Appendix F

Energy Conservation and Efficiency Information

TABLE OF CONTENTS

Appendix F-1

Energy Conservation and Efficiency Information

Minnesota Rule 7849.0290 requires a Certificate of Need application to provide information related to an applicant's energy conservation and efficiency programs and a quantification of the impact of these programs on the forecast information required by Minn. R. 7849.0270. The Applicants requested an exemption from this content requirement, and proposed to provide substitute information related either to their conservation programs or to the conservation programs that are available to their members serving load in Minnesota. The Applicants also proposed to provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.[1] In response, the Department agreed that the proposed information will better inform the record as to the need for the proposed Project and recommended that the Commission grant the requested exemption with the provision of the proposed alternative data.[2] The Commission approved the Applicants' requested exemption with provision of the alternative data.[3] The required information is provided below.

For decades, Minnesota has been a national leader in energy efficiency. The state's utility-sponsored energy efficiency programs are among the longest-standing in the country, and Minnesota is the only Midwestern state that is consistently ranked in the top ten on the American Council for an Energy Efficient Economy's (ACEEE) State Energy Efficiency Scorecard. Minnesota utilities' energy savings achievements through demand-side management (DSM) have saved billions of dollars for customers and avoided millions of tons of greenhouse gas and other pollutants while creating and supporting jobs in the state.[4] The Applicants provide below information related to their conservation programs, as well as a discussion of how conservation and energy efficiency was

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[1] *See* Docket No. E002, E017, ET2, E015, ET10/CN-22-538, *In the Matter of the Application for a Certificate of Need for the Big Stone South – Alexandria – Big Oaks Transmission Project*, Request for Exemption from Certain Certificate of Need Application Content Requirements (Mar. 3, 2023) at 8.

[2] *See* Docket No E002, E017, ET2, E015, ET10/CN-22-538, Comments of the Minnesota Department of Commerce, Division of Energy Resources (Mar. 30, 2023) at 5.

[3] *See* Docket No. E002, E017, ET2, E015, ET10/CN-22-538, Order Approving Notice Plan Petition and Request for Exemption from Certain Certificate of Need Application Content Requirements (Apr. 19, 2023).

[4] The Aggregate Economic Impact of the Conservation Improvement Program 2008-2013, Minnesota Department of Commerce, Division of Energy Resources, Cadmus (Oct. 2015), https://mn.gov/commerce-stat/pdfs/card-report-aggregate-eco-impact-cip-2008-2013.pdf.

considered by the Midcontinent Independent System Operator, Inc. (MISO) in its evaluation and approval of the Project.

A. Xcel Energy's Energy Conservation and Efficiency Programs

Xcel Energy has maintained a consistent and high level of DSM achievement. Between 1994 and 2022, Xcel Energy invested nearly $2.2 billion (nominal) resulting in 11,813 gigawatt hours (GWh) of electric energy savings, 3,733 megawatts (MW) of electric demand savings and an estimated 19.92 million dekatherms (Dth) of natural gas savings.[5] In its 2024-2026 Energy Conservation and Optimization Triennial Plan, dated June 29, 2023 (Xcel Energy's Triennial Plan), Xcel Energy continues to strive to provide customers with a wide variety of options for saving energy. Xcel Energy's Triennial Plan proposed ambitious goals of saving 1,734 GWh, 674 MW, and 3,918,970 Dth over the three-year period at a cost of approximately $530 million.[6] The proposed electric savings goals also aligned with Xcel Energy's DSM commitments in its most recent Integrated Resource Plan (Xcel Energy's IRP).

In its 2022 Conservation Improvement Program (CIP) Status Report, Xcel Energy stated that for more than a decade, its electric DSM portfolio has surpassed the statutory energy savings of 1.5 percent, and in 2022, achieved nearly 648 GWh of electric savings, or 2.33 percent of sales.[7] These savings exceeded the state's new energy savings target of 1.75 percent.[8] In 2022, Xcel Energy spent a total of $124 million to achieve its savings results, including $104 million on electric programs and approximately $20 million on natural gas programs.[9]

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[5] *See* Docket No. E,G002/CIP-23-92, Xcel Energy 2024-2026 Energy Conservation and Optimization Plan (June 29, 2023) at 2.

[6] *See* Docket No. E,G002/CIP-23-92, Xcel Energy 2024-2026 Energy Conservation and Optimization Plan (June 29, 2023) at 1.

[7] *See* Docket No. E,G002/CIP-20-473, 2022 CIP Status Report (Mar. 31, 2023) at 4.

[8] The Energy Conservation and Optimization Act of 2021 updated the electrical savings goal to 1.75 percent and the natural gas savings goal to 1.0 percent of annual retail energy sales; utilities filed their first CIP Triennial Plans under this requirement in 2023.

[9] *See* Docket No. E,G002/CIP-20-473, 2022 CIP Status Report (Mar. 31, 2023) at 5.

Likewise, Xcel Energy's initial IRP filing included energy efficiency (EE) and demand response (DR) investments, and Xcel Energy's Supplemental Plan[10] and Alternate Plan[11] continued to reflect those investments. Xcel Energy proposed to seek to achieve EE savings levels ranging from 2 to 2.5 percent annually, achieving average savings of over 780 GWh of energy in each of 2020-2034, and more than 800 MW of additional demand savings by 2034[12] when compared to the 1.5 percent level approved in the Company's prior IRP.[13] In addition, Xcel Energy proposed an incremental 400 MW of DR by 2023.[14]

B. Great River Energy's Energy Conservation and Efficiency Programs

Great River Energy's most recent IRP was filed with the Commission on March 31, 2023.[15] A comment period on that IRP ends on October 2, 2023.[16] Great River Energy's IRP covers the planning period for 2023 through 2037 and provides a comprehensive view of Great River Energy's portfolio plan (the "Plan") for the next 15 years. The Plan builds on changes in Great River Energy's resource portfolio that have already significantly reduced carbon emissions and increased generation from carbon-free resources. The Plan includes additions of only carbon-free resources consisting of wind, solar, and storage. In addition, and as relevant here, the Plan describes recent innovative initiatives regarding energy efficiency and demand response programs. A summary of those efforts is included below; for further detail, see Sections 9 and 10 of Great River Energy's IRP.

Great River Energy operates one of the most robust DR programs in the nation; these programs intentionally change our members' end-users' electric usage patterns from their normal consumption patterns in response to changes in the price of electricity or incentive payments. Great River Energy's energy efficiency programs use an "all of the

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[10] *See* Docket No. E002/RP-19-368, IRP Supplement Preferred Plan (Jun. 30, 2020).
[11] *See* Docket No. E002/RP-19-368, Xcel Energy Reply Comments (IRP Alternate Plan) (Jun. 25, 2021) and Order Approving Plan with Modifications and Establishing Requirements for Future Filings (Apr. 15, 2022) at 10.
[12] *See* Docket No. E002/RP-19-368, Xcel Energy Reply Comments (IRP Alternate Plan) (Jun. 25, 2021) at 10.
[13] *See* Docket No. E002/RP-15-21, 2016-2030 Upper Midwest Resource Plan (Jan. 2. 2015) and Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings (Jan. 11, 2017).
[14] *See* Docket No. E002/RP-19-368, Xcel Energy Reply Comments (IRP Alternate Plan) (Jun. 25, 2021) at 10.
[15] *In the Matter of Great River Energy's 2023-2037 Integrated Resource Plan*, Docket No. ET-2/RP-22-75 (Mar. 31, 2023), eDockets ID 20233-194396-01, 20233-194396-06.
[16] *Id.* at Notice of Comment Period (Apr. 5, 2023).

above" approach to member energy efficiency engagement. The total program is made up of five components:

- **Equipment incentive programs –** These programs provide incentives for members' end users to invest in equipment having greater efficiency than equipment that meets current federal standards. Incentives are based on budget and the current commercial state of the technology. As technologies mature and the market for these technologies transform, the overall rebate for those technologies will be decreased.
- **Consumer behavior programs –** Consumer behavior programs focus on educating end users about their energy use and providing relevant comparisons that seek to illustrate ways in which the member-consumer can reduce their consumption and lower their overall cost of energy. Several of Great River Energy's members have employed tools like SmartHub, which leverages member-owner investments in Advanced Metering Infrastructure to present energy consumption data through an online web portal. In addition, several members have employed direct appeals to their end users to reduce their consumption during the hottest months of the year. These "Beat the Peak" programs ask member-consumers to voluntarily reduce their consumption and are associated with contests that reward end users that realize the greatest reduction in their overall electric consumption.
- **Supply-side efficiency –** Efficiency is a central focus of Great River Energy's culture of business improvement. Recent generation efficiency improvements include combustion turbine tuning to minimize heat rates and major overhauls of several combustion turbines based on operating hours. In addition, Great River Energy has also been actively engaging with third-party wind forecasting developers to identify improvements in day-ahead wind forecasting ability. Additional efficiency gains are being developed with regard to Ambient Adjusted Ratings of Great River Energy's transmission lines which will aid in reducing both congestion charges and renewable energy generation curtailment.

- **Market transformation –** Great River Energy's long history of efficiency engagement with members has resulted in member-consumers who are well versed in the benefits associated with investments in efficiency. As the market share of products that carry labels indicating efficient products (e.g., ENERGY STAR®) have expanded, many members have adopted these technologies without taking advantage of rebate programs.
- **Demand response –** Great River Energy's robust demand response efforts are focused on modifying the load curve during the periods of monthly peak demand, as well as ongoing efforts to shift as many end uses to off-peak periods as possible. The effort to shift end uses to off-peak periods is most pronounced in the areas of electric storage water heating and EV charging efforts.

Great River Energy plans the following energy efficiency program activities throughout the Five-Year Action Plan identified in the IRP:

- Survey members in 2023 regarding key electric end uses within homes and businesses;
- Participate in research to further characterize energy efficiency end use technologies, including the expansion of the efficient fuel switching opportunities under Minnesota's 2021 Energy Conservation and Optimization Act;
- Work with members to identify and market new programs that improve awareness of energy consumption, increase the adoption of efficient end-use technologies where practical, and minimize rate impacts; and
- Further evaluate the efficiency opportunities within our members' service territories.

C. Minnesota Power's Energy Conservation and Efficiency Programs

Minnesota Power filed its 2022 CIP Consolidated Filing with the Commission on April 3, 2023 in Docket No. E015/M-23-135. A copy of the "Summary" section and the "2022 CIP Status Report" section of this filing is provided as **Appendix F-2**.

Minnesota Power filed its 2021 Integrated Resource Plan ("2021 IRP") with the Commission on February 1, 2021 in Docket No. E015/RP-21-33. Appendix B of the 2021 IRP filing contained information regarding Minnesota Power's planning and strategies for demand-side management, Energy Efficiency, and CIP. A copy of Appendix B of the 2021 IRP filing is provided as **Appendix F-3**. Additional information regarding Minnesota Power's conservation and demand-side management programs can be found on Minnesota Power's website at: https://www.mnpower.com/ProgramsRebates.

D. Otter Tail Power's Energy Conservation and Efficiency Programs

Otter Tail Power Company (Otter Tail) has a long history of delivering highly cost-effective demand-side solutions to our customers. Between 1994 and 2022, Otter Tail invested over $117 million (nominal) resulting in 882 gigawatt hours (GWh) of electric energy savings, 272 megawatts (MW) of electric demand. In 2022, Otter Tail achieved over 50 GWh of electric savings, or 2.99 percent of sales[17] while spending $7.7 million to achieve the savings results.

In its 2024-2026 Energy Conservation and Optimization Triennial Plan[18], dated June 30, 2023 (Otter Tail's Triennial Plan), Otter Tail's proposes to achieve over 2.5 percent energy savings, significantly higher than Minnesota's goal of 1.75 percent. In addition, Otter Tail's plan provides a wide breadth of energy solutions for customers, including heating and cooling solutions, water heating, building envelope, lighting, appliances, transportation, load management, renewables, education, and commercial/industrial process solutions.

Otter Tail's Triennial Plan proposed ambitious goals of saving 147 GWh, and 226 MW over the three-year period at a cost of approximately $30 million. The proposed electric

[17] *See* Docket No. E,G002/CIP-20-475, 2022 CIP Status Report (April 3, 2023)

[18] See Docket No. E017/CIP-23-94, Otter Tail Power Company's 2024-2026 Energy Conservation and Optimization Plan (June 30, 2023)

savings goals also align with Otter Tail's conservation commitments filed in its most recent Integrated Resource Plan (Otter Tail's IRP) [19].

In Otter Tail's IRP, the Company filed an Application for Supplemental Resource Plan Approval with the Minnesota Public Utility Commission (MPUC) on March 31, 2023. Consistent with the results of the 2018 Minnesota Energy Efficiency Potential Study[20], the Company included 1.9 percent to 2.0 percent annual savings for conservation efforts made by the Company for the 2024-2026 triennial period in the IRP. For the 2024-2026 Triennial Plan, Otter Tail has proposed energy savings goal at the 2.5 percent level, net of ECO-exempt sales. These aggressive goals go beyond the ECO Act requirement of 1.75 percent and support our Resource Plan objectives.

E. Western Minnesota's Energy Conservation and Efficiency Programs

Western Minnesota Municipal Power Agency owns generation and transmission facilities, the capacity and output of which are sold to Missouri River Energy Services (MRES). MRES provides energy and energy services to its 61 member municipal utilities, and assists member municipalities with their energy efficiency, conservation, and other DSM programs by providing incentives and developing joint programs with members. In its most recent IRP, MRES discussed the comprehensive portfolio of energy efficiency incentives developed by MRES for customers served by its member municipal utilities.[21] In 2020, MRES completed an updated study of the maximum amount of DSM that can be implemented for its members' retail customers, under certain avoided cost assumptions provided by MRES. The study results show an expected potential for DSM of up to 93.9 MW of demand savings by 2036, coincident with the peak demands of the MRES member loads. In 2022, MRES spent nearly $3 million resulting in 5,041 kilowatts (kW) of peak demand savings (not including load control savings and costs).

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[19] See Docket No. E017/RP-21-339, Otter Tail Power Company's 2022-2036 Integrated Resource Plan (March 31, 2023)
[20] Minnesota Energy Efficiency Potential Study: 2020-2029, Conservation Applied Research and Development (CARD) Final Report (December 4, 2018)
[21] *See* Docket No. ET10/RP-21-414, Missouri River Energy Services 2022-2036 Resource Plan (July 1, 2021) at 32.

F. MISO's Consideration of Conservation and Energy Efficiency in MTEP21

The Big Stone South – Alexandria – Big Oaks Transmission Project is not needed to support growing peak demand. Rather, the Project is needed to provide additional transmission capacity to transport increasing amounts of renewable generation on the system. More specifically, the existing 230 kV transmission system in eastern North Dakota and South Dakota plays a key role in transporting and delivering energy into Minnesota. The 230 kV system is at its capacity leading to a number of reliability concerns that could affect customers' service. The Project is needed to provide additional transmission capacity, to mitigate current capacity issues, and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region. Given that the need for this Project is not driven by increases in peak demand, the Commission granted the Applicants' request for exemption from certain forecasting data for Applicants' service areas and systems as required by Minn. R. 7849.0270, subp. 2. Instead, Applicants committed to provide forecast information utilized by MISO in studying, planning, and analyzing the Project as part of MISO's 2021 Transmission Expansion Plan (MTEP21).

MISO's annual transmission planning process develops multiple future scenarios to study transmission needs under a variety of economic, policy, and technological possibilities. Each future scenario contains assumptions about future fuel costs, environmental regulations, demand and energy levels, and technological possibilities.

As part of the development of these future scenarios, MISO develops forecasts for conservation, energy efficiency, and demand response, collectively referred to as "Distributed Energy Resources" (DER) by MISO. These forecasts are developed by aggregating each MISO member's load forecasts. To consider a broader range of potential DER outcomes, MISO creates forecasts considering varying adoption rates, technological advancements, and economic factors. MISO's forecasts are developed for each of MISO's 10 Local Resource Zones, to consider regional differences, and then are aggregated to a MISO-wide forecast.

Similar to previous MTEPs, MISO commissioned Applied Energy Group (AEG) to develop new DER technical potential for MTEP21. AEG developed estimates of DER impacts through survey of load-serving entities (LSE) and secondary research.

Based on analysis for MTEP20, with updated utility information and Futures narratives for this cycle, technical potential represents feasible potential under each scenario. To support modeling, AEG compiled DER programs by type and cost into program blocks for use in MISO's Electric Generation Expansion Analysis System (EGEAS) – an integrated resource planning tool.

The DER resources were modeled as program blocks in three main categories: Demand Response (DR), Energy Efficiency (EE), and Distributed Generation (DG). The DER programs also fall into two sectors: Residential and Commercial and Industrial (C&I). A complete list of the DER programs considered by MISO in MTEP21 is provided below in **Table F-1**.

Table F-1
MTEP21 Distributed Energy Resource Programs[22]

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response	C&I Price Response
DR	Residential Direct Load Control	Res. Direct Load Control
DR	Residential Price Response	Res. Price Response
EE	C&I High-Cost EE	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE*	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retrocommissioning Low
EE	C&I Mid-Cost EE	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retrocommissioning Mid
EE	Residential High-Cost EE	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE*	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV*	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV*	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

During the program selection phase for the MTEP21 Futures, each block was offered against supply-side alternatives to determine economic viability. For all three MTEP21 Futures, EGEAS selected the following program blocks, all within the C&I group: Customer PV, Utility Incentive PV, and Low-Cost Energy Efficiency. Additionally, Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals below. Only selected programs and stakeholder

[22] **Appendix E-1** at 41 (MTEP21 Report Addendum).

additions were implemented in the MTEP21 Futures models. **Table F-2** and **Table F-3** show the total DER technical potential and additions modeled in MTEP21 by Future. The additions are those that were found to be economically superior to other alternatives and thus were included in the MTEP21 Futures. All of the values shown in **Table F-2** and **Table F-3** are in addition to the DER included in MISO LSE base forecasts.

Table F-2
DER Capacity (GW): 20-Year Technical Potential and Additions in MISO

MTEP21 DERs Capacity (GW) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	5.2	0.9	5.9	0.9	5.9	0.9
Energy Efficiency (EE)	13.3	7.8	14.5	8.1	14.5	11.7
Distributed Generation (DG)	14.7	3.5	14.7	3.5	21.8	6.2

Table F-3
DER Energy (GWh): 20-Year Technical Potential and Additions in MISO

MTEP21 DERs Energy (GWh) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	442	118	498	118	498	118
Energy Efficiency (EE)	86,886	30,801	94,313	31,393	94,313	49,145
Distributed Generation (DG)	26,119	5,709	26,119	5,709	36,934	9,837

Appendix F-2

Minnesota Power 2022 Conservation Improvement Program
Status Report Summary

2022 Consolidated Filing

Conservation Improvement Program

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AN ALLETE COMPANY

April 3, 2023

Docket No. E-015/M-23-135 | E-015/CIP-20-476.02

30 West Superior Street
Duluth, MN 55802-2093
www.mnpower.com

April 3, 2023

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

Deputy Commissioner Michelle Gransee
Minnesota Department of Commerce
85 Seventh Place East, Suite 500
St. Paul, MN 55101-2198

Re: **2022 Conservation Improvement Program Consolidated Filing**
Docket Nos. E015/M-23-135, E015/CIP-20-476.02

Dear Mr. Seuffert and Ms. Gransee:

Attached please find via eFiling Minnesota Power's 2022 Conservation Improvement Program ("CIP") Consolidated Filing. This submittal includes a CIP Tracker Activity Report, a Financial Incentives Report, a Proposed Conservation Program Adjustment Factor, 2022 CIP Project Evaluations and a compliance with Department of Commerce ("DOC") orders section. Minnesota Power is filing this information pursuant to Minn. Stat. §§ 216B.241, 216B.16, subd, 6c, 216B.2401, and 216B.2411 and in compliance with Minnesota Public Utilities Commission ("MPUC") and DOC rules and orders relating to annual filings associated with Company-sponsored conservation program activities, including Minn. Rule 7690.0550.

Minnesota Power requests that the MPUC review the filed material and approve Minnesota Power's 2022 CIP Tracker Activity, Financial Incentives, proposed Conservation Program Adjustment ("CPA") factor, and a variance of Minn. Rules 7820.3500 and 7825.2600 to permit Minnesota Power to continue to combine the CPA factor with the Fuel Clause Adjustment on customer bills and/or combine the CPA factor with other currently applicable cost recovery riders on bills as the Minnesota Policy Adjustment when final rates in the Company's latest rate case are effective. Further, Minnesota Power requests that the DOC review and approve the evaluations of the various CIP projects included herein and the compliance with prior DOC orders. Minnesota Power has electronically filed this document and copies of this Cover Letter along with the Summary of Filing have been served on the parties on the attached service list.

If you have any questions regarding this filing, please contact me at (218) 355-3602 or avang@mnpower.com.

Sincerely,

Analeisha Vang
Senior Public Policy Advisor

AMV:th
Attach.

Summary

Minnesota Power

2022 Conservation Improvement Program ("CIP") Consolidated Filing

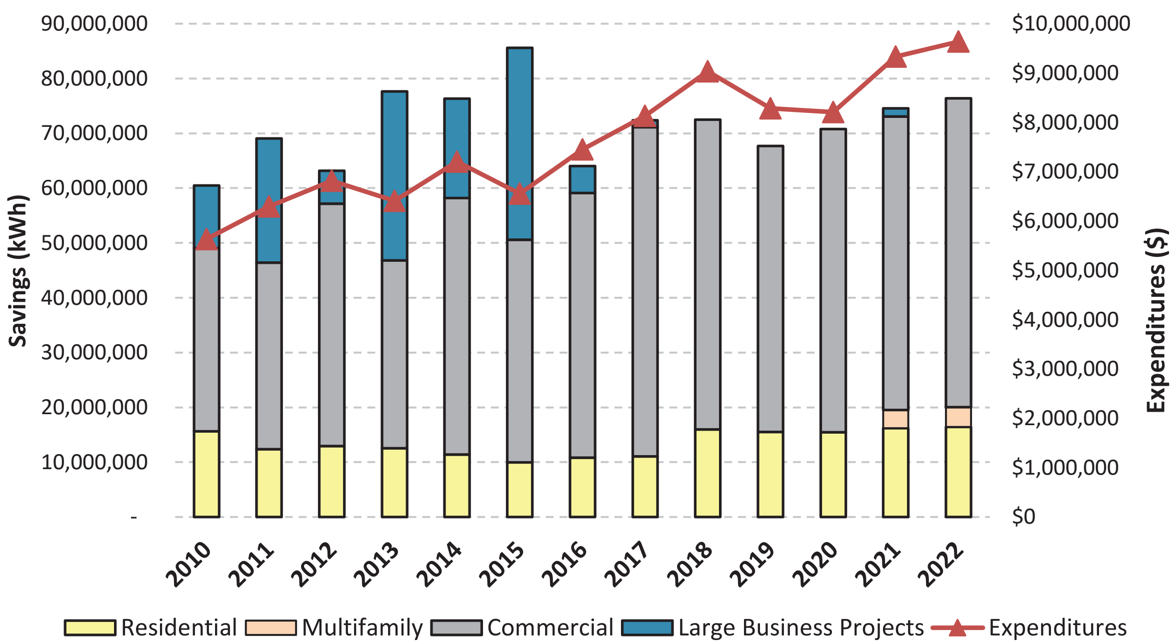
EXECUTIVE SUMMARY

Minnesota Power (or, "the Company") is pleased to report its 2022 energy conservation program results:

- Minnesota Power achieved energy savings of **2.9%** of gross annual retail energy sales,[1] well above the 1.5% energy-savings goal set in the 2021-2023 Triennial Order, and the 1.75% goal in the 2021 Energy Conservation and Optimization Act.[2]
- The Company achieved energy savings totaling **76,400,068 kilowatt hours ("kWh")**, which is **115%** of the approved energy-savings goal for the year. The Company also achieved demand savings of **8,195 kilowatts ("kW")**, which is **82%** of the approved demand-savings goal. The proposed energy-savings target for 2022 was well above the state 1.5% energy-savings goal for CIP.
- Expenditures totaled **$9,635,730**, which was **90%** of the approved budget for 2022.

The figure below illustrates historical and recent kWh energy-savings achievements, along with CIP expenditures. While Minnesota Power continues to have a successful track record of exceeding the state energy savings goal, the cost of delivering on these goals continues to increase. The Company anticipates the trend of increasing costs will continue as inflation impacts the cost of both products and labor and more cost-effective measures reach market saturation. Cost-effectiveness is also being impacted by lower avoided costs. While Minnesota Power's CIP portfolio continues to be cost-effective overall, higher cost programs – especially those serving income-qualified customers – are becoming increasingly less cost-effective.

Minnesota Power's 2005–2022 CIP Achievements



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[1] In accordance with Minnesota Rules part 7690.1200, weather-normalized average retail energy sales were used to calculate the electric savings goal for Minnesota Power's 2021–2023 Triennial Plan.

[2] While the Energy Conservation and Optimization Act (ECO Act) passed in 2021 with a higher savings goal, the energy savings goal for the 2022 Consolidated is based on the November 24, 2020 Order in Docket No. 20-476.

Minnesota Power's 2022 CIP Expenditures and Energy Savings

2022	*Expenditures*	*Energy Savings (kWh) at busbar*
Direct Savings Programs:		
Residential		
Energy Partners (Low Income)	$488,578	1,203,774
Home Efficiency (Residential)	$2,054,644	15,214,197
Multifamily		
Multifamily Direct Install	$156,743	351,955
Custom Multifamily Efficiency	$267,636	3,251,017
Commercial		
Prescriptive Business Efficiency	$59,247	1,013,699
Custom Business Efficiency (Business/Commercial/Industrial/Agricultural)	$4,474,126	55,365,426
Indirect Savings Programs:		
Customer Engagement	$640,290	
Energy Analysis	$700,495	
Research & Development	$148,909	
Evaluation & Program Development	$467,870	
Regulatory Charges	$177,191	
Total	**$9,635,730**	**76,400,068**

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 2022 Conservation Improvement Program Consolidated Filing	Reporting on CIP Tracker Account Activity, Financial Incentives Report, Proposed CPA Factors and 2022 Project Evaluations Docket No. E-015/M-23-135 E-015/CIP-20-476.02

SUMMARY OF FILING

Minnesota Power (or, "the Company") hereby files with the Minnesota Public Utilities Commission ("MPUC" or "Commission") and the Department of Commerce, Division of Energy Resources ("Department") its annual Conservation Improvement Program ("CIP") Consolidated Filing in compliance with Minn. Stat. § 216B.241. Minnesota Power requests approval of the following:

- Recovery of the 2022 CIP Tracker Account activity year-end balance of $1,321,045.
- A revised Conservation Program Adjustment ("CPA"), to be first implemented without proration on July 1, 2023, of $0.000306/kilowatt hour ("kWh").
- A variance of Minn. Rules 7820.3500 and 7825.2600 to permit the continued combination of the Conservation Program Adjustment with the Fuel and Purchased Power Clause Adjustment on customer bills, until final rates from Minnesota Power's latest rate case are implemented.[3]
- A variance of Minn. Rules 7820.3500 and 7825.2600 to permit the combination of the Conservation Program Adjustment with other currently applicable cost recovery riders (Rider for Transmission Cost Recovery, Rider for Renewable Resources, and Rider for Solar Energy Adjustment), on bills as the Minnesota Policy Adjustment when final rates are effective as detailed in the February 28, 2023 Order in Minnesota Power's latest rate case.[4]

Minnesota Power submits its Conservation Improvement Program Consolidated Filing via eFiling with the Department of Commerce, Division of Energy Resources to comply with annual CIP project evaluation filing requirements.

[3] *Minnesota Power's 2021 Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015/GR-21-335.
[4] From the docket above, see the February 28, 2023 Order at Order Point 43 and the September 1, 2022 ALJ's Findings of Fact, Conclusions of Law, and Recommendations at pp. 129-31.

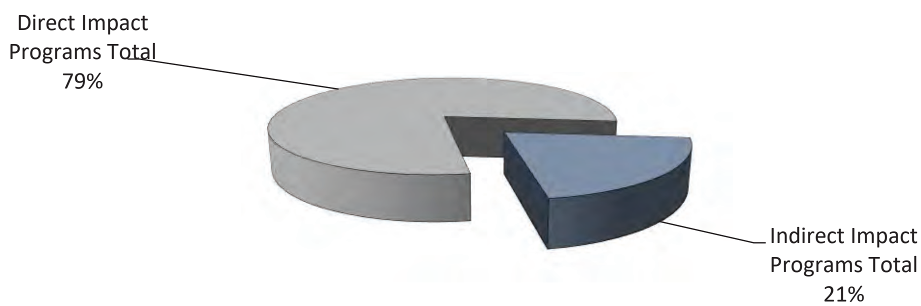
Status Report

Status Report

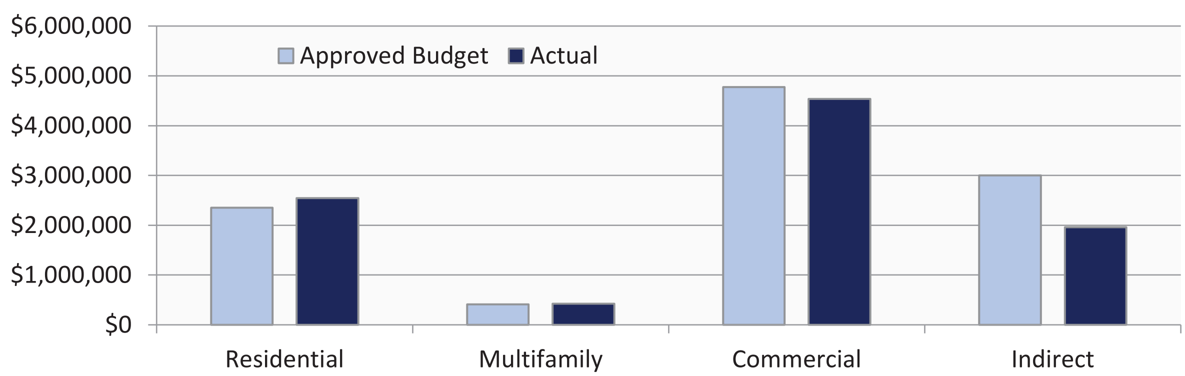
2022 CIP Status Report

Minnesota Power's energy conservation strategy provides a wide variety of program offerings to best serve its diverse customer mix. Each customer is unique in both their motivations for pursuing energy efficiency opportunities and their ability to engage in different offerings. With this knowledge, Minnesota Power provides a combination of traditional programs and innovative delivery strategies designed to address the needs and barriers of each customer segment including residential, multifamily and business. Minnesota Power's CIP portfolio includes a combination of "direct savings" and "indirect savings" programs that complement each other and provide for a balanced and meaningful customer experience.

2022 Program Spending By Direct and Indirect Savings Programs

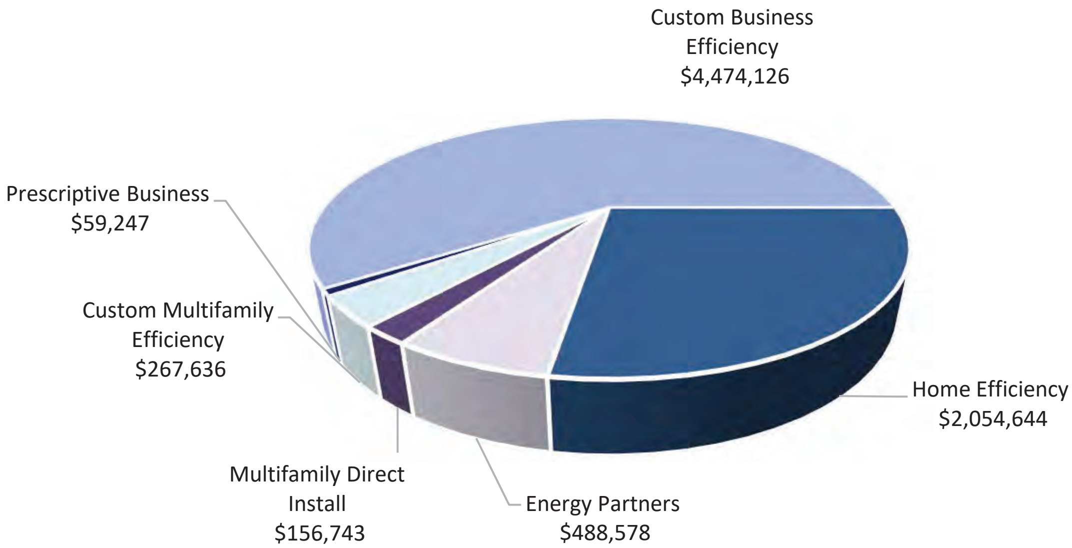


2022 Approved Budgets & Actual Spending Per Segment

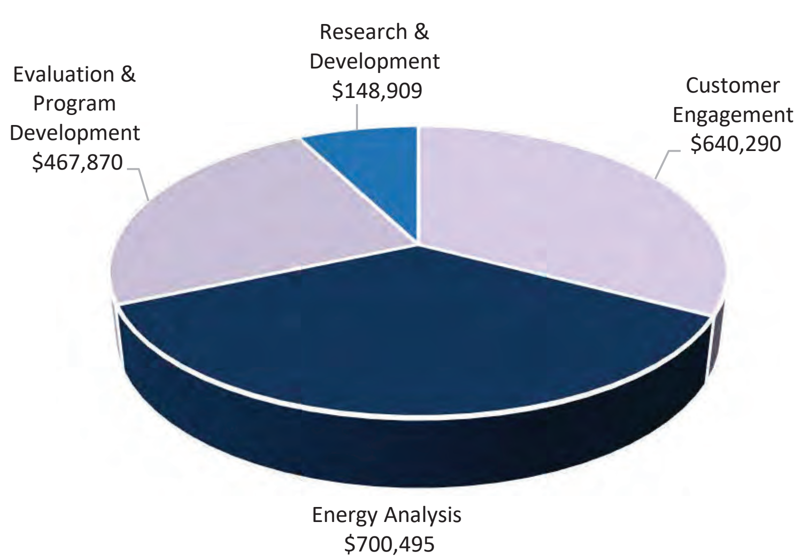


Investing in a range of programs is essential to keep Minnesota Power's program portfolio strong well into the future. Minnesota Power added three new programs to its CIP portfolio in the 2021-2023 Triennial Plan to better serve all customer segments. See the figures below for a breakdown of spending by program.

2022 Direct Savings Program Spending Breakdown

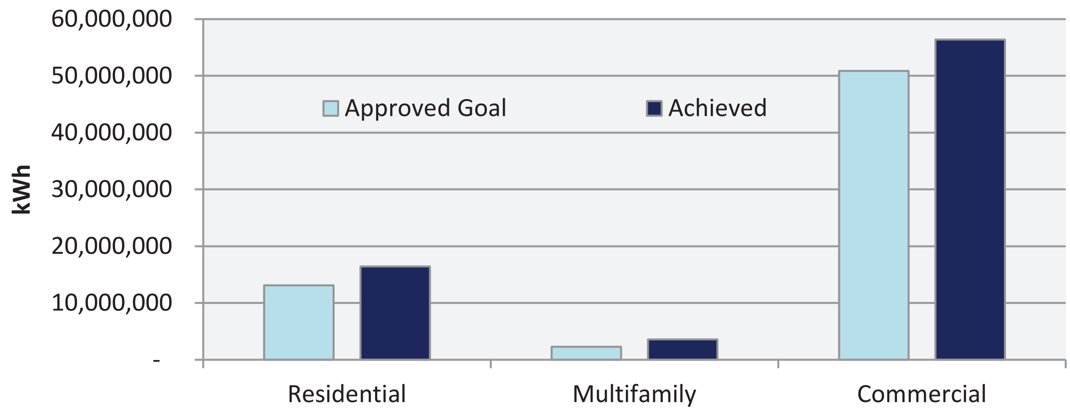


2022 Indirect Savings Program Spending Breakdown



Minnesota Power met or exceeded the energy savings goal in each segment of its CIP portfolio, as shown in the chart below. Two programs within those segments, Multifamily Direct Installation and Energy Partners, did not achieve the approved energy savings goal for various reasons as described in detail in the specific program descriptions. Minnesota Power continues to work with customers, stakeholders and delivery partners to identify opportunities to refine these offerings going forward.

2022 Approved Savings Goals & Achievements per Segment



For further context regarding Minnesota Power's energy conservation programs and the impact they have on customers, see the Successes section of this filing. These case studies highlight people, businesses and communities taking ownership of their energy usage and demonstrate how Minnesota Power connects with customers through conservation.

Looking Forward

There are many factors influencing the energy efficiency environment in Minnesota, including rising delivery costs, evolving state and federal policy, and changes in cost effectiveness. Minnesota Power has worked closely with customers, contractors, stakeholders, and regulators to ensure that programs are flexible and responsive to the evolving industry and has taken steps to modify programs as needed. However, additional actions will be required to ensure Minnesota Power's CIP portfolio continues to meet customer needs and encourages equitable access to customer programs as the environment continues to evolve.

Program delivery costs have increased significantly in recent years. The combination of inflation, supply chain disruptions, and economic uncertainty have impacted customers' ability to make capital improvements to their homes and businesses. Additionally, attracting and retaining talent in northern Minnesota has continued to create challenges for customers, delivery partners, and the Company. Encouraging customers to make energy-efficient investments has required higher incentives, more costly equipment and more resources than have historically been required.

In addition, the Company anticipates that recent federal and state policy changes will have a significant impact on Minnesota Power's CIP portfolio in the coming years. Initial guidance related to the ECO Act passed by the Minnesota legislature in 2021 was provided on March 15, 2022 as the result of a significant Department-led stakeholder working group.[17] This guidance will enable utilities to begin exploring new types of offerings including efficient fuel switching and load management activities. As utilities and stakeholders begin to utilize this guidance, further discussion and additional guidance will likely be needed. Meanwhile, the passage of the Inflation Reduction Act ("IRA") has introduced a significant amount of federal funding that will be available in the form of both rebates and tax credits on the purchase of energy efficient equipment and services. It will be critical for utilities and the Department of Commerce to coordinate on the design and implementation of these programs to ensure that customers are able to maximize the benefits of both CIP and IRA programs. While effective coordination and implementation of these funds could help address the rising costs of utility conservation programs, there is significant uncertainty around actual impacts.

Meanwhile, as the result of a robust series of Department-led working group efforts which included utilities, stakeholders, and industry experts, significant changes to the CIP/ECO evaluation framework and calculations have been proposed. Changes include the addition of a new primary screening test referred to as the Minnesota Cost Test ("MCT"), a test designed to reflect the State's energy policy goals and objectives, inclusion of new utility system and non-utility system impacts within the tests, and potential standardization of various existing impacts that historically have been utility specific. These changes, along with rising delivery costs and the new IRA programs described above, will make it difficult to predict the overall cost-effectiveness of CIP portfolios going forward. Flexibility to update and modify programs and portfolios will be more critical than ever going into the next Triennial.

Minnesota Power will continue to work with customers, stakeholders and regulators to ensure that programs are well-positioned to address challenges and opportunities associated with the rapidly evolving energy efficiency and optimization landscape into the future. Minnesota Power remains committed to providing sustainable, inclusive, and cost-effective energy-efficiency programs, with ongoing program development and increased efforts to raise program awareness and participation.

[17] Docket No. E,G999/CIP-21-837

Minnesota Power's 2022 CIP Expenditures & Achievements

2022	*Expenditures*				*Energy Savings (kWh @ Busbar)*				*Demand Savings (kW @ Busbar)*				*Participation*			
Direct Impact Programs	*Filed Budget*	*Approved Budget*	*Actual*	*Percent of Approved*	*Filed Goal*	*Approved Goal*	*Achieved*	*Percent to Goal*	*Filed Goal*	*Approved Goal*	*Achieved*	*Percent to Goal*	*Filed Goal*	*Approved Goal*	*Achieved*	*Percent to Goal*
Home Efficiency	$ 1,985,398	$ 1,985,398	$ 2,054,644	103%	11,847,171	11,847,171	15,214,197	128%	1,309	1,309	1,735.3	133%	225,559	225,559	309,430	137%
Energy Partners	$ 366,961	$ 366,961	$ 488,578	133%	1,246,050	1,246,050	1,203,774	97%	132	132	133.4	101%	14,126	14,126	12,735	90%
Multifamily Direct Install*	$ 247,228	$ 106,131	$ 156,743	148%	1,025,640	401,482	351,955	88%	112	43	39.9	92%	12,294	3,868	2,904	75%
Custom Multifamily Efficiency*	$ 140,588	$ 307,643	$ 267,636	87%	1,092,769	1,912,346	3,251,017	170%	184	350	628.4	179%	45	68	82	121%
Prescriptive Business Efficiency*	$ 123,323	$ 119,422	$ 59,247	50%	1,102,604	603,964	1,013,699	168%	123	88	173.4	198%	1,178	1,015	6,059	597%
Custom Business Efficiency	$ 4,651,797	$ 4,651,797	$ 4,474,126	96%	50,267,374	50,267,374	55,365,426	110%	8,101	8,101	5,484.9	68%	1,365	1,365	1,437	105%
Direct Impact Programs Total	**$ 7,515,295**	**$ 7,537,352**	**$ 7,500,974**	**100%**	**66,581,608**	**66,278,387**	**76,400,067.6**	**115%**	**9,962.1**	**10,023.0**	**8,195.2**	**82%**	**254,567**	**246,001**	**332,647**	**135%**
Indirect Impact Programs																
Customer Engagement	$ 864,900	$ 864,900	$ 640,290	74%									100,750	100,750	103,470	103%
Energy Analysis	$ 1,018,077	$ 1,018,077	$ 700,495	69%									6,145	6,145	5,771	94%
Evaluation & Program Development	$ 731,472	$ 731,472	$ 467,870	64%												
Research & Development	$ 384,600	$ 384,600	$ 148,909	39%												
Indirect Impact Programs Total	**$ 2,999,049**	**$ 2,999,049**	**$ 1,957,564**	**65%**	-	-	-						**106,895**	**106,895**	**109,241**	**102%**
Regulatory Charges	$ 200,000	$ 200,000	$ 177,191	89%												
Total	**$ 10,714,344**	**$ 10,736,401**	**$ 9,635,730**	**90%**	**66,581,608**	**66,278,387**	**76,400,068**	**115%**	**9,962.1**	**10,023.0**	**8,195.2**	**82%**	**361,462**	**352,896**	**441,888**	**125%**

*Approved budgets and goals for these programs reflect program modifications as filed and approved in Docket No. E015/CIP-20-476.

Appendix F-3

Minnesota Power Integrated Resource Plan, Appendix B

APPENDIX B: DEMAND SIDE MANAGEMENT

This Appendix of the 2021 Integrated Resource Plan ("2021 IRP") contains information regarding Minnesota Power's planning and strategies for demand side management ("DSM"), Energy Efficiency ("EE") and Conservation Improvement Programs ("CIP"). Minnesota Power's performance and planning outlooks for DSM, EE and CIP are broken into two parts in this Appendix:

1. Minnesota Power's Energy Efficiency Resource Alternatives and Conservation Program Strategy; and
2. Order Point 14 Considerations, Potential energy-efficiency competitive-bidding process.

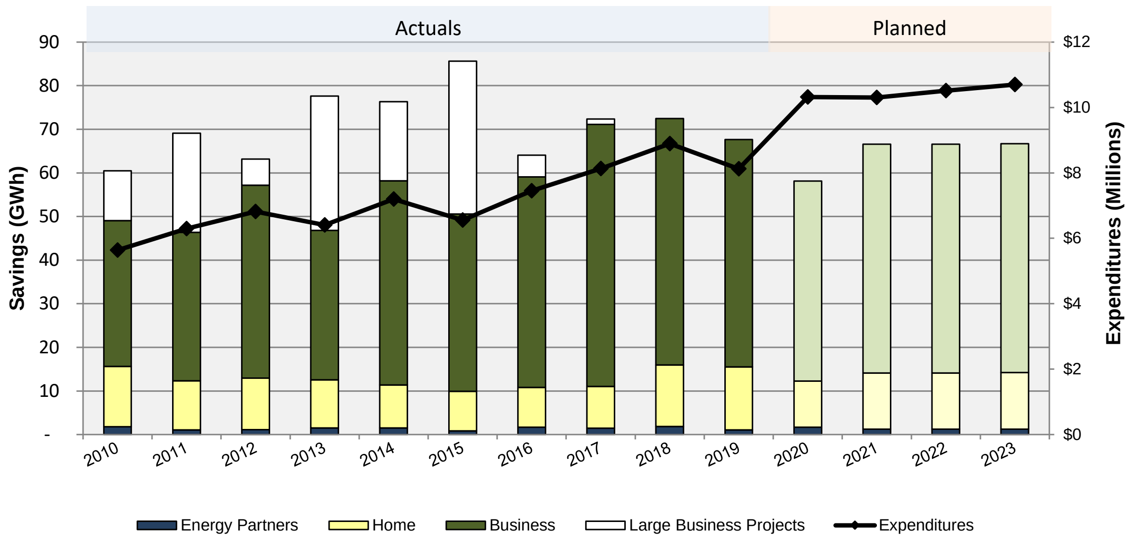
Part 1: Minnesota Power's Energy Efficiency Resource Alternatives and Conservation Program Strategy

Minnesota Power (or the "Company") is committed to providing sustainable energy-efficiency programs, as demonstrated by its strong historical CIP achievements. Since the Minnesota Next Generation Energy Act of 2007 ("NGEA"), Minnesota Power has been refining and expanding upon its proven conservation program platform to deliver cost-effective savings and customer value. The Company remains dedicated to continuous program improvement and views ongoing CIP initiatives as part of its broader *Energy**Forward*** resource strategy; a strategy designed to provide a safe, reliable and affordable power supply while identifying sustainable solutions for reducing carbon emissions further. Part 1 discusses the development of the Company's energy conservation targets included in the 2021-2023 CIP Triennial Plan filing[1] and the 2021 IRP baseline assumptions, as well as two increased EE alternative resource scenarios.

Figure 1 below reflects historical (first year) savings achievements and the proposed savings goals for 2021-2023, as filed in the 2021-2023 CIP Triennial Plan. Minnesota Power, together with its customers, community stakeholders and trade allies, has achieved success through its energy conservation programs, delivering energy savings at or above the state's 1.5 percent energy-savings goal since 2010 when the goal went into effect, all while maintaining focus on targeted program objectives – quality installations, informed decisions, EE and safety. The proposed goal for 2021-2023 and the assumed EE in the baseline forecast reflect the Company's intent to continue achieving savings of 2.5 percent which is well above the state's 1.5 percent goal.

[1] Docket No. E015/CIP-20-476.

Figure 1: Minnesota Power Historical CIP Achievements and 2021-2023 Goal



2021 IRP Baseline Assumptions and the 2021-2023 CIP Triennial

For purposes of both CIP Triennial planning and 2021 IRP modeling, Minnesota Power started with the 2020-2029 Minnesota State Demand Side Management Potential Study ("Potential Study") funded by the Department of Commerce and led by the Center for Energy and Environment ("CEE")[2]. The energy savings goals filed in the 2021-2023 CIP Triennial Plan are largely aligned with the Potential Study "Program", which will be referred to as the Baseline scenario (adjustments were made and discussed below and in Appendix A). Additionally, to align resource planning EE assumptions and modeling with CIP planning, the Company used the adjusted Baseline scenario that informed the CIP Triennial goals as the baseline EE assumption built into the custom demand forecast. These savings targets are well above the State of Minnesota's 1.5 percent energy-savings goal for CIP,[3] which equates to roughly 40 GWh on Minnesota Power's system. The adjusted Baseline scenario assumes roughly 65 GWH in 2021-2023 and ranges from 73 GWh in 2024 to 80 GWh by 2029. The average annual savings in the period after the current CIP Triennial (2024-2029) is roughly 77 GWh. This is in line with the Minnesota Public Utilities Commission's Order Point 12 from the Company's integrated resource plan ("IRP") filed in 2015,[4] which directed the Company to assume a planning goal of 76.5 GWh of EE. The savings goals in the CIP Triennial Plan and the efficiency levels assumed in the baseline assumptions for the IRP are aggressive, but the Company believes these are achievable. However, it is important to note that the significant impact of the COVID-19 pandemic, including a disruption in program services in the EE industry and potential long-term impacts, was not known or accounted for in the Baseline or alternative energy savings

[2] https://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf
[3] Minn. Stat. § 216B.241, subd. 1c(b) ("Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goals must be calculated based on the most recent three-year weather-normalized average.").
[4] Order Approving Resource Plan with Modifications, Docket No. E015/RP-15-690 (July 18, 2016) ("Minnesota Power's average annual energy savings goal is set at 76.5 GWh.").

scenarios. Therefore, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty.

Summary of Alternative Energy Efficiency Scenarios

Based on the aforementioned Potential Study, current CIP strategy, and analysis of historic performance and future opportunities, Minnesota Power provided two alternative EE scenarios with additional energy and capacity savings above the Baseline scenario (built into the base/expected 2020 Annual Electric Utility Forecast Report ("AFR2020") forecast). The Company further developed cost projections consistent with each outlook. The two alternative energy efficiency scenarios evaluated in the IRP analysis are:

1. "High" Scenario: modeled to reflect the midpoint between "Very High" and "Baseline" scenario (Program scenario from the Potential Study) scenarios, and
2. "Very High" Scenario: modeled after the adjusted Potential Study "Max Achievable" scenario.

Minnesota Power worked closely with CEE to update the original assumptions used in the Potential Study for the Minnesota Power-specific projections, in order to accurately capture the Company's specific territory, customer base, system, and historical experience with CIP.

The process of updating the CEE potential projections and method used to incorporate them into the load forecast are documented in the Company's AFR2020, included as Appendix A. These scenarios were incorporated in the EnCompass modeling process as supply side alternatives in the capacity expansion plan analysis.

The alternative efficiency scenarios ("High" and "Very High") considered in the IRP analysis begin in year 2024. These alternatives were not modeled as an option for 2021-2023 in light of currently-approved levels and due to limited ability to significantly increase EE above the approved 2021-2023 CIP Triennial Plan in the short-term. The potential study projected energy savings for the years 2021-2029. All three EE scenarios therefore assume new program implementation (and new savings) each year through 2029, after which no new saving programs were assumed. For the purposes of modeling the alternative scenarios in the 2021 IRP, only the additional costs and additional first year GWh/GW savings above the baseline are included. A high-level summary of the baseline EE (assumed in the forecast) and the increased efficiency scenarios modeled in the resource plan are shown in Table 1 and includes the following:

- % of Sales: Represents the level of 2024 savings under each scenario as a percentage of average weather normalized 2017-2019, non-CIP exempt retail sales—the baseline for the 2021-2023 CIP Triennial Plan.[5]
- Energy: Total estimated first year energy savings associated with each scenario for the year 2024.
- Energy Above Base: The additional GWh associated with each scenario in terms of first year savings as compared to the baseline plan (EE assumed in forecast).
- Summer Peak: Estimated first year GW demand savings coincident with Midcontinent Independent System Operator ("MISO") summer peak for the year 2024.

[5] In accordance with Minnesota Rules part 7690.1200, 2017-2019 weather-normalized average retail energy sales were used to calculate the electric savings goal for Minnesota Power's 2021-2023 Triennial CIP. This equated to 2,646,854,358 kWh, net of CIP exempt customers at the time of the Triennial Filing. Savings as a percent of sales in Table 1 were calculated using this figure.

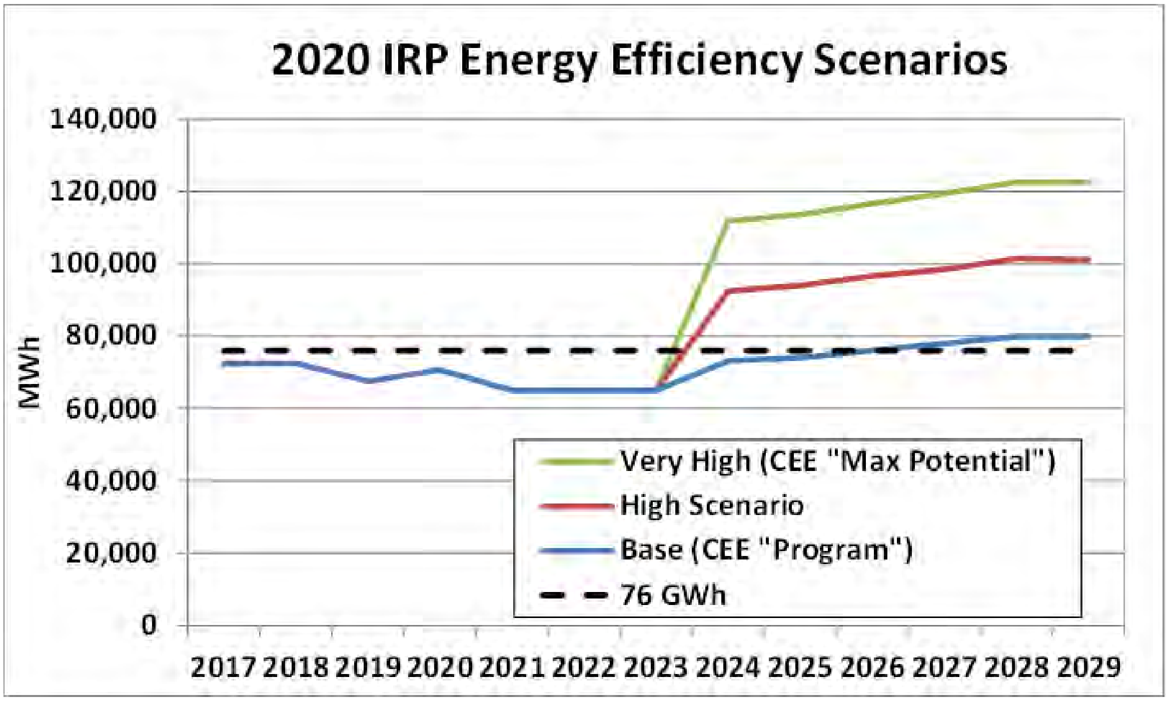
- Summer Peak Reduction Above Base: The additional first year GW demand savings associated with the scenario as compared to the baseline plan.
- Incentives: Rebates to incentivize customers to install/complete an efficiency measure.
- Non-Incentives: All other costs incurred by the Company to implement the 2024 EE plan.
- Total Cost: The estimated total program costs assumed to achieve the level of savings associated with each scenario in the year 2024.
- Total Cost Above Base: The estimated additional spending needed to achieve the incremental savings as compared with the existing plan for the year 2024.

Table 1: Summary of Energy Efficiency Scenarios

Scenarios		*First Year Annual Savings at the Generator (Energy: GWh/ Peak: MW)				First Year Program Costs (Million $)			
Plan	% of Sales** (Rounded)	Energy	Energy Above Base	MP Summer Peak	Summer Peak Reduction Above Base	Incentives	Non-Incentive	Total	Total Cost Above Base
Adjusted Base (CEE "Program")	2.76%	73.2	–	6.4	–	$10.42	$5.41	$15.81	$0
High	3.49%	92.5	19.3	8.1	1.7	$17.16	$6.86	$24.02	$8.19
Adjusted Very High (CEE "Max Achievable")	4.22%	111.8	38.7	9.7	3.3	$31.97	$8.31	$40.28	$24.45

Figure 2 below reflects the first year EE savings (measured at the generator) assumed in each year through 2029 for each of the three scenarios.

Figure 2: 2020 IRP Energy Efficiency Scenarios



Energy Efficiency Scenario Development and Assumptions

As previously noted, the Minnesota statewide Potential Study was the starting point for developing the baseline and alternative EE scenarios. As part of the Potential Study, CEE developed and defined two "achievable" potential scenarios. The following excerpt from the Final Report defines these two scenarios:

> *"In addition to total economic potential (i.e., the total potential if all possible measures were installed that meet cost-effectiveness criteria), two program scenarios were calculated:*
>
> - *Maximum achievable potential: This is the subset of economic potential that is achievable considering market barriers, given the most aggressive program scenario possible. This study assumed financial incentives would cover 100 percent of the incremental cost of each measure, along with very aggressive marketing and program designs to achieve maximum market penetration of the measures.*
> - *Program potential: The program potential is a subset of the maximum achievable, given constraints in implementation. This study assumed that financial incentive levels are dropped to 50 percent of the incremental cost of each measure, which is a typical scenario used for planning purposes in Minnesota, and a good benchmark for aggressive programs nationally. The project team still assumed aggressive marketing and program designs for this scenario."*

Savings Targets and Contributions

The goal of the Potential Study was to produce a statewide EE potential report, and while some regional and investor-owned utility ("IOU"-specific) inputs were used in the methodology, other major inputs were developed at the statewide level. CEE leveraged the load forecast file in the Company's most recent prior IRP (2015), which was a 2014 vintage and fairly optimistic in its outlook for customer demand growth. The Company recognized this likely resulted in an inflated estimate of kWh savings potential relative to its current, more moderate outlook, and conferred with CEE on reasonable methods for updating the potential savings estimates. The Company worked with CEE to update its model with the most current customer outlook and CIP exemptions to produce a more accurate estimate of Minnesota Power's potential savings. Once the savings potential was updated for the Baseline and Very High (Max Potential) scenarios, a third scenario was created (High scenario) with a target savings level at the mid-point between the adjusted Baseline (Program) and Very High levels.

Additionally, the Minnesota Power-specific savings contributions by class and technology included in the original Potential Study were evaluated and ultimately modified to better reflect Minnesota Power's history and anticipated opportunities based on experience and internal analysis. As a result of this process, for 2021-2023, these contributions were modified to reflect historical patterns, accounting for changes that impact measure and savings opportunities, including market penetration and updates to approved measures and savings calculations as defined in the Technical Reference Manual ("TRM").[6] Updated avoided costs and net benefit estimates were also taken into account to evaluate changes in cost-effectiveness for various technologies compared to in the past. The most significant change to the assumed measure contributions for 2021-2023 was an increase in lighting measures. The Potential Study originally assumed changes to lighting standards would significantly impact savings opportunity from lighting in CIP portfolios as early as 2022. However, the TRM used for the 2021-2023 CIP Triennial Plan was not updated to reflect changes in the calculation of lighting savings, allowing for utilities to maintaining higher levels of planned savings through lighting measures.

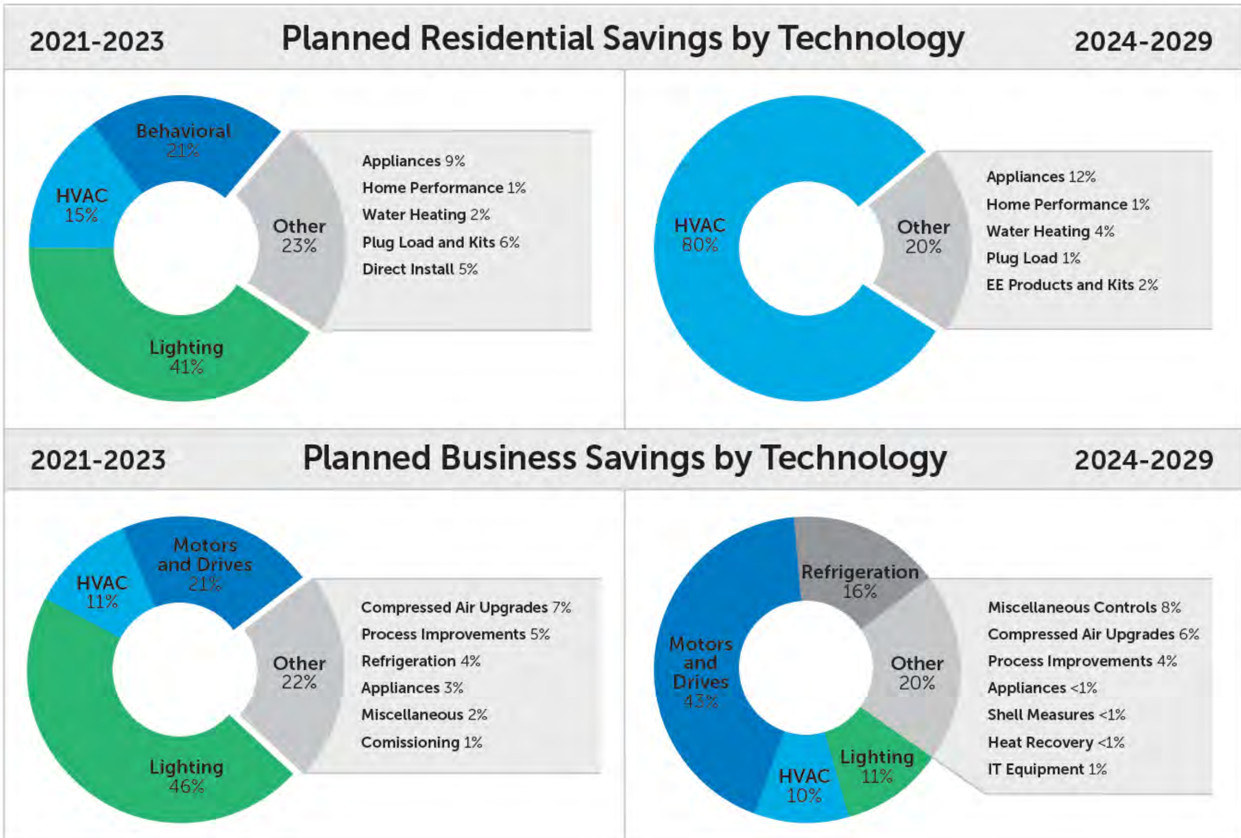
Beyond 2023, in the Baseline scenario, Minnesota Power updated the savings contributions by technology in each class to reflect anticipated reductions in lighting savings opportunity, which for both residential and commercial/industrial ("C/I") classes have historically accounted for the majority of the savings achievements. For residential, this resulted in a significant shift to Heating Ventilation & Air Conditioning ("HVAC") savings and for C/I this resulted in a noticeable shift away from lighting into other evolving technologies such as motors and Heating Ventilation Air Conditioning & Refrigeration ("HVACR").

For the alternative savings scenarios (High and Very High) – all measures in the Baseline scenario were scaled by the same percentage to achieve the targeted levels for each.

The graphs in Figure 3 below reflect Baseline savings contributions by technology for the 2021-2023 period and for 2024 and beyond:

[6] State of Minnesota Technical Reference Manual for Energy Conservation Improvement Programs (Jan. 20, 2020), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D0CDC86F-0000-C832-A29A-F7752BF4A0D9}&documentTitle=20201-159365-02.

Figure 3: Planned Savings by Technology



Scenario Cost Development

Cost assumptions were developed for each scenario for 2024 through 2029. For use in the 2021 IRP analysis, the costs associated with the High and Very High scenarios are incremental to the Baseline scenario. All costs were estimated for the year 2024 and escalated each year proportional to the change in energy savings.

Baseline Scenario

2024 cost assumptions for the Baseline scenario were developed to serve as the baseline costs against which the costs for the two higher scenarios would be compared. These costs were developed using the assumptions defined in the potential study and therefore reflect:

- Customer incentives (rebates) equal to 50 percent of the measures incremental cost where incremental cost is the difference between the cost of the standard efficiency product or action, or sometimes purchasing nothing/taking no action, compared to the cost of the efficient product or action.
- Aggressive program design and marketing. Non-incentive costs increase linearly with savings.

High Scenario

There is no equivalent scenario from the statewide Potential Study for this scenario, as it represents the midpoint between the adjusted Baseline scenario and the adjusted Very High (max achievable) scenario. The Company assumed:

- Customer incentives (rebates) would be set at 65 percent of incremental measure costs. This is roughly halfway between recent historical rebate levels and the max scenario (100 percent).
- Aggressive program design and marketing. Non-incentive costs increase linearly with savings.

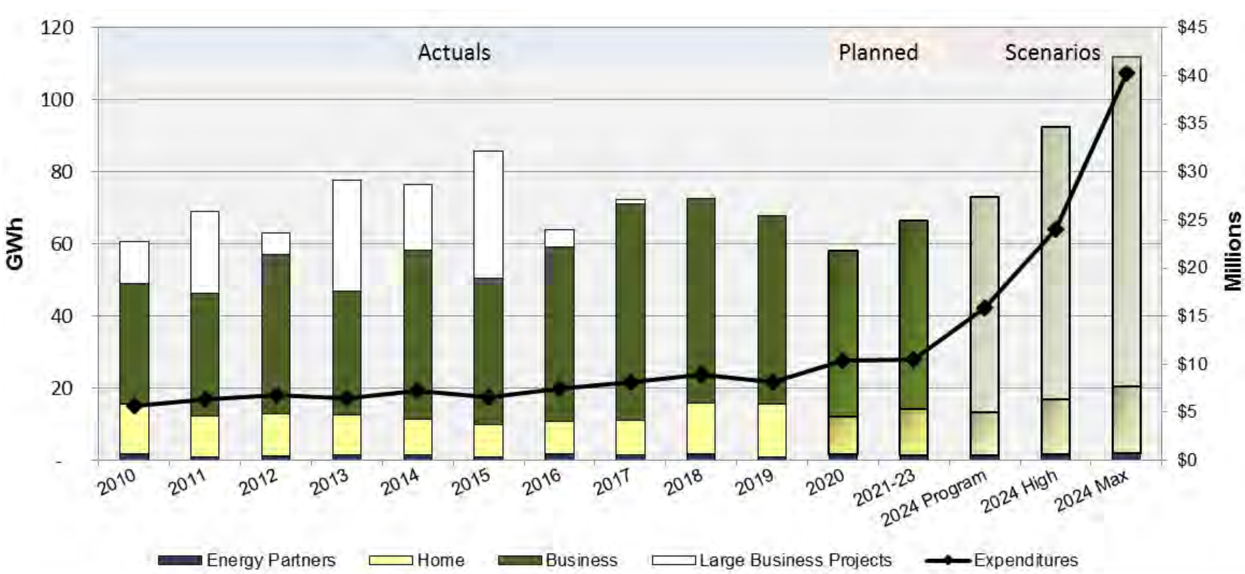
Very High (Max Achievable) Scenario

Like the Baseline scenario, Minnesota Power based incentive costs for the Very High scenario on the potential study scenario description:

- Customer incentives (rebates) are assumed at 100 percent of incremental measure costs.
- Aggressive program design and marketing. Non-incentive costs scale linearly with savings.

Figure 4 below expands on the Minnesota Power Historical CIP Performance graph (Figure 1) to include the planned costs and savings for 2020 and 2021-2023 (as filed in the respective triennial plans), and 2024 costs and savings as modeled for the Baseline and two alternative scenarios used in the 2021 IRP analysis:

Figure 4: Historical, Planned, and Modeled CIP Energy Savings (First Year) and Costs

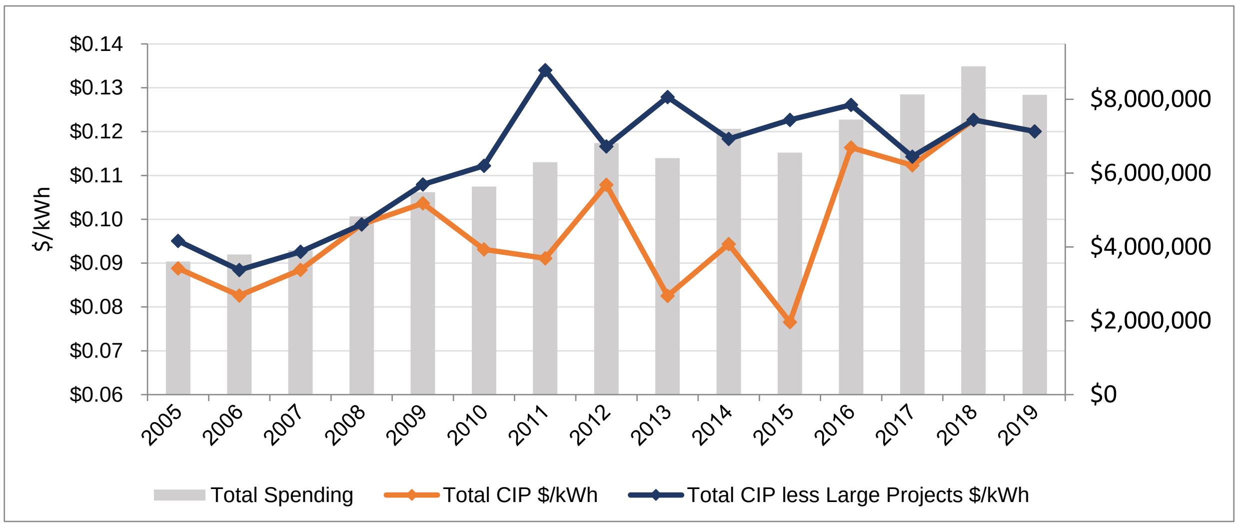


Discussion of Increasing Costs

Minnesota Power largely drew from the Potential Study assumptions to determine scenario costs for the 2021 IRP. The Company's own analysis of historical and anticipated cost trends indicates strong alignment with and support of the Potential Study assumptions. Specifically, stronger incentive levels and more aggressive program development and marketing will be critical to deliver at the levels discussed in the 2021 IRP.

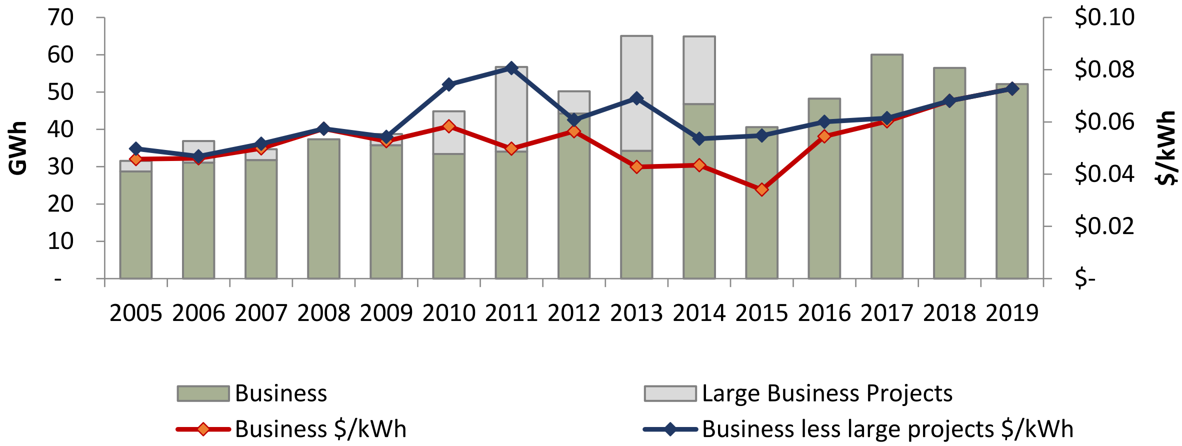
Further, costs have been increasing steadily over the past several years, in part due to the loss of large project opportunities. Between 2010 and 2015, such opportunities accounted for about 30 percent of total savings and only 4 percent of total spending. Figure 5 below reflects the (first year) cost per kWh saved trend between 2005 and 2019. Between 2010 and 2015, where significant large project savings were realized, the average cost per kWh saved was $0.09/kWh – compared to an average of $0.12/kWh between 2016 and 2019 when opportunities for these types of projects were no longer available.

Figure 5: Total Spending and Cost per kWh Trending



C/I savings have historically comprised the vast majority of the Company's savings achievements. Between 2005 and 2019, C/I savings accounted for approximately 80 percent of CIP savings – ranging from 73 percent to 88 percent in any given year. Similarly, C/I costs are a significant driver of overall costs. Figure 6 below shows how C/I costs per kWh have trended over time. Over the last three years, C/I costs per kWh saved have steadily increased even as savings have decreased. This suggests that in order to achieve higher savings goals, the cost per kWh saved will not only continue to trend up, it will increase more significantly with higher levels of EE. This increase will likely be further compounded as the opportunity for cost-effective lighting projects decreases.

Figure 6: Commercial and Industrial Cost per kWh (First-year Savings)



With the absence of large C/I projects, costs have increased over the last several years. However, cost-effective, efficient lighting products and projects across all customer sectors made their way to the forefront of Minnesota Power's CIP programs. Lighting measures became an obvious and easy energy saving option for customers to identify and adopt, especially as they also became increasingly cost-effective for consumers. Customer awareness and acceptance increased as LEDs became the primary option on the market. These factors, in combination with strategic program design, resulted in lighting making up the majority (over 50 percent) of savings over the last several years, helping to keep program costs lower despite the loss of large C/I projects.

However, with changing codes and standards impacting lighting measure baselines and significant market saturation of commercial efficient lighting, beginning in 2024 the majority of additional lighting opportunity is expected to go away. The Company will need to find ways to replace the most cost-effective and prevalent measure in its existing portfolio, which in 2019 accounted for nearly 37 GWh in savings (54 percent of total 2019 savings). The types of technologies that will need to replace those savings will be more costly measures that customers may not be as ready (or financially able) to adopt without significant education and incentives to do so. Increased education and outreach, along with higher rebate levels drive the increase in costs assumed in the 2024 Baseline scenario as compared to the 2021-2023 (filed) budgets.

Scenario Details

The following tables include the plan parameters for each scenario (savings, costs, participation for Baseline, High, and Very High scenarios).

Table 2: Year 2024 Energy and Demand Savings (MISO Summer Peak)

	Program	High	Very High	Program	High	Very High
	kWh - Generator	kWh - Generator	kWh - Generator	kW - Generator	kW - Generator	kW - Generator
Residential	12,019,394	15,202,866	18,423,077	1,377.1	1,742.9	2,111.2
HVAC	9,653,139	12,212,160	14,794,019	1,133.8	1,434.8	1,737.9
Home Performance	85,203	99,404	127,805	3.4	4.0	5.2
Energy Efficiency Products and Kits	272,032	344,568	417,620	23.8	30.1	36.5
Water Heating	449,076	569,730	690,423	37.2	47.2	57.2
Appliances	1,491,432	1,890,102	2,288,021	171.1	216.8	262.5
Plug Load	68,512	86,901	105,188	7.8	9.9	12.0
Admin Costs	0	0	0	0.0	0.0	0.0
Low Income	1,319,275	1,666,899	2,031,465	139.0	176.3	213.4
HVAC	50,927	58,157	83,974	13.4	16.9	20.4
Water Heating	535,470	678,921	822,080	44.4	56.3	68.2
Appliances	360,715	457,940	553,927	40.3	51.2	61.9
Energy Efficiency Products and Kits	372,162	471,881	571,483	40.9	51.9	62.9
Admin Costs	0	0	0	0.0	0.0	0.0
Business	59,826,687	75,624,419	91,373,241	4,866.8	6,143.8	7,395.2
Lighting	6,617,469	8,241,744	9,995,622	883.8	1,103.5	1,340.2
Refrigeration	9,621,879	12,232,833	14,838,140	655.2	829.3	1,002.9
Motors and Drives	25,946,629	32,872,342	39,949,432	946.9	1,195.5	1,443.4
HVAC	6,075,527	7,642,025	9,208,522	1,468.1	1,850.3	2,232.6
Compressed Air Upgrades	3,679,508	4,785,381	5,660,022	158.1	204.7	242.0
Process Improvements	2,253,887	2,575,871	3,219,838	163.2	186.6	233.2
Appliances	207,143	263,613	313,837	48.3	61.3	73.1
Shell Measures	269,540	394,856	402,419	1.7	2.0	2.4
Heat Recovery	170,483	230,992	250,778	86.8	130.3	130.3
Miscellaneous Controls	4,525,664	5,715,246	6,827,273	368.5	462.7	554.1
IT Equipment	458,959	669,518	707,358	86.2	117.6	140.9
Admin Costs	0	0	0	0.0	0.0	0.0
Indirect Impact	0	0	0	0.0	0.0	0.0
Grand Total	**73,165,356**	**92,494,183**	**111,827,783**	**6,383.0**	**8,062.9**	**9,719.8**

Table 3: Year 2024 Participation

	Program Participants	High Participants	Very High Participants
Residential (Measures)	9,439	11,962	14,489
HVAC	2,328	2,949	3,572
Home Performance	6	7	9
Energy Efficiency Products and Kits	698	884	1,071
Water Heating	3,006	3,812	4,617
Appliances	2,845	3,605	4,366
Plug Load	556	705	854
Admin Costs	0	0	0
Low Income (Measures)	6,409	8,125	9,840
HVAC	94	118	144
Water Heating	2,707	3,431	4,155
Appliances	622	790	956
Energy Efficiency Products and Kits	2,986	3,786	4,585
Admin Costs	0	0	0
Business (Projects)	968	1,226	1,482
Lighting	121	152	185
Refrigeration	78	100	121
Motors and Drives	366	465	564
HVAC	264	333	402
Compressed Air Upgrades	29	38	45
Process Improvements	7	8	10
Appliances	37	47	56
Shell Measures	9	11	13
Heat Recovery	9	11	13
Miscellaneous Controls	45	57	68
IT Equipment	3	4	5
Admin Costs	0	0	0
Indirect Impact	0	0	0
Grand Total	**16,816**	**21,313**	**25,811**

Table 4: Year 2024 Costs

	Program	High	Very High
Residential	$2,559,353.02	$3,883,875.36	$6,511,717.62
HVAC	$1,553,904.76	$2,560,462.35	$4,770,536.21
Home Performance	$25,410.89	$41,871.06	$78,012.24
Energy Efficiency Products and Kits	$5,865.83	$9,665.49	$18,008.30
Water Heating	$15,358.79	$25,307.62	$47,151.97
Appliances	$76,151.80	$125,479.92	$233,788.43
Plug Load	$6,072.98	$10,006.81	$18,644.23
Admin Costs	$876,587.97	$1,111,082.11	$1,345,576.24
Low Income	$291,046.68	$425,437.51	$674,977.75
HVAC	$17,026.96	$28,056.36	$52,273.33
Water Heating	$8,953.71	$14,753.57	$27,488.19
Appliances	$100,274.73	$165,228.71	$307,846.55
Energy Efficiency Products and Kits	$22,418.33	$36,940.04	$68,824.98
Admin Costs	$142,372.95	$180,458.83	$218,544.70
Business	$10,130,018.60	$16,103,811.76	$28,725,696.97
Lighting	$841,029.45	$1,385,814.80	$2,581,986.70
Refrigeration	$1,816,645.37	$2,993,395.86	$5,577,158.07
Motors and Drives	$2,523,251.68	$4,157,713.61	$7,746,461.57
HVAC	$1,405,354.45	$2,315,687.09	$4,314,482.13
Compressed Air Upgrades	$261,445.31	$430,799.16	$802,645.28
Process Improvements	$479,785.07	$790,570.73	$1,472,955.18
Appliances	$32,908.50	$54,225.33	$101,030.14
Shell Measures	$28,227.85	$46,512.74	$86,660.40
Heat Recovery	$152,354.21	$251,043.21	$467,732.22
Miscellaneous Controls	$959,192.95	$1,580,519.94	$2,944,752.36
IT Equipment	$83,405.00	$137,431.42	$256,055.94
Admin Costs	$1,546,418.76	$1,960,097.87	$2,373,776.98
Indirect Impact	$2,845,049.47	$3,606,122.45	$4,367,195.43
Grand Total	**$15,825,467.77**	**$24,019,247.08**	**$40,279,587.77**

Table 5: Baseline Scenario Cumulative Effects

year	Administration	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2024	$5,410,429.15	$10,415,038.65	$15,825,467.80	12,939	6,383	6,180	73,165,356	12,939	6,383	6,180	73,165,356
2025	$5,512,787.14	$10,612,077.08	$16,124,864.22	13,083	6,433	6,238	73,992,182	26,021	12,816	12,418	147,157,537
2026	$5,643,574.95	$10,863,842.70	$16,507,417.65	13,432	6,607	6,391	76,103,887	39,450	19,422	18,806	223,248,792
2027	$5,776,670.66	$11,120,051.03	$16,896,721.69	13,783	6,772	6,556	77,977,293	53,141	26,145	25,284	300,733,290
2028	$5,944,155.48	$11,442,458.15	$17,386,613.64	14,143	6,953	6,720	79,906,922	67,190	33,048	31,924	380,137,737
2029	$5,941,977.80	$11,438,266.12	$17,380,243.91	14,142	6,953	6,720	79,905,018	81,235	39,950	38,562	459,528,328
2030	$0.00	$0.00	$0.00	0	0	0	0	81,137	39,898	38,478	459,001,824
2031	$0.00	$0.00	$0.00	0	0	0	0	80,995	39,826	38,360	458,245,514
2032	$0.00	$0.00	$0.00	0	0	0	0	80,529	39,550	37,949	455,706,460
2033	$0.00	$0.00	$0.00	0	0	0	0	80,152	39,321	37,615	453,650,748
2034	$0.00	$0.00	$0.00	0	0	0	0	79,301	38,782	36,921	448,165,605
2035	$0.00	$0.00	$0.00	0	0	0	0	78,435	38,234	36,213	442,598,403
2036	$0.00	$0.00	$0.00	0	0	0	0	76,566	36,685	34,622	430,246,558
2037	$0.00	$0.00	$0.00	0	0	0	0	74,684	35,126	33,024	417,837,180
2038	$0.00	$0.00	$0.00	0	0	0	0	73,092	33,733	31,689	406,972,381
2039	$0.00	$0.00	$0.00	0	0	0	0	63,276	28,593	28,172	345,400,838
2040	$0.00	$0.00	$0.00	0	0	0	0	53,836	23,720	24,993	286,577,308
2041	$0.00	$0.00	$0.00	0	0	0	0	44,160	18,746	21,759	226,194,881
2042	$0.00	$0.00	$0.00	0	0	0	0	33,069	13,997	17,361	163,447,735
2043	$0.00	$0.00	$0.00	0	0	0	0	21,746	9,142	12,899	99,380,815
2044	$0.00	$0.00	$0.00	0	0	0	0	9,908	3,991	8,127	33,904,849
2045	$0.00	$0.00	$0.00	0	0	0	0	7,014	2,898	5,669	23,777,119
2046	$0.00	$0.00	$0.00	0	0	0	0	4,047	1,779	3,150	13,393,670
2047	$0.00	$0.00	$0.00	0	0	0	0	1,063	650	619	2,958,141
2048	$0.00	$0.00	$0.00	0	0	0	0	531	325	309	1,478,688

Table 6: High Scenario Cumulative Effects

year	Administration	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2024	$6,857,761.25	$17,161,485.81	$24,019,247.06	16,362	8,063	7,813	92,494,183	16,362	8,063	7,813	92,494,183
2025	$6,976,564.68	$17,458,790.31	$24,435,354.99	16,629	8,196	7,953	94,059,438	32,991	16,259	15,766	186,553,621
2026	$7,139,531.26	$17,866,612.72	$25,006,143.98	17,074	8,412	8,150	96,619,127	50,062	24,669	23,914	283,156,772
2027	$7,302,400.68	$18,274,191.98	$25,576,592.67	17,395	8,583	8,323	98,410,169	67,340	33,190	32,137	380,942,274
2028	$7,513,916.18	$18,803,507.62	$26,317,423.80	17,917	8,831	8,556	101,428,868	85,138	41,958	40,592	481,735,556
2029	$7,507,429.90	$18,787,275.74	$26,294,705.64	17,879	8,827	8,547	101,174,504	102,894	50,720	49,036	582,259,545
2030	$0.00	$0.00	$0.00	0	0	0	0	102,770	50,654	48,930	581,593,691
2031	$0.00	$0.00	$0.00	0	0	0	0	102,591	50,563	48,780	580,636,908
2032	$0.00	$0.00	$0.00	0	0	0	0	102,000	50,214	48,260	577,420,840
2033	$0.00	$0.00	$0.00	0	0	0	0	101,524	49,924	47,838	574,820,361
2034	$0.00	$0.00	$0.00	0	0	0	0	100,469	49,253	46,970	568,065,110
2035	$0.00	$0.00	$0.00	0	0	0	0	99,356	48,549	46,063	560,889,411
2036	$0.00	$0.00	$0.00	0	0	0	0	96,992	46,592	44,049	545,258,616
2037	$0.00	$0.00	$0.00	0	0	0	0	94,612	44,601	41,997	529,515,369
2038	$0.00	$0.00	$0.00	0	0	0	0	92,598	42,820	40,276	515,722,358
2039	$0.00	$0.00	$0.00	0	0	0	0	80,140	36,281	35,781	437,534,740
2040	$0.00	$0.00	$0.00	0	0	0	0	68,135	30,061	31,706	362,741,808
2041	$0.00	$0.00	$0.00	0	0	0	0	55,822	23,715	27,553	286,063,076
2042	$0.00	$0.00	$0.00	0	0	0	0	41,838	17,713	21,987	206,958,437
2043	$0.00	$0.00	$0.00	0	0	0	0	27,499	11,568	16,332	125,712,436
2044	$0.00	$0.00	$0.00	0	0	0	0	12,551	5,050	10,297	42,955,125
2045	$0.00	$0.00	$0.00	0	0	0	0	8,891	3,668	7,190	30,146,320
2046	$0.00	$0.00	$0.00	0	0	0	0	5,134	2,250	4,000	16,998,416
2047	$0.00	$0.00	$0.00	0	0	0	0	1,358	823	796	3,793,798
2048	$0.00	$0.00	$0.00	0	0	0	0	679	412	398	1,896,517

Table 7: Very High Scenario Cumulative Effects

year	Administration	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2024	$8,305,093.35	$31,974,494.41	$40,279,587.76	19,758	9,720	9,439	111,827,783	19,758	9,720	9,439	111,827,783
2025	$8,440,342.21	$32,495,200.64	$40,935,542.86	20,088	9,899	9,595	113,621,147	39,846	19,619	19,034	225,448,930
2026	$8,635,487.58	$33,246,507.59	$41,881,995.17	20,618	10,176	9,882	116,648,550	60,460	29,793	28,913	342,077,974
2027	$8,828,130.71	$33,988,180.97	$42,816,311.68	21,099	10,422	10,099	119,397,418	81,417	40,140	38,891	460,718,885
2028	$9,083,676.88	$34,972,030.22	$44,055,707.10	21,675	10,682	10,356	122,595,685	102,948	50,746	49,124	582,545,801
2029	$9,072,882.00	$34,930,470.05	$44,003,352.05	21,668	10,680	10,350	122,571,522	124,468	61,347	59,349	704,330,413
2030	$0.00	$0.00	$0.00	0	0	0	0	124,317	61,267	59,221	703,526,200
2031	$0.00	$0.00	$0.00	0	0	0	0	124,101	61,157	59,040	702,368,931
2032	$0.00	$0.00	$0.00	0	0	0	0	123,386	60,735	58,411	698,477,555
2033	$0.00	$0.00	$0.00	0	0	0	0	122,809	60,384	57,900	695,330,534
2034	$0.00	$0.00	$0.00	0	0	0	0	121,535	59,566	56,844	687,158,206
2035	$0.00	$0.00	$0.00	0	0	0	0	120,238	58,736	55,769	678,866,523
2036	$0.00	$0.00	$0.00	0	0	0	0	117,359	56,331	53,286	659,790,040
2037	$0.00	$0.00	$0.00	0	0	0	0	114,449	53,887	50,774	640,488,029
2038	$0.00	$0.00	$0.00	0	0	0	0	112,014	51,738	48,690	623,796,477
2039	$0.00	$0.00	$0.00	0	0	0	0	96,964	43,854	43,268	529,097,753
2040	$0.00	$0.00	$0.00	0	0	0	0	82,443	36,361	38,371	438,583,478
2041	$0.00	$0.00	$0.00	0	0	0	0	67,604	28,713	33,365	346,171,372
2042	$0.00	$0.00	$0.00	0	0	0	0	50,640	21,432	26,612	250,315,647
2043	$0.00	$0.00	$0.00	0	0	0	0	33,293	13,993	19,761	152,169,633
2044	$0.00	$0.00	$0.00	0	0	0	0	15,163	6,103	12,439	51,891,028
2045	$0.00	$0.00	$0.00	0	0	0	0	10,739	4,434	8,683	36,410,539
2046	$0.00	$0.00	$0.00	0	0	0	0	6,190	2,718	4,820	20,490,213
2047	$0.00	$0.00	$0.00	0	0	0	0	1,636	996	957	4,563,879
2048	$0.00	$0.00	$0.00	0	0	0	0	818	498	478	2,281,557

Summary of Findings

Minnesota Power has a proven track record of successful CIP performance and anticipates continuing this trend into the future, as indicated by the aggressive goals set forth in the 2021-2023 Triennial Plan and assumed in the 2021 IRP baseline forecast. However, the Company acknowledges that the current EE environment is rapidly evolving in ways that will continue to present new challenges. Changing baselines, uncertain economic conditions (whether related to the current pandemic in the near term, or resulting from other, unknown events that may occur over the longer term), and decreased avoided costs will all contribute to Minnesota Power's ability to offer cost-effective, meaningful programs to customers. While Minnesota Power continues to build on the successes of its existing programs and adapting to challenges through unique and innovative program offerings and delivery strategies, achieving this higher level of savings through less cost-effective measures will be more resource intensive. Additionally, long-term EE savings require customers to take specific actions year after year, which introduces uncertainty regarding whether or not these savings will materialize. For these reasons, among others, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty. The Company has done so, while also testing what could be achieved by including alternative scenarios in its IRP analysis.

Part 2: Order Point 14, Potential Energy-Efficiency Competitive Bidding Process

In the Order approving Minnesota Power's 2015 Integrated Resource Plan ("2015 Plan"),[1] the Minnesota Public Utilities Commission (or "Commission") required that for its next resource plan, the Company must "investigate the potential for an energy-efficiency competitive-bidding process to supplement its existing conservation improvement program, open to both CIP-exempt and non-CIP-exempt customers, and shall summarize its investigation and findings in its next resource plan." This portion of Appendix B addresses this Commission requirement.

Specifically, Minnesota Power investigated the potential for an energy-efficiency competitive-bidding process to supplement its existing conservation-improvement program by researching best practices and examining how large customers who are exempt from CIP focus on conservation efforts within their operations. The Company's research and analysis, discussed below, indicated that many of the bidding programs available for review had the following characteristics that set the programs up for success: a dedicated funding source, bidding platform, and a process for customer communications. Conversely, the Company was not able to identify specific direction in either Minnesota policy or statutes that provided direction on how the Company might recover costs of a competitive-bidding process from either CIP-exempt or non-CIP exempt customers. The lack of explicit cost recovery authorization presents an important barrier to all potential stakeholders. Additionally, the Company has already demonstrated an outstanding CIP achievement record for non-exempt customers, along with aggressive future goals. For these reasons the Company does not feel that a competitive-bidding process would add value at this time. Nevertheless, the Company summarizes here its investigation and findings.

The first section below provides details on the Company's investigative research that has been completed with respect to energy-efficiency competitive-bidding processes. The second section focuses on energy-efficiency efforts of CIP-exempt customers, along with additional considerations.

Energy-Efficiency Competitive-Bidding Process Research

Minnesota Power identified the following competitive-bidding programs to assess best practices, potential outcomes, and possible barriers to success for any program Minnesota Power might initiate. Each program is discussed in turn, and includes a combination of deregulated, regulated and a statewide efficiency program not run by the individual utilities.

Energize Missouri Industries program, is an initiative of the Missouri Department of Natural Resources ("Missouri DNR"). Between 2010 and 2011, the Missouri DNR provided grants to energy efficiency ("EE") companies that competitively bid for EE incentives through a reverse auction. The overall goal of the online reverse auction was to provide industries and commercial entities with an opportunity to realize measurable energy savings that would result in reduced energy costs and increased market competitiveness. The online reverse auction allowed pre-qualified providers to bid on $3 million in incentives on a $/kWh saved basis for expected EE projects. Available incentive dollars were allocated based on a lowest-price obtained, thus increasing the cost-effectiveness of the program and allowing the Missouri DNR to spread the dollars further. The program was funded by a $3 million grant from the American Recovery and Reinvestment Act of 2009 ("ARRA").

[1] Order Approving Resource Plan with Modifications, Docket No. E015/RP-15-690 (July 18, 2016).

Focus on Energy is a company that partners with Wisconsin utilities on an efficiency bidding program. Bids are submitted through an online auction where business incentive program customers and/or trade allies bid for additional financial incentives above current prescriptive and custom levels. Customers who qualify for the business incentive program include commercial and industrial ("C/I") businesses who average less than 1,000 kW per month. Typical businesses include, but are not limited to, banks, hotels, grocery stores, breweries, food processing, and manufacturing. Customers and trade allies can submit bids, using an online auction platform, which identifies the unit price needed to deliver the estimated kWh or therms savings from the EE project.

The Focus on Energy efficiency auction is a type of reverse auction in which the role of the buyer and seller are reversed. The pre-qualified bidders compete by offering rates on a price per annual kWh or a price per therms reduced basis until no pre-qualified bidder is willing to make a lower bid. During the live auction, pre-qualified bidders will be logged into an online platform and will actively submit bids to compete for the EE incentives. The auctions will start at an established bid ceiling price and pre-qualified bidders will bid down on this price at predefined increments. Pre-qualified bidders will be able to see live results and their position for an auction. At the end of the auction, the bidders with the lowest price per annual kWh or therms reduced bids are considered the winners of the auction and are then tasked with implementing their energy-saving project(s). The winning bidder is provided a financial incentive, which is limited to $200,000 per project and $400,000 per customer per calendar year for all Focus on Energy Incentives. The funding comes from Focus on Energy partnership with 107 utilities throughout Wisconsin. Each participating utility pays in either a portion of their revenue or a set amount by meter. Focus on Energy then uses that funding to provide cost-effective programs that support EE projects.

Bid4Efficiency is a reverse auction program run by American Electric Power Ohio. In the reverse auction program, interested customers (nonresidential customers that use more than 200,000 kWh per year) respond to a request for qualifications ("RFQ"). As part of the pre-qualification process customers or service providers are required to attend training and mock auctions. After customers respond to the RFQ, these large C/I customers are eligible to become prequalified bidders. The bidders then send in bids to an online live auction platform in the form of price per annual kWh or watts reduced for energy-efficiency projects such as process-improvement initiatives or compressed-air systems costing more than $25,000. C/I customers as well as trade allies can bid for planned and unplanned projects. Starting at the bid ceiling price, prequalified bidders compete with one another to determine who can submit the lowest $/kWh saved for their specific project. The bidder with the lowest price per annual kWh (or price per watts reduced) is granted an award from $25,000 to $500,000 to complete their project. Additional details of the reverse auction include: bidders can only win one auction, non-winning bidders are offered a default incentive rate 10-20 percent lower than the lowest winning bid, and winners that achieve 80 percent or more of the total awarded auction incentive amount receive a $0.005 per kWh bonus.

Kansas City Power and Light (now Evergy) historically offered a block bidding program, which featured separate auctions for C/I customers and for trade allies. The auctions consisted of two blocks: one for projects in excess of $100,000 and one for those exceeding $400,000. To participate in the program, potential bidders responded to the request for quotation for the auction and attend a webinar to learn how the auction process would work. If the request for quotation was approved for the customer's project, that customer was then allowed to participate in the online auction. Projects that were eligible to receive the program incentives were required to save more than 1 million kWh annually and have a minimum payback of at least two years.

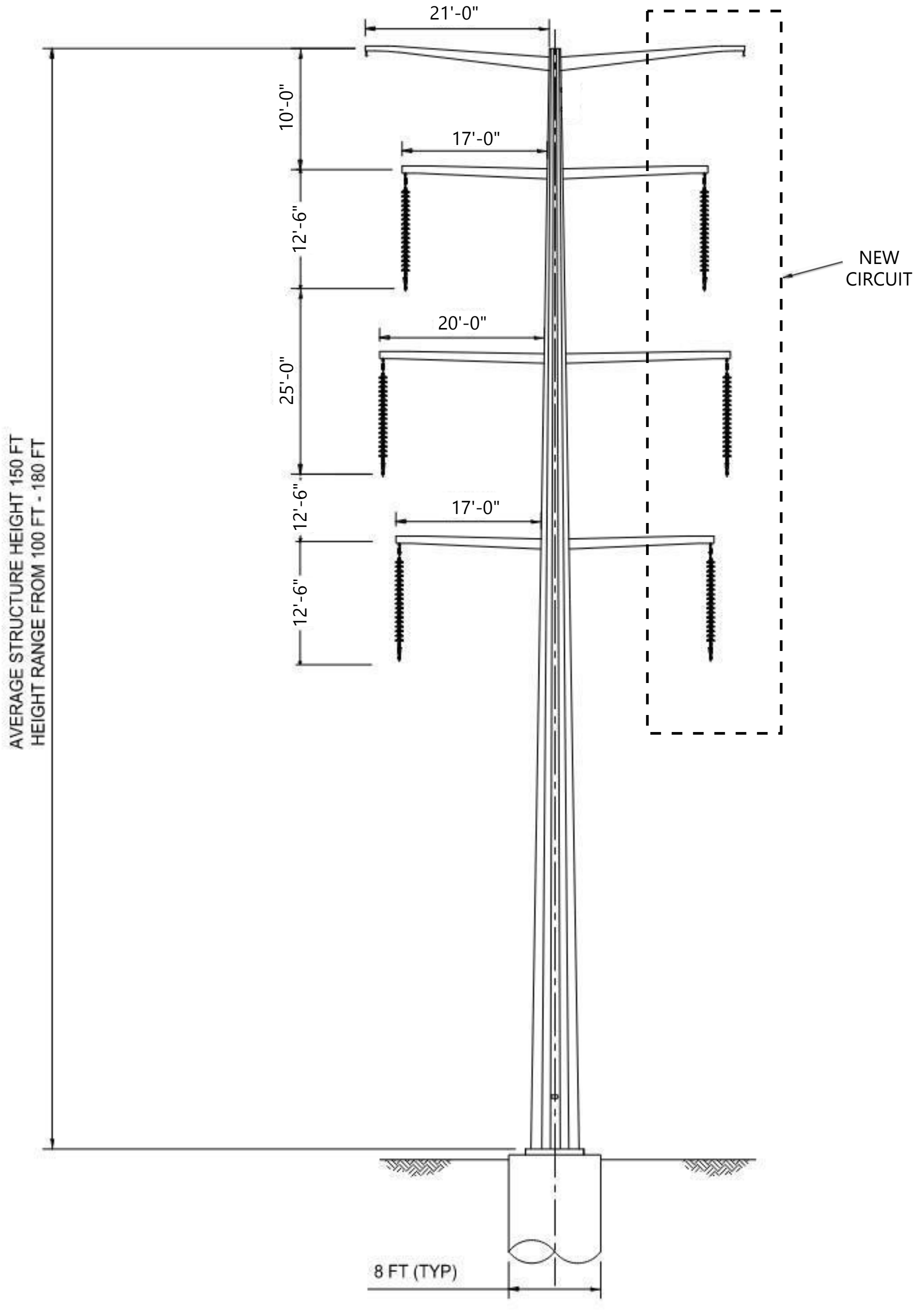
Energy-Efficiency Competitive-Bidding for CIP-Exempt Customers

Minnesota Power's CIP-exempt group is comprised of large industrial customers that have identified through a state legislative designation to be considered "exempt" from the conservation program established in Minnesota. CIP exceptions are defined by Minnesota Statutes § 216B.241, subd. 1a(b), which states in part: "The owner of a large customer facility may petition the commissioner to exempt both electric and gas utilities serving the large customer facility from the investment and expenditure requirements [of CIP]" and "[t]he 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." Under this statute, customers seeking an exemption are required to file with the commissioner of the Minnesota Department of Commerce and must prove that they are implementing energy conservation and efficiency improvements. They also must show there is no need for additional incentives to manage, complete, and address EE measures. Exempt customers must provide a filing every five years to the commissioner explaining measures that they are already taking to be efficient. However, a large customer facility that is, under an order from the commissioner, exempt from the investment and expenditure requirements as of December 31, 2010, is not required to submit a report to retain its exempt status, except with respect to ownership changes.

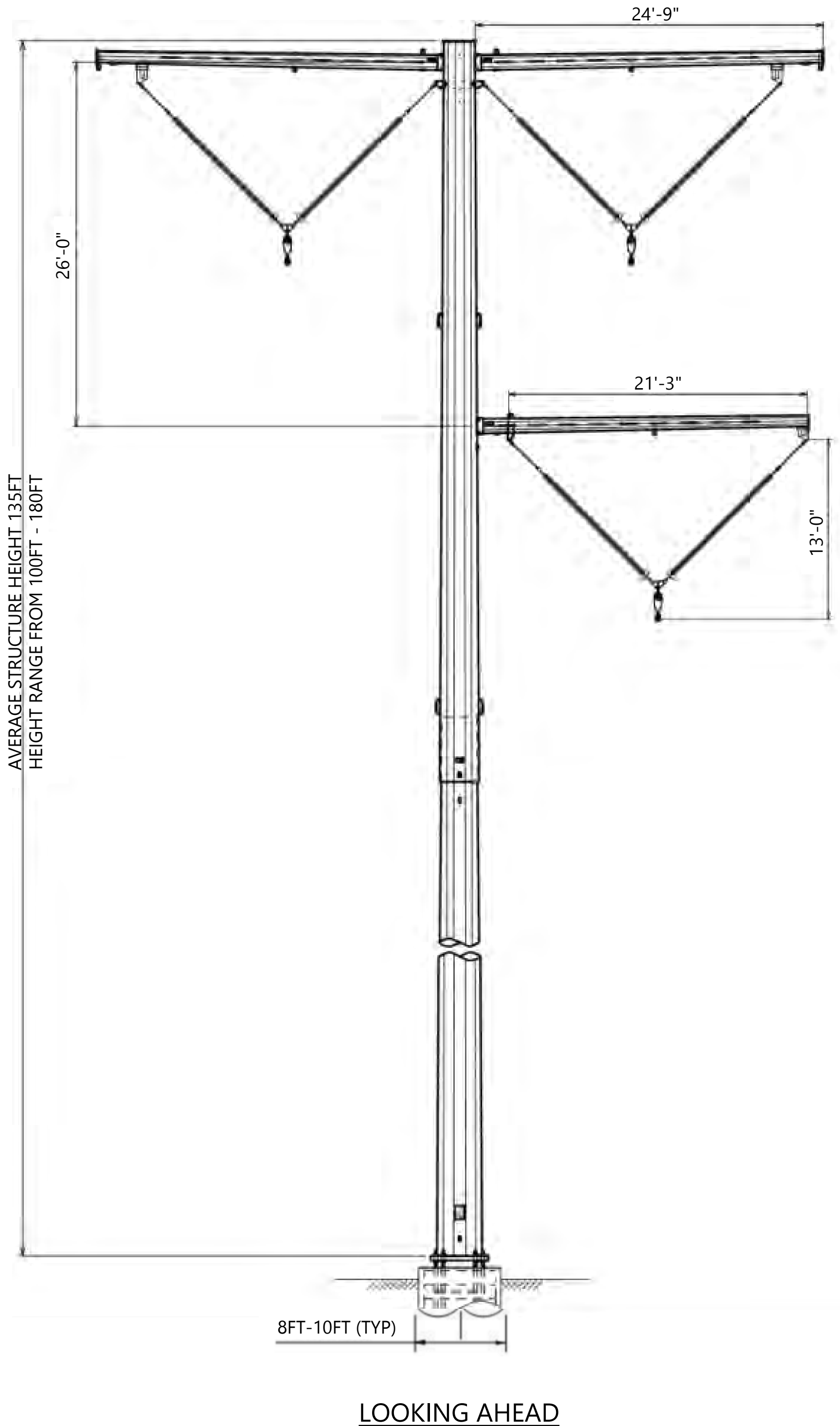
There are approximately 14 Minnesota Power customers at the time of this filing that fall under the CIP-exempt classification, most of whom have submitted multiple reports to the Department of Commerce detailing efforts to implement EE and energy conservation strategies. These CIP-exempt customers compete in global markets and in industries that have an advantage because of other nations' favorable tax policies, trade laws, health care costs, environmental compliance or other subsidies. CIP-exempt customers are naturally incentivized to pursue all efficiency improvements to keep their product costs as low as possible, including any and all economically viable efficiency improvements related to energy.

Appendix G

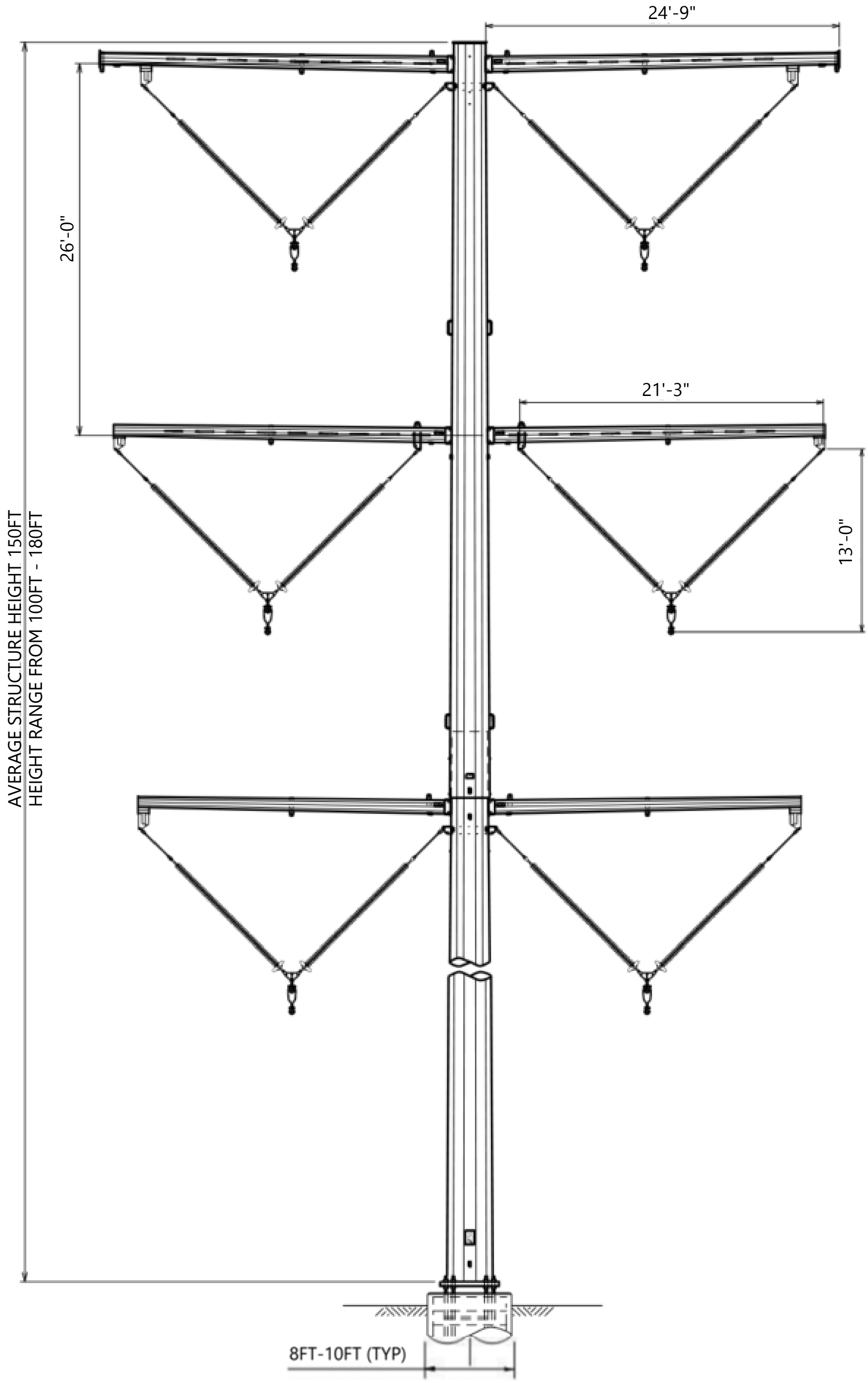
Technical Diagrams of Typical 345 kV Structures



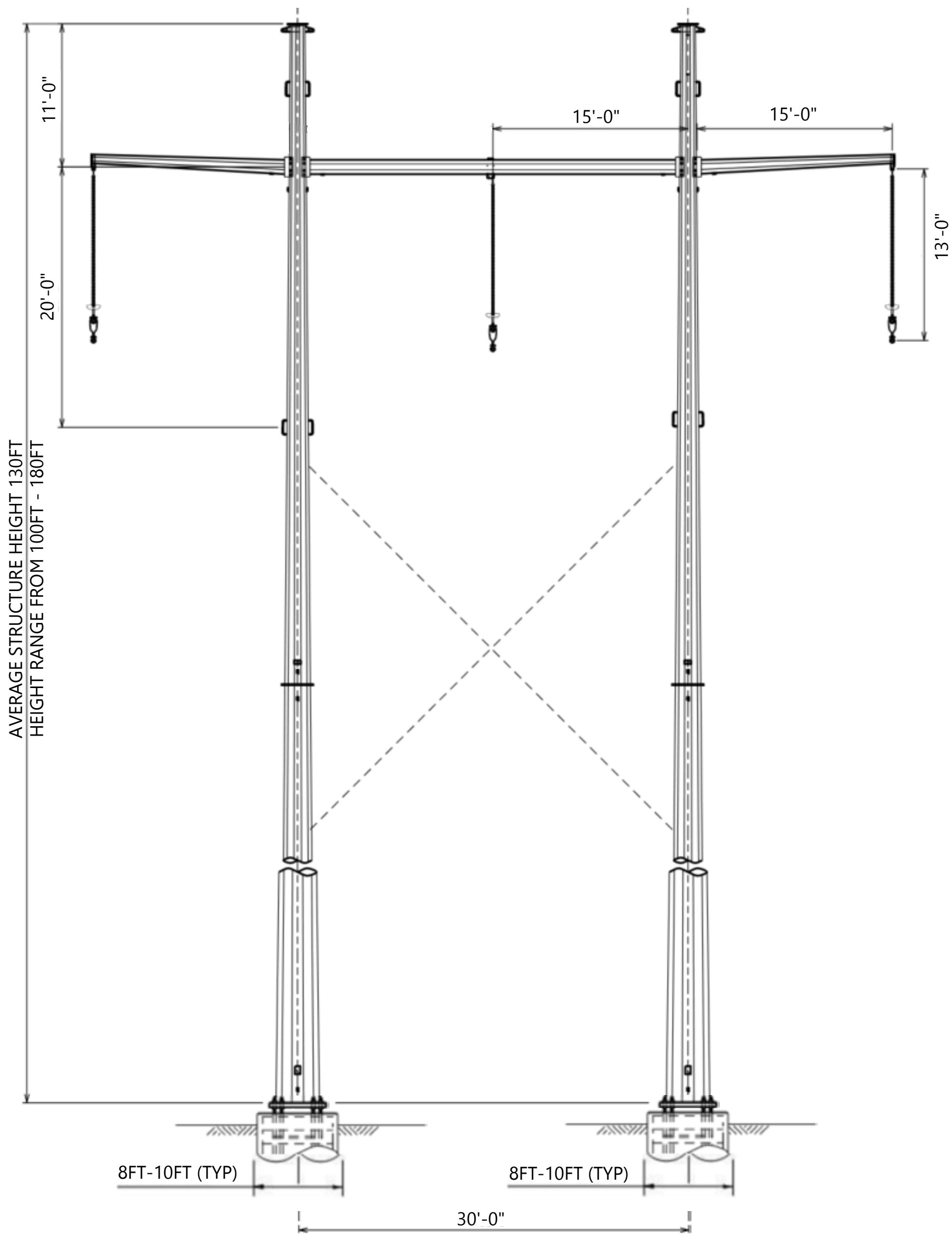
LOOKING AHEAD
EXISTING DOUBLE-CIRCUIT
MONOPOLE TANGENT STRUCTURE
STANDARD SPAN



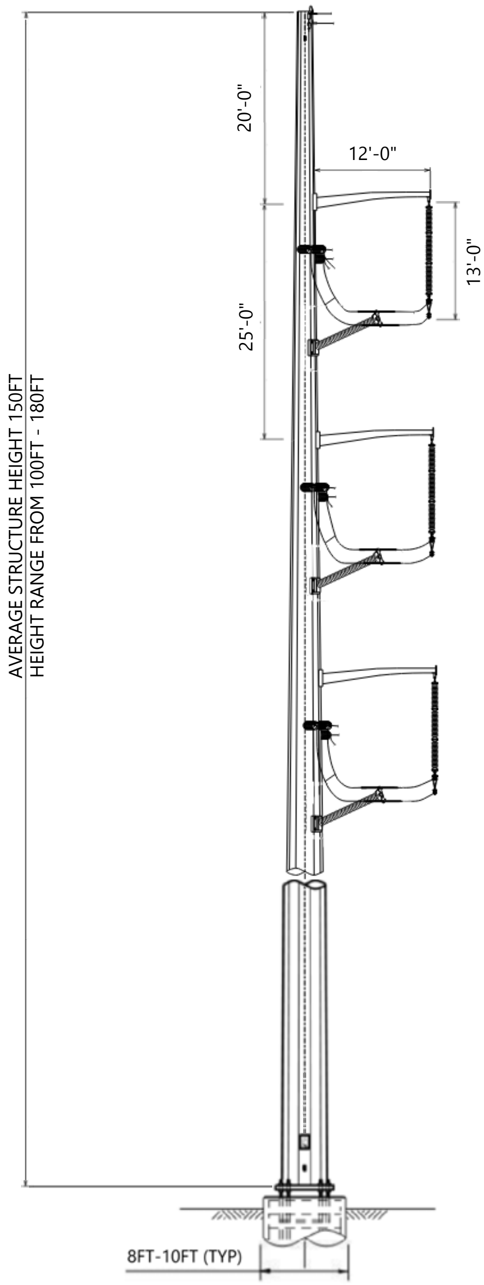
LOOKING AHEAD
SINGLE-CIRCUIT MONOPOLE
TANGENT STRUCTURE
STANDARD SPAN



LOOKING AHEAD
DOUBLE-CIRCUIT MONOPOLE
TANGENT STRUCTURE
STANDARD SPAN



LOOKING AHEAD
SINGLE-CIRCUIT H-FRAME
TANGENT STRUCTURE
STANDARD SPAN



LOOKING AHEAD
MONOPOLE
DEAD END STRUCTURE
STANDARD SPAN

Appendix H

Xcel Energy Rate Impact Calculations

LRTP2 - Years 1 thru 20

Line No.	Amounts in dollars	Line (A)	Subs (B)	Total
1	**LRTP2 - Revenue Requirement**	**90,755,344**	**145,146,185**	**235,901,530**
2				
3				
4	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%
5	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%
6				
7	**Net cost to MN Jurisdiction**	**65,938,800**	**105,456,768**	**171,395,568**

NOTE: Tax assumptions include 21% corp Fed tax rate

LRTP2 - Year 1 Revenue Requirement

Amounts in dollars

Line No.		Line (A)	Subs (B)	Total
1	**LRTP2 - Revenue Requirement**	**5,921,759**	**9,376,996**	**15,298,755**
2				
3				
4	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%
5	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%
6				
7	**Net cost to MN Jurisdiction**	**4,302,487**	**6,812,909**	**11,115,396**

NOTE: Tax assumptions include 21% corp Fed tax rate

LRTP2 - Total

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	**Project Spend**								
2	Line	47,254,900							
3	Sub	76,300,000							
4	**Total**	123,554,900							
5									
6	Revenue Requirement								
7	Line		5,921,759	5,765,773	5,588,309	5,421,735	5,264,963	5,117,085	4,975,439
8	Sub		9,376,996	9,137,236	8,862,796	8,605,940	8,364,911	8,138,242	7,921,636
9									
10	**Total Revenue Requirements - NSP**		15,298,755	14,903,010	14,451,105	14,027,675	13,629,873	13,255,327	12,897,074
11									
12	FERC Interchange Agreement allocator to NSPM		83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
13	Demand Allocator - MN Jurisdiction		86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%
14									
15	**Total Revenue Requirements - MN Jurisdiction**		11,115,396	10,827,865	10,499,531	10,191,885	9,902,860	9,630,731	9,370,441
16									
17									
18	**Discount Rate =**	0.06349334							
19									
20	**Present Value of Revenue Requirements - NSP**	139,175,804	14,385,379	13,176,633	12,014,252	10,965,959	10,018,852	9,161,821	8,382,002
21									
22									
23									
24			12.38%	12.06%	11.70%	11.35%	11.03%	10.73%	10.44%

LRTP2 - Total

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1	**Project Spend**									
2	Line									
3	Sub									
4	**Total**									
5										
6	Revenue Requirement									
7	Line	4,835,789	4,696,079	4,556,369	4,416,659	4,276,949	4,137,239	3,997,529	3,857,819	3,735,958
8	Sub	7,708,254	7,494,773	7,281,293	7,067,813	6,854,333	6,640,853	6,427,373	6,213,893	6,029,233
9										
10	**Total Revenue Requirements - NSP**	12,544,043	12,190,853	11,837,663	11,484,473	11,131,283	10,778,092	10,424,902	10,071,712	9,765,191
11										
12	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
13	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%
14										
15	**Total Revenue Requirements - MN Jurisdiction**	9,113,944	8,857,332	8,600,720	8,344,107	8,087,495	7,830,883	7,574,271	7,317,659	7,094,954
16										
17										
18	**Discount Rate =**									
19										
20	**Present Value of Revenue Requirements - NSP**	7,665,832	7,005,209	6,396,144	5,834,834	5,317,750	4,841,610	4,403,370	4,000,200	3,646,904
21										
22										
23										
24		10.15%	9.87%	9.58%	9.30%	9.01%	8.72%	8.44%	8.15%	7.90%

LRTP2 - Total

Line No.	Rate Analysis	Year 17	Year 18	Year 19	Year 20
1	**Project Spend**				
2	Line				
3	Sub				
4	**Total**				
5					
6	Revenue Requirement				
7	Line	3,649,855	3,581,600	3,513,346	3,445,091
8	Sub	5,902,309	5,804,204	5,706,100	5,607,995
9					
10	**Total Revenue Requirements - NSP**	9,552,163	9,385,804	9,219,445	9,053,086
11					
12	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%
13	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%	86.6%
14					
15	**Total Revenue Requirements - MN Jurisdiction**	6,940,177	6,819,308	6,698,439	6,577,570
16					
17					
18	**Discount Rate =**				
19					
20	**Present Value of Revenue Requirements - NSP**	3,354,367	3,099,171	2,862,491	2,643,024
21					
22					
23					
24		7.73%	7.60%	7.46%	7.33%

LRTP2 - Subs
Based on 56 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	Plant Investment		76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve		(1,545,115)	(3,090,231)	(4,635,346)	(6,180,462)	(7,725,577)	(9,270,693)	(10,815,808)
3	Removal Expense		-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(652,365)	(2,291,518)	(3,722,348)	(4,966,786)	(6,042,373)	(6,964,460)	(7,814,182)
5			74,102,520	70,918,252	67,942,305	65,152,752	62,532,050	60,064,847	57,670,010
6									
7	Average Rate Base		75,201,260	72,510,386	69,430,278	66,547,529	63,842,401	61,298,449	58,867,428
8									
9	Debt Return		1,571,706	1,515,467	1,451,093	1,390,843	1,334,306	1,281,138	1,230,329
10	Equity Return		3,654,781	3,524,005	3,374,312	3,234,210	3,102,741	2,979,105	2,860,957
11	Current Income Tax Requirement		821,652	(217,880)	(69,931)	59,958	175,785	279,421	304,135
12									
13	Book Depreciation		1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax		652,365	1,639,153	1,430,831	1,244,438	1,075,587	922,087	849,722
15	ITC Flow Thru		-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		3,815,000	7,248,500	6,523,650	5,875,100	5,287,590	4,753,490	4,501,700
17	Tax Depreciation on Easements		-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-
21	Property Tax @ 1.4828%		1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376
22									
23	Total Revenue Requirements - NSP		9,376,996	9,137,236	8,862,796	8,605,940	8,364,911	8,138,242	7,921,636
24									
25	Discount Rate =	0.06349334							
26									
27	Present Value of Revenue Requirements	85,546,670	8,817,165	8,078,771	7,368,285	6,727,585	6,148,758	5,624,993	5,148,390
28									
29	**Level Annual Revenue Requirement**	**5,610,224**							
30									
31	**57 Year Life LARR %**	**7.35%**							

LRTP2 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1	Plant Investment	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve	(12,360,924)	(13,906,039)	(15,451,154)	(16,996,270)	(18,541,385)	(20,086,501)	(21,631,616)	(23,176,732)	(24,721,847)
3	Removal Expense	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(8,663,905)	(9,515,820)	(10,365,542)	(11,217,458)	(12,067,180)	(12,919,095)	(13,768,818)	(14,620,733)	(14,823,561)
5		55,275,172	52,878,141	50,483,303	48,086,272	45,691,435	43,294,404	40,899,566	38,502,535	36,754,592
6										
7	Average Rate Base	56,472,591	54,076,656	51,680,722	49,284,788	46,888,854	44,492,919	42,096,985	39,701,051	37,628,564
8										
9	Debt Return	1,180,277	1,130,202	1,080,127	1,030,052	979,977	929,902	879,827	829,752	786,437
10	Equity Return	2,744,568	2,628,125	2,511,683	2,395,241	2,278,798	2,162,356	2,045,913	1,929,471	1,828,748
11	Current Income Tax Requirement	257,194	208,039	163,269	114,114	69,344	20,188	(24,581)	(73,737)	534,728
12										
13	Book Depreciation	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax	849,722	851,915	849,722	851,915	849,722	851,915	849,722	851,915	202,828
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	4,501,700	4,509,330	4,501,700	4,509,330	4,501,700	4,509,330	4,501,700	4,509,330	2,250,850
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376
22										
23	Total Revenue Requirements - NSP	7,708,254	7,494,773	7,281,293	7,067,813	6,854,333	6,640,853	6,427,373	6,213,893	6,029,233
24										
25	Discount Rate =									
26										
27	Present Value of Revenue Requirements	4,710,617	4,306,709	3,934,239	3,590,894	3,274,522	2,983,128	2,714,855	2,467,983	2,251,675
28										
29										
30										
31										

LRTP2 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 17	Year 18	Year 19	Year 20
1	Plant Investment	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve	(26,266,962)	(27,812,078)	(29,357,193)	(30,902,309)
3	Removal Expense	-	-	-	-
4	Accumulated Deferred Taxes	(14,379,495)	(13,935,429)	(13,491,363)	(13,047,296)
5		35,653,543	34,552,493	33,451,444	32,350,395
6					
7	Average Rate Base	36,204,067	35,103,018	34,001,969	32,900,919
8					
9	Debt Return	756,665	733,653	710,641	687,629
10	Equity Return	1,759,518	1,706,007	1,652,496	1,598,985
11	Current Income Tax Requirement	1,153,700	1,132,119	1,110,537	1,088,956
12					
13	Book Depreciation	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax	(444,066)	(444,066)	(444,066)	(444,066)
15	ITC Flow Thru	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-
18	AFUDC Expenditure	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-
20	Avoided Tax Interest	-	-	-	-
21	Property Tax @ 1.4828%	1,131,376	1,131,376	1,131,376	1,131,376
22					
23	Total Revenue Requirements - NSP	5,902,309	5,804,204	5,706,100	5,607,995
24					
25	Discount Rate =				
26					
27	Present Value of Revenue Requirements	2,072,673	1,916,535	1,771,653	1,637,239
28					
29					
30					
31					

LRTP2 - Line
Based on 63 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	Plant Investment		47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve		(1,074,986)	(2,149,972)	(3,224,958)	(4,299,945)	(5,374,931)	(6,449,917)	(7,524,903)
3	Removal Expense		-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(370,102)	(1,351,351)	(2,203,581)	(2,940,371)	(3,572,588)	(4,109,737)	(4,602,068)
5			45,809,812	43,753,576	41,826,361	40,014,584	38,307,382	36,695,247	35,127,929
6									
7	Average Rate Base		46,532,356	44,781,694	42,789,969	40,920,472	39,160,983	37,501,314	35,911,588
8									
9	Debt Return		972,526	935,937	894,310	855,238	818,465	783,777	750,552
10	Equity Return		2,261,473	2,176,390	2,079,592	1,988,735	1,903,224	1,822,564	1,745,303
11	Current Income Tax Requirement		541,977	(103,486)	(13,505)	65,290	135,376	197,913	211,570
12									
13	Book Depreciation		1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax		370,102	981,250	852,229	736,790	632,216	537,149	492,331
15	ITC Flow Thru		-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		2,362,745	4,489,216	4,040,294	3,638,627	3,274,765	2,943,980	2,788,039
17	Tax Depreciation on Easements		-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-
21	Property Tax @ 1.4828%		700,696	700,696	700,696	700,696	700,696	700,696	700,696
22									
23	Total Revenue Requirements - NSP		5,921,759	5,765,773	5,588,309	5,421,735	5,264,963	5,117,085	4,975,439
24									
25	Discount Rate =	0.06349334							
26									
27	Present Value of Revenue Requirements	53,629,134	5,568,215	5,097,861	4,645,967	4,238,373	3,870,093	3,536,828	3,233,612
28									
29	**Level Annual Revenue Requirement**	**3,477,024**							
30									
31	**63 Year Life LARR %**	**7.36%**							

LRTP2 - Line
Based on 63 YEAR LIFE

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
1	Plant Investment	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve	(8,599,889)	(9,674,875)	(10,749,861)	(11,824,847)	(12,899,834)	(13,974,820)	(15,049,806)	(16,124,792)
3	Removal Expense	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(5,094,399)	(5,588,089)	(6,080,420)	(6,574,110)	(7,066,441)	(7,560,131)	(8,052,462)	(8,546,152)
5		33,560,612	31,991,936	30,424,618	28,855,943	27,288,625	25,719,949	24,152,632	22,583,956
6									
7	Average Rate Base	34,344,270	32,776,274	31,208,277	29,640,281	28,072,284	26,504,287	24,936,291	23,368,294
8									
9	Debt Return	717,795	685,024	652,253	619,482	586,711	553,940	521,168	488,397
10	Equity Return	1,669,132	1,592,927	1,516,722	1,440,518	1,364,313	1,288,108	1,211,904	1,135,699
11	Current Income Tax Requirement	180,849	148,757	119,381	87,288	57,912	25,820	(3,556)	(35,649)
12									
13	Book Depreciation	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax	492,331	493,690	492,331	493,690	492,331	493,690	492,331	493,690
15	ITC Flow Thru	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	2,788,039	2,792,765	2,788,039	2,792,765	2,788,039	2,792,765	2,788,039	2,792,765
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696
22									
23	Total Revenue Requirements - NSP	4,835,789	4,696,079	4,556,369	4,416,659	4,276,949	4,137,239	3,997,529	3,857,819
24									
25	Discount Rate =								
26									
27	Present Value of Revenue Requirements	2,955,215	2,698,500	2,461,904	2,243,941	2,043,228	1,858,483	1,688,514	1,532,217
28									
29									
30									
31									

LRTP2 - Line
Based on 63 YEAR LIFE

Line No.	Rate Analysis	Year 16	Year 17	Year 18	Year 19	Year 20
1	Plant Investment	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve	(17,199,778)	(18,274,764)	(19,349,750)	(20,424,736)	(21,499,723)
3	Removal Expense	-	-	-	-	-
4	Accumulated Deferred Taxes	(8,637,842)	(8,328,891)	(8,019,940)	(7,710,989)	(7,402,038)
5		21,417,280	20,651,245	19,885,210	19,119,175	18,353,139
6						
7	Average Rate Base	22,000,618	21,034,262	20,268,227	19,502,192	18,736,157
8						
9	Debt Return	459,813	439,616	423,606	407,596	391,586
10	Equity Return	1,069,230	1,022,265	985,036	947,807	910,577
11	Current Income Tax Requirement	339,543	721,243	706,228	691,213	676,198
12						
13	Book Depreciation	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax	91,690	(308,951)	(308,951)	(308,951)	(308,951)
15	ITC Flow Thru	-	-	-	-	-
16	Tax Depreciation & Removal Expense	1,394,020	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-
21	Property Tax @ 1.4828%	700,696	700,696	700,696	700,696	700,696
22						
23	Total Revenue Requirements - NSP	3,735,958	3,649,855	3,581,600	3,513,346	3,445,091
24						
25	Discount Rate =					
26						
27	Present Value of Revenue Requirements	1,395,229	1,281,694	1,182,636	1,090,838	1,005,785
28						
29						
30						
31						

Key Inputs

Line No	Capital Structure			
1			**2024**	
2	Capital Structure	Cost	Ratio	WACC
3	Long Term Debt	4.4000%	47.0800%	2.07%
4	Short Term Debt	4.1700%	0.4200%	0.02%
5	Preferred Stock	0.0000%	0.0000%	0.00%
6	Common Equity	9.2500%	52.5000%	4.86%
7	**Required Rate of Return**			6.95%
8	(Rates and Ratios from Settlement in Docket E002/GR-21-630)			
9				
10	**Property Tax Rates**			
11	Property Tax Rate			1.4828%
12	(percentage based on last TCR filing in Docket No. E002M-21-814)			
13				
14	**Income Tax Rates**			
15	Federal Tax Rate			21.00%
16	StateTax Rate			9.80%
17	State Composite Income Tax Rate			28.7420%
18				
19	**Allocators (2024 Estimate)**			
20	MN 12-month CP demand (Electric Demand)			86.6326%
21	NSPM 36-month CP demand (Interchange Electric)			83.8663%
22	Jurisdictional Allocator			72.6556%
23				
24	**Book Depreciation Lives**			
25	Land			0.00
26	Line			63.28
27	Sub			56.43
28				
29	**Net Salvage %**			
30	Land			0.00%
31	Line			-43.95%
32	Sub			-14.26%
33				
34	**Book Depreciation Rates**			
35	Land			0.00%
36	Line			2.2749%
37	Sub			2.0251%