade allies, technical training, marketing, payments to third-party consultants, and administration and management of energy efficiency programs.					Yes		Yes		Yes			
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of energy efficiency programs.					Yes		No	this is a deviation from the past and think it is important to consider the implications of including this in the test.	No	Including Utility Performance Incentives as a program cost would create a circular calculation and conflict with the utility financial incentive calculation. To calculate net benefits for the utility's financial incentive, the incentive would need to be known ahead of time which would be a circular calculation. Also, to include Utility Performance Incentives as a cost, one would also have to include the utility's loss revenues as a benefit to customer since the utility did not collect revenues from energy and demand sales.	No	Including the incentives in the calculation of the Utility Cost Test (via inclusion in Utility System Impacts) would thus create circularity in the calculation. Also, it is difficult to determine Utility Performance Incentives for individual measures as the current mechanism includes multiple factors based on the achievement of the entire portfolio and includes caps. Inclusion of performance incentives may make more sense when the incentive mechanism is of a more prescriptive design (e.g., based simply on units of energy saved). While understanding the impact of incentive amounts is important, the design of the mechanism in Minnesota limits the overall share of utility system benefits awarded and utilities regularly (if not uniformly) report the net benefits after the incentive in their Status Reports. If the performance incentive is included in the utility system impacts, the Company recommends that it be applied only at the portfolio level and that it be applied as a final step in the calculation as commonly presented in utility Status Reports.
	Credit and Collection Costs	Utility costs associated with arrearages, disconnections, and reconnections.					Yes		Yes		Yes		No	The inclusion of Credit and Collection Costs and Risk as components of the Utility System Impacts is somewhat tenuous. First, it is not clear that energy efficiency has substantial impacts on these costs – or, if such impacts exist, that they can be meaningfully expressed in terms of cost per kWh or Dth saved. Second, these costs (particularly Credit and Collection Costs) are not typically included in the assessment of other utility system resources and their inclusion in a Minnesota Test risks introducing bias across resource investment decisions.
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks.		I'm very skeptical that the current practice for IRPs and IDPs adequately addresses the "3 R's" (i.e., the ability to quantify the impact of EE on Risk, Reliability and Resilience). On the other hand, I agree these could be very difficult (and controversial) to try to monetize. See comment about being very careful when claiming what the MN Test "includes".	Yes	CEE supports Synapse's proposal. We look forward to learning about this issue. CEE notes that is important that inputs for risk, reliability, and resilience reflect the added risks posed by climate change and the costs of adaptation.	Yes		Yes	Clarification on quantifying Credit and Collect Costs, Risk, Reliability, and Resilience will be important	No	benefits and costs associated with Risk, Reliability, and Resilience, are included in Generation, Transmission, and Distribution categories which are already included in the Primary Test. When the electric utility plans for supply-resources, transmission investments, or distribution investments the benefits/costs of Risk, Reliability, and Resilience is inherently included in the planning process. Otter Tail designs it's system for 100 percent		
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.			Yes		Yes		Yes		No			
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions.			Yes		Yes		Yes		No			

First column for individual commenters reflects whether the individual/organization supports or does not support including the item (? Indicates not clear whether or not support)

Category	Impact	Description	CEE	Rationale / Comments	CenterPoint	Rationale / Comments	MEEA	Rationale / Comments	Xcel Energy	Rationale/Comments
Commodity / Supply	Fuel	Purchasing gas at specific locations on the gas system and the variable cost of getting the gas where, and when, it will be used.		The Straw Proposal includes fuel as an input in the proposed gas utility system impacts for the primary cost-effectiveness test. CEE supports including fuel costs in the primary test. However, we recommend including a factor or other mechanism to represent the risk of price volatility in fuel markets. Storm Uri is the most recent example of price volatility in fuel markets, but many similar examples have occurred in the past due to geopolitical events, extreme weather events, and pipeline issues. The risk of price volatility does not appear to be included in the input titled "Risk" under "General Impacts." There, risk is defined as "Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks."						Company notes that the descriptions of "Fuel," "Transportation," and "Delivery" appear to risk double-counting some costs. "Fuel" is described as "purchasing gas at specific locations on the gas system and the variable cost of getting the gas where, and when, it will be used." "Transportation" is described as "the transport of gas from delivery points located on interstate and intrastate pipelines to distribution utility city gate" while "Delivery" is "Delivery of gas from the city gate to retail customers." It is unclear what costs are intended to be included in "the variable cost of getting the gas where, and when, it will be used" that are distinct from those included in Transportation and Delivery.
	Capacity & Storage	The gas and storage capacity required to meet forecasted peak load.								
	Environmental Compliance	Actions to comply with environmental regulations.								
	Market Price Effects	The decrease (or increase) in wholesale prices as a result of reduced (or increased) customer consumption.								
	Losses (not in Straw Proposal - CEE suggests including)			The proposed inputs for the gas utility system impacts for the primary cost-effectiveness test do not include any input that explicitly mentions losses on the gas system. The Department should consider adding an input that represents losses on the gas system, both in terms of fuel costs and emissions.						
Transportation	Transportation	The transport of gas from delivery points located on interstate and intrastate pipelines to distribution utility city gate.								See Above
Delivery	Delivery	Delivery of gas from the city gate to retail customers.								See Above
General (same as Electric	Program Incentives	Utility financial support to participants or other market actors; typically includes rebates, upstream payments, interest rate buy-down.								
	Program Administration Costs	Utility outreach to trade allies, technical training, marketing, payments to third-party consultants, and administration and management of energy efficiency programs.								
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of energy efficiency programs.			No	That said, CenterPoint Energy would note that there is a policy issue that should be discussed in future workshops related to incorporating utility performance incentives into UCT testing. The current utility financial incentive mechanism is based on the UCT and therefore the inclusion of utility performance incentives into the test creates circular reasoning in the cost-effectiveness calculations. Under the existing financial incentive mechanism, adding these costs to the test doesn't provide much informational value because when the incentive is a percent of net benefits the cost will scale based on the test results and not substantially change relative outcomes for measures or programs. The Company recommends that the implications of this topic be discussed in one of our future workshops because of the potential issues this change could create for cost-effectiveness models.		In general agreement with what has been proposed		
	Credit and Collection Costs	Utility costs associated with arrearages, disconnections, and reconnections.								
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks.								
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.								
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions.								

Appendix H – Stakeholder Comments on Straw Proposal (From Proposed Decision)

Cost-Effectiveness Test for Minnesota Conservation Improvement Programs

Straw Proposal for the Primary Test

Prepared for the Minnesota Cost-Effectiveness Advisory Committee

MK comments 6/14/22

June 8, 2022

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EXECUTIVE SUMMARY

Synapse Energy Economics, Inc. (Synapse) is assisting the Minnesota Department of Commerce (DOC) with guiding the Conservation Improvement Program (CIP) Cost-Effectiveness Advisory Committee (CAC) through *the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*[75] (NSPM for DERs) process to develop a primary cost effectiveness test for Minnesota through a series of workshops.

The goal of the workshops is to develop a primary jurisdiction-specific cost-effectiveness test for Minnesota, the MN Test, for use by the Investor-owned utilities (IOUs) in their upcoming 2024-2026 Triennial Plans. While the purpose of the workshops is to develop a test for assessing the cost-effectiveness of energy efficiency, the MN Test should ideally be applied to all types of DERs.

The workshops cover the NSPM for DERs five-step process for developing a primary test:

Step 1. Articulate Applicable Policy Goals.
Step 2. Include All Utility System Impacts.
Step 3. Decide Which Non-Utility System Impacts to Include.
Step 4. Ensure that Benefits and Costs are Properly Addressed.
Step 5. Establish Comprehensive, Transparent Documentation.

Each step in the process is guided by the eight principles of the NSPM for DERs:

Principle 1: Treat DERs as a Utility System Resource. DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.

Principle 2: Align with Policy Goals. Utilities invest in or support energy resources to meet a variety of goals and objectives. The primary cost-effectiveness test should therefore reflect this intent by accounting for the state's applicable policy goals and objectives.

Principle 3: Ensure Symmetry. Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.

Principle 4: Account for Relevant, Material Impacts. Cost-effectiveness tests should include all relevant (according to applicable policy goals) material impacts including those that are difficult to quantify or monetize.

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

Principle 5: Conduct Forward-Looking, Long-term, Incremental Analyses. Cost-effectiveness analyses should be forward-looking, long-term, and incremental to what would have occurred absent the DER. This helps ensure that the resource in question is properly compared with alternatives.

Principle 6: Avoid Double-Counting Impacts. Cost-effectiveness analyses present a risk of double-counting benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double-counting.

Principle 7: Ensure Transparency. Transparency helps to ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.

Principle 8: Conduct BCAs Separately from Rate Impact Analyses. Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses, and therefore should be conducted separately from rate impact analyses.[76]

Thus far, the CAC has discussed the first three-steps in the NSPM process over the course of two workshops. Based on verbal input from CAC stakeholders, written comments, and the draft list of applicable policy goals developed by the DOC, Synapse developed a MN Test straw proposal for stakeholder consideration.

The MN Test is intended to be the primary test. The purpose of a primary test is to inform whether an IOU's proposed investments in energy efficiency create more benefits than costs and therefore merit approval. The primary test is the main determinant of whether a program should be included in the Triennial Plan. Secondary tests can be developed to help enhance the overall understanding of energy efficiency impacts. The additional information from a secondary test can help to prioritize energy efficiency programs and to inform decisions regarding marginally cost-effective programs and allocation of resources. The secondary test is not intended to undermine the purpose of the primary test and may include a subset of the impacts included in the primary test or additional impacts.

Table 1 shows the impacts that we recommend be included the MN Test, based on our interpretation of the Minnesota policy goals and the stakeholder input to date. Stakeholders are encouraged to provide comments on this straw proposal to ensure it is consistent with their interpretation of Minnesota policy goals. Each impact will be discussed in more detail within the remainder of this report.

Table 1 indicates which impacts should be included in the MN Test as the primary cost-effectiveness test for the IOUs next Triennial Plan. These impacts should be monetized for inclusion in future benefit-cost assessments to the extent practical. Even if an impact is deemed too difficult to quantify and monetize it should be included by other means. This can include discussing the potential positive or negative impacts in a qualitative manner or using proxies or percentage adders, which are discussed in more detail below.

[76] NSPM for DERs, pg. iv.

Table 1. MN Test Straw Proposal

	Category	Impact	Include in MN Test
Utility System	Electric Utility System	All	✓
	Gas Utility System	All	✓
Non-Utility System	Other Fuels	Other Fuels	✓
	Water	Water	-
	Participant	Participant Costs	✓
		Participant Benefits	✓
	Low-Income	Low-Income	✓
Societal	Societal Impacts	Greenhouse Gas Emissions	✓
		Criteria Air Emissions	✓
		Solid Waste	Included in Other Environmental
		Water Impacts	Included in Other Environmental
		Land Impacts	Included in Other Environmental
		Other Environmental	✓
		Public Health	-
		Economic and Jobs	✓
		Energy Security	✓
		Energy Equity	✓
		Resilience	-

1. Utility System Impacts

All Utility System Impacts Included

Step 2 of the NSPM for DERs indicates that al utility system impacts should be included in cost-effectiveness tests. Utility system impacts are defined as the elements of the electricity or gas system required to deliver service to utility customers. For electric utilities, this includes generation, transmission, distribution, and utility operations. For gas utilities, this includes transportation, delivery, fuel, and utility operations.

It is important to include all elements of utility system impacts in a cost-effectiveness test for several reasons. It allows for DERs like energy efficiency to be treated consistently with other utility resources and ensures that at a minimum the cost-effectiveness test will show whether total utility system costs are reduced or increased by the investment in energy efficiency.

Table 2 and Table 3 provide a list of the electric and gas utility system impacts for inclusion in the MN Test. Based on the comments submitted by the MN IOUs, some of the below impacts are not currently included in cost-effectiveness. It therefore may not be feasible for all new impacts to be quantified and monetized for inclusion on the MN Test for the upcoming Triennial Plan. However, this does not indicate that these impacts should not be included in the MN Test. Such impacts could be addressed through a proxy or adder or discussed qualitatively. How these impacts are valued should be the subject of future workshops.

Table 2. Proposed Electric Utility System Impacts

Category	Impact	Description
Generation	Energy Generation	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load.
	Environmental Compliance	Actions to comply with environmental regulations. This can include compliance with federal regulations like the Clean Air Act or state or local greenhouse gas emissions mandates.
	Renewable Portfolio Standard Compliance	Actions to comply with renewable portfolio standards or clean energy standards.
	Market Price Effects	The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption.
	Ancillary Services	Services required to maintain electric grid stability and power quality (i.e., frequency regulation, voltage regulation, spinning reserves, and operating reserves).
Transmission	Transmission Capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably.
	Transmission System Losses	Electricity lost through the transmission system.
Distribution	Distribution Costs	Maintaining the availability of the distribution system to transport electricity safely and reliably; includes capacity, O&M, voltage.
	Distribution System Losses	Electricity lost through the distribution system.
General	Program Incentives	Utility financial support to participants or other market actors; typically includes rebates, upstream payments, interest rate buy-down.
	Program Administration Costs	Utility outreach to trade allies, technical training, marketing, payments to third-party consultants, and administration and management of energy efficiency programs.
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of energy efficiency programs.
	Credit and Collection Costs	Utility costs associated with arrearages, disconnections, and reconnections.
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks.
	Reliability	Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions.

Table 3. Proposed Gas Utility System Impacts

Category	Impact	Description
Commodity/ Supply	Fuel	Purchasing gas at specific locations on the gas system and the variable cost of getting the gas where, and when, it will be used.
	Capacity & Storage	The gas and storage capacity required to meet forecasted peak load.
	Environmental Compliance	Actions to comply with environmental regulations.
	Market Price Effects	The decrease (or increase) in wholesale prices as a result of reduced (or increased) customer consumption.
Transportation	Transportation	The transport of gas from delivery points located on interstate and intrastate pipelines to distribution utility city gate.
Delivery	Delivery	Delivery of gas from the city gate to retail customers.
General	Same as Electric Utility System Impacts	

Additional Guidance

i. Environmental Compliance

There was significant stakeholder discussion around the treatment of greenhouse gas (GHG) emissions, criteria air pollutants, and the regulatory cost of carbon as to whether these are utility system or societal impacts.

It is important that anything considered a regulatory cost or mandated cost be included as a utility system cost. If the cost of such regulations or mandates are currently or anticipated to be paid by ratepayers over the BCA study period, then it is considered a utility system cost. If the social cost of carbon (SCC) is also included as a societal benefit, the GHG and carbon values already included in the utility system costs should be subtracted out to avoid double counting.

ii. Risk, Reliability, and Resilience

No parties oppose the inclusion of risk, reliability, and resilience impacts in the MN Test. However, the question for how to account for these impacts remains. Based on feedback from the CAC, the impacts of risk, reliability, and resilience may already be embedded in other utility system impacts through the Integrated Resource Plan (IRP) and Integrated Distribution Plan (IDP) process. For the sake of transparency, the utilities should document in which utility system impacts these are included and adjust definitions accordingly. If after review, these impacts are not included, they should be included individually within the appropriate utility system impact category.

2. Non-Utility System Impacts

Policy goals

The decision for which non-utility system impacts to include should be based upon Minnesota's applicable policy goals.[77] As part of the CAC workshops, stakeholders submitted homework indicating whether the impacts of participant Impacts, other fuels, water, and low-income should be included in the primary test. The DOC and Synapse also reviewed applicable policy goals and mapped those to each

[77] NSPM for DERs, page 3-7.

impact. Based on these responses and discussions during the workshops, we propose the below non-utility system impacts for the straw proposal.

Participant Impacts

Participant impacts are those impacts pertaining to a utility customer that participates in a program. The decision to include participant impacts is a policy decision and should be based on the applicable policy goals of Minnesota. Based on the initial review of Minnesota policies, there is a relatively weak link to participants, primarily in relation to cost-effectiveness as described in Minn. Stat. § 216C.05, Subd 1 and Minn. Stat. § 216b.241, Subd 14. However, most CAC stakeholders indicated these impacts should be included, as long as participant costs and benefits are treated symmetrically.

For these reasons, we recommend that participant costs and benefits be included in the MN Test. This will ensure the MN Tests adheres to Principle 3 of the NSPM for DERs by creating symmetry and avoiding unintended bias in the assessment of energy efficiency resources.

Table 4 below provides a proposed initial list of participant impacts for inclusion in the MN Test.

Table 4. Participant Impacts

Type	Participant Impact	Description
Participant Energy Impacts	Participant portion of DER costs	Costs incurred to install and operate DERs
	Participant transaction costs	Other costs incurred to install and operate DERs
	Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER. Should be incremental to that included in Utility System Impacts.
	Reliability	The ability to prevent or reduce the duration of host customer outages. Should be incremental to that included in Utility System Impacts.
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions. Should be incremental to that included in Utility System Impacts.
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs
Participant Non-Energy Impacts	Water	Changes in water consumption resulting from a DER (e.g., reductions from low-flow showerheads, spray valves, clothes washers)
	Asset value	Changes in the value of a home or business resulting from a DER (e.g., increased building value, improved equipment value, extended equipment life)
	Productivity	Changes in a customer's productivity (e.g., changes in labor costs, operational flexibility, O&M costs, reduced waste streams, reduced spoilage)
	Economic well-being	Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)
	Comfort	Changes in comfort level (e.g., thermal, noise, and lighting impacts)
	Health & safety	Changes in customer health or safety (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths)
	Empowerment & control	The satisfaction of being able to control one's energy consumption and energy bill
	Satisfaction & pride	The satisfaction of helping to reduce environmental impacts (e.g., one of the reasons why residential customers install rooftop PV)

It may not be realistic to quantify all NEIs listed in Table 4 by the next triennial plan. Therefore, we recommend prioritizing the NEIs that are likely to have the most significant impacts on cost-effectiveness. Table 5 provides the relative impact of NEIs to total benefits by program for Rhode Island's 2022 energy efficiency programs. Programs with measures related to weatherization, such as retrofit programs, typically have the largest NEIs.

Within the residential programs, NEIs related to comfort, health and safety, and asset value have the largest impact and for C&I programs operation and maintenance NEIs are the largest. It would therefore make sense to start with an examination of these NEI values for similar programs in Minnesota.

Table 5. NEI Benefits as a Percentage of Total Benefits

Sector	Program	NEIs as % of Total Benefits
Residential	New Construction	2%
	HVAC	3%
	Single-Family Retrofit	8%
	Multi-Family Retrofit	31%
	Behavioral	0%
	Products	0%
Low-Income	Single-Family Retrofit	44%
	Multi-Family Retrofit	47%
Commercial & Industrial	New Construction	-5%
	Retrofit	14%
	Small Business	15%

Other Fuels Impacts

The impact of other fuels captures the impacts on fuels that are not provided by the relevant utility, for example, electricity (for a gas utility), gas (for an electric utility), oil, propane, gasoline, and wood.

The impact of other fuels should be included in the MN Test. There is a clear policy mandate for the inclusion of other fuels within the MN Test. There is mention of other fuels within 13 policies as included in the Summary of MN Energy Policies as included as an attachment to this straw proposal. For example, the Energy Conservation & Optimization Act of 2021 specifically includes language related to other fuels and Strategic Electrification.

Low-Income Impacts

Impacts related to low-income customers should be included in the MN Test. There are several Minnesota policies that specifically mention the importance of providing programs to low-income customers and ensuring their protection, including Minn. Stat. § 216B.2427, Subd 2, Minn. Stat. § 216b.2403, Subd 5, and Minn. Stat. § 216b.241, Subd 7 as included in the attached Summary of MN Energy Policies.

Furthermore, current cost-effectiveness practice indicates that low-income programs do not have to be cost-effective for inclusion in the IOUs' CIPs. This practice is based on the premise that the benefits of offering low-income programs outweigh the costs, but those benefits are not monetized.
IOUs could continue this practice as a means to include low-income benefits in the MN Test. In the future, these benefits could also be monetized for inclusion in the benefit-cost assessments. Low-income benefits will be similar to many of the participant NEIs but may have a greater magnitude due to the baseline of housing stock for this subset of customers. Table 6 provides a summary of low-income single-family NEIs as currently included in Rhode Island's energy efficiency programs. The table provides the monetized value and the measure group it is applied to within the cost-effectiveness test.

Table 6. Rhode Island Natural Gas Measure NEIs

Low-Income Benefits	Description	Measure Categories	Annual Value
Safety-Related Emergency Calls	Financial savings to the utility as a result of fewer safety related emergency calls being made.	Heating System	$8.43
Thermal Comfort	Greater participant-perceived comfort in home.	Insulation	$30.13
		Air Sealing	$35.89
		Heating System	$33.24
Noise Reduction	Less participant-perceived noise in the home.	Insulation	$13.56
		Air Sealing	$16.39
Home Durability	Increased home durability in terms of maintenance requirements because of better quality heating, cooling and structural materials.	Insulation	$8.76
		Air Sealing	$10.61
		Heating System	$27.43
Equipment Maintenance	Reduced maintenance costs of owning newer and/or more efficient appliances.	Heating System	$9.72
Health Benefits	Fewer colds and viruses, improved indoor air quality and ease of maintaining healthy relative humidity as a result of weatherization in home.	Insulation	$17.40
		Air Sealing	$230.08
		Heating System	$213.13
Improved Safety	Reduced risk of fire and fire-related property damage.	Insulation	$17.40
		Air Sealing	$2.24
		Heating System	$18.87

Source: National Grid Rhode Island Technical Reference Manual: 2022 Program Year. Appendix B: Non-Energy Impacts.

3. Societal Impacts

Policy Goals

This category captures the impacts of energy efficiency to society, incremental to what may already be embedded in utility system impacts. These impacts are often referred to as externalities. The decision of whether to include societal impacts should be based on Minnesota's policy goals. The impacts included in Table 7 should be included in the MN Test due to their strong linkage to Minnesota policy goals.

Table 7. Societal Impacts

Category	Impact	Description
Societal Impacts	GHG Emissions	Non-embedded GHG emissions. Should be incremental to values included in utility system impacts.
	Criteria Air Emissions	Emissions of criteria pollutants.
	Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts.
	Economic and Jobs	Incremental economic development and job impacts.
	Energy Security	Reduction in imports of various forms of energy to help inform the goals of energy independence and security.
	Energy Equity	Energy equity requires intentionally designing systems, technology, procedures, and policies that lead to the fair and just distribution of benefits in the energy system.

GHG Emissions

Societal GHG emissions are considered externalities because they are not included in the cost of electricity and gas. This impact is meant to capture the additional cost of GHG emissions after environmental compliance regulations have been met.

It is important that any environmental compliance costs associated with the reduction of GHG emissions that are already included in Utility System Impacts be subtracted from this impact to avoid double counting.

We recommend including this impact in the MN Test because reducing GHG emissions is identified in 12 policies as described in the attached Summary of MN Energy Policies. Specifically, the Energy Conservation & Optimization Act of 2021, indicates the need to reduce pollution and emissions that cause climate change.

Criteria Air Emissions

Under the federal Clean Air Act, the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for six common air pollutants, commonly referred to as "criteria air pollutants", that contribute to environmental and health problems. These include carbon monoxide, lead, nitrogen oxides, ground-level ozone, particle matter, and sulfur oxides.[78] To the extent the impacts from these emissions are not included in the cost of electricity and gas, it would be accounted for here as a societal impact. This impact is meant to capture the additional costs associated with criteria air emissions after environmental compliance regulations have been met.

We recommend including this impact in the MN Test because reducing criteria air emissions is identified in MN Statute 216B.03 on page 55 of the attached Summary of MN Energy Policies.

There is potential for this impact to overlap with the environmental compliance impacts within the utility system impacts, thus care should be taken to avoid double-counting.

[78] https://www.epa.gov/criteria-air-pollutants/naaqs-table

Other Environmental

This impact is intended to be a catch-all for all other environmental impacts. This could include air emissions, solid waste, land, water, and other environmental impacts that are not already embedded in environmental compliance costs that are included in the utility system impacts.

We recommend including this impact in the MN Test because reducing other environmental impacts is identified in Minnesota statutes as a policy goal. Specifically, the Next Generation Energy Act of 2007 describes the importance of environmental protection[79], Natural Gas Innovation Act of 2021 discusses reductions in waste[80], and the CIP IOU statutory requirements detail disposal of LEDs.[81]

Economic and Jobs

Investment in energy efficiency resources will result in additional jobs and economic development in several ways. There are jobs associated with managing and delivering the efficiency programs and jobs associated with the companies that implement the programs (such as contractors, vendors, product manufacturers, etc.). Further, efficiency savings provide consumers with more disposable income, which helps creates jobs and spurs economic development.

The NSPM for DERs states that economic development can be shown as changes to employment (in job-years), gross domestic product (in $), personal income (in $), or state tax revenues (in $).[82] The economic indicators are interrelated and cannot be added together. Further, the monetary values of economic development cannot be added to the monetary cost-effectiveness analysis results because that would result in double-counting. Therefore, the estimates of economic development impacts should be presented alongside the rest of the results of the BCA. Synapse recommends that the number of job-years be used to represent economic development, because job growth is easily understood and relatively easy to isolate from the other indicators.

There is a clear policy linkage in Minnesota to economic and job benefits. It is mentioned in five policies in the attached summary, most notably the Energy Conservation & Optimization Act of 2021 states the need to "improve the competitiveness and profitability of businesses, create more energy-related jobs."[83]

We recommend including this impact in the MN Test because reducing economic development is identified in several statutes as a policy goal for Minnesota.

Energy Security

Energy efficiency can sometimes reduce imports of fossil fuels that are used to generate electricity, heat buildings, or power industries in Minnesota. Reducing imports of fossil fuels can help advance the goals of energy independence and security.

We recommend including this impact in the MN Test because reducing fossil fuel consumption, specifically fuel imports, is identified in three policies within the attached Summary of MN Energy Policies. Specifically, the Energy Conservation & Optimization Act of 2021 state the need to "reduce the

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[79] Summary of MN Energy Policies, pg. 9.
[80] Id., pg. 15.
[81] Id., pg. 40.
[82] NSPM for DERs, pg.4-22.
[83] Summary of MN Energy Policies, pg. 8.

economic burden of fuel imports"[84] and the Next Generation Energy Act of 2007 "finds and declares that the protection of life, safety, and financial security for citizens during an energy crisis is of paramount importance".[85]

There is potential for this impact to overlap with the utility system impacts of reliability and risk, thus care should be taken to avoid double-counting.

Energy Equity

While there are multiple definitions of energy equity, Pacific Northwest National Laboratory defines it as:

> "An equitable energy system is one where the economic, health, and social benefits of participation extend to all levels of society, regardless of ability, race, or socioeconomic status. Achieving energy equity requires intentionally designing systems, technology, procedures, and policies that lead to the fair and just distribution of benefits in the energy system."[86]

We recommend including this impact in the MN test. The attached Summary of MN Energy Policies includes five energy policies with mention of equity. While there is not a direct linkage to the definition of equity provided here, the policies note the need to provide energy efficiency to all utility customers and utility sectors. In addition, the stakeholders noted that this is an important, emerging policy goal for Minnesota.

4. Excluded Impacts

There are three impacts we exclude from the straw proposal. These include the non-utility system impact of water and the societal Impacts of public health and resilience. We provide a definition of these impacts and reasons for exclusion below.

Water

Investments in energy efficiency can reduce water consumption.

We recommend excluding this impact from the MN Test because there is no link to Minnesota's policy goals and this value would likely be accounted for as a participant benefit from the installation of energy efficiency measures that also produce water savings.

Public Health

Investments in energy resources can create health impacts for populations impacted by fuel extraction, combustion, and transportation. This can lead to impacts on the level of societal investment required in medical facility infrastructure and economic productivity.

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[84] Summary of MN Energy Policies, pg. 8.
[85] Id., pg. 9.
[86] Pacific Northwest. n.d. (PNNL Energy Equity). Pnnl.com website. https://www.pnnl.gov/projects/energyequity#:~:text=What%20is%20energy%20equity%3F,energy%2Defficient%20housing%20and%20transportation

We recommend excluding this impact from the MN Test because there is no link to Minnesota's policy goals and this impact could be accounted for anyway in either criteria air pollutants or participant and low-income NEIs.

Resilience (Societal)

This impact is meant to reflect resilience impacts beyond those experienced by utilities or participants.

We recommend excluding this from the MN Test because of CAC stakeholder comments that this may be accounted for within the utility system impacts.

Memo

To: Department of Commerce

From: Center for Energy and Environment

CC: Synapse Energy Economics

Date: June 29, 2022

Subject: Feedback on CIP Cost-Effectiveness Straw Proposal

Center for Energy and Environment (CEE) respectfully submits the following written feedback on the June 8, 2022 *Cost-Effectiveness Test for Minnesota Conservation Improvement Programs Straw Proposal* ("Straw Proposal") for the primary cost-effectiveness test to the Minnesota Department of Commerce, Division of Energy Resources ("Department").

First, CEE thanks the Department and its consultant, Synapse Energy Economics ("Synapse"), for leading the Cost-Effectiveness Advisory Committee ("CAC") through the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* ("NSPM") process to develop a Minnesota-specific primary cost-effectiveness test for the Conservation Improvement Program ("CIP"). We believe this process will help to ensure that Minnesota's CIP continues to advance the important goals and objectives of our state's energy policy well into the future.

CEE generally supports the Straw Proposal. The Straw Proposal reflects Minnesota's relevant policies as well as CAC stakeholders' feedback to date. However, we have a few recommendations and considerations regarding specific inputs proposed for inclusion or omission in the Straw Proposal. We share those below.

Utility System Impacts

Electric Utility System Inputs:

- Environmental Compliance

CEE supports including environmental compliance costs as a utility system impact in the primary CIP cost-effectiveness test. The Straw Proposal notes that environmental compliance costs can include costs associated with compliance with federal regulations or state or local greenhouse gas goals.

CEE recommends that the Department and the CAC consider incorporating the long-term incremental energy system costs associated with meeting Minnesota's greenhouse gas emissions reduction goal.[87]These incremental costs are significant, as modeled for a recent

[87] Minnesota Statute 216H.02

stakeholder process focused on reducing the emissions of natural gas end-uses in Minnesota.[88] Incremental energy system and resource costs will be necessary for meeting the state goal of an 80 percent emissions reduction by 2050. Those incremental energy system costs should be considered in calculating the avoided costs for long-lived energy efficiency measures.

In the stakeholder process, the CAC discussed the use of the regulatory compliance cost of carbon in integrated resource plans and the possibility of including that cost in the primary CIP cost-effectiveness test. CEE understands that the idea behind the regulatory cost of carbon is that at some point in the future the federal government may implement a regulatory fee or tax on utility greenhouse gas emissions. That regulatory tax or fee would aim to internalize some or all of the externality costs of emissions. Therefore, it would not be appropriate to use both an externality value and a regulatory cost of carbon together for the same emissions.

Given this logic, CEE believes that it is reasonable to continue using greenhouse gas externality values to estimate the avoided costs of greenhouse gas emissions. The CIP environmental damage factor reflects an externality value and is based on the Minnesota Public Utilities Commission's approved externality values of emissions from Docket Number E999 CI-14-643. These externality values represent a comprehensive estimate of damage caused by greenhouse gas emissions over time. Using the externality value of greenhouse gas emissions rather than using two separate values for emissions that occur at different times would maintain simplicity, while still capturing the full cost of emissions over time. However, if the DER considers updates to the utility cost test, it may be appropriate to include the regulatory cost of emissions in that test as a utility system cost.

- Risk, Reliability, and Resilience

Page five of the Straw Proposal states:

> *Based on feedback from the CAC, the impacts of risk, reliability, and resilience may already be embedded in other utility system impacts through the Integrated Resource Plan (IRP) and Integrated Distribution Plan (IDP) process. For the sake of transparency, the utilities should document in which utility system impacts these are included and adjust definitions accordingly. If after review, these impacts are not included, they should be included individually within the appropriate utility system impact category.*

CEE supports Synapse's proposal. We look forward to learning about this issue. CEE notes that is important that inputs for risk, reliability, and resilience reflect the added risks posed by climate change and the costs of adaptation.

[88] Page 35 of Appendix VII. (https://e21initiative.org/wp-content/uploads/2021/07/Decarbonizing-NG-End-Uses-Stakeholder-Process-Summary.pdf)

Gas Utility System Inputs:

- Fuel Price

The Straw Proposal includes fuel as an input in the proposed gas utility system impacts for the primary cost-effectiveness test. CEE supports including fuel costs in the primary test. However, we recommend including a factor or other mechanism to represent the risk of price volatility in fuel markets. Storm Uri is the most recent example of price volatility in fuel markets, but many similar examples have occurred in the past due to geopolitical events, extreme weather events, and pipeline issues. The risk of price volatility does not appear to be included in the input titled "Risk" under "General Impacts." There, risk is defined as "Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks."

- System Losses

The proposed inputs for the gas utility system impacts for the primary cost-effectiveness test do not include any input that explicitly mentions losses on the gas system. The Department should consider adding an input that represents losses on the gas system, both in terms of fuel costs and emissions.

Non-Utility System Impacts

- Participant Impacts

The Straw Proposal includes both participant costs and participant benefits in the proposed primary CIP cost-effectiveness test. CEE does not support including participant costs and benefits in the primary CIP cost-effectiveness test. Instead, we recommend using the participant cost test as a secondary cost-effectiveness test to evaluate cost-effectiveness from the participant perspective and inform program design.

First, CEE does not believe there is a strong policy argument to include participant costs in the primary cost-effectiveness test based on Minnesota policy and the NSPM process. On page six of the Straw Proposal, Synapse states, "Based on the initial review of Minnesota policies, there is a relatively weak link to participants, primarily in relation to cost-effectiveness as described in Minn. Stat. § 216C.05, Subd 1 and Minn. Stat. § 216b.241, Subd 14." Synapse continues, "However, most CAC stakeholders indicated these impacts should be included, as long as participant costs and benefits are treated symmetrically."

We agree that there is not a clear link to participant costs and benefits in relevant Minnesota statutes. Additionally, after the robust conversations in the CAC stakeholder meetings, we believe it is unclear whether most CAC stakeholders still favor inclusion of participant costs and benefits. CAC stakeholders provided initial feedback on cost-effectiveness inputs through a survey early in the CAC process, prior to discussing the pros and cons of including participant costs and benefits. If stakeholder opinion is the primary reason to include these costs and benefits, we recommend that CAC stakeholders are surveyed again.

Second, while participant costs, which include the costs to install or implement an energy efficiency or fuel-switching project, are relatively simple to quantify, participant benefits are not. Participant benefits include a range of non-energy impacts, including comfort, economic well-being, increased asset value, productivity, and health and safety. These non-energy benefits are difficult to quantify and monetize and can be very specific to a project and participant. For instance, increased productivity can be a significant benefit for a commercial customer, but less significant for a residential customer. Even within one customer class, participant benefits can vary widely. For instance, the value a specific residential customer receives from increased comfort for an insulation and air sealing project differs widely based on housing characteristics, location, and layout.

Synapse acknowledges the challenge of quantifying these broad participant non-energy benefits. On page four of the Straw Proposal, Synapse states, It therefore may not be feasible for all new impacts to be quantified and monetized for inclusion on the MN Test for the upcoming Triennial Plan. Synapse goes on to say, However, this does not indicate that these impacts should not be included in the MN Test. Such impacts could be addressed through a proxy or adder or discussed qualitatively. How these impacts are valued should be the subject of future workshops.

We disagree with this approach. We do not believe it is a good use of time and resources to develop interim or longer-term proxies and adders to estimate participant benefits for the primary cost-effectiveness test. Quantifying broad participant non-energy benefits is time-consuming, labor intensive, expensive, and can result in relatively arbitrary adders and estimates that fluctuate based on unrelated factors. These values can be very difficult to then support, or defend, with strong data-driven evidence. Supporting the inputs and values in the primary cost-effectiveness test is especially important as it is used as the regulatory screening test.

Importantly, including only participant costs, which are easy to quantify, in the primary cost-effectiveness test will result in asymmetry and unreasonably reduce cost-effectiveness of energy efficiency and fuel-switching programs.

Given the lack of a clear policy link to participant costs and benefits in Minnesota statute, the many problems in quantifying and supporting participant non-energy benefits, and the need for symmetry in the test, we recommend excluding participant costs and benefits from the primary cost-effectiveness test.

We believe that the participant cost test is much better suited to evaluate cost-effectiveness for participants. Unlike the proposed primary cost-effectiveness test, the participant cost test includes both upfront participant project costs and *participant utility bill impacts*. While consumers are experienced in evaluating upfront costs for products and services, and do so on a daily basis, consumers are less equipped to predict utility bill impacts, especially for efficient fuel-switching measures. We believe that the CIP participant cost test should be reviewed, potentially updated to improve symmetry of costs and benefits, and used as a secondary test to design programs, incentives, and potentially rates (outside of CIP). Given that it is not the primary regulatory screening test, we believe that it may be appropriate to develop adders or proxies to estimate participant non-energy benefits for the participant cost test.

- Low-Income Impacts

The Straw Proposal includes low-income impacts as an input in the primary CIP cost-effectiveness test. CEE supports including low-income impacts in the primary cost-effectiveness test. Quantifying and monetizing the non-energy impacts of energy efficiency for low-income customers should be a high priority for the Department and the CAC. These impacts are unique, significant, and more easily quantifiable than traditional, market rate participant non-energy impacts. Additionally, there are many existing studies to draw from that quantify low-income-specific impacts.

Societal Impacts

- Greenhouse Gas Emissions

The Straw Proposal includes greenhouse gas (GHG) emissions as an input into the primary CIP cost-effectiveness test. On page 10 of the Straw Proposal, Synapse explains, Societal GHG emissions are considered externalities because they are not included in the cost of electricity and gas. This impact is meant to capture the additional cost of GHG emissions after environmental compliance regulations have been met.

CEE supports including GHG emissions as a societal impact in the primary CIP cost-effectiveness test. We believe this is well-supported through Minnesotas energy policy. We agree with Synapses statement that if a regulatory cost of carbon is included as a utility system impact, that value should be subtracted from the externality value reflecting the damage of greenhouse gas emissions. However, as noted above, simply using the full externality value to reflect greenhouse gas emissions would be simpler and, based on our understanding, would not change the overall value of emissions included in the primary cost-effectiveness test (it would only change the category in which the impacts are reported).

In determining the appropriate values for GHG externalities, we note that the ECO statute (216B.241, Subdivision 2(k)) requires:

> *A public utility filing a conservation and optimization plan that includes an efficient fuel-switching program to achieve the utility's energy savings goal must, as part of the filing, demonstrate by a comparison of greenhouse gas emissions between the fuels that the requirements of subdivisions 11 or 12 are met, as applicable, using* ***a full fuel-cycle energy analysis.*** [emphasis added]

The full fuel cycle analysis is defined by the U.S Environmental Protection Agency as: Lifecycle analysis, sometimes referred to as fuel cycle or well-to-wheel analysis, is used to assess the overall greenhouse gas (GHG) impacts of a fuel, including each stage of its production and use.[89]

We support including full fuel cycle GHGs in the cost-benefit analysis for fuel-switching measures in ECO and note that the Department and other stakeholders have already worked to quantify the full fuel cycle emissions of natural gas and electric resources in Docket Number G-999/CI-21-566. These values may be used to estimate emissions on a carbon-equivalent basis for CIP and ECO as well.

Also in Docket Number G-999/CI-21-566, the Department and stakeholders discussed the most appropriate externality values for GHG emissions, based on the high and low ranges approved by the Commission in Docket E-999/CI-14-643.[90] Stakeholders and the Department agreed that using the high range externality values was appropriate given the most recent science on GHG emissions and climate change. We support using the high externality values, approved by the Commission for each year of analysis of a measure, program, or portfolio in CIP and ECO as well.

- Energy Security

The Straw Proposal includes energy security as a societal impact for the primary CIP cost-effectiveness test. On page 12 of the Straw Proposal, Synapse explains, We recommend including this impact in the MN Test because reducing fossil fuel consumption, specifically fuel imports, is identified in three policies within the attached Summary of MN Energy Policies.

CEE recommends that this input be re-defined as Reduced Economic Burden of Fuel Imports. We agree with Synapse that Minnesota policy clearly states that reducing the economic burden of fuel imports is an objective of energy conservation and optimization. Minnesota Statute 216B.2401 states:

> *The legislature further finds that cost-effective energy savings and load management programs should be procured systematically and aggressively in order to reduce utility costs for businesses and residents, improve the competitiveness and profitability of businesses, create more energy-related jobs, **reduce the economic burden of fuel imports**, and reduce pollution and emissions that cause climate change.* [emphasis added]

However, we do not know of any relevant Minnesota policy that describes “energy security.” Therefore, we recommend changing this input to Reduced Economic Burden of Fuel Imports,” defined and quantified as the economic impact of reduced dollars flowing out of Minnesota to purchase fuels from other states. Minnesota produces no fossil fuels in the

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[89] https://www.epa.gov/renewable-fuel-standard-program/lifecycle-analysis-greenhouse-gas- emissions-under-renewable-fuel
[90] January 3, 2018 Order in Docket Number E999/CI-14-643

state. Therefore, 100 percent of Minnesota dollars spent on fossil fuels leave our state and do not benefit our state's economy. That economic loss should be quantified and included in the primary cost effectiveness test for CIP and ECO.

Excluded Impacts

- Water

To the extent that water savings occur as a result of CIP and ECO projects, we recommend that water savings be included in "Other Environmental Impacts" under the proposed inputs for Societal Impacts.

- Public Health

We generally agree that public health impacts of energy are included in the externality values for criteria pollutants, which is included in the Straw Proposal under Societal Impacts. We note that any additional public health impacts specific to low-income participants should be included in the Low-Income Impacts in the Non-Utility Impacts.

Conclusion

CEE appreciates the Department's open and extensive engagement with CAC stakeholders through this process. We believe that this process has been extremely informative and valuable and we look forward to continuing our work as part of the CAC.

If you have any questions, please contact Audrey Partridge at apartridge@mncee.org or 651-269-8414.

505 Nicollet Mall
PO Box 59038
Minneapolis, MN 55459-0038

June 29, 2022

To: Minnesota Conservation Improvement Program Cost-Effectiveness Advisory Group

From: CenterPoint Energy

RE: Comments on Cost-Effectiveness Straw Proposal

In a Conservation Improvement Program ("CIP") Cost-Effectiveness Advisory Committee ("CAC") meeting on June 15th, 2022, Department of Commerce Staff ("Department Staff") requested stakeholders provide comments on the straw proposal for a new, revised cost-effectiveness test for Minnesota. The straw proposal was developed and provided by Synapse for stakeholder review on June 8, 2022 and discussed in the June 15th meeting.[91] Department Staff requested written feedback by June 29th, 2022.

CenterPoint Energy ("the Company") appreciates the opportunity to review and provide feedback on these topics, as well as the time and effort Department Staff, Synapse, and stakeholders put into developing this initial straw proposal. The Company provides the following feedback on the straw proposal.

I. Primary Minnesota Cost-Effectiveness Test

CenterPoint Energy is generally supportive of the proposed straw proposal for Minnesota's primary cost-effectiveness test. The Company only has a few comments in support of particular aspects of the proposal.

CenterPoint Energy supports expanding the scope of benefits (and costs) accounted for in a version of the societal cost-effectiveness test to be used as the primary Minnesota test. Energy efficiency is an important resource for meeting energy needs. Expanding the system boundary of a cost-effectiveness analysis in order to fully value energy efficiency will help incentive implementation of the most impactful solutions through CIP portfolio development. The Company agrees it is worthwhile to explore the inclusion of other effects of energy efficiency such as on economics and the environment effects, as long

[91] Lane, C.; Woolf, T. *Cost-effectiveness Test for Minnesota Conservation Improvement Programs*. June 8, 2022. Memo

as the additional effects are empirically based, consistently applied, and not overly administratively burdensome. The Company looks forward to better understanding what these effects look like for Minnesota and what they imply about revisions to the cost-effectiveness tests for the 2024-2026 CIP Triennial Plan.

CenterPoint Energy is also supportive of including both participant costs and benefits in a primary cost-effectiveness test for Minnesota. The Company believes there are opportunities and risks associated with either removing participant costs or adding participant benefits to the primary test. The risks associated with quantifying participant benefits were well covered in the workshop, but the Company believes the risks associated with removing participant costs are more significant. Relative to including additional societal benefits in the primary test, removing participant costs from the primary test seems likely to affect the cost-effectiveness of the utilities' current CIP portfolios more significantly. The change seems potentially significant enough that a complete reevaluation of programs and their services might be needed for aligning with the new cost-effectiveness results. The Company is open to having that discussion, but it seems like those changes are likely to lead to a protracted CIP Triennial Planning process, and a significant focus of the new triennial could be revisions rather than expanding services related to recently passed legislation such as efficient fuel switching. The Company agrees that including participant costs in the primary test is the right approach in the near-term, at minimum.

II. **Utility Cost-Effectiveness Test ("UCT")**

CenterPoint Energy supports including additional utility benefits and costs in the UCT. Similar to the primary Minnesota cost-effectiveness test, the Company supports efforts to improve the accuracy and precision of our cost-effectiveness tests for evaluating the value of energy efficiency, as long as those efforts are empirically based, consistently applied, and not overly administratively burdensome.

That said, CenterPoint Energy would note that there is a policy issue that should be discussed in future workshops related to incorporating utility performance incentives into UCT testing. The current utility financial incentive mechanism is based on the UCT and therefore the inclusion of utility performance incentives into the test creates circular reasoning in the cost-effectiveness calculations.[92] Under the existing financial incentive mechanism, adding these costs to the test doesn't provide much informational value because when the incentive is a percent of net benefits the cost will scale based on the test results and not substantially change relative outcomes for measures or programs. The Company recommends that the implications of this topic be discussed in one of our future workshops because of the potential issues this change could create for cost-effectiveness models.

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[92] *In the Matter of Commission Review of Utility Performance Incentives for Energy Conservation Pursuant to Minn. Stat. § 216B.241, Subd. 2c,* Docket No. E,G-999/CI-08-133, Order Adopting Modifications to Shared Savings Demand-Side Management Financial Incentive Plan (Dec. 9, 2020).

Brian Edstrom <briane@cubminnesota.org>
Tuesday, June 28, 2022 4:39 PM
Zoet, Adam (COMM); gstaples@mendotagroup.com
Re: Straw Proposal and 6/15 CIP Cost-Effectiveness Advisory Committee Mtg

Hi Adam and Grey,
Just offering a comment on the straw proposal.
I disagree somewhat (or at least suggest an addition) with Table 4.

Though I think bill savings is a participant benefit inherently considered in several categories included in the straw proposal, I think it could/should be called out more specifically as its own category Though bill savings is inherently related to "participant portion of DER costs" and "Participant transaction costs" I think it is broader and somewhat distinguishable from those two categories, too. Also, though I see "economic well-being" *beyond* bill savings, I think the actual bill savings are the more immediate, tangible benefit that should be considered. Could "bill impacts" be its own row/category in Table 4? Or is it already addressed elsewhere, in your opinion?

Thanks for your hard work on this.

Best, Brian

Cost-Effectiveness Test for Minnesota Conservation Improvement Programs: Fresh Energy's Comments on Synapse's Straw Proposal for the MN Test

Date: June 29, 2022

To: Minnesota Department of Commerce

From: Joe Dammel, Caitlin Echten, Mari Ojeda, Fresh Energy

Overview

Fresh Energy submits these Comments in response to the MN Test Straw Proposal prepared for the Minnesota Cost -Effectiveness Advisory Committee by Synapse Energy Economics on June 8, 2022. These comments will address several impacts included in the straw proposal that warrant additional discussion, including participant non-energy impacts, criteria air pollutants, energy equity, and public health. We focused comments on a subset of impacts included in the Straw Proposal; for those impacts not discussed below, we have no objection to the treatment of those particular impacts as defined in the Straw Proposal

Non-Utility System Impacts

Participant Impacts

Fresh Energy appreciates the discussion on the inclusion of participant costs and benefits (non-energy impacts or NEIs) in the MN Test. In survey responses, stakeholders were generally supportive of including participant NEIs in development of the straw proposal, provided the resulting impacts adhere to NSPM principles, specifically the principle of symmetry. In the June 15, 2022 workshop #3, however, several stakeholders expressed concern over the inclusion of participant NEIs in the MN Test.

In general, those stakeholders who expressed concern raised several points. First, that participant NEIs can be difficult to quantify and could lead to an unbalanced result, with easier-toquantify costs outweighing difficult-to-quantify benefits. Second, some stakeholders note that there is not a strong statutory connection to support inclusion of participant NEIs. We understand that of the stakeholders who expressed concern, the primary recommendation is to exclude both participant costs and benefits, but, if participant costs are included in the MN Test, that participant benefits should also be calculated and included.

We are persuaded that participant NEIs should *not* be included in the MN Test at this time given the concerns raised by stakeholders. At the outset, Fresh Energy was intrigued by the data from Rhode Island that were provided by Synapse showing the impact of inclusion of NEIs on the net benefits of programs such as multi-family retrofits. Inclusion of NEIs in that state appeared to positively impact the cost-effectiveness of programs that have traditionally been difficult to address, but beneficial in terms of improving both existing housing stock and low-income programs. But it is our understanding that Rhode Island also includes participant costs in its MN Test. In other words, Rhode Island's approach conforms to the secondary recommendation of stakeholders, which is to include participant benefits *if* participant costs must be part of the test. We agree that if participant costs are included in the MN Tests, benefits should be as well, but our primary recommendation is to not include either in the MN Test.

We considered and were persuaded by stakeholders' arguments in Workshop 3 that including participant NEIs could lead to an unbalanced test due to the difficulty in calculating some participant NEIs. We do not agree, however, with the contention that there is little statutory connection to evaluating participant costs and benefits given the statutory requirement for cost-effectiveness to be evaluated considering “the costs and benefits to . . . participants . . . .”[93] While there may be a more appropriate test within which participant NEIs could be considered, as discussed below, there is a reasonable statutory connection for participant NEIs to be considered in the MN Test if the Department chose to do so now or in the future.

At this time, however, the better evaluative test to consider participant NEIs is the Participant Cost Test (PCT). As the name suggests, the PCT evaluates a program from the perspective of the program participant. By design, the PCT values benefits based on avoided electricity and gas rates as opposed to avoided utility system costs.[94] Because of this, the PCT has little value in cost-effectiveness screening, but it “can be useful for informing efficiency program design by providing insight into energy bill impacts on participants.”[95]In the 2018 Synapse study, the report authors recommended including participant NEIs, noting that “Minnesota only includes incremental participant O&M savings” as a non-energy benefit in the PCT.[96] We recommend that future workshops of this committee include discussion on a full suite of participant NEIs in the context of the PCT and we recommend that future work be done to address possible valuation of these NEIs.

Incorporation of participant NEIs in the PCT will be an important update to ensure that CIP programs are designed to address needs of participants. If Minnesota adopts participant NEIs and does the work to assign values to the participant NEIs, this exercise could also inform future discussions about participant NEIs for use in the MN Test. At this time, we recommend that participant NEIs (inclusive of costs and benefits) be excluded from the MN Test, but we recommend that they be developed and included in the PCT, for the reasons noted above.

Water Impacts

As discussed during workshop #3, if water is not treated as a participant impact (or if participant impacts are not considered in the MN Test, as we recommend), then water should be included as a non-utility system impact and treated similarly to impacts from other fuels. In the Straw Proposal, Synapse recommended excluding this impact from the MN Test because it would likely be accounted for as a participant benefit from the installation of energy efficiency measures that also produce water savings. But if participant benefits are not included in the MN Test, we this impact should be included to account for reduced water consumption due to investments in energy efficiency.

Low-Income Impacts

Fresh Energy agrees that low-income impacts should be included in the MN Test. We are interested in working to monetize the benefits of these programs that are currently assumed to pencil out. Valuation of these non-energy benefits could help policymakers, utilities, and stakeholders design and implement low-income CIP programs that can more effectively serve participants’ needs. We are supportive of the current assumption that the benefits to these

[93] Minn. Stat. § 216B.241, subd. 1c(e).
[94] Synapse Energy Economics, Inc., Updating Minnesotas Energy Efficiency Cost-Effectiveness Framework 42 (2018).
[95] *Id.*
[96] *Id.* at 46.

programs outweigh the costs—we strongly believe that they do—but we are also interested in refining this analysis with real values to more effectively serve this important group.

Societal Impacts

GHG Emissions

Fresh Energy agrees with the proposal to include this impact in the MN Test. As noted in the Straw Proposal, societal GHG emissions are externality costs and these costs are borne by society, not utilities. And a s noted by the Commission in a 2020 Order on establishing a regulatory cost of carbon, "[e]nvironmental costs address the costs that the emissions of greenhouse gasses such as CO2 impose on society, and increase over time; regulatory costs address the costs that utilities are expected to incur to comply with future regulations addressing CO2 emissions."[97] The Commission in the regulatory cost Order further cautioned against simply adding the two values together for electricity resource planning purposes.[98]

We agree that double counting values would violate NSPM principles and we look forward to future discussion about any possible overlap between regulatory costs and societal costs of carbon. There should be very little overlap in the values that both approaches attempt to capture, but we do not oppose an exercise to attempt to identify any overlapping costs. In addition, as we move into the valuation phase the valuation of GHG emissions in CIP must follow the latest science and guidance, especially as it relates to the social cost of carbon, which should be valued at the high end of the values approved by the Commission in the 2018 Order in docket 14-643.

Criteria Air Emissions

We recommend combining criteria air emissions within the public health impact, as discussed during workshop #3. Health problems cause d by criteria air emissions will therefore be captured in the "Public Health" impact, which we recommend including in the MN Test (see below for discussion). Environmental impacts caused by criteria air emissions should be captured in the "Other Environmental" impact.

Economic and Jobs

Fresh Energy agrees with the proposal to include this impact in the MN Test and we are interested to discuss how economic and workforce development will be valued in future committee discussions.

Energy Equity

Fresh Energy agrees with the proposal to include this impact in the MN Test.

As the Straw Proposal notes, there are multiple definitions of energy equity and the proposal provides a definition from the Pacific Northwest National Laboratory. In addition to "intentionally designing systems, technology, procedures, and policies that lead to the fair and just distribution of benefits in the energy system," the Department should establish a definition of energy equity (and the resulting metrics) that seek to rectify historical inequitable disparities that frontline, under-resourced, and BIPOC communities currently face. We recommend utilizing

[97] Order Establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs, *In the Matter of Establishing an Updated 2020 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06,* Docket No. E-999/DI-19-406 3-4 (Sep. 30, 2020).
[98] *Id.*

resources from The Energy Equity Project[99] or ACEEE 's "Leading with Equity" report and initiative to assist in establishing a definition and values for this important impact and we look forward to future discussions about this issue.[100]

Excluded Impacts

Public Health

In accordance with our recommendation that criteria pollutant impacts be folded into public health impacts, we recommend that public health impacts be included in societal impacts. This is also consistent with the recommendation from Synapse's 2018 report that public health benefits should be included in the MN Test. We recommend combining the criteria air emissions impact within the public health impact, and including this combined impact in the MN Test. The public health impact should capture reductions in the frequency and/or severity of health problems of populations due to reductions in criteria air emissions and waste, and improved indoor air quality. Such reductions can have positive implications for the level of societal investment required in medical facility infrastructure, as well as in the health, wellbeing, and economic productivity of the populace.

We believe it is especially important to include public health impacts in the MN Test if participant NEIs (and therefore the health & safety subcategory) are excluded from the MN Test. In the Straw Proposal, Synapse had noted that the public health impact would be partially accounted for in participant NEIs in the MN Test as part of the justification for excluding public health as a societal impact. This will not be the case if participant NEIs are not considered in the MN Test, as we recommend. Public health impacts are an important consideration when evaluating energy efficiency and other energy resources and should be accounted for in the MN Test.

The Straw Proposal noted the statutory link to criteria air pollutant impacts and so folding these impacts within a broader public health category retains this statutory link. We disagree that societal public health impacts have no connection to Minnesota energy policy. The cost-effectiveness approach outlined in Minn. Stat § 216B.241 requires an assessment of costs and benefits to society stemming from CIP programs. One of the most significant impacts that our energy system has on society is on public health. Further, public health impacts have an established and growing role in the decisions made by energy policymakers in Minnesota today. In the Minnesota Power (MP Integrated Resource Plan (IRP), for example, Fresh Energy and our partners submitted a report detailing the public health implications of MP's IRP plan.[101] Public health principles are also woven into customer-focused utility laws and policies such as the Cold Weather Rule, service quality reporting, and more.

If criteria pollutant impacts are folded into a broader public health impact category, we recommend organizing such a list as follows:

[99] https://energyequityproject.com or https://energyequityproject.com/wp-content/uploads/2021/05/EEP-brochure.pdf.

[100] https://www.aceee.org/energy-equity-initiative

[101] Kelsey Bilsback et al., *Incorporating Health and Equity Metrics into the Minnesota Power 2021 Integrated Resource Plan*, PSE Healthy Energy on behalf of Fresh Energy, MCEA, and the Sierra Club (April 2022).

Public Health

- o Health impacts of criteria air pollutants
- o Healthcare system costs
- o Declines in productivity
- o Investment in medical infrastructure
- o Improved community resilience/health during extreme weather events
- o Improved mental health

It may be the case that the value of the impacts related to criteria pollutants is much greater than any of the other additional considerations, but we are supportive of a process that considers additional public health-related impacts as we move into the phase where values for these impacts begin to be considered.

Conclusion

Fresh Energy appreciates the discussion amongst the Department and its consultants and stakeholders thus far in the process of re-imagining Minnesota's cost-effectiveness tests. In addition to the recommendations above, we also look forward to future meetings/workshops to address fuel costs used in cost-effectiveness calculations and to discuss how fuel switching measures will be incorporated into the cost-effectiveness tests that are currently being developed.

From: Gregory Ehrendreich - MEEA <Gehrendreich@mwalliance.org>
Sent: Wednesday, June 29, 2022 12:07 PM
To: Zoet, Adam (COMM); gstaples@mendotagroup.com
Subject: RE: Comments Reminder: CIP Cost-Effectiveness Advisory Committee

Categories: Cost-Effectiveness

Here's my comments outlining where I am on this Straw Proposal.

Areas in Agreement with Straw Proposal

Utility System Impacts

- In general agreement with what has been proposed

Non-Utility System Impacts

- it makes sense to focus on the NEIs that have the largest impacts & the programs that are most impacted by NEIs

I like the approach of Table 6 - defined NEI annual values - rather than having each utility work through the methodology and everything on their own it makes more sense to do it once for everyone and supply the values to use (perhaps with a caveat of "if these are wrong for you, provide another value showing all of your work")

Societal Impacts

- In general agreement
- A lot of this is stuff that has potential overlap with the system impacts and therefore has to avoid double counting. The straw proposal doesn't really get into the "how to" of things which gives me a little bit of concern - it's easy to say to just account for the part that is incremental to the previously counted, but from a practical standpoint is it going to be straightforward to do so?
- What /metric/ would be used to include Equity in BCA?

Excluded Impacts

- In general agreement with the proposal

Areas in Disagreement with Straw Proposal

Utility System Impacts

- no areas of substantial disagreement

Non-Utility System Impacts

- no areas of substantial disagreement

Societal Impacts

- I have to admit, I don't really understand the explanation of why the economic indicators can't be added together & how economic development would be double-counting. If this is about what is/is not included in the BCA and this is proposing a separate side-analysis to accompany the BCA, then is this really included in the BCA?

Excluded Impacts

- no areas of substantial disagreement
- in some states where EE is less supported than in MN, the public health NEIs might be more important in demonstrating that there is non-participant value. Minnesota doesn't seem to have that political problem, so sticking with participant health and/or value of reduced criteria pollutants in the utility system is fine with me

Gregory Ehrendreich | MEEA

From: O'Rourke, Katie <KORourke@appliedenergygroup.com>
Sent: Wednesday, June 29, 2022 4:15 PM
To: Zoet, Adam (COMM); gstaples@mendotagroup.com
Cc: Reilly, Joseph
Subject: RE: Notes and Next Steps: CIP Cost-Effectiveness Advisory Committee

Adam & Grey,

MERC has no comments at this time. However, we appreciate the thoughtful and methodical direction you all have provided, along with the Synapse team, and looking forward to continued participation in the CEAC.

Best, Katie

Katie O'Rourke
Senior Program Manager
218.994.1666 (O)
appliedenergygroup.com

To: Adam Zoet, Grey Staples
From: Minnesota Power
Subject: Comments on Synapse MN Test Straw Proposal
Date: June 29, 2022

Overall Minnesota Power is on board with the categories included in the proposed MN test and has no areas of strong disagreement. However, the Company has some concerns regarding the level of new inputs to be explored and quantified and concerns over the ability to quantify many of these categories with any level of accuracy, especially in a timeline that will still allow utilities to evaluate programs (which will likely look quite different than normal) for the new triennials. Utilities may require more time than usual to evaluate new programs and measures within a brand new BAC framework and will need the inputs to be worked out with enough time to evaluate and adapt as necessary. There are more unknowns in this triennial planning period than ever before. Furthermore, Minnesota Power thinks it will be important to balance the need for symmetry with making sure inputs are meaningful. There are many new inputs that have never been quantified before in Minnesota, a lot of which are very difficult to quantify, especially within the participant impacts. Only incorporating meaningful inputs that are based on sound information should be prioritized over attempting to include as many inputs as possible through utilization of erroneous adders.

Utility System Impacts:

- Overall agree with all of the inputs included with the exception of "Utility Performance Incentives"
- Don't necessarily disagree with including Utility Performance Incentives, however this is a deviation from the past and think it is important to consider the implications of including this in the test.
- Clarification on quantifying Credit and Collect Costs, Risk, Reliability, and Resilience will be important
- It will be important to clarify how and where the environmental and emissions related impacts are being calculated and applied so that the appropriate costs and avoided costs are both being captured and so that double counting is not occurring between the different components (mostly utility and societal).

Participant Impacts:

- Minnesota Power believes there is justification for the participant impacts to be included or excluded but understands the Departments hesitation to remove them. As such the Company agrees with the inclusion of these impacts but believes there is significant potential to bias the test or reduce the meaningfulness of the evaluation through inclusion of too many impacts that need to be very roughly estimated or applied through generic adders. Especially given that participant benefits are so specific to just the participants, weighting the MN test too heavily with lots of participant NEI's could lead to all customers funding programs that provide a lot of value to very specific customer groups.
- It will be important to prioritize which impacts to include, ideally based on level of impact and ability to accurately quantify the impacts and ideally in a way that still allows for symmetry within the impact category.
- To the extent that a lot of participant impacts need to be studied and quantified, who would fund this effort and who would be responsible for developing the assumptions etc.? Minnesota Power's preference is that much of this would could be completed by consultants and reviewed by utilities.

Low Income:

- Minnesota Power's preference is to continue the existing practice of allowing LI programs to not be cost-effective, therefore assuming the benefits to LI outweigh the costs without the need to spend significant resources on quantifying those benefits.

Societal:

- Minnesota Power agrees with the importance of capturing the impacts listed under the societal category.
- MP agrees the emissions categories are very important and are a policy focus. Time should be spent clarifying how these are captured.
- MP agrees Economic and Jobs impacts are important and have become a larger policy focus in recent years.
- MP agrees Energy Equity is an important factor. It has always been a focus to ensure programs are offered such that as many different customers as possible are able to participate in some way in our energy efficiency programs. This often means offering programs that are less cost-effective using the existing BAC tests rather than focusing entirely on the most cost-effective programs. Finding ways to recognize and quantify this would align BAC results better with the MN priority of energy equity, making it easier to design and offer an equitable portfolio of programs.

June 29, 2022

Cost-Effectiveness Advisory Committee

RE: This letter is in response to the Straw Proposal for the Primary Test prepared by Synapse Energy Economics, Inc. for the Minnesota Cost-Effectiveness Advisory Committee.

Dear Cost-Effectiveness Advisory Committee:

Otter Tail Power Company (Otter Tail or the Company) appreciates the opportunity to provide comment on Synapse Energy Economics, Inc.'s (Synapse's) Straw proposal for a new Primary Test for evaluating the cost-effectiveness of utility demand side management programs.

Otter Tail agrees with the list of eight principles listed by Synapse as guide for determining the process for what benefits and what costs to include in a new Primary Test. The first principal listed by Synapse is as follows:

> Principle 1: Treat DERs as a Utility System Resource. DERs are one of many energy resources that can be deployed to meet utility/power system needs. DERs should therefore be compared with other energy resources, including other DERs, using consistent methods and assumptions to avoid bias across resource investment decisions.

Otter Tail verbally supported Principal 1 in the virtual stakeholder meetings and believes DERs should be evaluated similarly to supply-side resources which are thoroughly vetted through the Integrated Resource Plan (IRP) process. Otter Tail stresses the importance of including the same benefits and costs in choosing demand-side utility investments and supply-side investments. Any asymmetry in benefits or costs when evaluating these resources will create non-cost-effective resource selection for customers. Otter Tail applies Principal 1 when considering the introduction of any new benefits or costs for the Primary Test.

1. UTILITY SYSTEM IMPACTS

The Synapse Straw Proposal includes, in Table 2, a listing of proposed electric utility system impacts by Category/Impact area. Otter Tail reviewed categories of Generation, Transmission, and Distribution and believes the impacts listed in these categories is consistent with the IRP process and Transmission and Distribution planning processes. The General category is a bit more ambiguous for inclusion in a Primary Test. Otter Tail supports the inclusion of Program Incentives, Program Administration Costs, and Credit and Collection Costs, but does support the additional inclusion of Utility Performance Incentives, Risk, Reliability, and Resilience.

Including Utility Performance Incentives as a program cost would create a circular calculation and conflict with the utility financial incentive calculation. To calculate net benefits for the utility's financial incentive, the incentive would need to be known ahead of time which would be a circular calculation. Also, to include Utility Performance Incentives as a cost, one would also have to include the utility's loss revenues as a benefit to customer since the utility did not collect revenues from energy and demand sales.

Benefits and costs associated with Risk, Reliability, and Resilience, are included in Generation, Transmission, and Distribution categories which are already included in the Primary Test. When the electric utility plans for supply-resources, transmission investments, or distribution investments the benefits/costs of Risk, Reliability, and Resilience is inherently included in the planning process. Otter Tail designs it's system for 100 percent up-time of electric service and typically builds in redundancy of the system to mitigate risk and maximize reliability and resilience.

2. PARTICIPANT IMPACTS

Participant Impacts should not be included in the Minnesota Primary Test but instead should be included in a separate Participant Test. Including Participant benefits and cost within the Primary test is not in alignment with the IRP process and opposes Principal 1. Including Participant benefits and costs could distort the cost-effectiveness of demand-side investments when comparing to supply-side investments.

3. LOW-INCOME IMPACTS

Otter Tail overwhelmingly supports low-income programming and routinely spends far beyond statutory minimum spending levels. However, Otter Tail believes the inclusion of benefits and costs from low-income programming in the Primary Test would be out of alignment with the IRP process. Similar to participant impacts, including low-income benefits and cost within the Primary test is not in alignment with the IRP process and opposes Principal 1. Policy goals of Minnesota support low-income programs and spending, but the Company does not believe those impacts should be included in the Primary test. Otter Tail recommends a better place to include non-energy impacts could be in a separate low-income test to prove the value of low-income programs.

4. SOCIETAL IMPACTS

The only impacts from Table 7's Societal Impact listing, that are not included in the IRP process should be included in the Minnesota Primary test. Including benefits from Economic and Jobs, Energy Security, and Energy Equity, while important are not included in the IRP's vetting of new resources so they cannot be included in a Primary Test. Including these benefits would oppose Principle 1.

If you have any questions, please contact me at (218) 739-8639 or JGrenier@otpco.com.

Sincerely,

/s/ JASON GRENIER
Jason Grenier, Manager
Market Planning

Date: July 1, 2022

To: Cost Effectiveness Advisory Committee From: Xcel

Energy

Re: Feedback on Straw Proposal

Below Xcel Energy ("Company") presents the following Written Comments on the Straw Proposal for the Cost Effectiveness Advisory Committee's consideration. Additionally, we provide further recommendations for consideration.

Xcel Energy appreciates the work of the committee and, specifically, the careful consideration and work conducted by Synapse. We agree with the majority of Synapse's recommendations for the Proposed Electric Utility System Impacts. However, the Company believes that the cost effectiveness standard should be guided by the objectives of the Conservation Improvement Program (CIP). CIP is part of Minnesota's strategy for most effectively meeting the state's energy needs at a reasonable cost to customers. It provides funding for utility-led programs that clears pathways for customers to cut their utility bills and energy waste while simultaneously contributing to Minnesota's growing low-carbon economy. The ability to produce customer bill savings, as promised by CIP, is reduced if CIP program costs rise faster than the energy savings that spend produces, becoming less cost-effective. It is with this concern, that the Company identifies the following issues as high priority for consideration of the Cost Effectiveness Advisory Committee since these issues will impact the program administrators' ability to effectively manage customer costs.

- **Utility System Impacts:** We recommend that program incentive costs be treated as both a benefit and a cost in the primary test, the same way they are treated in the current Societal Test, as well as a standard Total Resource Cost test. We also recommend removing utility performance incentives. The current incentive mechanism is awarded as a fraction of the net benefits from the secondary Utility Cost test. Including the utility performance incentive as a Utility System Impact is circular because it is derived as a share of the other Utility System Impacts and is therefore not a unique value. The Company notes that its historical practice has been to report the net effect of the performance incentive on Utility Cost Test results in its annual Status Reports; continuing this practice will provide transparency in how the performance incentive relates to the overall Utility System Impacts.

- **Non-Utility System Impacts:** The Company strongly agrees with the straw proposal that suggests participant Impacts should remain part of the primary cost-effectiveness tests. Without this factor as part of cost-effectiveness, Program Administrators' ability to manage programs that reduce electric bills could be at risk. We also acknowledge the wide variety of non-energy impacts realized by participants but suggest careful consideration regarding which of these benefits to include for CIP programs.

I. Utility System Impacts

The Company agrees with most of Synapse's recommendations for the Proposed Utility System Impacts, except for the inclusion of the Utility Performance Incentives. We also provide clarification on Program Incentives. Program Incentives should be included as both a benefit and a cost[102]; and therefore, cancel out in the assessment of overall cost-effectiveness. While this treatment can help identify whether a program is cost-effective, the Company notes that it means the Minnesota Test would not be informative in assessing the proper level of Program Incentive for a given measure. That is, the test could indicate whether a certain measure should be incentivized, but not whether a given level of incentive is reasonable; other analyses would be required to answer that question.

As far as the Utility Performance Incentives, the Company disagrees with inclusion because Utility Performance Incentives are based on a fraction of the net benefits resulting from Utility Cost Test. Including the incentives in the calculation of the Utility Cost Test (via inclusion in Utility System Impacts) would thus create circularity in the calculation. Also, it is difficult to determine Utility Performance Incentives for individual measures as the current mechanism includes multiple factors based on the achievement of the entire portfolio and includes caps. Inclusion of performance incentives may make more sense when the incentive mechanism is of a more prescriptive design (e.g., based simply on units of energy saved). While understanding the impact of incentive amounts is important, the design of the mechanism in Minnesota limits the overall share of utility system benefits awarded and utilities regularly (if not uniformly) report the net benefits after the incentive in their Status Reports. If the performance incentive is included in the utility system impacts, the Company recommends that it be applied only at the portfolio level and that it be applied as a final step in the calculation as commonly presented in utility Status Reports.

[102] i.e., as a utility system cost and a participant benefit.

The inclusion of Credit and Collection Costs and Risk as components of the Utility System Impacts is somewhat tenuous. First, it is not clear that energy efficiency has substantial impacts on these costs – or, if such impacts exist, that they can be meaningfully expressed in terms of cost per kWh or Dth saved. Second, these costs (particularly Credit and Collection Costs) are not typically included in the assessment of other utility system resources and their inclusion in in a Minnesota Test risks introducing bias across resource investment decisions.

With regard to the proposed Gas Utility System Impacts, the Company notes that the descriptions of "Fuel," "Transportation," and "Delivery" appear to risk double-counting some costs. "Fuel" is described as "purchasing gas at specific locations on the gas system and the variable cost of getting the gas where, and when, it will be used." "Transportation" is described as "the transport of gas from delivery points located on interstate and intrastate pipelines to distribution utility city gate" while "Delivery" is "Delivery of gas from the city gate to retail customers." It is unclear what costs are intended to be included in "the variable cost of getting the gas where, and when, it will be used" that are distinct from those included in Transportation and Delivery.

Additionally, as our prior comments indicated, we believe Renewable Portfolio Standard Compliance and Market Price Effects are already implicitly included in other impacts that are derived from resource planning and market forecasting tools.

II. Non-Utility System Impacts

Participant Impacts should remain a part of the primary cost-effectiveness tests. We believe that participant impacts, both benefits and costs, can still be quantified and are useful in screening out measures or technologies that CIP programs cannot cost-effectively incentivize. Removing participant impacts from the primary tests limits the program administrators' ability to effectively manage the programs. Specifically, it is important the transparency be retained in CIP reporting regarding customer motivations. Removing participant cost and benefit data would erode the ability to demonstrate that the activities supported by CIP are incremental to the naturally occurring adoption. The Company strives to ensure that its CIP portfolio does not inappropriately support savings that may result from projects that either have a low cost and/or short payback or a long payback based on energy savings, but substantial participant benefits due to quantitative or qualitative factors other than energy savings. Further, it will remove an important barrier to increasing overall customer costs for CIP programs – specifically impacting vulnerable customers and non-participants.

The Company does not dispute that the Participant Non-Energy Impacts exist, but inclusion of broadly-applied Participant Non-Energy Impacts will also cause risk in delivering cost-effective programs for a couple of reasons.

First, if a technology requires non-energy benefits to pass the test because the energy benefits are too small relative to participant costs, the probability that CIP support can motivate the customer decreases as the share of the participant cost covered by rebates and energy savings decreases. The Company does not believe that the alternative of paying rebates that exceed the energy benefits is appropriate unless a specific objective (e.g. Low Income CIPs) directs where that practice is in the public interest. Furthermore, the issue of paying rebates in excess of the energy benefits for non-Low-Income CIPs would require changes in the incentive mechanism.

Second, the Participant Non-Energy Impacts will potentially vary significantly and would require costly studies to arrive at accurate values that all parties can agree on, driving up CIP program costs.

To remove this risk in the event that broadly applied Participant Non-Energy Impacts are included, the Company proposes an additional requirement to the primary test. This requirement would be that the benefits from Utility

System Impacts must exceed a minimum percentage of the Participant Energy Impacts, plus the quantified non-energy impacts from Water and Productivity. The Company initially proposes that this percentage be 50%. Water and Productivity non-energy impacts can be accurately determined without the need for additional studies. This requirement will help ensure measures that cannot be cost-effectively incentivized through CIP programs are prevented from eroding the cost-effectiveness and incremental effects that are expected to result from CIP programs. Without this requirement, the Company does not support including non-energy benefits beyond Water and Productivity in the primary cost-effectiveness test.

Non-Utility System Impacts:

Participant Impacts

- LI programs should not be driven around these NEI's because they are so hard to quantify. The Company suggests that a targeted approach may make the most sense, focusing NEIs on specific measures where literature indicates NEIs may be highest (e.g. insulation and air sealing) rather than a blanket adder. The Company also suggests that LI Spend requirements are more effective in maximizing the cost-effectiveness of LI Spend, rather than a primary cost-effectiveness test that dictates the measures and spend levels for LI programs. Finally, NEI values for LI programs should be the same as those used for other programs unless there is sufficient evidence to conclude that given measure or program will have a meaningfully different effect in a low-income context than it would in another context. This may well be the case in some instances, but it should not be the assumption.

We appreciate the opportunity to provide these comments on the proposal and look forward to further discussion.

Appendix I – Cost Effectiveness Advisory Committee Notes (From Proposed Decision)

Please see the separate attachments that were uploaded to eDockets for Appendix I’s content.

Appendix J - Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance

A. Executive Summary

This Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance (CE Technical Guidance) supplements the Minnesota Department of Commerce's (Department) March 15, 2022, Technical Guidance (ECO Act Technical Guidance) related to implementing the Energy Conservation and Optimization Act (ECO Act).[103] The CE Technical Guidance is intended to help Minnesota's electric and gas investor-owned utilities (IOUs or utilities) conduct cost-effectiveness evaluations of their efficient fuel-switching (EFS) and load management (LM) programs.

The CE Technical Guidance covers a range of topics raised by CIP Cost-Effectiveness Advisory Committee (CAC) members. The document seeks to clarify how IOUs will conduct cost-effectiveness evaluations of EFS and LM programs per ECO Act and ECO Act Technical Guidance requirements. CAC members also provided comments on the November 7, 2022, Draft of the CE Technical Guidance. The Department and The Mendota Group revised the document to address these comments.

As presented in the CE Technical Guidance, utilities will be required to submit the following in their CIP Triennial Plan and Status Report filings:

- Demonstration that the overall portfolio and designated segments are cost-effective based on the Minnesota Test[104];
- Presentation of portfolio, segment, and program cost-effectiveness results based on the Minnesota Test and the following secondary tests – Societal Cost Test (SCT), Utility Cost Test (UCT), Participant Cost Test (PCT), Ratepayer Impact Test (RIM);
- Creation of an EFS segment that contains only EFS measures;
- For EFS improvements, consideration of cost-effectiveness at the program level based on the Minnesota Test, the SCT, UCT, and the PCT (natural gas utilities also include RIM);
- For LM programs and programs that include LM elements, consideration of cost-effectiveness at the program level based on the Minnesota Test, the SCT, UCT, PCT, and RIM;
- Methods for allocating costs for EFS, LM, and EE measures to programs that include multiple program types, and
- How the utility evaluated cost-effectiveness for programs that include LM and EE or EFS elements based on each of the program types associated with the program.

[103] "In the Matter of Technical Guidance for the Inclusion of Efficient Fuel-Switching, Load Management, and Pre-Weatherization Measures in CIP" (Docket E,G999/CIP-21-837), Commissioner Decision, Minnesota Department of Commerce, March 15, 2022, Appendix A. The ECO Act is the Minnesota Energy Conservation and Optimization Act of 2021.

[104] The Low-Income segment is excluded from this requirement. Utilities need not demonstrate that the segment is cost-effective. See third bullet related to the EFS segment.

B. Efficient Fuel-Switching and Load Management Cost-Effectiveness Technical Guidance

The CE Technical Guidance was developed in collaboration with the CAC, The Mendota Group, and Department Staff. In response to Staff's request, CAC members suggested topics that the guidance should help clarify. As shown in Attachment A, many of the CAC's comments on EFS and LM topics were unrelated to cost-effectiveness evaluations. Department Staff appreciate the CAC's broader feedback and have included it in Attachment A for potential future consideration and discussion. This CE Technical Guidance document is focused on cost-effectiveness issues associated with EFS and load management and associated reporting requirements.

The Department's March 15, 2022 ECO Act Technical Guidance provides a detailed step-by-step process that utilities and others proposing CIP programs must follow to incorporate EFS measures into programs. Step 6 is repeated here for reference. Attachment B includes additional information from the ECO Act Technical Guidance related to reporting.

STEP 6 – COST EFFECTIVENESS CALCULATIONS

Instructions and Guidance[105]:

- *EFS cost-effectiveness will be reviewed and approved at the program level.*
- *Electric and natural gas utilities, in proposing EFS improvements for Department approval, should include cost-effectiveness evaluations based on the Societal Test, the Utility Test, and the Participant Test (natural gas utilities shall also include the Ratepayer Impact Test in their evaluations).*
- *The primary cost-effectiveness determinant regarding whether an EFS measure is deemed "efficient," according to the ECO Act, will be whether it passes the Societal Test, unless or until the Department updates the primary test Minnesota utilities will use to evaluate demand-side programs.[106]*
- *For natural gas utilities that do not have access to relevant electric information or an electric cost-effectiveness model, the Department will provide the requisite information and tools to enable the utility to conduct EFS cost-effectiveness testing for switches to electricity measures.*
- *Utilities implementing an EFS improvement for customers whom they do not provide either the beginning or the ending fuel shall, nonetheless, include the avoided (and increased supply as may be the case) costs for the non-served fuel in their cost-effectiveness calculations.*
- *Utilities should strive to use up-to-date measure load shapes for EFS improvements to help improve the accuracy of cost-effectiveness and other program-related estimates.*
- *It is anticipated that specific measure-based inputs to cost-effectiveness tests will be considered as part of revisions to the TRM, particularly for EFS Improvements that will be implemented numerous times.*
- *Utilities may include other features, such as load management, in their cost-effectiveness calculations, although such combinations should incorporate costs and benefits associated with the additional features.*

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[105] "In the Matter of Technical Guidance for the Inclusion of Efficient Fuel-Switching, Load Management, and Pre-Weatherization Measures in CIP" (Docket E,G999/CIP-21-837), Commissioner Decision, Minnesota Department of Commerce, March 15, 2022, Appendix A, p. 45.

[106] Special attention must also be paid to the costs to consumers through the Participant Test. Marketing EFS measures to consumers without them knowing that their costs may increase is unfair to the consumer and could undermine the public's trust in investing in other EFS measures.

- *Until such time as the Department has adopted a revised approach for utility cost-effectiveness testing as part of the CAC, utilities may propose, on a custom basis, ways of assessing EFS Improvements based on the cost-effectiveness tests described herein.*

In this context, custom process means that utilities can propose to the Department for review and approval EFS improvements and associated methods of estimating cost-effectiveness. When submitting a proposed custom EFS improvement that has an electric ending fuel, it is recommended that utilities follow the electrification cost-effectiveness guidance described in Chapter 10 of the National Standard Practice Manual (NSPM).[107]

***Process for applying this criterion**: Utilities shall submit with their triennial plan filings or program modifications descriptions of the elements incorporated into the EFS improvement offering or program that meets this step, along with relevant assumptions.*

The following sections of this document update and provide additional guidance regarding certain aspects of the ECO Act Technical Guidance as it specifically relates to EFS and LM cost-effectiveness evaluations.

As stated earlier in this Decision, the new Minnesota Test will be used as CIP's primary cost-effectiveness test. The other cost-effectiveness tests (Societal, Utility, Participant, Ratepayer Impact) will serve as CIP's secondary tests. Additionally, as discussed earlier in this Decision, Synapse's approach to primary and secondary cost-effectiveness tests, as presented in Synapse's June 8, 2022 Straw Proposal (see Appendix H), will be adopted. Specifically, as described in Synapse's Straw Proposal:

> The primary test is the main determinant of whether a program should be included in the Triennial Plan. Secondary tests can be developed to help enhance the overall understanding of energy efficiency impacts. The additional information from a secondary test can help to prioritize energy efficiency programs and to inform decisions regarding marginally cost-effective programs and allocation of resources. The secondary test is not intended to undermine the purpose of the primary test and may include a subset of the impacts included in the primary test or additional impacts.

1. Combining Gas and Electric

a. Modelling

Historically, gas utilities with programs and projects including gas and electric impacts have incorporated the "other fuel's" impact in BENCOST calculations as an adjustment to the gas savings and associated incremental costs. Joint electric-gas utilities have followed a similar approach, although projects which primarily save electricity are modeled using electric cost-effectiveness software with adjustments to participant operations and maintenance (e.g. if a project saves electricity but increases gas usage, this increased gas usage is incorporated as a participant impact and not a decrement to gas savings). Electric-only utilities have generally not modeled gas impacts in cost-effectiveness estimates, considering the impacts to participants and to their portfolio calculations as being minimal.

[107] NESP (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. Framingham, MA: National Efficiency Screening Project. Available at https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

EFS, by definition, impacts multiple fuels. If the utility's cost-effectiveness software accommodates such an approach, utilities should model programs that include EFS measures in a single cost-effectiveness evaluation and not break out the electric and gas components to model them separately.

b. Reporting

The ECO Act Technical Guidance states the following:

- Savings for EFS measures shall be reported for site-based savings by converting the individual measure/project BTU savings to electric or gas savings (applicable to the reporting utility – dual-fuel utilities will report savings based on the primary ending fuel) using standard kWh/BTU and therms/BTU conversions. First-year savings are based on the first year, while lifetime savings will be based on annualized BTU savings multiplied times the kWh/BTU for each year of the EFS's Measure lifetime.[108]

It is acknowledged that this approach to reporting EFS savings creates a misalignment between reported savings and actual impacts on utility systems. For example, gas-to-electric EFS projects reduce natural gas and increase electricity usage. For electric utilities, converting project results from BTU to kWh would falsely imply that the project was saving electricity when, in fact, it would increase electricity usage. Similarly, it is anticipated that gas utilities will report EFS project BTU savings converted to therms, rather than therms savings without considering the increased electricity impacts. This approach is intended to create symmetry between the way gas and electric utilities report savings, namely based on overall project BTU impacts.

The ECO Act Technical Guidance further requires that utilities report results from EFS projects in a separate EFS Segment.[109] In addition, per Minn. Stat. §216B.241, Sub. 12(b), only gas utilities can use savings from EFS measures and projects in calculating shareholder incentives and in meeting gas savings goals. For electric utilities, the total portfolio reported electricity savings, for purposes of calculating shareholder incentives, excludes EFS Segment results. Therefore, reporting EFS projects as BTU-converted electric savings will have no impact on portfolio-reported savings.

Although guidance related to how utilities report savings from EFS projects is technically not in the CAC's scope, it is recommended here that utilities report the following in their Triennial Plans and Annual Status Reports:

Table 1 - Efficient Fuel-Switching Reporting for BTUs, kWh, Therms, and GHGs[110]

Utility Type	How to Report EFS Programs in EFS Segment	How to Report EFS Segment in Overall CIP Portfolio
Electric	• BTU Savings • BTU Savings converted to kWh • Actual kWh Impacts	• BTU Savings • BTU Savings converted to kWh • GHG Reductions
Gas	• BTU Savings	• BTU Savings • BTU Savings converted to therms

[108] ECO Act Technical Guidance, p. 47.
[109] ECO Act Technical Guidance, p. 46.
[110] ECO Act Technical Guidance on page 47 also indicates that Status Reports should include "Overall reductions in both site and source energy use, in BTUs and in the relevant fuel denominations (kWh, therms, gallons [gasoline, diesel], etc.) from EFS during the program year." Therefore, the information in this table should be for both site and source-based values.

	• BTU Savings converted to therms • Actual Therms Impacts	• GHG Reductions

In Table 1, "actual therms impacts" and "actual kWh impacts" refers to the non-BTU-converted impacts on the utility's system. For gas utilities, this reporting would generally produce higher therms values than EFS project BTU-converted therms. For electric utilities, this reporting would generally produce lower (likely negative) kWh values than EFS project BTU-converted therms.

2. Other Costs

EFS projects will frequently require upgrades to a building's electric infrastructure (e.g. panel or other service upgrades). Under the Minnesota Test, this additional participant cost will not be included in the primary test's cost-effectiveness evaluations. However, this cost should be incorporated into other tests such as the Societal Cost Test (SCT) and Participant Cost Test (PCT), both of which include incremental participant costs associated with measure installations. This is important because the SCT and PCT estimate overall societal and participant impacts and should recognize real cost barriers customers may face in adopting EFS measures.[111] Unless and until the TRM determines such an approach is warranted, utilities are encouraged to use the following approach to account for these costs in their cost-effectiveness tests. Utilities should discount these Other Costs based on information they collect regarding the percentage of customers who will likely need to upgrade services and apply an assumed apportionment of the service upgrade's cost to the relevant measure(s). The assumed apportionment would be based on the long-term benefits customers will realize from the upgrades. In other words, although a customer may require a panel upgrade to accommodate an electrification measure, the upgrade will provide benefits for future electric investments the customer may make (for example, if they purchase an electric vehicle).

Similarly, for example, if the utility estimates that 30 percent of residential customers participating in a program that provides incentives for air source heat pumps will require, on average, $4,000 in service upgrades, the utility can reduce the participant cost by this percentage. Extending the example provided, for an air source heat pump incentive program (Deemed) that estimates 30 percent of customers will require average upgrades of $4,000 and these customers will derive additional benefits from the upgrade such that 30 percent should be apportioned to the program, the assigned cost to the measure would be $4,000*.30*.30 = $360 (discount of 90%). A rule of thumb would be to discount the per measure average upgrade costs by 50 – 95 percent.

3. Retail Rates

Incorporating the relevant retail rates into cost-effectiveness calculations will become increasingly important as EFS accelerates. Retail rates are particularly relevant to the PCT, which evaluates the benefits and costs to participants in making an EFS investment. In developing their cost-effectiveness models that include EFS improvements, utilities should seek to ensure that they include the most up-to-date and relevant customer retail rates applicable to participants. The number of included rates need not be significant, and utilities can incorporate weighted-average values based on the proportion of customers who are likely to participate in the program. If utilities adopt new retail rates, for example,

[111] It is worth noting that the CAC chose not to modify the participant impacts portion of the Societal and Participant Cost Tests. As such, as currently constituted, these tests do not include non-energy benefits that customers derive from adopted EE or EFS measures. This is an issue that future Cost-Effectiveness Advisory Committees may wish to address.

rates that may encourage the adoption of EFS measures, the utility may wish to file a program modification that reflects this change.

This will be especially important for any "bill impact" analyses that utilities conduct, although any such comparisons will need to include both the rate (and fuel) associated with the technology from which the customer was switched. Utilities should be mindful in designing programs that include EFS measures to fully inform customers about impacts on gas and electric bills.

4. Shared Utility Programs and Projects

In cases where multiple utilities invest in joint programs in overlapping service territories, it is expected that the utilities will report impacts and incorporate them into cost-effectiveness analyses based on their respective financial contributions to programs and projects.[112] For example, if a gas and an electric utility jointly offer an EFS program that provides incentives for air source heat pumps and the gas utility contributes 30 percent to the overall program's costs, the gas utility would claim 30 percent of savings and incorporate 30 percent of program costs and savings into its cost-effectiveness evaluations. "Savings" would be based on the program's BTU savings, with apportionment to the respective utilities based on their fuels.

5. Program-Level Filing and Reporting Information

The ECO Act Technical Guidance indicates that utilities can evaluate cost-effectiveness at the program level for programs that combine EFS, LM, and EE measures.[113] However, to support reporting, the values for energy and demand (savings/increases) associated with the different elements should be tracked and provided in the utility's Triennial filing. This is necessary because the ECO Act limits spending on EFS improvements (until 7/1/26) to 0.35 percent (averaged over 3 years) of a utility's gross operating revenues and the manner in which the Department must approve EFS Improvements per Minn. Stat. §216B.241, sub. 11-12.

Utilities in their CIP Triennial filings should propose methods for allocating costs for EFS, LM, and EE measures to programs and report on these cost allocations in their Status Reports.

6. Low-Income Programs

As discussed in the Cost-Effectiveness Advisory Committee Working Group Report (8/18/22),[114] many CIP low-income programs (most of which by design are intended to exclusively serve the needs of low-income customers) have, historically, not been cost-effective. However, in recognition of their importance in serving this customer group, the Department has allowed non-cost-effective low-income programs to be included in utility CIP portfolios. In addition, Minn. Stat. 216B.241 subd. 7(i) allows utilities to remove negative low-income program net benefits from performance incentive calculations.

This practice is based on the premise that the benefits of offering low-income programs outweigh the costs. Staff recommend maintaining the current policy which does not require that low-income programs pass the primary cost-effectiveness test. However, utilities should pay special attention to how programs perform on the Participant Cost Test (PCT) as programs that are not cost-effective based on the PCT indicate that the program is not beneficial to customers.

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[112] See Appendix C.

[113] Minn. Stat. §216B.241, Subd. 2(b).

[114] https://mendotagroup.com/mn-cost-effectiveness-ac/#WGReport1

7. Combination Programs

Utilities will likely incorporate into programs both EFS and non-EFS measures (and, as discussed in B.3., LM elements). Therefore, it is important to understand how to model these combination programs. Staff do not have specific recommendations regarding how utilities model combination programs except to say that utilities need to be able to apply the step-by-step process described in the ECO Act Technical Guidance and report both savings and cost-effectiveness results associated with EFS improvements. It is acknowledged that this implies a measure-level evaluation, although utilities are free to bundle multiple EFS measures into a single evaluation if the bundle will be offered as part of the same program.

As an example, a residential home upgrade program may include air source heat pumps and heat pump water heater measures. If the load shapes are the same for these measures, the utility can combine the measures in its evaluation based on the ECO Act Technical Guidance. As provided in the ECO Act Technical Guidance's Step 6, this would also include assessing the cost-effectiveness of the bundle. If the load shapes are not the same, the measures would need to be modeled at the measure level.

C. Load Management Cost-Effectiveness Technical Guidance

1. Avoided Costs

Although it is likely the case that electric demand-side resources (energy efficiency, EFS, load management) will avoid different types of generating units (e.g. some resources by their load shapes and usage avoid a combustion turbine while others avoid utility-scale battery storage), for the sake of developing consistency among Minnesota utilities, utilities should use a single method for estimating avoided costs (energy and capacity) and apply it to all CIP resources. This does not preclude the potential for changes in the future to this approach wherein separate avoided cost estimates are derived for and applied to different types of programs.

At this stage of the process for implementing EFS and load management measures and programs, it is more important that focus is placed on the relevant load shapes that should apply to each measure. To the extent a utility believes that an alternate approach is preferable (for example, a load management program that is specifically designed to shift load to periods when the system has an excess of renewable generation), utilities can propose this modification in their CIP Triennial Plan filing or as a Custom approach.

2. First-Year and Lifecycle Analyses

In assessing LM program cost-effectiveness, utilities should use a lifetime that aligns with the equipment that is installed to facilitate the program or the period during which the intervention(s) will occur. Examples of equipment can be a control device that is installed on a piece of equipment (such as an air conditioner or water heater) or the device itself (smart thermostat used for load management), with the caveat that the measure lifetime should not exceed the remaining life of the equipment on which it is installed. Device lifetimes (to include controllers and smart thermostats) will be included in the Technical Reference Manual (TRM). Behavioral demand response programs and other programs that rely upon continuing interventions (messaging, customer discounts for participating, etc.) should only use a single-year lifetime unless the customer is making more than a one-year commitment to participate in the program.

3. Conservation and Load Management

LM programs that shift energy usage from one time period to another but do not have net energy savings are not considered conservation for purposes of estimating a utility's net benefits. Utilities should specify the types of LM programs they are offering and indicate in their filings for approval whether the program will have energy and demand savings. As discussed in Section B.1., utilities wishing to offer load-shifting programs may want to propose alternative methodologies for estimating avoided costs to align with the program's design.

4. Programs with Load Management Elements

Utilities should evaluate cost-effectiveness for EFS and energy efficiency programs that include LM elements based on each of the program types associated with the program. In other words, a program that combines EFS, energy efficiency, and LM, should evaluate, submit for approval, and track and report cost-effectiveness for the separable components. This is necessitated by statute[115] and the ECO Act Technical Guidance that require the need to evaluate and qualify EFS <u>improvements</u>. This does not preclude the utility from combining these elements into a single program and providing an aggregated cost-effectiveness analysis for the program. However, it is important that utilities track and report results based on the different elements, to include energy efficiency/conservation, EFS, and LM.

For example, a program that provides incentives to customers to install air source heat pumps in place of a natural gas furnace and air conditioner, and includes a LM feature that enables the utility to control the air conditioner during summer peak times and the heating load during winter peak times, can include all relevant costs and benefits in calculating the program's cost-effectiveness based on the relevant tests. For filing, tracking and reporting purposes, the utility would need to have a mechanism to separate out and apply costs to the relevant features.

5. Natural Gas Load Management Programs

Utilities are permitted to propose natural gas LM programs. As currently constituted, the BENCOST model has a specified peak reduction factor (1 percent) that applies to all programs and the opportunity to include both demand costs and demand savings. Utilities proposing natural gas LM programs are permitted to both propose different percentage peak reduction factors for their programs that are designed to reduce system peak loads and avoided demand costs and demand impacts. Future iterations of the BENCOST model may seek to develop separate avoided demand cost estimates.

6. Other Cost-Effectiveness Tests

Utilities are free to use additional cost-effectiveness tests to evaluate their proposed programs. However, the Department will only consider those authorized for CIP application as official tests.

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[115] see Minn. Stat. §216B.2402, sub. 4, Minn. Stat. §216B.241, sub. 1c.(f)-(g), Minn. Stat. §216B.241, Subd. 2(b).

Attachment A – Side-by-Side of Comments Received

CAC responses to requests for key questions, issues, and/or concerns related to developing EFS and LM cost-effectiveness guidelines.

EFS LM CE
Guidance

Attachment B – Reporting Information from ECO Act Technical Guidance

REPORTING EFFICIENT FUEL-SWITCHING IMPROVEMENTS

Subject: How should utilities report EFS improvements?

Instructions and Guidance:

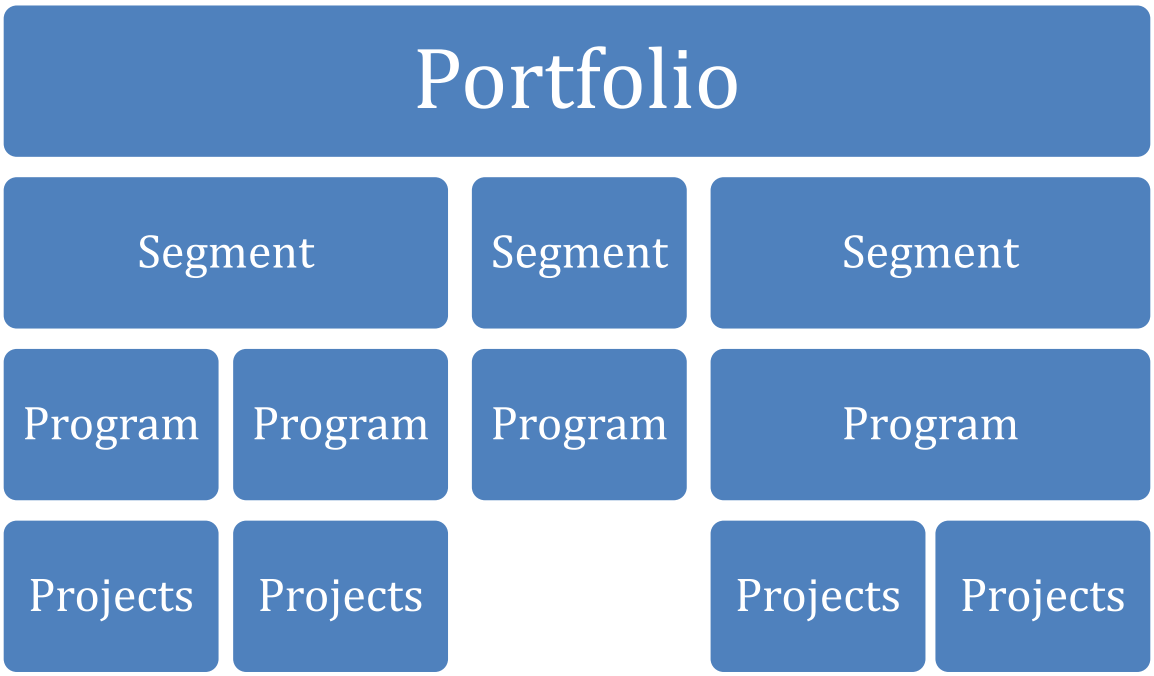
- Utilities implementing EFS measures shall create an EFS segment within their CIP portfolios. Utilities can opt to bundle EFS measures into programs. Similarly, these programs can be included in the CIP segment that the utility deems most appropriate. However, to ensure that EFS improvements can be assessed and tracked separately from other aspects of utilities' CIP programming, utilities will also, as part of their CIP plans and annual reports, present efficient fuel-witching improvements separately.
- Savings for EFS measures shall be reported for site-based savings by converting the individual measure/project BTU savings to electric or gas savings (applicable to the reporting utility – dual-fuel utilities will report savings based on the primary ending fuel) using standard kWh/BTU and therms/BTU conversions. First-year savings are based on the first year, while lifetime savings will be based on annualized BTU savings multiplied times the kWh/BTU for each year of the EFS's Measure lifetime.
- Electric and gas utilities shall use the same baseline and savings estimations for EFS measures that both may offer in overlapping service territories and, as discussed in Step 2, such savings estimates should be based on comparable technology (and reflected, where applicable, in the TRM).
- To reduce customer confusion and "incentive competition", electric and utilities offering the same or similar EFS measures in overlapping service territories should coordinate offerings and aim for consistency in terms of incentive levels and other features.
- IOUs that opt to count net benefits, from EFS improvements that are part of programs that have energy efficiency as their primary purpose and effect, shall identify in their triennial plans (or other appropriate filings) those programs for which they plan to count net benefits, along with how the net benefits will be estimated. In turn, the utility should provide in its annual report the resulting net benefits and how the estimation method was consistent with the proposed approach;[116]
- In Annual Reports, utilities should report, at a minimum, the following:
    - Number of EFS improvements during the program year.
    - Number of EFS customer participants during the program year.
    - Increases of electricity energy consumption (kWh) and demand (kW) from EFS improvements during the program year (this reporting requirement applies to both electric and natural gas utilities).[117]

[116] *See* Minn. Stat. §216B.241, Subd. 11(b).
[117] *See* Minn. Stat. §216B.241, Subd. 1c(f).

    - Overall reductions in both site and source energy use, in BTUs and in the relevant fuel denominations (kWh, therms, gallons [gasoline, diesel], etc.) from EFS during the program year.
    - Overall reductions in GHGs from EFS during the program year.
- To help inform the public about EFS programs, their impacts and ways utilities are continuously improving their EFS programs, utilities should also consider including in their Annual Reports other useful information, such as the types of EFS improvements incentivized by category (e.g. water heating, space heating/cooling, EVs, etc.), learnings from any recent reports or analyses related to EFS, changes to EFS offerings during the year, or mechanisms/features incorporated to broaden customer access and participation.

Attachment C – Clarifications

Program and Projects – This document uses the terms "programs" and "projects" to refer to differ aspects of utility CIPs. "Projects" refers to individual Custom projects or projects within a program that relies on deemed savings (for example, a residential program that provides incentives for customer projects to install air source heat pumps). Custom projects are also part of a program. Programs are included in segments. Together, the various segments make up a utility's CIP Portfolio.



Appendix K – Utility System Impact Methodologies

Deputy Commissioner requires the IOUs to use the Utility System Impact methodology descriptions outlined in this Appendix, which include the following methods organized by fuel type:

Electric Impacts

1. Ancillary Services (Electric)
2. Environmental Compliance (Electric)
3. Generating Capacity (Electric)
4. Marginal Energy (Electric)
5. Market Price Effects (Electric)
6. Renewable Portfolio Standard Compliance (Electric)

Gas Impacts

7. Environmental Compliance (Gas)
8. Market Price Effects (Gas)

Electric and Gas Impacts

9. Utility Performance Incentives (Electric and Gas)

1. Methodology Description: Ancillary Services (Electric)

1. Background[118]

Ancillary services are those services required to maintain electric grid stability. They typically include frequency regulation, voltage regulation, spinning reserves, and operating reserves. These services are either traded in wholesale energy markets or self-supplied by utilities. The Midwest Independent System Operator's (MISO) three main ancillary services products are regulation[119], spinning reserves[120], and supplemental reserves.[121,122]

A DER's net effect on ancillary services depends on its load impact profile and what the real-time system conditions are at the time of its operation. The DERs that are the subject of this paper, namely energy efficiency, efficient fuel-switching, and load management, may not be actively dispatched to provide ancillary services (load management is the potential exception – efficient-fuel switching measures, if they increase loads, will increase ancillary services requirements).[123] As the MTR points out, though, even if a DER's operation is not directly in response to a signal to provide ancillary services, it may nevertheless create an impact. A DER that reduces energy consumption would create a benefit by avoiding the average ancillary service price, whereas a DER that increases usage would create a cost equal to the average price.

2. Example Methodologies

The MTR points to two primary methods of estimating DER effects on ancillary services namely the historical market data method and the production cost model method. The Historical Market Method takes historical data from wholesale markets to determine the average price that DERs would receive from participating in ancillary services markets and involves analyzing data to determine trends that can be used to project future prices. The Production Cost Model Method uses models to calculate revenues based on DERs' ability to participate in ancillary services markets. The model selects the optimal dispatch of resources between energy and ancillary services based on combinations of load and availability and the capability of DERs.

Although potentially less accurate, the Historical Data Method is more straightforward and transparent since it is based on publicly available data. It also assumes that historical trends indicate future trends, which also may not be the case. In addition, MISO does not have a means for energy efficiency resources in particular to directly participate in ancillary services markets. Therefore, the Production Cost Model would be difficult to develop.

3. Required Values

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[118] Summary description derived from "Methods, Tool and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" (March 2022), National Energy Screening Project.

[119] Regulation service is used to constantly and automatically balance small fluctuations in supply and demand in real time. Generation units that are providing regulation service must be able to respond to automatic generation control (AGC) signals from the system operator and change their output accordingly on very short time scales, typically on the order of one to several seconds. Survey of U.S. Ancillary Services Markets, Energy Systems Division, Argonne National Laboratory, January 2016, p.1

[120] Spinning reserves specified percentage, based on Applicable Reliability Standards, of Contingency Reserve that must be synchronized to the Transmission System and that meets all Applicable Reliability Standards, and that can be converted to Energy within the Contingency Reserve Deployment Period following a deployment instruction." MISO Tariff, Module A, § I.S.

[121] Supplemental Reserves (also called non-spinning reserves), are intended to help the system recover from unplanned contingencies. However, non-spinning reserves can also be provided by generation units that are offline, as long as they are able to start up and increase their output to the target level within a predefined period of time, usually 10 to 30 minutes, depending on the market. Online units with available capacity can also provide non-spinning reserves.

[122] 2020 State of the Market Report for the MISO Electricity Market, Potomac Economics, p. 11.

[123] The two types of DERs that can participate in the MISO ancillary services markets are demand response resources and storage.

- The required value for the 2024-2026 Triennial for Ancillary Services is a 1 percent adder, calculated against both electric energy and capacity.

Reasoning: Where we were able to obtain data, we found a wide range of values. Impacts on ancillary services, though, were considerably lower than, for example, market effects. The numbers suggest that a 1 percent adder to both electric energy and capacity is a reasonable starting point until further analyses can be conducted. See Attachment A.

Year	Study	Jurisdiction	Ancillary Services ($/kWh)	% of Energy	Reference Energy ($/kWh)	Notes
2018	Rutgers - Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions	New Jersey	$0.000096	0.26%	$0.036	Ancillary services include regulation, scheduling, dispatch and system control, reactive power, and synchronized reserves, and their cost in 2016 was $.96/MWh. The cost of ancillary reserves should be added to wholesale electricity prices.
2009	Finding and Order: In the Matter of Protocols for the Measurement and Verification of Energy Efficiency and Peak Demand Reduction Measures.	Ohio		2-4%		p. 12.
2017	Distributed Solar in the District of Columbia Policy Options, Potential, Value of Solar, and Cost-Shifting	DC	$0.0	0%		Value of solar study - As explained in a 2014 value of solar study from Virginia (also in PJM), "previous VOS studies have come to differing conclusions about the extent to which distributed solar either decreases or increases the need for grid support services, but agree that the overall impact is likely marginal. ... As such, the [Virginia Solar Stakeholder Group] recommends only addressing grid support services as part of the broad VOS methodology."381
2022	ANNUAL ENERGY EFFICIENCY PLAN FOR 2022 - Naragansett Electric Company	Rhode Island	$0.0	0%		Considered not applicable to EE.
2021	AESC	New England				Included in Wholesale Risk Premium
2022	California	California	$0.0038800	9.84%	$0.03942	Spinning Reserves, Regulation (NP-15). 2022 value (2018$)

Additional information: Using MISO historical values for the three primary ancillary services markets, and assuming that incremental reductions (or increases) in energy use reduce (or increase) wholesale market ancillary services requirements, the following method could be used to calculate the $/MWh value assigned to ancillary services in the MN Test's benefit-cost analysis. In essence, if DERs were able to participate in MISO ancillary services markets, the estimated value would be the revenues they could produce.

Ancillary Services $/MWh = (3-year historical average) Regulation + Spinning Reserve + Supplemental Reserves. Historical values are:[124]

Year	Regulation ($/MWh)	Spinning Reserves ($/MWh)	Supplemental Reserves ($/MWh)	Total ($/MWh)
2021	$13.55	$3.54	$1.11	$18.20
2020	$8.26	$1.93	$0.25	$10.44
2019	$8.15	$2.23	$0.55	$10.93
2018	$10.63	$2.97	$0.91	$14.51

4. References

- Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions (for the New Jersey Office of Clean Energy), Rutgers University Center for Energy, Economic & Environmental Policy, March 13, 2018, https://njcleanenergy.com/files/file/Library/Market%20Research/Avoided%20Cost%20Memo%20(3-13-18).pdf
- Finding and Order: In the Matter of Protocols for the Measurement and Verification of Energy Efficiency and Peak Demand Reduction Measures (Case No. 09-512-GE-UNC), Public Utilities Commission of Ohio, October 15, 2009, https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A09J15B23707E63875.

[124] "2021 State of the Market Report for the MISO Electricity Markets" (June 2022), p. 9, and "2020 State of the Market Report for the MISO Electricity Markets" (May 2021), p. 12, "2019 State of the Market Report for the MISO Electricity Markets" (June 2020), p.8. Prepared by Potomac Economics.

- Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting, Synapse Energy Economics, April 12, 2017, https://www.synapse-energy.com/sites/default/files/Distributed-Solar-in-DC-16-041.pdf
- Annual Energy Efficiency Plan for 2022 - Narragansett Electric Company, October 1, 2022, http://rieermc.ri.gov/wp-content/uploads/2022/02/5189-ngrid-energy-efficiency-plan-2022-puc-10-1-21.pdf
- Avoided Energy Supply Components in New England: 2021 Report, Prepared for AESC 2021 Study Group, March 15, 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf
- California Avoided Cost Calculator (2022), https://willdan.app.box.com/v/2022CPUCAvoidedCosts/folder/172811717028
- 2021 State of the Market Report for the MISO Electricity Markets, (June 2022)
- 2020 State of the Market Report for the MISO Electricity Markets, (May 2021)
- 2019 State of the Market Report for the MISO Electricity Markets, (June 2020)

Attachment A

Year	Study	Jurisdiction	Ancillary Services ($/kWh)	% of Avoided Energy[125]	Reference Energy ($/kWh)	Notes
2022	Annual Energy Efficiency Plan for 2022 - Narragansett Electric Company	Rhode Island	$0.0	0%		Considered not applicable to EE.
2022	California	California	$0.0038800	9.84%	$0.03942	Spinning Reserves, Regulation (NP-15). 2022 value (2018$)
2021	Avoided Energy Supply Costs Study in New England (AESC)	New England				Included in Wholesale Risk Premium
2018	Rutgers - Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions	New Jersey	$0.000096	0.26%	$0.036	Ancillary services include regulation, scheduling, dispatch and system control, reactive power, and synchronized reserves, and their cost in 2016 was $.96/MWh. The cost of ancillary reserves should be added to wholesale electricity prices.
2017	Distributed Solar in the District of Columbia Policy Options, Potential, Value of Solar, and Cost-Shifting	DC	$0.0	0%		Value of Solar Study - As explained in a 2014 value of solar study from Virginia (also in PJM), "previous VOS studies have come to differing conclusions about the extent to which distributed solar either decreases or increases the need for grid support services, but agree that the overall impact is likely marginal. ... As such, the [Virginia Solar Stakeholder Group] recommends only addressing grid

125 Value in Ancillary Services $/kWh column and divided by Reference Energy ($/kWh). If no value is included in the Reference Energy ($/kWh) column, the percentage listed in the % of Avoided Energy column is from the data source.

Year	Study	Jurisdiction	Ancillary Services ($/kWh)	% of Avoided Energy[125]	Reference Energy ($/kWh)	Notes
						support services as part of the broad VOS methodology."
2009	Finding and Order: In the Matter of Protocols for the Measurement and Verification of Energy Efficiency and Peak Demand Reduction Measures.	Ohio		2-4%		p. 12.

2. Methodology Description: Environmental Compliance (Electric)

1. Background[126]

There are many environmental requirements that impact the electric utility system. Utilities experience environmental compliance impacts and pass them on to all customers through revenue requirements and rates. These costs are embedded in the rates customers pay. In many cases, DERs will help to reduce the costs of environmental requirements by reducing air emissions and other environmental impacts of electricity generation, transmission, and distribution. In some cases, DERs might increase the costs of environmental requirements, for example, if they create a net increase in GHG or criteria pollutant emissions.

Some of the key environmental regulations that impact the electricity industry include:

- Federal regulations such as the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act.
- Federal, regional, state, or local GHG emission mandates.
- State or local air, land, or water emission constraints.

BCAs should account for all environmental requirements expected to be in effect over the study period, including those in place but not yet in effect, and those that are not in place but are likely to be in place during the study period. Similarly, BCAs should also account for environmental requirements that have not yet been established but are reasonably likely to be established within the study period.

To the extent that environmental compliance impacts are already included in the cost of the relevant energy resource, they should not be included in this category of impacts in a BCA to avoid double-counting of these costs.

Environmental compliance costs are different but related to environmental damage costs. It is important to distinguish between environmental compliance costs – a utility system impact – and environmental damage costs – a societal impact – to avoid double counting. *Environmental damage costs* reflect the external costs associated with emissions or other types of pollution that impact society as a whole and are not reflected in utility rates. *Environmental compliance costs* internalize some or all the costs of environmental damage and are embedded in utility rates.

Importantly, the current CIP Societal Cost Test includes an environmental damage factor to represent the environmental impacts of greenhouse gas emissions (GHG) and criteria pollutants. This factor is based on environmental cost values established in the Commission's January 3, 2018 Order in Docket Number E999/CI-14-643. Staff recommend that environmental damage associated with greenhouse gas emissions and criteria pollutants also be included in the MN Test as a Non-Utility System (societal) impact. Staff note that the societal input for GHG emissions should be "incremental to values included in utility system impacts." See further discussion in Non-Utility System Impacts.

2. Example Methodologies

The MTR provides the following examples of ways to estimate Electric Environmental Compliance impacts:

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[126] Summary description derived from "Methods, Tool and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" (March 2022), National Energy Screening Project.

a) Methods for Calculating Pollution Control Equipment Costs

For situations where pollution control equipment costs are not accounted for in the other estimates of avoided costs, several sources of publicly available information can be used to determine what these costs are likely to be for different generation facilities (see U.S. EIA 2020;[127] Synapse 2021 RI[128]).

The costs of pollution control equipment should be put in terms of revenue requirements for the purpose of creating inputs to a BCA. For capital costs, this requires amortizing the costs over the book life of the asset, and estimating the annual depreciation, equity, debt, and taxes associated with those costs. Non-capital costs, such as fuel and O&M costs, are typically recovered from customers on a passthrough basis, and therefore the revenue requirements for them will be the same as the annual costs.

b) Methods for Calculating Fees and Permits Costs

Information on fees and permits required for electricity generators can be obtained from several publicly available sources (see NACAA 2018;[129] NY DEC 2021; RAP 2013, page 32;[130] and U.S. EPA 2021 NPDES[131]).

c) Methods for Calculating Anticipated Environmental Requirements

In general, anticipated environmental requirements can be estimated with the same methods as existing requirements. The main difference is that there might be some uncertainty about the timing or the details of the requirements. In these cases, uncertainty techniques can be applied to determine the most likely impacts (see RAP 2013, pages 32-33). For example, if the likelihood of the promulgation of a future environmental regulation is 70 percent, then the environmental compliance cost for that regulation can be multiplied by 70 percent.

3. Required Values

- The required value for the 2024-2026 Triennial for Electric Environmental Costs is zero.

Reasoning: The zero value is based on the challenge of estimating non-GHG environmental compliance costs in the time available. This does not preclude the opportunity for the factor to be updated at a future time if it is determined that there are identifiable and calculable environmental compliance costs. Environmental Compliance will remain a category within the MN Test and serve as a placeholder to capture any future compliance costs that are not embedded in other utility system impacts.

4. References

- Regulatory Assistance Project. 2013. (RAP 2013). *Recognizing the Full Value of Energy Efficiency*. J. Lazar and K. Colburn. https://www.raponline.org/wp-content/uploads/2016/05/rap-lazarcolburnlayercakepaper-2013-sept-09.pdf

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[127] U.S. Energy Information Administration. 2020. (U.S. EIA 2020). *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*. February.

[128] Synapse Energy Economics. 2021. (Synapse 2021 RI). *Macroeconomic Impacts of the Rhode Island Community Remote Net Metering Program*. Prepared for the Rhode Island Division of Public Utilities and Carriers. March. www.ripuc.ri.gov/generalinfo/Synapse-CRNM-Macroeconomic-Report-2021.pdf.

[129] National Association of Clean Air Agencies. 2018. (NACAA 2018). NACAA Title V Fees Survey: Compilation of Completed Surveys. June.

[130] Regulatory Assistance Project. 2013. (RAP 2013). *Recognizing the Full Value of Energy Efficiency*. J. Lazar and K. Colburn. https://www.raponline.org/wp-content/uploads/2016/05/rap-lazarcolburnlayercakepaper-2013-sept-09.pdf

[131] U.S. Environmental Protection Agency. n.d. (U.S. EPA NPDES). "National Pollutant Discharge Elimination System (NPDES)". epa.gov website. www.epa.gov/npdes.

- National Association of Clean Air Agencies, 2018. (NACAA 2018), NACAA Title V Fees Survey: Compilation of Completed Surveys, June.
- U.S. Environmental Protection Agency. n.d. (U.S. EPA NPDES). “National Pollutant Discharge Elimination System (NPDES)”. epa.gov website. www.epa.gov/npdes.

3. Methodology Description: Generating Capacity (Electric)

1. Background[132]

Generating capacity is the amount of installed capacity (i.e., kW) required to meet the forecasted peak load, which typically includes an additional reserve margin. A utility either needs to build generating capacity or procure it to ensure it has sufficient generating capacity to meet planning requirements. DERs that decrease or increase loads impact generating capacity needs.

2. Example Methodologies

MTR describes the following methodologies:

Proxy Unit Method	Peaker Plant Method	Market Data Method	Power Sector Modeling	Public and Proprietary Forecasts
• Determine capacity saved/created by proposed DER • Identify most likely proxy unit • Determine long-term capital and fixed O&M	• Determine capacity resource on the margin • Determine per-unit fixed costs of the resource • Escalate fixed costs over study period	• Use market auction results to determine capacity prices through recent auction year • Determine capacity price forecasts for future years by calculating ratio of auction results to net cost of new entry	• Method 1: Estimate cost of new entry for marginal units by comparing Reference Case forecast to DER Case forecast • Method 2: Perform capacity market simulation by modeling resource build-out and dispatch to find avoided capacity costs	• Use publicly available historical energy cost data as benchmark • Use publicly available forecasts as inputs • Obtain propietary generation capacity impact forecasts to use as inputs, if possible

Minnesota electric utilities have historically used the Proxy Unit method based on a recent vintage Combustion Turbine (CT)[133]. Historically, Minnesota's electric utilities have considered capacity values Trade Secret. The Department has recommended that utilities seek to increase the transparency of such costs. "The Deputy Commissioner determines that improvements to the transparency of electric avoided costs be included as one of the priority cost-effectiveness issues to explore leading up to the 2024-2026 CIP Triennials." (CIP-18-782, CIP-18-783, 2/11/20).

In CAC discussions, two utilities, Xcel Energy and Otter Tail Power, support using publicly available values. Otter Tail proposed using a generation capacity value based on MISO's calculated Cost of New Entry (CONE) for Local Resource Zone 1 (Minnesota). The MISO CONE for 2023 is based on an Advanced Combustion Turbine. MISO explains that they used an Advanced CT because such facilities are likely to actually be constructed in the MISO region due to an Advanced CT's economic and operating characteristics. According to MISO, CONE is first converted to a daily value and then used primarily as the maximum offer and maximum clearing price in the Planning Resource Auctions.[134]

CAC members also suggested reviewing MISO's Generation Interconnection Que (GIQ) to assess what resources are used in expansion plans. It was suggested that, for future triennial plans, the avoided

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[132] Summary description derived from "[Methods, Tool and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis]" (March 2022), National Energy Screening Project.
[133] Using a CT combines the Proxy Unit Method and Peaker Plant Method since CTs are typically used as peaker plants.
[134] "MISO Cost of New Entry (CONE) Planning Year 2023/2024", Presentation to Resource Adequacy Subcommittee, October 12, 2022, https://cdn.misoenergy.org/20221012%20RASC%20Item%2004c%20CONE%20Update626542.pdf, p 4.

capacity cost could be based on cost estimates associated with the mix of resources used in expansion plans.

Another CAC member pointed out that MISO is moving to a four-season capacity construct. Capacity planning will not be driven primarily by the summer season but, rather, utilities will need to meet capacity requirements for Winter, Spring, Summer, and Fall. Generating capacity values for future Triennial plans should reflect different capacity costs associated with seasonal differences.

3. Required Values

- The required Generating Capacity value for the 2024-2026 Triennial is based on MISO's Local Resource Zone 1 Cost of New Entry.[135]
    - 2023/2024 - $104.17/kW-year

Reasoning: The MISO CONE value for the Local Resource Zone that includes most of Minnesota serves as a good proxy value for estimates of capacity costs avoided (or increased) by CIP Distributed Energy Resources as it represents the value of a generating unit that could be constructed to meet marginal capacity requirements. The value has the added benefit of being a publicly available number that all Minnesota electric utilities can use in their BCAs.

4. References

- Filing of the Midcontinent Independent System Operator, Inc. Regarding Local Resource Zone CONE Calculation, September 30, 2022, https://cdn.misoenergy.org/MISO%202022%20Annual%20CONE%20filing626484.pdf
- Deputy Commissioner Decision, CIP Gas and Electric Utilities – 2021-2023 Cost-Effectiveness Review (Docket Nos. G999/CIP-18-782, E999/CIP-18-783), February 11, 2020;
- Information Request Response 11 from MN Department of Commerce, Electric Utilities 2021-2023 Cost-Effectiveness Review, Xcel Energy, October 31, 2019;
- Deputy Commissioner Decision, CIP Electric Utilities – 2020-2022 Cost-Effectiveness Review (Docket No. E999/CIP-18-783), May 20, 2019;
- Deputy Commissioner Decision, CIP Gas Utilities – 2020-2022 Cost-Effectiveness Review (Docket No. G999/CIP-18-782), May 20, 2019;
- Information Request Response 7 from MN Department of Commerce, Electric Utilities 2020-2022 Cost-Effectiveness Review, Xcel Energy, February 19, 2019;
- Information Request Response 3 from MN Department of Commerce, Electric Utilities 2020-2022 Cost-Effectiveness Review, Minnesota Power, February 15, 2019;
- Information Request Response 5-6 from MN Department of Commerce, Electric Utilities 2020-2022 Cost-Effectiveness Review, Otter Tail Power, January 14, 2019.

5. Additional Information

From "Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota, Application of the National Standard Practice Manual to Minnesota", Synapse Energy Economics, August 8, 2018.

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[135] "Filing of the Midcontinent Independent System Operator, Inc. Regarding Local Resource Zone CONE Calculation",
Attachment B, September 30, 2022,
https://cdn.misoenergy.org/MISO%202022%20Annual%20CONE%20filing626484.pdf

The NSPM recommends using a reporting template to provide clear and consistent information for all interested parties.

In their current state, the screening tools are not transparent and do not provide supporting measure or cost details. The interviewees agreed that the tools can be difficult to work with, especially when trying to screen multiple measures with different saving assumptions, or when working with multiple utilities on a single project. Such tools are the heart of cost-effectiveness screening and should be designed carefully to allow detailed transparency.

We recommend Minnesota develop a comprehensive, transparent screening tool common across natural gas and electric utilities that includes measure-level assumptions and inputs. The model should allow the user to easily trace formulas back to the model inputs and should allow utilities flexibility to screen more complicated projects.

One interviewee explained that efficiency and load management programs can support renewable integration by better matching a utility's load to renewable generation profiles. However, current cost-effectiveness tests do not capture the time-varying value of energy efficiency that could achieve system efficiency and decarbonization goals through greater renewable integration.

4. Methodology Description: Marginal Energy (Electric)

1. Background[136]

Energy generation costs consist of the fuel and variable O&M costs from the production or procurement of energy (i.e. kWh) from generation resources. Energy generation costs can vary significantly by season and time of day.

2. Example Methodologies

The MTR describes the following methodologies:

- **Proxy Unit Method**: Using DERs overall load profile, determine unit (CT, CC) avoided, use unit costs and escalation rates to project energy costs.
- **Power System Modeling**: Run capacity expansion model without DER resources to determine needs and run production costs model to determine hourly energy costs.
- **Market Data Method**: Using DERs overall load profile, weight LMPs by load impact profile and escalate.
- **Public and Proprietary Forecasts**: Use publicly available historical and forecast energy cost data or proprietary (Wood Mackenzie, HIS Global, and Bentek) data.

Minnesota utilities use different approaches – all consider marginal energy data Trade Secret. The Department has recommended that utilities seek to increase transparency of such costs. "The Deputy Commissioner determines that improvements to the transparency of electric avoided costs be included as one of the priority cost-effectiveness issues to explore leading up to the 2024-2026 CIP Triennials." (CIP-18-782, CIP-18-783, 2/11/20).

3. Required Values

The Deputy Commissioner will allow electric IOUs to use internally-provided marginal energy data, presumed to be the most up-to-date forecasts that would be used for Resource Plan modeling.

The Deputy Commissioner remains concerned about the lack of transparency regarding the marginal energy values electric IOUs use in their cost-effectiveness analyses. With this in mind, the Deputy Commissioner requires that as part of their 2024-2026 triennial plan filings, the electric IOUs should:

- describe the methods used to estimate their avoided marginal energy cost values;
- share avoided marginal energy cost data in a form that is not considered Trade Secret (e.g. monthly, seasonal, or annual values, by daytype and season, etc.), **AND/OR** provide a clear and simplified way for interested parties to receive the Trade Secret avoided marginal energy cost data (e.g. through a non-disclosure agreement with the utility).

For future triennials, the Deputy Commissioner directs Staff to explore establishing estimation methods for avoided marginal energy costs that both facilitate using the most up-to-date information possible and that enable this data to be shared publicly.

4. References

- Deputy Commissioner Decision, CIP Gas and Electric Utilities – 2021-2023 Cost-Effectiveness Review (Docket Nos. G999/CIP-18-782, E999/CIP-18-783), February 11, 2020;

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[136] Summary description derived from "Methods, Tool and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" (March 2022), National Energy Screening Project.

- Information Request Response 11 from MN Department of Commerce, Electric Utilities 2021-2023 Cost-Effectiveness Review, Xcel Energy, October 31, 2019;
- Deputy Commissioner Decision, CIP Electric Utilities – 2020-2022 Cost-Effectiveness Review (Docket No. E999/CIP-18-783), May 20, 2019;
- Deputy Commissioner Decision, CIP Gas Utilities – 2020-2022 Cost-Effectiveness Review (Docket No. G999/CIP-18-782), May 20, 2019;
- Information Request Response 7 from MN Department of Commerce, Electric Utilities 2020-2022 Cost-Effectiveness Review, Xcel Energy, February 19, 2019;
- Information Request Response 3 from MN Department of Commerce, Electric Utilities 2020-2022 Cost-Effectiveness Review, Minnesota Power, February 15, 2019;
- Information Request Response 5-6 from MN Department of Commerce, Electric Utilities 2020-2022 Cost-Effectiveness Review, Otter Tail Power, January 14, 2019.

5. Additional Information

From "Updating the Energy Efficiency Cost-Effectiveness Framework in Minnesota, Application of the National Standard Practice Manual to Minnesota", Synapse Energy Economics, August 8, 2018.

The NSPM recommends using a reporting template to provide clear and consistent information for all interested parties.

In their current state, the screening tools are not transparent and do not provide supporting measure or cost details. The interviewees agreed that the tools can be difficult to work with, especially when trying to screen multiple measures with different saving assumptions, or when working with multiple utilities on a single project. Such tools are the heart of cost-effectiveness screening and should be designed carefully to allow detailed transparency.

We recommend Minnesota develop a comprehensive, transparent screening tool common across natural gas and electric utilities that includes measure-level assumptions and inputs. The model should allow the user to easily trace formulas back to the model inputs and should allow utilities flexibility to screen more complicated projects.

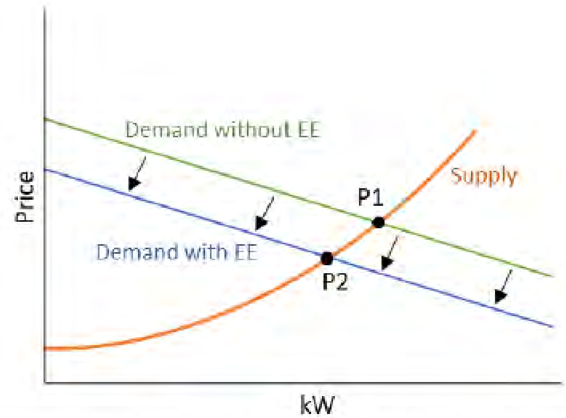
One interviewee explained that efficiency and load management programs can support renewable integration by better matching a utility's load to renewable generation profiles. However, current cost-effectiveness tests do not capture the time-varying value of energy efficiency that could achieve system efficiency and decarbonization goals through greater renewable integration.

5. Methodology Description: Market Price Effects (Electric)

1. Background[137]

In jurisdictions with competitive wholesale electricity markets, wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers at any given instant. When DERs reduce (or increase) the demand for electricity, they reduce (or increase) the wholesale market prices. This change creates benefits (or costs) for all customers participating in the wholesale market at that time. This effect is sometimes referred to as demand reduction induced price effect (DRIPE).

Figure 1: Theoretical effect of DRIPE on the price of electricity



Source: Adapted from DOE 2015, State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All, December, page 7.

Minnesota electric utilities are Load Serving Entities (LSEs) that are part of the Midcontinent Independent System Operator (MISO). MISO manages competitive wholesale energy and operating reserves markets in which Minnesota's electric IOUs participate as both buyers and sellers. Reductions in utility energy and capacity requirements through energy efficiency and load management, in turn, impact the MISO wholesale electricity and reserves markets as described above. Increases in utility energy and capacity requirements through electrification increase utility demand, thereby reducing any market effects from energy efficiency and load management.

2. Example Methodologies

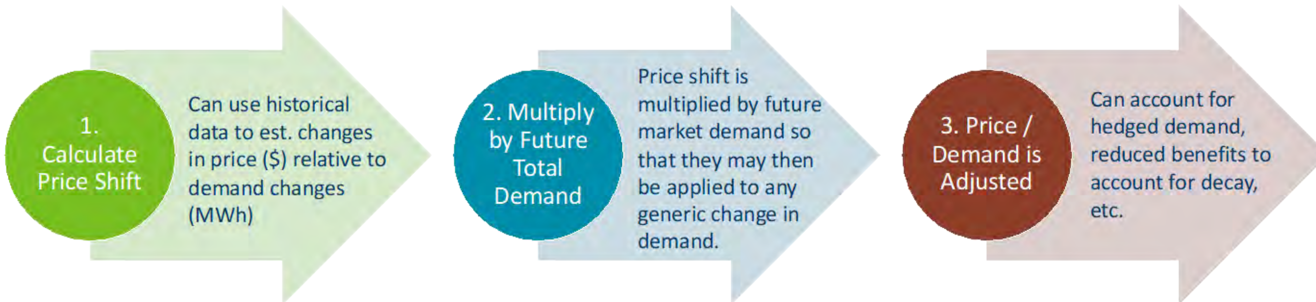
Sutter, et al. (Sutter LBL) note that 30 percent of the jurisdictions that they reviewed (30) measure some energy or capacity price suppression, and also that the methods for doing so are complex and require particular expertise.[138] They cite two of these studies, a 2014 Maryland analysis and the New England Avoided Energy Supply Components (AESC) report. The AESC analysis uses the MTR's combination approach, which involves the following three steps:

1. First, a "price shift" is calculated. This shift represents the change in price (e.g., dollars per MWh) for a change in demand (e.g., MWh). Aggregated over many data points, this price shift represents the supply curve of a particular resource.

[137] Summary description derived from "Methods, Tool and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" (March 2022), National Energy Screening Project.

[138] "Applying Non-Energy Impacts from Other Jurisdictions in Cost-Benefit Analyses of Energy Efficiency Programs: Resources for States for Utility Customer-Funded Programs", Mary Sutter, Jenn Mitchell-Jackson, Steven R. Schiller, Lisa Schwartz, and Ian Hoffman, Lawrence Berkeley National Laboratory, May 2020.

2. These price shifts are multiplied by total future market demand, so that they may then be applied to any generic change in demand. In other words, the price shift is expressed in terms of price-per-demand. Multiplying the price shift by demand translates it into a price-per-demand value that can then be multiplied by a measure's anticipated savings.
3. Finally, the price-per-demand value is adjusted. This may include accounting for hedged demand which has, in theory, already been purchased and is not subject to price shifts. Or, it may involve reducing benefits to account for decays in effects, or "phasing in" of effects to describe a lag in the way the market realizes these impact. Importantly, only some categories of DRIPE have these shifts applied.



Discussions among the CAC also highlighted that impacts may differ per utility based on whether the utility is a net importer or net exporter (which could also change year-by-year). For utilities that are net exporters of electricity, if market prices decline, the utility will receive lower revenues for its sales. This makes the utility's ratepayers worse off. If the utility is a net importer, lower market prices mean that the utilities' costs are lower, making their ratepayers better off. Thus, the impact of reduced market prices due to energy savings may depend on whether the utility is a net importer or a net exporter. If the utility is neither an importer nor an exporter, the benefits and costs associated with lower market prices would offset one another.

Example values collected from various jurisdictions are included in Table 1.

3. Required Values

- The required value for the 2024-2026 Triennial for Electric Market Price Effects is 1 percent, applied to both energy and capacity values for all years.

Reasoning: Given the limited time frame available to the CAC for estimating values for electric market effects, and the challenges that utilities would face in developing electric market effects estimates to use in cost-effectiveness analyses, using a very modest proxy value of 1% is prudent. Future evaluations of Electric Market Price Effects should consider the degree to which individual utilities are net importers or exporters and possibly apply the factor differentially to utilities on this basis.

The compiled data follows:

Table 1 - Example Electric Market Effects Values

Source	Jurisdiction	Energy ($/kWh)	% of Energy	Capacity ($/kW)	% of Capacity	Reference Energy ($/kWh)	Reference Capacity	Notes
2022-2024 Conservation & Load Management Plan (2022) - Uses AESC	Connecticut	$0.025	66%	$76.60	160%	$0.038	$48.00	Includes own-fuel DRIPE and cross-fuel DRIPE (Connecticut DRIPE and rest-of-pool), CT summer on-peak, 15-year levelized basis; Capacity DRIPE includes Connecticut and rest-of-pool components, cleared capacity values, 15-year levelized. (p.160) VT applies 50%, MA applies 100%
Analysis of Electric Energy DRIPE in Illinois (2014)	Illinois		20-40%					Levelized over 20 years
EMPower MD DRIPE Values (2018)	Maryland	$0.017		$11.86				Nominal. Average 2018-2021 (only applies to 4 years). Capacity is kW-year.
Order Adopting First New Jersey Cost Test (2020)	New Jersey	unavailable		unavailable				Calculated by regressing historical electric energy prices as a function of load to determine the impact of load on electric energy prices
Xcel Cost Benefit Analysis of Non-Wires Alternatives - ICF (2022)	Colorado	$0.00		$0.00				Because PSCo is not a part of an organized wholesale market, and because Public Service has a relatively high and growing level of renewable energy on its system that is sometimes curtailed, it is unclear what the wholesale market price effects would be. Thus, the value would be zero and will not be included as a value stream within the NWA CBA methodology.
Annual Energy Efficiency Plan - Naragansett Electric (2022)	Rhode Island	unavailable		unavailable				DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. (p.11).

4. References

- Annual Energy Efficiency Plan for 2022 - Narragansett Electric Company, October 1, 2022, http://rieermc.ri.gov/wp-content/uploads/2022/02/5189-ngrid-energy-efficiency-plan-2022-puc-10-1-21.pdf
- The Value of Demand Reduction Induced Price Effects (DRIPE), Presented by Paul Chernick and Chris Neme, March 18, 2015, https://www.raponline.org/knowledge-center/the-value-of-demand-reduction-induced-price-effects-dripe/
- State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All, SEEAction, Industrial Energy Efficiency & Combined Heat and Power Working Group, December 2015, https://www.energy.gov/sites/default/files/2021-07/SEEAction-DRIPE.pdf.
- Order Adopting the First New Jersey Cost Test, In the Matter of the Implementation of P.L. 2018, Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs (Docket No. QO19010040), August 24, 2020, https://www.state.nj.us/bpu/pdf/boardorders/2020/20200824/8A%20-%20ORDER%20New%20Jersey%20Cost%20Test.pdf
- Cost-Benefit Analysis of Non-Wires Alternatives, Public Service Company of Colorado, Prepared by ICF, Submitted in Colorado Public Utilities Commission Docket No. 22A-0189E, May 1, 2022.
- 2022-2024 Conservation & Load Management Plan, Connecticut's Energy Efficiency and Demand Management Plan, Submitted by: Eversource Energy, United Illuminating, Connecticut Natural Gas, and Southern Connecticut Gas, March 1, 2022, https://energizect.com/sites/default/files/documents/Final%202022%202024%20Plan%20030122.pdf

6. Methodology Description: Renewable Portfolio Standard Compliance (Electric)

1. Background[139]

In jurisdictions that have adopted a renewable portfolio standard (RPS) or similar regulatory mechanisms like clean energy standards (CES) or clean peak standards (CPS), DERs can impact the cost of compliance. DERs can reduce compliance costs either by reducing the target (lowering overall electricity energy and demand requirements) or increasing the level of qualified renewable or clean energy generation (not applicable to the Minnesota situation because CIP does not currently include renewable energy). Alternatively, if a DER increases electricity requirements (e.g., electrification), it will require additional renewable purchases and, therefore, increase the compliance costs of meeting the standard.

Minnesota has a Renewable Energy Objective that applies differentially to Xcel Energy and Otter Tail Power/Minnesota Power. Xcel Energy is required to, by 2020, obtain 30 percent of its supply to serve Minnesota customers from renewable resources while OTP/MP were required by 2020 to obtain 20 percent. By 2025, OTP/MP are required to obtain 25 percent from renewables. For Xcel, of the 30 percent, at least 25 percent must come from wind or solar.

2. Example Methodologies

The MTR describes two methodologies, the Proxy Unit Method and the Modelling method. We note that the Modelling Method would require additional modeling that, outside of an IRP process is not likely to happen in time for the next Triennial filing.[140] For reference, the two MTR methods for calculating RPS Compliance include:

- **Proxy Unit Method**
  - Choose a proxy unit that represents a conventional (fossil-fueled) generator on the system
  - Compare costs (fuel, generation capacity, O&M, transmission, ancillary services, emissions) of RPS resources with the levelized cost of the proxy unit
- **Modelling Method**
  - Use dispatch and capacity expansion models to model generation built and dispatched with and without the addition of renewable generation required to meet the RPS.

The MTR indicates that the Modelling Method is likely more accurate while the Proxy Unit Method is easier to calculate. As further discussed, the main disadvantage to the Proxy Unit Method is that it does not account for load impact profiles of renewable resources and does not reflect the fact that RPS requirements could displace more than one type of generation. The proxy unit, therefore, may not reflect the conventional generation the RPS resources are avoiding, leading to inaccurate avoided costs.

Most relevant, though, to Minnesota is that all three electric utilities are currently exceeding their REO requirements, and it is anticipated that this will continue into the future as they add even more renewables to their generating mixes. In other words, there is no IRP modelling that shows the incremental difference in costs related to complying with the REO because meeting the REO is already

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[139] Summary description derived from "Methods, Tool and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" (March 2022), National Energy Screening Project.

[140] It may be possible to use the Modelling Method if, during each electric IOU's IRP process there is a specific request to model the incremental costs associated with complying with the State's Renewable Energy Objective.

part of the base case. Therefore, although it may be possible to do a Proxy Unit Method comparison, it is not appropriate since the likely more accurate Modelling Method is not relevant since utilities are already exceeding the REO.

3. Required Values

- The RPS Compliance value for the 2024-2026 Triennial shall be set to 0.

Reasoning: The zero value is based on the fact that Minnesota's electric utilities are currently exceeding Minnesota's Renewable Energy Objective and this is considered to persist through the Triennial period. The value may be revisited if it is later determined that estimates of DER impacts on utility selection of renewables to meet the REO requirements are relevant to include in BCAs. For example, as customers continue to electrify, electricity requirements will likely increase which will mean that electric IOUs will need to add even more renewables to comply with the REO. The target REO values that utilities must achieve could also increase.

4. References

- Minnesota Statutes §216B.1691, Renewable Energy Objectives, https://www.revisor.mn.gov/statutes/cite/216b.1691

7. Methodology Description: Environmental Compliance (Gas)

1. Background[141]

Gas utilities incur costs for compliance with environmental requirements. These costs are then passed on to all gas customers through revenue requirements and rates. Many such requirements are included in gas fuel and capacity impacts and therefore do not need to be calculated separately.

Some of the key environmental regulations that impact the natural gas industry include:

- Federal regulations such as the Clean Air Act, the Clean Water Act, and U.S. EPA methane emissions standards.
- Federal, regional, state, or local greenhouse gas (GHG) emissions mandates.
- State and local air, land, or water emission limits.

Environmental compliance costs are different but related to environmental damage costs. It is important to distinguish between environmental compliance costs – a utility system impact – and environmental damage costs – a societal impact – to avoid double counting. *Environmental damage costs* reflect the external costs associated with emissions or other types of pollution that impact society as a whole and are not reflected in utility rates. *Environmental compliance costs* internalize some or all the costs of environmental damage and are embedded in utility rates.

Similar to electric environmental compliance costs, gas impacts associated with GHG emissions are included as a non-utility system impact.

2. Example Methodologies

The MTR describes the following methodologies:

a) Methods for Calculating Pollution Control Equipment Costs

For situations where pollution control equipment costs are not accounted for in the other estimates of avoided costs, several sources of publicly available information can be used to determine what these costs are likely to be for different generation facilities (see U.S. EIA 2020;[142] Synapse 2021 RI[143]).

The costs of pollution control equipment should be put in terms of revenue requirements for the purpose of creating inputs to a BCA. For capital costs, this requires amortizing the costs over the book life of the asset, and estimating the annual depreciation, equity, debt, and taxes associated with those costs. Non-capital costs, such as fuel and O&M costs, are typically recovered from customers on a passthrough basis, and therefore the revenue requirements for them will be the same as the annual costs.

[141] Summary description derived from "Methods, Tool and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" (March 2022), National Energy Screening Project.

[142] U.S. Energy Information Administration. 2020. (U.S. EIA 2020). *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*. February.

[143] Synapse Energy Economics. 2021. (Synapse 2021 RI). *Macroeconomic Impacts of the Rhode Island Community Remote Net Metering Program*. Prepared for the Rhode Island Division of Public Utilities and Carriers. March. www.ripuc.ri.gov/generalinfo/Synapse-CRNM-Macroeconomic-Report-2021.pdf.

b) Methods for Calculating Fees and Permits Costs

Information on fees and permits required for electricity generators can be obtained from several publicly available sources (see NACAA 2018;[144] NY DEC 2021; RAP 2013, page 32;[145] and U.S. EPA 2021 NPDES[146]).

c) Methods for Calculating Anticipated Environmental Requirements

In general, anticipated environmental requirements can be estimated with the same methods as existing requirements. The main difference is that there might be some uncertainty about the timing or the details of the requirements. In these cases, uncertainty techniques can be applied to determine the most likely impacts (see RAP 2013, pages 32-33). For example, if the likelihood of the promulgation of a future environmental regulation is 70 percent, then the environmental compliance cost for that regulation can be multiplied by 70 percent.

The U.S. Environmental Protection Agency recently (2022) proposed requirements to reduce methane emissions from natural gas transmission and storage facilities.[147] Given that these new requirements have not yet been implemented, they constitute an example of future costs that are not yet incorporated into utility natural gas revenue requirements. We have assumed that the proposal will be adopted as is (100% probability factor). When the rule has been adopted and implemented by the industry, these costs will be internalized in the cost of gas utilities recover as part of their revenue requirements. Until that time, though, these values should be incorporated into the Gas Environmental Compliance factor.

2. Required Values

- The required value for the 2024-2026 Triennial for Gas Environmental Compliance Impacts is 1.40% of the $/MCF commodity cost for 2024 – 2045.

Reasoning: The initial value is based solely on proposed federal methane emissions standards that the EPA anticipates finalizing in 2024. All other gas environmental compliance factors are assumed to be 0 for this Triennial. We derived the 1.40% estimated based on the EPA's Regulatory Impact Analysis (RIA) for the proposed regulations. The RIA estimates natural gas commodity price impacts for the 2023-2035 period (see Table 1 below). As the analysis provides estimated impacts for five discrete years (2023, 2025, 2026, 2030, 2035), we used this data to extrapolate annual values for the 2023-2035 period. The 1.40% is a simple average of this period. Extrapolating values out to 2045 (the period covered by the BENCOST model) had a minimal impact on this estimate (1.38%) and, therefore, we suggest using the 1.40% as it is based on the time period included in the EPA analysis.

Information taken from the EPA's Regulatory Impact Analysis follows:

[144] National Association of Clean Air Agencies. 2018. (NACAA 2018). NACAA Title V Fees Survey: Compilation of Completed Surveys. June.

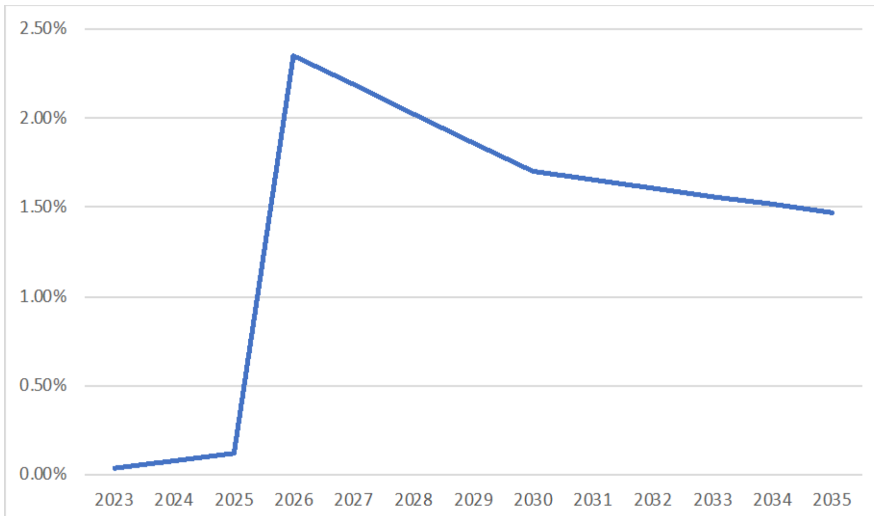
[145] Regulatory Assistance Project. 2013. (RAP 2013). *Recognizing the Full Value of Energy Efficiency*. J. Lazar and K. Colburn. https://www.raponline.org/wp-content/uploads/2016/05/rap-lazarcolburnlayercakepaper-2013-sept-09.pdf

[146] U.S. Environmental Protection Agency. n.d. (U.S. EPA NPDES). "National Pollutant Discharge Elimination System (NPDES)". epa.gov website. www.epa.gov/npdes.

[147] https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-supplemental-proposal-reduce

Table 2 - Estimated Natural Gas Production and Prices Changes under the Proposed NSPS OOOOb and EG OOOOc Option[148]

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0.04%	0.08%	0.12%	2.35%	2.19%	2.03%	1.86%	1.70%	1.65%	1.61%	1.56%	1.52%	1.47%



4. References

- Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, U.S. Environmental Protection Agency, published in Federal Register on December 6, 2022, https://www.govinfo.gov/content/pkg/FR-2022-12-06/pdf/2022-24675.pdf
- Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, U.S. Environmental Protection Agency, November 2022, https://www.epa.gov/system/files/documents/2022-12/Supplemental-proposal-ria-oil-and-gas-nsps-eg-climate-review-updated.pdf

148 "Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," U.S. Environmental Protection Agency, November 2022, Table 4-5, p. 102.

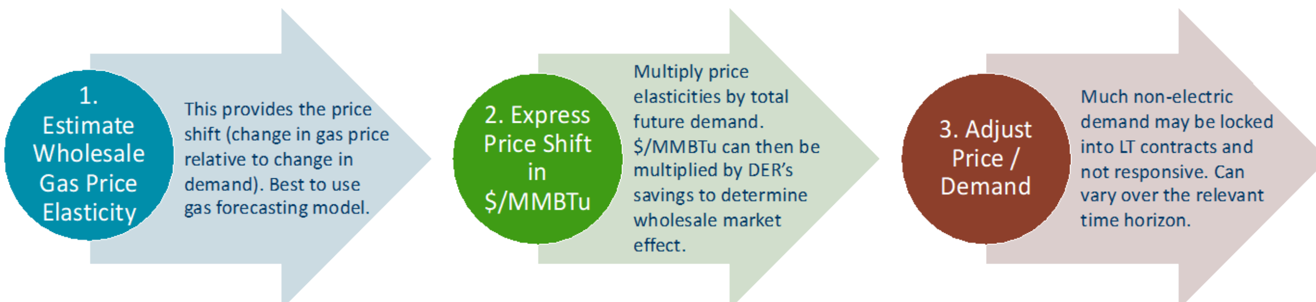
8. Methodology Description: Market Price Effects (Gas)

1. Background[149]

Wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers. When DERs reduce (or increase) the demand for gas, they reduce (or increase) the wholesale market prices, which creates benefits (or costs) for all customers participating in the wholesale market at that time. Even a very small perturbation of the market price can have large impacts when applied across all wholesale customers. This effect is sometimes referred to as demand reduction induced price effect (DRIPE).

2. Example Methodologies

The MTR describes the following methodologies for estimating Gas Market Price Effects:



[149] Summary description derived from "Methods, Tool and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" (March 2022), National Energy Screening Project.

Figure 1: Steps to calculate gas wholesale market price effects

Step 1 Estimate the wholesale gas price elasticity

This is the "price shift," which represents the change in gas price ($/MMBtu) for a change in gas demand (MMBtu). Aggregated over many data points, this price shift represents the supply curve of a particular DER. Wholesale gas price elasticities are best estimated using an integrated natural gas market forecasting model to assess the impact of a specific change in demand on gas prices at specific market locations. In the absence of such a model, wholesale gas price elasticities can be calculated using a regression analysis, where many historical datapoints are analyzed to establish a relationship between prices and demand. Information for these regression analyses can be obtained from the U.S. EIA (see U.S. EIA AEO 2022).[10]

Step 2 Express the price shift in terms of price-per-demand (in $/MMBtu of demand)

This can then be applied to any generic change in demand. This can be achieved by multiplying the price elasticities by total future market demand. The price-per-demand value can then be multiplied by a DER's anticipated savings to determine the wholesale market price effect.

Step 3 Adjust the price-per-demand value to account for market conditions that affect the magnitude of the wholesale market price effect

For gas markets, a portion of non-electric gas consumption is often locked up in short-term contracts and is therefore unresponsive to price changes. Therefore, this portion of gas consumption should be excluded from the calculation. For example, the AESC study assumes that the percentage of non-electric natural gas consumption which is unresponsive to DRIPE varies by year: in year one, 50 percent is assumed unresponsive; in year two, 20 percent is assumed unresponsive; and in year three and all years thereafter 0 percent is assumed unresponsive (see AESC 2021, pages 217 – 218).

As noted in CAC discussions, under most conditions, the supply curve Minnesotans face is perfectly elastic (a horizontal supply curve). Any increase or decrease in demand for gas will likely have a limited effect on prices. However, when there is a critical event, like a winter storm, which affects demand for more states and thus demand is increasing by a large amount, gas energy savings could have an impact on price In this situation, an adder for the impact of gas energy savings on market prices could focus on:

1. The probably of critical weather event;
2. The price of gas during the critical weather event;
3. The number of hours of the critical weather event;
4. The price impact of reductions in demand during a critical weather event.

As further noted, if there is an adder included for Gas Market Price Effects, it should likely be a low value to reflect: 1) the inapplicability of estimates from other regions to Minnesota, 2) the fact that DRIPE values tend to decay over time, and 3) that there may be a lag in what year DRIPE values occur.

There were few example estimates of Gas Market Effects. Table 1 shows the single example, from the Connecticut Program Administrators 2022-2024 filing.

Table 3 - Examples of Gas Market Price Effects

Source	Jurisdiction	Energy ($/MMBTU)	% of Energy Price	Reference Energy Price ($/MMBTU)	Notes
2022-2024 Conservation & Load Management Plan (2022) - Uses AESC	Connecticut	$1.170	18%	$6.480	Southern New England Region, all retail end-uses, 15-year levelized basis

3. Required Values

- The required value for the 2024-2026 Triennial for Gas Market Price Effects is zero.

Reasoning: The considerable uncertainty about whether Gas Market Price Effects exist in Minnesota led to the recommendation to include a zero value for the variable for the upcoming Triennial.

4. References

- 2022-2024 Conservation & Load Management Plan, Connecticut's Energy Efficiency and Demand Management Plan, Submitted by: Eversource Energy, United Illuminating, Connecticut Natural Gas, and Southern Connecticut Gas, March 1, 2022, https://energizect.com/sites/default/files/documents/Final%202022%202024%20Plan%20030122.pdf

9. Methodology Description: Utility Performance Incentives (Electric and Gas)

1. Background[150]

DER program administrators are offered financial incentives for meeting specific performance metrics related to the success of DER programs (Utility Performance Incentive). These performance incentives represent a cost associated with the delivery of the DER program.

In Minnesota, CIP performance incentives are a form of shared savings mechanism, with utility and ratepayers sharing in the net benefits from CIP. Currently, electric IOUs cannot include net benefits associated with their Efficient Fuel-Switching programs in cost-effectiveness calculations while natural gas IOUs can. There is not currently a separate performance incentive mechanism for load management programs.

2. Example Methodologies

The MTR indicates that financial incentives related to CIP performance that utilities earn should be treated as a Utility System Impact (cost). The incentives are a cost associated with the delivery of the program, similar to utility administrative costs, program rebates to customers, etc. These costs are included in the new MN Test, and in relevant secondary tests that include utility costs (e.g. UCT, SCT, RIM).

3. Required Values

- There are no results to provide as this is a methodological approach.
- The Utility Performance Incentive impact should be included in the MN Test and in relevant secondary tests that include utility costs (e.g. UCT, SCT, RIM).

Reasoning: The tests that include utility administrative costs should also include performance incentives as they are utility costs (that gets passed on to ratepayers).

4. Avoiding Circular Calculations When Including the Utility Performance Incentive as a Cost-Effectiveness Impact

Some CAC members pointed out that including the Utility Performance Incentive as a program cost in the MN Test would create circular calculations and conflict with the utility financial incentive calculation. However, Staff outline below how IOUs can include the Utility Performance Incentive impact in the MN Test and secondary tests while avoiding any circular calculation issues associated with using the MN Test's net benefits to calculate the CIP 2024-2026 Shared Savings financial incentive (Financial Incentive) and to screen program cost-effectiveness.

The Utility Performance Incentive cost-effectiveness test impact is defined in the NSPM for DERs as "Incentives offered to utilities to encourage successful, effective implementation of energy efficiency programs." In Minnesota this impact is referred to as the CIP Financial Incentive. The Financial Incentive is designed to motivate Minnesota's IOUs to maximize cost-effective energy savings by providing them with an increasing incentive as the CIP investments of the IOUs and their customers result in higher net benefits.[151]

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[150] Summary description derived from "Methods, Tool and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" (March 2022), National Energy Screening Project.

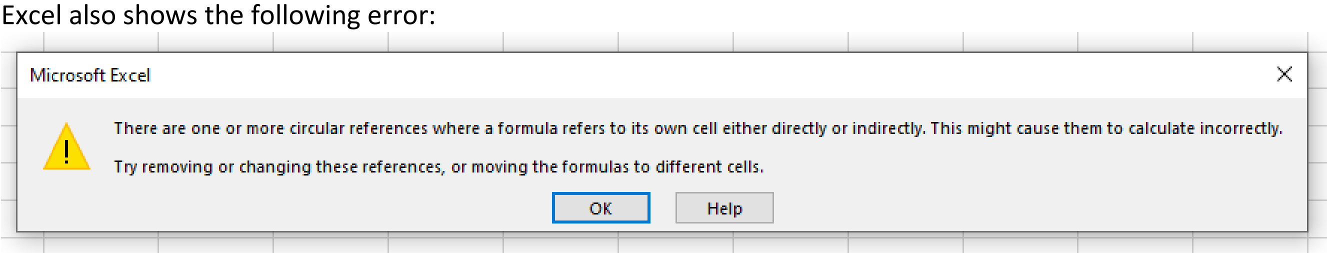
[151] Shared Savings DSM Financial Incentive Mechanism. Docket No. E,G999/CI-08-133.

G. Example: Circular Calculation Issue

To illustrate the circular calculation issue, suppose the Financial Incentive is calculated as a proportion of the MN Test's net benefits and the Utility Performance Incentive is also included as a cost-effectiveness impact in the MN Test. This would cause a circular calculation because the Utility Performance Incentive impact is used to calculate the MN Test's net benefits, and, in turn, these net benefits determine the Financial Incentive's value.[152] We can see this in Excel as follows:

Category	MN Test
	Net Benefits ($)
Benefits	
Avoided Revenue Requirements	
Generation	$117,000,000
T & D	$16,000,000
Marginal Energy	$239,000,000
Environmental Externality	$ 35,000,000
Total Benefits	$ 407,000,000
Costs	
Utility Project Costs	
Customer Services	$4,000,000
Project Administration	$43,000,000
Advertising & Promotion	$8,000,000
Measurement & Verification	$2,000,000
Rebates	$48,000,000
Subtotal	$105,000,000
Financial Incentive	$ -
Total Costs	$125,100,000
Net Benefit (Cost)	$ 281,900,000

Excel also shows the following error:

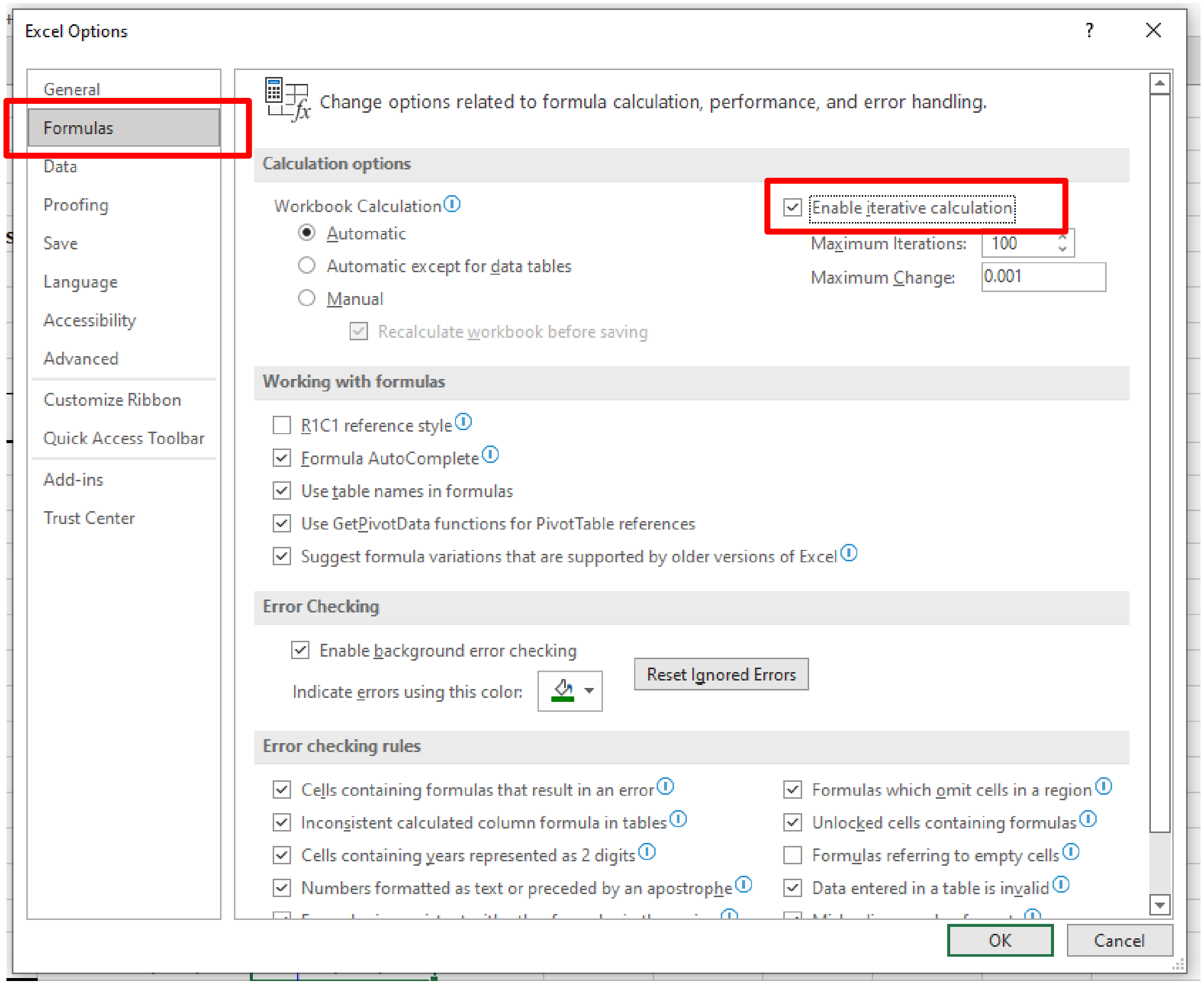


H. Overcoming the Circularity Issue

[152] Although the example uses MN Test Net Benefits, the Department is still working with stakeholders to determine the approach for calculating utility performance incentives that will be proposed for consideration by the Minnesota Public Utilities Commission. The current utility performance incentive methodology uses Utility Test Net Benefits.

Utilities can overcome the circularity issue by iteratively calculating and recalculating the MN Test's net benefits and the Utility Performance Incentive until both calculations converge.

To perform the calculation iteratively, go Excel's search bar and type "options". This will open the Excel Options dialogue box. Go to the formulas option and click on the check box that enables iterative calculation. Then, click OK.



Then, Excel will start with an initial Utility Performance Incentive value, estimate the net benefits, update the Utility Performance Incentive value based on the net benefits, re-estimate the net benefits and repeat the calculations iteratively. The iterative calculations will eventually converge, and you will arrive at the correct result.

For the purposes of this example, say we are trying to solve for the Financial Incentive equaling 10% of the MN Test's net benefits while also including the Utility Performance Incentive impact as a cost in the MN Test. Following this procedure for the values in the above table, we get the following result:

Category	MN Test
	Net Benefits ($)
Benefits	
Avoided Revenue Requirements	
Generation	$117,000,000
T & D	$16,000,000
Marginal Energy	$239,000,000
Environmental Externality	$ 35,000,000
Total Benefits	$ 407,000,000
Costs	
Utility Project Costs	
Customer Services	$4,000,000
Project Administration	$43,000,000
Advertising & Promotion	$8,000,000
Measurement & Verification	$2,000,000
Rebates	$48,000,000
Subtotal	$105,000,000
Financial Incentive	$ 27,454,545
Total Costs	$132,454,545
Net Benefit (Cost)	$ 274,545,455

Observe, now that the Financial Incentive is 10% of the MN Test's net benefits and the MN Test's net benefits includes the Utility Performance Incentive impact as a cost, thus avoiding the circularity problem.

I. Additional Guidance

The following additional guidance assumes that the CIP Financial Incentive would be based on utility energy savings performance relative to goals and achieved MN Test's net benefits. Although the example uses MN Test net benefits, the Department is still working with stakeholders to determine the approach for calculating utility performance incentives that will be proposed for consideration by the Minnesota Public Utilities Commission.

Table 4 - Reporting Guidance for Including Utility Performance Incentives in BCA Tests

Test	Triennial Plan	CIP Status Report
Minnesota	Portfolio, Segment, Program	Portfolio, Segment, Program
Societal Cost	Portfolio, Segment, Program	Portfolio, Segment, Program
Utility Cost	Portfolio, Segment, Program	Portfolio, Segment, Program
Participant	N/A	N/A
Ratepayer Impact Measure	Portfolio, Segment, Program	Portfolio, Segment, Program

Planning: 2024-2026 Triennial Plans

- For planning purposes (CIP Triennial filings), estimated (reasonable projection) Utility Performance Incentives will be applied to cost-effectiveness estimates at the portfolio, segment and program levels based on the respective percentage contributions to overall portfolio lifetime energy savings.
- MN Test, UCT, SCT, RIM should include estimate of Utility Performance Incentive impact as a utility-system cost.
  - Estimates are based on achieving 100% of goals.
  - Costs are distributed among segments based on segment and program percentages of portfolio lifetime savings.

Actuals: 2024-2026 Status Reports

- For annual CIP Status reporting, Utility Performance Incentives shall apply to MN Test (and other relevant test) calculations at the portfolio, segment, and program levels, again based on the segment or program percentage contribution to portfolio lifetime savings.
- Utilities calculate Utility Performance Incentives based on prior year's program results (savings and costs).
  - Financial Incentive Calculation Process:
    - First Run: Utilities use portfolio results to determine initial Utility Performance Incentives values.
    - Iterative Runs: Use Excel iterative calculation tool to develop final Utility Performance Incentive values and final Net Benefits values. [*]
  - Utilities include the Utility Performance Incentive as a utility system cost in calculating MN Test, UCT, SCT, and RIM cost-effectiveness results.
    - Portfolio cost-effectiveness based on interpolated costs from *.
    - Costs are distributed among segments and programs based on segment and program's percentage of portfolio lifetime savings.
    - Segment and program CE are re-calculated using Utility Performance Incentive costs.

5. References

- Michigan PA 342 of 2016 - https://legislature.mi.gov/documents/2015-2016/publicact/htm/2016-PA-0342.htm. How Michigan treats utility performance incentives for energy efficiency programs in its statutory policy framework specifying the cost-effectiveness test to be used in Michigan.

Appendix L – Inputs to BENCOST for Natural Gas Investor-Owned Utilities' 2024-2026 Conservation Improvement Program Triennium

Below are the Inputs to BENCOST for the Natural Gas IOUs' 2024-2026 CIP Triennial filings. For reference, the table below compares the approved values from the 2021-2023 Inputs to BENCOST and the values contained in the 2024-2026 Inputs to BENCOST.

General Inputs	2021-2023 BENCOST Inputs	2024-2026 BENCOST Inputs[153]
Gas Escalation Rate (%)	4.69%	2.61%
Non-Gas Escalation Rate (%)	3.59%	1.63%
Commodity Cost ($/Dth)	$3.25	$4.52
Peak Reduction Factor (%)	1.0%	1.0%
Non-Gas Fuel Cost ($/fuel unit)	$26.57	$44.14
Non-Gas Fuel Loss Factor (%)	7.70%	8.22%
Gas Environmental Damage Factor ($/Dth)	$2.07/Dth	$3.83/Dth
Non-Gas Environmental Damage Factor ($/MWh)	$19.84/MWh	$25.36/MWh
GDP Escalation Rate (%)	2.3%	-
Participant Discount Rate (%)	3.02% (for residential customers) Utility WACC (for non-residential customers)	3.30% (for residential customers); CIP Utility Discount Rate (for non-residential customers)
Societal Discount Rate (%)	3.02%	3.30%
CIP Utility Discount Rate (%)	CIP Utility Discount Rate (See Input 12)	CIP Utility Discount Rate (See Input 12)
Environmental Compliance	-	1.40% of the $/MCF commodity cost

[153] Values in the table reflect first-year information while escalators are the average escalation rates applied over the period. See discussion under Escalation Rates.

INPUTS TO BENCOST FOR NATURAL GAS INVESTOR-OWNED UTILITIES' 2024-2026 CONSERVATION IMPROVEMENT PROGRAM TRIENNIUM

Summary of changes in 2024-2026 Inputs document and the BENCOST model:

- Includes inputs associated with the newly adopted Minnesota Cost Test (the primary CIP cost-effectiveness test) and revisions to secondary tests;
- Adds features that enable cost-effectiveness estimates based on the Minnesota Cost Test and revised Societal Cost, Utility Cost, Participant Cost, and Ratepayer Impact Measure tests;
- Incorporates into the BENCOST spreadsheet documentation associated with individual inputs (documentation was previously included in separate documents); and
- Uses year-by-year forecasted values for inputs instead of static escalator values for those inputs that have year-by-year forecast details.

The inputs necessary to run the 2024-2026 INPUTS TO BENCOST FOR GAS IOUs (BENCOST) model are listed below. Following this list, Staff provide a description and the source(s) for each of the inputs.

Table 5 - BENCOST Inputs

I. General Inputs	II. Utility, Project, and Program-Specific Inputs
Retail Rate ($/Dth)	Utility Project Costs ($)
Non-Gas Fuel Retail Rate ($/Fuel Unit)	Direct Participant Project Costs ($/Participant)
Commodity Cost ($/Dth)	Participant Non-Energy Costs (Annual $/Part)
Demand Cost ($/Dth/Yr)	Participant Non-Energy Savings (Annual $/Part)
Peak Reduction Factor (%)	Project Life (Years)
Variable O&M ($/Dth)	Avg. Dth/Participant Saved
Non-Gas Fuel Cost ($/Fuel Unit)	Avg. Non-Gas Fuel Units/Part. Saved
Non-Gas Fuel Loss Factor (%)	Avg. Additional Non-Gas Fuel Units/Part. Used
Gas Environmental Damage Factor ($/Dth)	Number of Participants
Non-Gas Fuel Environmental Damage Factor ($/MWh)	Total Annual Dth Saved
Environmental Compliance (% or $/Dth)	Incentive/Participant
Market Price Effects (% or $/Dth)	Utility Performance Incentives
Other Environmental	
Economic and Jobs (Macroeconomic)	
Energy Security	
Energy Equity	
Credit and Collection Costs	
Risk	
Reliability	
Resilience	
Participant Discount Rate (%)	
Societal Discount Rate (%)	
General Input Data Year	
Project Analysis Year	
Escalation Rate (%)	

As outlined in Table 1, general data inputs are either directly specified by Staff or are utility-specific; they are used in analyzing all direct impact CIP projects. By contrast, the specific project data inputs may vary from project to project.

Escalation Rates

In response to stakeholder suggestions that the Department use year-by-year PUC environmental cost values from the Commission's January 3, 2018 Order Updating Environmental Cost Values, the Department revised its approach for using starting values with static escalation rates to, instead, use year-by-year forecasted values for those indexes for which this level of detail exists. The BENCOST includes a tab labeled "Escalation Rates" to show, for informational purposes, the average escalation rates over the periods covered by the data. The average escalation rate information is also reflected in Table 1.

A description of the data for each BENCOST input follows.

I. GENERAL INPUTS

Input 1 **The Retail Rate ($/Dth)**: The natural gas rate for the specific customer class or classes (*i.e.*, commercial, industrial, or residential) that are expected to participate in the project. The *Retail Rate* is calculated by adding the following:

- the utility's currently-approved tariffed non-natural gas margin in the customer class that is expected to participate in a project (or a weighted average non-natural gas margin if more than one customer class is expected to participate in the project), which is on file with the Department of Commerce;
- the *Commodity Cost* of $4.52/Dth, which is described below in Input No. 3; and
- the per Dth *Demand Cost* from the utility's March 2023 Purchased Gas Adjustment (PGA) filing, as described below in Input No. 4.

The *Retail Rate* does not include the annual true-up adjustment or the annual Conservation Cost Recovery Adjustment, if applicable. Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used in determining the non-gas margin and demand cost components of this input.

The *Retail Rate* is multiplied by variable escalation rates between 2023 and 2043, averaging **2.61 percent**. Staff calculated the Annual Escalation Rates using the projected average percent changes in the price of natural gas from 2023 through 2043 (20-year period) to all users in the West North Central Region as estimated in the Energy Information Administration's 2022 *Annual Energy Outlook*.[154]

Input 2 **The Non-Gas Fuel Retail Rate ($/Fuel Unit)**: The estimated non-natural gas (*e.g.*, electricity) retail rate for the specific customer class or classes (i.e., commercial,

[154] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2022&region=1-4&cases=ref2022&start=2020&end=2050&f=A&linechart=~~ref2022-d011222a.118-3-AEO2022.1-4&map=ref2022-d011222a.4-3-AEO2022.1-4&ctype=linechart&sourcekey=0

industrial, or residential) that is or are expected to participate in a project, if applicable. If this input is an electric retail rate, it should be based on a tariffed rate for the customer class that is expected to participate in a project (or a weighted average retail rate if more than one customer class is expected to participate in a project). Each utility that chooses to use this input must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used to calculate the *Non-Gas Fuel Retail Rate*.

The *Non-Gas Fuel Retail Rate* is multiplied by variable escalation rates between 2023 and 2043, averaging **1.63 percent**. The Annual Escalation rate for the non-gas fuel was developed using the "Chained Price index - Consumer Electricity" projected price index for the 2023-2043 period. The Minnesota Department of Management & Budget (Budget) provides this value.

Input 3 **The Commodity Cost ($4.52/Dth)**: The value is determined by developing average purchase gas adjustment costs (total $ / total sales to non-exempt customers) from November 2020 through October 2022 for CenterPoint Energy, Great Plains Gas, Greater Minnesota Gas, Minnesota Energy Resources Corporation, and Xcel Energy. Each utility's average purchased gas adjustment costs for the period are then weighted by the utility's proportion of total utility sales and summed.

The *Commodity Cost* input is also multiplied by variable escalation rates between 2023 and 2043, averaging **2.61 percent**, which is described above in Input No. 1.

Input 4 **The Demand Cost ($/Dth/Year)**: The estimated annual fixed demand costs that the utility would save from buying one fewer Dth of demand services.

The source for this figure is the utility's March 2023 PGA, which reflects the demand costs from that peaking season. Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions used in determining this input.

The *Demand Cost* uses the escalation rates described in Input No. 1.

Input 5 **The Peak Reduction Factor (1 percent)**: The estimated average annual effect of the project on system peak. The factor is presented as the percent of energy savings occurring on peak, which is estimated at one percent for most projects. Utilities that believe a different Peak Reduction Factor should apply to specific programs or segments may propose alternate values (with explanations for the alternate values in their Triennial filings).

Input 6 **Variable O&M ($/Dth)**: The variable costs, other than fuel and purchased energy costs, that are included as expenses in delivering energy to the end use consumer.

For utilities that have flexible rate tariffs, *Variable O&M* is the minimum transportation flexible rate, which is generally based on the utility's best estimate of variable costs. Each utility must fully explain how it determines the *Variable O&M* input.

This cost uses the escalation rates described in Input No. 1.

Input 7 **The Non-Gas Fuel Cost ($44.14/Fuel Unit)**: Used to project society's avoided or increased costs of non-natural gas fuels (*e.g.*, electricity) associated with participation in a natural gas CIP project, if applicable.

Staff calculated an average cost of $44.14/MWh, equal to the average of daily real-time final market locational marginal prices (LMP) at the Minnesota Hub from January 1, 2022 to December 31, 2022 using data from Midwest Independent System Operator (MISO).[155] This value is escalated using Input No. 2.

At this time, Staff are not issuing a proxy for electric transmission and distribution costs. If a utility wishes to propose such costs, or if a utility wishes to propose non-natural gas fuel costs other than those associated with electricity, it must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used in determining such a proposed cost amount.

Input 8 **The Non-Gas Fuel Loss Factor (8.22 percent)**: The electric transmission and electric distribution line losses associated with participating in a natural gas CIP project, if applicable.

Staff calculated the *Non-Gas Fuel Loss Factor* by taking the average of Minnesota Power, Xcel Energy, and Otter Tail Power's reported 2021 transmission and distribution loss factors and weighting by the utilities' 2017-2019 average retail sales.

Input 9 **The Gas Environmental Damage Factor ($3.83/Dth in 2023 and escalated through 2043)**: The long-term "external" cost to society and the environment from burning natural gas.

The factor includes damage factors associated with both criteria air emissions and greenhouse gases (GHGs). The value for the criteria emissions component is calculated using the high range of the final metropolitan fringe environmental cost values approved by the Minnesota Public Utilities Commission (Commission)[156] for sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), carbon monoxide (CO), nitrogen oxides (NO_x), and lead (Pb), along with estimated natural gas emission factor (or factors) for each pollutant provided by the U.S. Environmental Protection Agency.[157] For the carbon dioxide (CO_2) GHG,[158] Staff used as the starting point the high externality value of $45.16/ton in 2023 from the Commission's January 3, 2018 Order Updating Environmental Cost Values.

The PUC's Environmental Cost Values are provided in 2014 and 2016 dollars. Staff escalated the values to 2023 dollars using U.S. Bureau of Labor CPI-U statistics for the 2014-2022 period (average annual rate of 2.86%).

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[155] https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AReal-Time%20Final%20Market%20LMPs%20(csv)&t=10&p=0&s=MarketReportPublished&sd=desc

[156] January 3, 2018, Order Updating Environmental Cost Values, Docket No. E-999/CI-14-643.

[157] AP-42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources.

[158] Additional greenhouse gases include: methane, nitrous oxide, and fluorinated gases such as hydrofluorocarbons. The PUC factor focuses on CO_2, the primary greenhouse gas emitted through human activities.

Staff then escalated the 2023 values for criteria air emissions using the escalation rates built into PUC's Environmental Cost Values for CO_2. The escalation rate averages 1.69 percent annually from 2023 to 2043.

Input 10 **The Non-Gas Fuel Environmental Damage Factor ($25.36/MWh)**: The long-term "external" cost to society and the environment of generating electricity. BENCOST Non-Gas factors are denominated in kWh. Therefore, the value is converted to $0.02536/kWh.

The factor includes damage factors associated with both criteria air emissions and greenhouse gases (GHGs). The value for the criteria emissions component is calculated using the high range of the final metropolitan fringe environmental cost values approved by the Minnesota Public Utilities Commission (Commission)[159] for sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), carbon monoxide (CO), nitrogen oxides (NO_x), and lead (Pb); along with estimated 2020 emission factor (or factors) for each pollutant provided by the Environmental Protection Agency[160] and the Minnesota Pollution Control Agency.[161] For the carbon dioxide (CO_2) GHG, Staff used the high externality value of $45.16/ton in 2023 from the Commission's January 3, 2018 Order Updating Environmental Cost Values.

The *Non-Gas Environmental Damage Factor* is reported in 2023 dollars, which Staff calculated by inflating the Commission-approved dollar per ton environmental cost values using U.S. Bureau of Labor CPI-U statistics for the 2014-2022 period (average annual rate of 2.86%).

The *Non-Gas Environmental Damage Factor* is escalated using the rates built into PUC's Environmental Cost Values for CO_2. The values average 1.69 percent from 2023 to 2043.

If a utility proposes to use an environmental damage factor associated with a type of fuel other than electricity, it must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to supporting documents) used in determining this input.

Input 11 **The Participant Discount Rate (percent)**: The *Participant Discount Rate* for residential customers is equal to the *Societal Discount Rate* of 3.30 percent, as discussed in Input No. 13. Such a discount rate would reflect a residential customer's likely opportunity costs (*i.e.*, the return on investment that a residential customer would forgo to invest in a CIP measure).

The *Participant Discount Rate* for commercial and industrial customers is equal to the CIP Utility Discount Rate, which is described below in Input 12. Although this discount

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159 January 3, 2018, Order Updating Environmental Cost Values, Docket No. E-999/CI-14-643.

160 January 27, 2022, Emissions & Generation Resource Integrated Database 2020 (eGRID). *Environmental Protection Agency.* <https://www.epa.gov/egrid>.

161 2020 Point Source Air Emissions Data. *Minnesota Pollution Control Agency.* <https://public.tableau.com/app/profile/mpca.data.services/viz/Pointsourceairemissionsdata_v10_5-11130/Byfacility>.

rate may be lower than the actual discount rate for a particular commercial/industrial customer, it represents an attempt to reflect in a simple manner a reasonable estimate of a business customer's opportunity costs.

Input 12 **The CIP Utility Discount Rate (percent)**: The discount rate used in the Utility Cost Test and Ratepayer Impact Measure Test to value, in current dollars, the future stream of utility system benefits and costs (excluding benefits resulting from avoided environmental damage, as discussed above in Input No. 9) resulting from a conservation investment.

The CIP Utility Discount Rate is based on the theory that CIP investments are funded by both the utility and the ratepayers that participate in CIP. Utilities invest money in CIP programs and customer participants pay incremental costs. The future benefits of energy savings come from the avoided costs resulting from the customer and utility investments.

The gas IOUs shall apply the following utility-specific CIP Utility Discount Rates in the Utility Cost Test for the purposes of 2024-2026 CIP cost-effectiveness testing:

- Xcel Gas: 5.34 percent
- CenterPoint: 5.39 percent
- MN Energy Resources: 5.57 percent
- Greater MN Gas: 5.61 percent
- Great Plains: 5.79 percent

For details about how the CIP Utility Discount Rate is calculated, see pages 21-22 of the *Deputy Commissioner's Decision – In the Matter of CIP Gas and Electric Utilities 2021-2023 Cost-Effectiveness Review.* February 11, 2020. Docket Nos. G999/CIP-18-782, E999/CIP-18-783. These values are unchanged from the 2021-2023 Triennium.

Input 13 **The Societal Discount Rate (3.30 percent)**: The discount rate used in the Minnesota Cost Test, the Societal Cost Test, and the (residential) Participant Cost Test to value, in current dollars, the future stream of societal benefits and costs resulting from a conservation investment.

The *Societal Discount Rate* is calculated using the United States Department of the Treasury's (Treasury) 20-year Constant Maturity (CMT) Rate, which averaged 3.3 percent between January 03, 2022 through December 30, 2022.

The Treasury's 20-year Daily CMT Rate captures the market's expectations regarding inflation, along with a small risk factor. At this time, Staff conclude that a rate including inflation expectations and a small risk factor is a reasonable method for estimating a social discount rate for externalities.

Input 14 **The General Input Data Year** for the 2024-2026 benefit/cost analysis is 2023.

Input 15 **Project Analysis Year:** Year 1 is 2024, Year 2 is 2025, Year 3 is 2026.

II. UTILITY, PROJECT, and PROGRAM-SPECIFIC INPUTS

Input 16 **The Utility Project Costs**: The sum of all of the utility's estimated project costs. Examples of these costs include administrative and operating costs and incentive costs paid to the participant.

Input 17 **Direct Participant Costs ($/Participant)**: The incremental "out-of-pocket" expenses that the participant would pay to install the conservation measure. For example, the cost to a customer to install a high efficiency furnace is the difference in installation costs between high efficiency equipment and equipment that meets code.

This input is not reduced by the amount of any rebate that the utility will provide to the participant through the CIP project. Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions used in determining this input.

Input 18 **Participant Non-Energy Costs (Annual $/Participant):** Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions used in determining this input.

This figure is entered as an annual cost and is escalated using the rates discussed in Input 2.

Input 19 **Participant Non-Energy Savings (Annual $/Participant):** This figure is entered as an annual benefit and escalated using the rates discussed in Input 2.

Input 20 **The Project Life**: The expected lifetime of a particular energy conservation measure, expressed in number of years.

The project life used in the BENCOST model is based on specific energy conservation measures. Projects with expected lives shorter than 20 years use lower figures. Each utility must show the reasonableness of its expected lifetime for a particular energy conservation measure or project. In most cases, the maximum life used is limited to 20 years for the following reasons:

a) benefits are more uncertain the further out in time the model is extended;
b) benefit streams diminish further out in time and have lesser effects on cost-effectiveness than more current years;
c) the further out in time the model is extended, the more uncertain it becomes that current ratepayers, who are funding CIP, receive the full benefits of CIP; and
d) if a project cannot pay for itself within 20 years, ratepayers should consider funding other, more cost effective projects.

Input 21 **The Average Dth/Participant Saved**: The estimated annual amount of Dth saved from the energy conservation measure. Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions used in determining this input.

Input 22 **The Average Non-Gas Fuel Units/Participant Saved**: The estimated amount of non-natural gas fuel (*e.g.*, electricity) saved per participant in a project.

Each utility that includes such fuel savings must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used in determining this input.

Input 22a **The Average Additional Non-Gas Fuel Units/Participant Saved**: The amount of non-natural gas fuel (e.g., electricity) used per participant in a project.

Each utility that includes such fuel usage must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used in determining this input.

Input 23 **The Number of Participants**: The estimated number of participants based on the utility's expected market penetration levels, on past experience in a similar project, or on marketing penetration studies for similar projects.

Input 24 **The Total Annual Dth Saved**: The total amount of savings projected for a year. The savings are computed by the model by multiplying Input No. 23 by Input No. 21.

Input 25 **The Incentive per Participant**: The utility incentive costs identified in Input No. 16 divided by the *Number of Participants* identified in Input No. 23. This figure is computed within the model.

Input 32 **Utility Performance Incentives**: Utility performance incentives are costs that are passed on to ratepayers and, therefore, should be included in cost-effectiveness calculations. The values utilities include in this input are based on projected performance incentives for each year of the triennium.

III. NEW GENERAL INPUTS

Input 26 **Environmental Compliance**: Current and future environmental compliance requirements that impact utility rates; environmental compliance impacts already included in the cost of the relevant energy resource should not be included in this category of impacts to avoid double-counting.

The required value for Environmental Compliance Impacts for the 2024-2026 Triennium is 1.40% of the $/MCF commodity cost. The value is based on impacts from proposed federal methane emissions standards that the U.S. EPA anticipates finalizing in 2024.

Input 27 **Market Price Effects**: Wholesale market prices are a function of the demand of buyers and the marginal costs of suppliers. When DERs reduce the demand for gas, they reduce (or increase) the wholesale market prices, which creates benefits for all customers participating in the wholesale market at that time. Market Price Effects quantifies the estimated impact on market prices from CIP programs.

The required value for the 2024-2026 Triennium for Market Prices Effects is zero (as yet unquantified).

Input 28 **Other Environmental**: Serves as a catch-all quantification of all other environmental impacts including other air emissions, solid waste, land, water, and other environmental impacts not accounted for in other critieria.

The required value for the 2024-2026 Triennium for Other Environmental is zero (as yet unquantified).

Input 29 **Economic and Jobs (Macroeconomic)**: Quantifies the incremental economic development and job impacts resulting from CIP programs.

The required value for the 2024-2026 Triennium for Economic and Jobs is zero (as yet unquantified).

Input 30 **Energy Security**: CIP investments can reduce energy imports to help advance the goals of energy independence and security. It is important that the quantification of this criterion not overlap with reliability and risk criteria.

The required value for the 2024-2026 Triennium for Energy Security is zero (as yet unquantified).

Input 31 **Energy Equity**: Benefits from CIP programs that are specifically designed to mitigate concerns about equity (namely concerns that the economic, health, and social benefits of participation are not shared by all levels of society, regardless of ability, race, or socioeconomic status) can be quantified and applied to BCAs for programs that meet relevant criteria.

The required value for the 2024-2026 Triennium for Energy Equity is zero (as yet unquantified).

Input 33 **Credit and Collection Costs**: CIP investment can help reduce utility costs associated with arrearages, disconnections, and reconnections.

The required value for the 2024-2026 Triennium for Credit and Collection is zero (as yet unquantified).

Input 34 **Risk**: CIP programs, by reducing required utility resources to serve customer needs, can help mitigate operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks.

The required value for the 2024-2026 Triennium for Risk is zero (as yet unquantified).

Input 35 **Reliability**: CIP investments can improve system reliability by reducing utility system requirements and helping the system withstand instability, uncontrolled events, cascading failures, or unanticipated losses of system components.

The required value for the 2024-2026 Triennium for Reliability is zero (as yet unquantified).

Input 36 **Resilience**: Resilience refers to the ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions. CIP programs can improve utility resilience.

The required value for the 2024-2026 Triennium for Resilience is zero (as yet unquantified).