MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	Tuesday July 2, 2024	Agenda Item **4
Company	Minnesota Power	
Docket No.	**E015/M-23-258**	
	In the Matter of Minnesota Power's 2023 Integrated Distribution Plan	

Issues

1. Should the Commission accept or reject Minnesota Power's 2023 Integrated Distribution Plan (IDP)?
2. Should the Commission approve, modify, or reject Minnesota Power's Transportation Electrification Plan (TEP)?
3. Should the Commission require any additional information or adjust any of the IDP filing requirements for Minnesota Power?
4. Should the Commission take any other action related to Minnesota Power's IDP?

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✓ **Relevant Documents**	**Date**
Minnesota Power – 2023 Integrated Distribution Plan, Parts 1 and 2	October 16, 2023
Department of Commerce – Initial Comments	April 5, 2024
Clean Energy Groups – Initial Comments	April 5, 2024
Minnesota Power – Reply Comments	April 26, 2024
Clean Energy Groups – Reply Comments	May 10, 2024
Department of Commerce – Reply Comments	May 10, 2024
Minnesota Power Information #1 Request Response	May 13, 2024

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Acronyms

AMI	Advanced Metering Infrastructure
Area EPS	Area Electric Power System
BIPOC	Black, Indigenous, and People of Color
BYOC	Bring Your Own Charger
CCT	Coalition for Clean Transportation
CEG	Clean Energy Groups
CIAC	Contribution In Aid of Construction
CSA	Customer Service Agreement
DCFC	Direct Current Fast Charger
DIC	Disproportionately Impacted Community
ECO	Energy Conservation and Optimization
EJ	Environmental Justice
EPA	Environmental Protection Agency
ESB	Electric School Bus
EV	Electric Vehicle
EVAAH	EV Accelerate At Home
EVSE	Electric Vehicle Supply Equipment
EVSI	Electric Vehicle Supply Infrastructure
IDP	Integrated Distribution Plan
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IT	Information Technology
MADA	Minnesota Automobile Dealers Association
MDU	Multi-Dwelling Unit
MN DIP	Minnesota Distributed Interconnection Procedures
MPCA	Minnesota Pollution Control Agency
NEVI	National EV Infrastructure Program
O&M	Operations and Maintenance
OAG	Office of the Attorney general

PEV	Plug-in Electric Vehicle
PHEV	Plug-in Hybrid Electric Vehicle
PIM	Performance Incentive Mechanism
REC	Renewable Energy Credit
SAIPE	Small Area Income and Poverty Estimates
TEP	Transportation Electrification Plan
TOD	Time of Day
TOU	Time of Use
V2G	Vehicle to Grid
WACC	Weighted Average Cost of Capital

1. Statement of the Issues

1. Should the Commission accept or reject Minnesota Power's 2023 Integrated Distribution Plan?
2. Should the Commission accept or reject Minnesota Power's Transportation Electrification Plan?
3. Should the Commission require any additional information or adjust any of the IDP filing requirements for Minnesota Power?
4. Should the Commission take any other action related to Minnesota Power's IDP?

2. Introduction and Background

A. Introduction

Minnesota Power's 2023 Integrated Distribution Plan includes information on spending allocations, a transportation electrification plan, and how to enhance the resiliency of the distribution system. Minnesota Power's 2023 Integrated Distribution Plan will be reviewed for acceptance that has no bearing on the prudency or certification of specific proposed investments.

B. Background

On October 16, 2023, Minnesota Power (or "the Company") filed the Company's 2023 Integrated Distribution Plan ("IDP") in response to filing requirements established by the Commission's prior orders. Specifically, in the Commission's February 20, 2019, Order, in Docket No. E-015/CI-18-254 the Commission adopted IDP filing requirements and ordered the Company to file an IDP biennially.

In its February 20, 2019, Order,[1] the Commission identified the following IDP objectives:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;

[1] *In the Matter of Distribution System Planning for Minnesota Power Association*, Docket No. CI-18-254, Order (Feb. 20, 2019).

- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility's short-term and long-term distribution system plans, the costs and benefits of specific investments, and comprehensive analysis of ratepayer cost and value.

The Commission accepted the Company's 2021 IDP in its December 8, 2022, Order[2] in Docket No. E-015/M-21-390 and included new filing requirements for the Company's 2023 IDP. The January 9, 2023, Order,[3] approving Minnesota Power's 2021 Integrated Resource Plan in Docket No. E-015/RP-21-33, required the Company to file its consultant-led non-wires alternative study with its 2023 IDP and to discuss how to integrate non-wires solutions into all of the Company's planning practices. The December 8, 2022, and January 9, 2023, Order, imposed the following requirements on the Company's 2023 IDP:

- Set the forecasts for distributed energy resources consistently in its IRP and IDP.
- Conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level.
- Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources.
- Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs.
- Plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.
- Inclusion of the Transportation Electrification Plan.

On April 5, 2024, the Minnesota Department of Commerce – Division of Energy Resources ("Department") and the Clean Energy groups[4] filed initial comments.

On April 26, 2024, Minnesota Power filed reply comments.

On May 10, 2024, the Department and the Clean Energy Groups filed reply comments.

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[2] *In the Matter of a Commission Inquiry into Electric Vehicle Charing and Infrastructure; In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan; In the Matter of Minnesota Power's 2021 Integrated Distribution System Plan; In the Matter of Distribution System Planning for Otter Tail Power Company*, Docket Nos. E-99/17-879, E-002/M-21-694, E-015/M-21-390, E-017/M-21-612, Order (Dec. 8, 2022).

[3] *In the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan*, Docket No. E-015/RP-21-33, Order (Jan. 9, 2023).

[4] Parties include: Fresh Energy, Union of Concerned Scientists, Sierra Club and Plug in America.

Staff notes that several topics raised by the Department in Dakota's IDP were common across multiple IDPs. Staff prepared Joint Briefing Papers which should be seen as a companion to these briefing papers.

3. Summary of IDP

A. Themes

Minnesota Power indicated its four themes in its 2023 IDP: customer, community, climate, and Company.[5]

1. Customer: Enhancing the Customer Experience

The Company is focused on improving the customer experience with the utility as customers will serve an increasingly interactive role in maintaining the reliability of the distribution system, particularly during moments of peak demand and demand response programs.

2. Community: Enhancing Resiliency to Ensure Grid Reliability

The Company recognizes the need to plan for a reliable and resilient power supply due to an increase in extreme weather events impacting the Company's distribution system. The 2023 IDP outlines plans to create a more resilient grid, including: asset renewal investments, strategic undergrounding, grid modernization efforts, and more.

3. Climate: Optimizing the Grid for Demand Side Resources and Electrification

To support the Company's carbon-free vision and the State's energy policy objectives, the Company is focused on right time/right fit investments, operational efficiencies, and reliability/resiliency upgrades to ensure a modern grid can continue to support further transformation. While the Company is aware of the recently passed Distributed Solar Generation Standard ("DSES") the Company did not have sufficient time to incorporate this new standard's impact into the 2023 IDP.

4. Company: Securing the Grid Future

As the electric grid continues to evolve to meet demands from new technologies, customers, and extreme weather, the Company is focused on the physical and cyber security of the system. The Company's 2023 IDP includes investments to ensure the distribution system meets those needs while operating efficiently and securely.

C. Overview of the Company

Minnesota Power is headquartered in Duluth, Minnesota with a service territory of 26,000 square miles and 150,000 customers, municipal systems, and some of the nation's largest industrial customers. Minnesota Power's distribution system is comprised of 6,216 miles of

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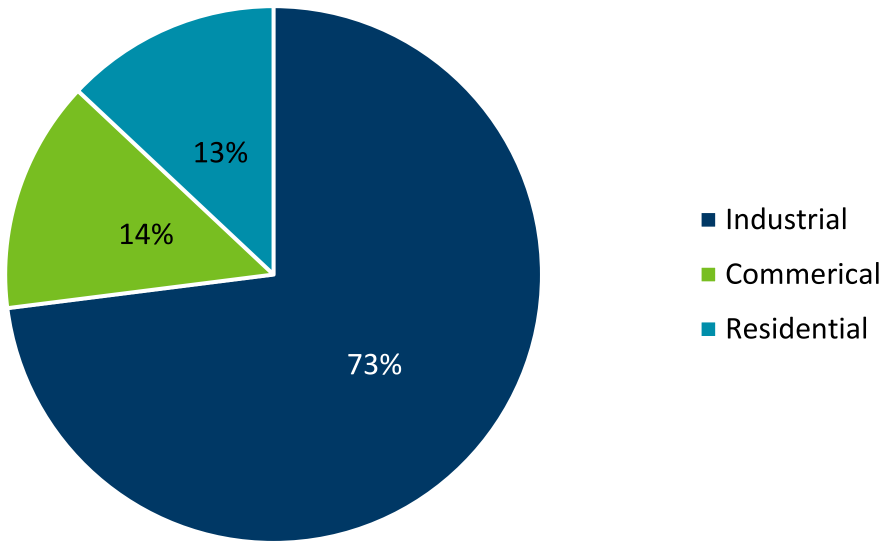
[5] Docket No. E-015/M-23-258, *In the Matter of Minnesota Power's Integrated Distribution Plan*, Minnesota Power Integrated Distribution Plan at 11 (Oct. 16, 2023) (hereinafter "MP IDP").

distribution lines and 201 distribution substations.[6] While the residential class is only 14% of the Company's annual retail electric sales, it makes up a large portion of the company's distribution system load.[7] Below is a graph illustrating the customer class percentage in the Company's service territory.

Figure 1: Customer Class Size



D. Staff Summary of the Issues

Minnesota Power recommends the Commission accept Minnesota Power's 2023 IDP with clarification that acceptance is not an advanced determination of prudency certification of specific proposed investments. If the Commission accepts the Company's 2023 IDP, it may select **Decision Option 1**.

The Department recommends the Commission accept Minnesota Power's 2023 IDP with certain modifications. The Department found the Company's 2023 IDP was largely compliant but asked the Commission to accept the filing with the following modification. If the Commission accepts the Company's 2023 IDP subject to certain modifications, it may select **Decision Option 2** to pair with other decision options.

E. System and Financial Overview

i. <u>Existing System Summary</u>

Overview of Minnesota Power's Current Customer Focused and Operational Systems

Minnesota Power lists continual investments, specific to customer relations and operations, in new technologies and customer-facing improvements. Those investments include the following:

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[6] MP IDP at 3.
[7] *Id.* at 3 - 4.

Figure 2: System and Financial Overview[8]

Customer-Focused Systems	
Customer to Meter ("C2M") Customer Information System	Core customer information system designed to securely store customer information and act as the primary billing and rate engine for Minnesota Power customers.
Meter Data Management ("MDM")	The MDM was implemented as part of the C2M and is the module that provides a data engine that performs validation, editing, estimating, and organized storage of both rate and operational information from metering systems.
MyAccount	Online portal that allows customers to view and pay bills, look at and track daily and hourly usage, request a stop, start, or transfer of service, and perform other account functions, which will continually be enhanced through investments over the next 10 years.
Automated Meter Reading ("AMR")	Legacy metering system that was decommissioned in April of 2023 in favor of Advanced Metering Infrastructure.
Advanced Metering Infrastructure ("AMI")	Advanced two-way metering system that can enable time-of-use rates. The current AMI system is fully deployed and includes further integration with other operational software systems.
Meter Asset Management	Module to store information on AMI meters, i.e., firmware management, time-of-use schedules, load/voltage profile structure.
Outage Management System ("OMS")	Reports outages, reduce restoration times, and predicts failed equipment and fault location reported on the system. This system is slated for replacement in early 2024.
Website updates	Applications for new construction now have an online fillable form. Customer service-focused improvements to the website have been integrated for new and existing customers and construction services.
Operational Systems	
Geographic Information Systems ("GIS") /Utility Network Model	The Company moved to a next generation GIS to integrate asset models from generation, transmission, and distribution systems to create a real-time Utility Network model.
Energy Management System ("EMS") Distribution Management System ("DMS")	The Company upgraded the EMS in 2024 to improve situational awareness tools that will help the operator's visibility to real time and state estimator data with improved alarm and event filtering capabilities.

[8] *Id.* at 16 - 19.

Distributed Energy Resource Management System ("DERMS")	
Infrastructure/Distribution Asset Management	Strategic approach to target key feeder and substation connected assets to bolster impact customer reliability and system resiliency.

To perform system communication functions, the Company recently selected Synergi as its long-term distribution planning software to perform these same functions. In addition, Synergi will be able to communicate directly with the Company's GIS model (Utility Network) and billing data (Customer-To-Meter) to provide accurate information for distribution planning studies. The software is also able to provide more advanced analysis routines for DER interconnections and planning and offer an integrated hosting capacity tool.[9]

To monitor and control the distribution system, the Company uses four system communication methods.

Figure 3: System Communication Methods[10]

Control or Monitor Method	Purpose of Method	Method Details
Supervisory Control and Data Acquisition (SCADA)	Oversees the state and health of the distribution system on half of the Company's feeds	Measures analog data (Amps, MW, MVAR, MVA, and kV) in 4 second intervals
		Measures binary information in 60 second intervals
		Remote operational breaks and motor operated switches
		50% of the Company's distribution feeders have SCADA at the feeder breaker (170 feeders)
Smart Sensors	Monitors voltage and current near the feeder breaker and stores data offsite	Installed on feeders that do not currently have SCADA installed
		Generally, in remote rural locations with limited communication paths
		40% of the Company's distribution feeders have smart sensors (136 feeders)
		The Company is testing control capabilities through smart sensors and faulted circuit indicators.
Manual Reads		Collected by operations personnel during substation inspections

[9] *Id.* at 48 – 50.
[10] *Id.* at 19 - 20.

	Collect peak amp data each month and area reset after reading	Many 4kV feeders on the distribution system that serve a very small number of customers
		Most of these locations will see investment upgrades in future years
AMI Systems	Standard for metering	Records voltage, kW, kilowatt-hours, kilovar-Hour, click counts and informs the OMS of customer outages and restorage.
		Collects 15-minutes interval data
		99.7% of AMIs have been deployed as of Jan. 2023

Communications Strategy

The Company utilizes three strategies to communicate coordination with its distribution system.

Fault Location, Isolation, and Service Restoration System ("FLISR")

Minnesota Power's FLISR system, which includes reclosers and smart switches, is connected via fiber optic network that is isolated from other Minnesota Power communication systems. The Company currently plans to extend fiber communications for additional smart switch devices as it is the Company's preferred solution.

Land Mobile Radio Based SCADA Communications

The Company's land mobile radio system provides a low-speed SCADA connection to a device within the radio coverage area. The radio system has coverage in a large majority of the Company's service territory making it a wide scale and cost-effective communication tool. The Company is upgrading this system to enable this function system wide by 2025.

Unlicensed 900 MHz radios, licensed 450 MHz radios or short fiber optic extensions that connect to a Remote Terminal Unit

These solutions leverage existing substation Remote Terminal Units that are located near the distribution device and are already connected to the EMS via the transport community system. This solution is a low-cost communication channel which utilizes existing substations.[11]

Cyber Security

The Company has built a multi-layered cyber security program based on the Center for Internet Security's internally accepted Critical Security Controls for Effective Cyber Defense framework. The goal of the program is to prevent, limit the impact of, and ultimately recover from cyber security threats.[12]

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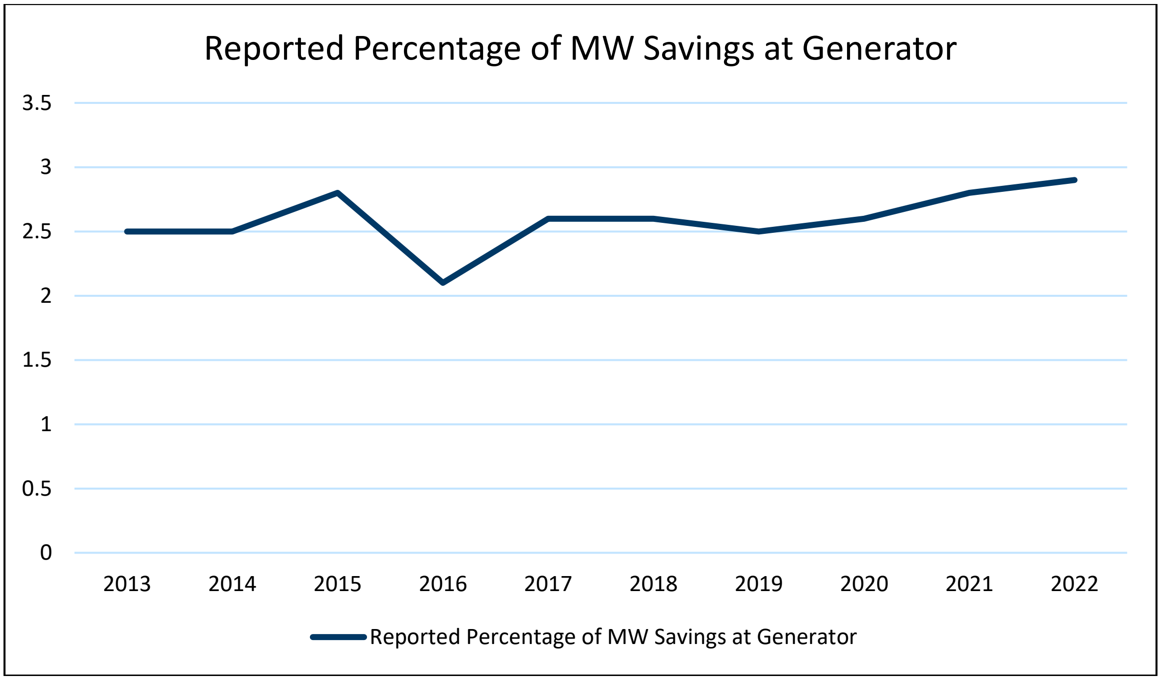
[11] *Id.* at 52 – 54.
[12] *Id.* at 54 – 55.

Energy Conservation Efforts

Minnesota Power achieved an average of 74 gigawatt hours in incremental annual energy savings, with achievements ranging from 64 GWh to 85 GWh through its Conservation Improvement Program ("CIP") between 2013 and 2022. Beginning in 2017, Minnesota Power was required to start reporting peak demand savings from CIP coincident with the MISO system peak. The average peak demand savings reports for 2017 through 2022 was 8.0 MW. Below is a graph of the reported percentage of MW savings at generators from the Company.[13]

Figure 4: Average Total Savings[14]



DERs and Demand Response

The Company reported 819 DER systems total 277,035 kW interconnected to the distribution system. The Company's IDP provides a visual of total customer sited DERs.

Figure 5: Current DER Systems[15]

DER System	Number of Systems	System Capacity
Solar	786	19,382 kW
Storage	15	163 kW
Hydro	2	142,314 kW
Wind	15	175 kW
Combined Heat and Power	1	115,000 kW

[13] MP IDP at 23.
[14] *Id.* at 24.
[15] *Id.* at 27.

Minnesota Power's Demand Response programs has approximately 240 MW of MISO accredited demand response from the Company's large industrial customers, representing approximately 15 percent of peak demand. The Company also offers a Dual Fuel rate that allows the Company to curtail mainly heating load of approximately 3 MW during the summer months and to 30 MW of load in the winter months, or 2 percent of peak winter load. The Company continues to pursue at least 50 MW of additional long-term demand response by 2030 as required by prior Commission order.[16]

Electric Vehicles

The Company estimates about 500 light duty EVs operate in Minnesota Power's retail service territory. According to the Minnesota Department of Transportation Electric Vehicle Dashboard, 61 public EV charging stations are in current operation in Minnesota Power's territory. Further, the Company notes there are 87 level 2 charging ports and 53 level 3 charging ports within its service territory. Lastly, there are 27 residential customers enrolled in the Company's Off-Peak Residential Electric Vehicle rate and 15 customers enrolled in the Commercial Electric Vehicle rate.[17]

The Company has plans to install 16 direct current fast charging stations ranging from 50 kW to 350 kW, to be operational in 2024, as approved by the Commission in Docket No. E015/M-21-257.[18] From the Company's most recent compliance filing, the Company has selected vendors and ordered charging equipment to install these charging stations. The Company is currently working with prospective site hosts on site host agreements.[19]

Small-Scale Solar

The Company has satisfied the requirements of the Solar Energy Standard and is considering how to implement the DSES. During the 2022 calendar year, Minnesota Power interconnected 186 distributed generation systems to its distribution system.[20]

Initial Comments

Department of Commerce

Advanced Metering Infrastructure

The Department believes further discussion about the costs and benefits of the AMI program are not warranted because it has already been approved by the Commission and deployed by the Company.[21]

Fault Location, Isolation, and Service Restoration

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[16] *Id.* at 27-28.
[17] *Id.* at 28.
[18] *Id.* at 29.
[19] Minnesota Power Compliance Filing, Docket No. E015/M-21-257, at 12 -13 (June 3, 2024).
[20] MP IDP at 29 – 32.
[21] Docket No. E-015/M-23-258, *In the Matter of Minnesota Power's Integrated Distribution Plan*, Department of Commerce, Initial Comments at 15 (April 5, 2024). (hereinafter "Department Initial Comments")

The Department notes Minnesota Power has not fulfilled several filing requirements:

- Discuss the cost recovery mechanism (Filing Requirement 3.D.1.a)
- Present an analysis of alternative investments (Filing Requirement 3.D.1.c)
- Present a discussion of customer anticipated benefit (Filing Requirement 3.D.1.g)
- Discuss a plan to manage rate bill impacts (Filing Requirement 3.D.1.i)
- Present the net present value of system costs (Filing Requirement 3.D.1.j)
- Present a cost-benefit analysis, if available (Filing Requirement 3.D.1.k).[22]

The Department requests the Company provide such information in reply comments.

Smart Sensors

The Department finds that the Company has presented sufficient information of its Smart Sensor Program but notes some insufficiencies regarding filing requirements.[23]

Outage Management System and Geographic Information System

The Company provides that GIS is going to replace the OMS system to allow for more real time mapping. The OMS system will be replaced in 2024, however, the Company does not state a timeline to deploy the GIS. Further, the Company includes over $3 million in "Other" spending but did not provide details on that spending.[24]

Management System

Currently, the Company utilizes its Energy Management System (EMS) to enhance the capabilities of its system. The Company provides that it is updating its EMS with an operational date in the fourth quarter of 2023. The Company also mentions the possibility of a Distributed Energy Resource Management System (DERMS) and an Advanced Distribution Management System (ADMS). The status or planning of such systems has not been provided.[25]

Reply Comments

Minnesota Power

Additional Information about the Company's FLISR program

The Company reiterated its intention to extend the isolated fiber optic network system because this is the Company's preferred communications solution for additional smart switch devices. The Company also reiterated the anticipated benefits of the FLISR program are improved reliability and resiliency.[26]

Additional Information about the Smart Sensor program

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[22] *Id.* at 16 – 17.
[23] *Id.* at 17 – 18.
[24] *Id.* at 18.
[25] *Id.* at 18 – 19.
[26] Docket No. E-015/M-23-258, *In the Matter of Minnesota Power's Integrated Distribution Plan*, Minnesota Power Reply Comments at 8 (April 26, 2024). (hereinafter "MP Reply Comments")

The Company reiterated that Smart Sensors will provide additional visibility into areas of the system where SCADA and fiber communication is not readily available. Benefits anticipated from the program include improved reliability, resiliency, and improved power quality.[27]

Additional Information about the Company's OMS and GIS programs

The Company anticipates deploying OMS in December 2024 with a budget of $4 million. The chosen OMS vendor aligns well with the Company's future Emergency Management Systems ("EMS") and GIS plans. The GIS program will be deployed in December 2024 with a budget of $2.07 million.[28]

Additional Information to deploy EMS, DERMs, and ADMS

The EMS was upgraded and placed into service on February 21, 2024. The Company has no plans to install a DERMs or ADMS between 2023 to 2027.[29]

Department of Commerce

Grid Modernization Investment Plans and Cost-Benefit Analysis

The Department maintained its position from initial comments that the Company has not provided all required information on benefits and costs for its grid modernization investments. Specifically, the Company has not provided cost-benefit analyses for its FLISR project, Smart Sensor Program, or OMS and GIS projects. Therefore, the Department recommends the Commission direct Minnesota Power to file separate cost-benefit analyses for FLISR, the Smart Sensor Program, OMS and GIS through supplemental filings.

Measuring the Impact of Distribution Grid Investments

To optimize planning and investment, the Department believes the Company should endeavor to quantify the impacts of its traditional distribution grid investment in key dimensions. The Company should quantify the following impacts for its investments:

- Capacity – marginal expected increase in MW capacity (at the level of system/substation/feeder)
- Reliability – marginal expected increase in reliably, as per SAIDI/SAIFI or other metrics
- Ratepayer impacts – marginal increase/decrease in rates and average bills
- Equity impacts – impacts on reliability, rates/bills, or other metrics by income group, race, environmental justice community, and potentially other dimensions. **(Decision Option 4).**

Staff Analysis

The Departments requests the Commission require the Company to provide supplemental filings on the cost-benefit analyses for FLISR, the Smart Sensor Program, OMS, and GIS, through

[27] *Id.* at 8.
[28] *Id.* at 8 – 9.
[29] *Id.* at 9.

supplemental filings within 180 days of the final Order. The Company did not provide cost-benefit analyses for each item and provided the following responses:

Figure 6: Benefit-Cost Analysis Decision

Department Requested Benefit-Cost Analysis	Minnesota Power Response
FLISR	FLISR is the Company's preferred communications solution for additional smart switch devices
Smart Sensor Program	Smart Sensors will provide additional visibility into areas of the distribution system where fiber communication is not readily available.
OMS and GIS Program	The chosen OMS vendor aligns well with the Company's future EMS and GIS plans.

Staff is not persuaded by the record that a cost-benefit analysis submitted through a supplemental filing is necessary for each identified item. A cost-benefit analysis is one tool to distinguish between various investments, it is not the lone decision-making tool. A cost-benefit analysis is often a useful tool to distinguish between competing options, but these investments, as illustrated by each utility response, does not show the need for a cost-benefit analysis to distinguish between competing options. Further, roughly 40% of the Company's distribution feeders have smart sensors currently installed and FLISR is currently operational. Therefore, a cost-benefit analysis may be useful for the OMS and GIS Program, but the FLISR and the Smart Sensor programs are already deployed where such an analysis may not prove helpful in accepting the Company's IDP.

Alternatively, if the Commission agrees with the Department and would like to see cost benefit analysis for the above items, it may select (**Decision Option 2a**).

ii. Historic and Forecasted Budget

Historic Budget

The Company has traditionally followed a depreciation level spending pattern for its distribution system. Figure 7 below reflects depreciation level spending until 2021. After 2021, the Company increased its investments above depreciation level spending to accelerate asset renewal, modernization, and reliability projects.

Figure 7: Historical Distribution Spending[30]

Investments by Category ($ in millions)	2018	2019	2020	2021	2022
A: Age Related & Asset Renewal	$10.226	$11.421	$10.439	$13.975	$26.478
B: Capacity	$0.267	$0.124	$0.805	$0.565	$0.114
C: Reliability & Power Quality	$3.717	$4.289	$6.168	$3.579	$3.462

[30] MP IDP at 25.

D: New Customer/ New Revenue	$4.242	$3.322	$3.484	$5.079	$10.883
E: Grid Mod & Pilot Projects	$0.152	$0.237	$0.815	$0.999	$0.504
F: Government Requirements	$1.938	$2.201	$2.120	$1.515	$2.444
G: Metering	$7.107	$6.255	$12.523	$4.653	$2.912
H: Other	$0.207	$0.151	$3.480	$2.618	$3.993
Total	**$27.856**	**$28.000**	**$39.834**	**$32.983**	**$50.790**

Forecasted Budget

The long-range plan generally utilizes historical spending to establish amounts for routine maintenance while accommodating other investments, such as:

- Localized distribution system reliability;
- Asset renewal needs; and
- Larger-scale projects where transmission-to-distribution substation reliability, capacity, or asset renewal are necessary.[31]

Figure 8 depicts the Company's investments for the following five years for the 2023 IDP.

Figure 8: Five Year Future Investments by Category[32]

Planned Distribution Capital Investments by Category ($ in millions)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
A: Age related & Asset Renewal	$25.5	$18.3	$37.3	$40.7	$38.2	$51.7
B: Capacity	$0.7	$3.9	$2.6	$1.6	$7.9	$7.0
C: Reliability & Power Quality	$8.5	$8.4	$11.5	$11.8	$9.9	$7.7
D: New Customer/New Revenue	$13.2	$14.0	$22.0	$14.0	$14.0	$14.0
E: Grid Mod & Pilot Projects	$3.5	$4.0	$5.5	$4.5	$4.5	$4.5
F: Government Requirements	$2.0	$2.0	$2.2	$2.2	$2.2	$2.5
G: Metering	$2.4	$2.4	$5.5	$4.6	$4.9	$3.9
H: Other	$0.4	$0.4	$0.9	$0.9	$0.4	$0.4
Total:	**$56.1**	**$53.2**	**$87.4**	**$80.4**	**$81.9**	**$91.7**

Each spending category is described below by the Company.[33]

Figure 9: Category Investment Spending

Category	**Category Description**
A: Age Related & Asset Renewal	Replace failing and end of life infrastructure on the distribution system
B: Capacity	Improve load-serving capacity or customer reliability

[31] *Id.* at 74.
[32] *Id.* at 37.
[33] *Id.* at 37 – 41.

C: Reliability & Power Quality	Improve customer reliability
D: New Customers/New Revenue	Construction of distribution line extensions to serve new customer load.
E: Grid Modernization & Pilot Projects	Necessary to keep pace with changing technology, regulatory requirements, and customer expectations
F: Government Requirements	Relocation of distribution lines located in public rights-of-way and relocation to avoid road construction conflicts
G: Metering	The procurement, installations, and communications of energy measurement technologies used for financial transactions
H: Other	Distribution asset operations but do not fall into other categories

Initial Comments

Department of Commerce

The Department notes that the Company's 2023 IDP spending has increased since its 2021 IDP. The Company's 2021 IDP projected a total distribution spending of $221.12 million between 2022 and 2026. The Company's 2023 IDP increased that projection to $394.73 million between 2024 and 2028, or an increase of approximately 79 percent. Figure 10 depicts the change in spending between the Company's 2021 IDP and the 2023 IDP.

Figure 10: Department's Comparison of Minnesota Power's Distribution System Spending Projections 2021 and 2023 IDP[34]

	2021 IDP (2022-2026)	**2023 IDP (2024-2028)**	**Change**
IDP Budget Category	**Spending (Millions)**	**Spending (Millions)**	**Spending (Millions)**
Age-Related Replacements and Asset Renewal	$112.75	$186.15	$73.40
System Expansion or Upgrades for Capacity	$5.22	$22.95	$17.73
System Expansion or Upgrades for Reliability and Power Quality	$39.97	$49.25	$9.28
New Customer Projects and New Revenue	$21.29	$78.00	$56.71
Grid Modernization and Pilot Programs	$18.90	$23.00	$4.10
Projects related to Local (or other) Government Requirements	$3.75	$11.10	$7.35
Metering	13.65	21.30	7.65
Other	$5.60	$2.98	$-2.63
Total Spending	**$221.12**	**$394.73**	**$173.60**

[34] Department Initial Comments at 20.

Figure 11 depicts the Department's comparison between the two IDP budgets overlapping years, 2024-2026.

Figure 11: Department Comparison of Minnesota Power's Distribution System Spending Projections for the 2024-2026 Period within the 2021 and 2023 IDPs[35]

	2021 IDP (2024-2026)	2023 IDP (2024-2026)	Change
IDP Budget Category	**Spending (Millions)**	**Spending (Millions)**	**Spending (Millions)**
Age-Related Replacements and Asset Renewal	$69.21	$96.28	$27.07
System Expansion or Upgrades for Capacity	$1.88	$8.05	$6.17
System Expansion or Upgrades for Reliability and Power Quality	$25.95	$31.65	$5.71
New Customer Projects and New Revenue	$12.77	$50.00	$37.23
Grid Modernization and Pilot Programs	$14.20	$14.00	$-0.20
Projects related to Local (or other) Government Requirements	$2.10	$6.40	$4.30
Metering	$5.85	$12.50	$6.65
Other	$2.24	$2.18	$-0.07
Total Spending	**$134.20**	**$221.06**	**$86.86**

Minnesota Power's total planned distribution system spending over 2024-2026 period increased by 65%, or $86.86 million. The primary driver behind this increase is due to the increases in Age-Related Replacements and Asset Renew, and New Customer Projects and New Revenue.

While the increase in Age-Related Replacements and Asset Renewal spending may increase the Company's budget, this increase is consistent with the Company's general trend of increasing its budget for the replacement of aging equipment over the coming decade.

Staff Analysis

The Department recommends that the Commission require Minnesota Power to provide a proposal for measuring the capacity, reliability, ratepayer, and equity impacts of its distribution grid investments in its next IDP. The proposal would specifically address the level of granularity at which the Company will evaluate these impacts for each budget category.

The Department provided this recommendation in reply comments after the Company provided its own reply comments, leaving the Company without an opportunity to provide a written response to this recommendation.

Staff notes the Department made identical recommendations across other utility IDPs. Staff provided analysis and recommendations in the Joint Briefing Papers. (**Decision Option 1**) is

[35] *Id.* at 21.

Staff's recommendation from those briefing papers, (**Decision Option 4**) in the 2023 Minnesota Power IDP Briefing Papers implements the Department's recommendation.

iii. Summary of System Planning Process

The Company's system planning process consists of incorporating small scale solar, load forecast development, and operational technology timelines. Each influence the Company's IDP planning process.

Distributed Solar Energy Standard ("DSES") and Ongoing System Planning

The Company is utilizing the recent statutory requirement, the DSES, and a recent Commission order to plan for an additional 300 MW of regional/in-service territory, or net-zero solar resources, by 2026 to be interconnected to its distribution system.[36]

Load Forecast Development

The Company's Transmission & Distribution Planning and Resource Planning departments work in close collaboration with one another to ensure integrated system planning for the Company. Specific to load forecasting, Distribution Planning obtains historical loading information by feeder from SCADA and meter data for its entire system on an annual basis. Load forecasting develops projected annual growth rates by feeder based on the latest Annual Forecast Report ("AFR") and supplies the growth rates to Distribution Planning to be used to develop an out-year peak load scenario for distribution planning analysis. Specific to this IDP, the Company is operating on system loss data as of 2021. The Company will refresh this information and file updated data with its 2025 IDP.[37]

System Implementation Timeline

Minnesota Power provides a roadmap of the distribution system projects the Company has, or plans to, implement between 2010 and 2029. Figure 11 depicts the Company's provided estimated implementation timeline.

Figure 11: System Implementation Timeline[38]

System Type	Implementation Timeline
AMI Deployment	2010-2020
AMI Optimization	2020-2029
CIS Implementation	2012-2015
Mobile Workforce Deployment	2015-2020
MDM Deployment	2018-2020
MDM Optimization	2022-2029

[36] MP IDP at 33.
[37] *Id.* at 9.
[38] *Id.* at 21.

OMS Upgrade	2021-2022
GIS/Utility Network Implementation	2021-2023
EMS/DMS/DERMS Upgrade	2022-2023
Distribution Planning Software Upgrade	2021-2022
Customer Self-service (MyAccount)	2013-2029

Advanced Metering Infrastructure (AMI)

As of January 2023, 147,164 AMI meters were deployed on Minnesota Power's system, or around 99.7% of deployed meters. Figure 11 depicts the Company's AMI deployment progress to date.

Figure 12: AMI Deployment Plan[39]

	AMI Meters Installed	Remaining AMR Meters
2016 Actual	11,092	92,084
2017 Actual	11,476	80,608
2018 Actual	13,155	67,453
2019 Actual	10,635	56,818
2020 Actual	35,437	21,381
2021 Actual	18,392	5,656
2022 Actual	6,109	203
2023 Plan	203	0 (likely will not be "0" due to potential AMI opt-outs)

Pilot Programs and Potential Pilot Programs

Figure 13 lists the Company's current and potential pilot programs in the 2023 IDP.

Figure 13: Potential and Existing Pilot Programs[40]

Pilot Programs	Potential Pilot Programs
Strategic Undergrounding	Renewable Load Optimization Program
Municipal Solar plus Storage System	Selective Customer Sub-Metering Applications

[39] *Id.* at 52.
[40] *Id.* at 57 – 64.

Distribution Utility Scale Solar Installations	Solar/Storage Applications
Reconnection Pilot Program	Conversation Voltage/Volt VAR Optimization
Street Lighting – LED	Battery Energy Storage System

iv. Forecast

Residential Time-of-Day Rate

The Company conducted an elasticity analysis using peak period pricing and observed customer load behavior from its legacy TOD pilot participants to estimate a price elasticity of about –0.35, i.e. a 10 percent increase in the price of electricity led to a 3.5 percent decrease in quantity demanded. The –0.35 elasticity estimate was applied to the on-peak price where the on-peak price (12.05 cents/kWh) reflects a 44% increase over base residential rates. Under this analysis, the Company estimates a 15% reduction in on-peak energy usage.[41]

Load and DERs

The Company accounts for existing DERs at the distribution system via two methods:

- In the load forecast by reducing customer demand based on historical DER usage or product; or
- The DER is accredited as a capacity resource and used to meet the Planning Reserve Margin Requirement in MISO.[42]

In the Company's 2021 IRP, the Company developed three scenarios for DER, namely DG solar, and EVs on the distribution system. The 2023 IDP leverages three scenarios for DER, namely DG solar, and EVs on the distribution system and updates them slightly to include assumptions for Time-of-Day rate adoption and potential installation of 16 new Direct Current Fast Chargers. Those scenarios include:

Figure 14: Forecast Scenarios[43]

Base Case	Consistent with the 2023 Annual Forecast Report assumptions for light duty EV ownership and distributed solar generation. It assumes a transition of residential billing to a TOD rate by 2027. Excludes assumptions for medium and heavy-duty vehicles.
Medium DER	Assumes slightly accelerated adoption of EVs and distributed solar generation, a transition to 100 percent residential TOD participation by 2026, and the installation of 16 new DCFC for EVs beginning in 2024. Medium and heavy-duty EV forecast ownership penetration rate is consistent with light duty Base Case.

[41] *Id.* at 87.
[42] *Id.* at 78.
[43] MP IDP at 79.

High DER	Assumes aggressive adoption of EVs and distributed solar generation, all residential customers on TOD by 2025, and installation of DCFC by 2024. Medium and heavy-duty EV adoption is accelerated.

Distributed Solar Generation

The number of new solar distributed generation installation are projected to grow, along with increased sizing (kW capacity), capacity factor, and seasonal production. The Company's Base Case forecast assumes 2,920 new small-scale solar installations connected to the grid by 2035, adding almost 28,000 KW of nameplate capacity.[44]

Light-, Medium- and Heavy-Duty Electric Vehicles

The Company's projected residential passenger EV, or light-duty EV, adoption rate is based on a national-level outlook that has been scaled to the Minnesota Power region. Minnesota Power's forecasts continue to reflect the EV adoption rate lags in Minnesota Power's territory when compared to national trends in each of its three scenarios. This lag, as identified by the Company, is about a six-year lag between the Company's service territory and national trends in the Base Case.

In the Company's Base Case forecasts, the Company projects that by late 2035, approximately 11% of regional light-duty EV ownership, approximately 23,200 light-duty EV's, or about 20% of households, will own and power a light-duty EV in Minnesota Power's service territory. The Company projects this equates to about 57,600 MWh in additional energy requires in the residential sector and an estimated increase of 7MW in the 2035 summer months and 21 MW in 2035 winter month.[45]

In the Company's Medium Scenario, the Company assumes light-duty EV penetration levels are only three years behind the national average. Meanwhile, the Company's High Scenario assumes light-duty EV penetration levels remain about three years behind national trends through 2027, but then about two years behind the national average through 2035.[46]

Commercial (Public) EV Charging

Minnesota Power's DCFC Infrastructure filing includes the construction of 16 DCFC stations within the Company's service territory ranging from 50 kW to 350 kW in capacity. The Company estimates the 16 DCFC stations will add about 1,000 MWh of energy use by 2030 and contribute about 0.2 MW to Minnesota Power's 2030 summer peak. By 2035, the 16 DCFC EV charging stations would add about 2,900 MWh of annual energy usage.[47]

Initial Comments

[44] *Id.* at 81.
[45] *Id.* at 82.
[46] *Id.* at 82 – 83.
[47] *Id.* at 86.

Department of Commerce

The Department is concerned how DERs will be treated in forecast data and if a double counting issue will emerge. For example, if the Company adds new installations separately, it leaves the potential that the DG Solar and EVs could be added once in forecast data and a second time in the DER forecast. The Department recommends that the Company consider this issue when developing future DG Solar and EV forecasts.

4. Resilience

A. Initial Filing

Distribution system resilience is an explicit key theme of the Company's IDP. Under the Community theme of the IDP, the Company provides resilience efforts to include asset renewal investments, strategic undergrounding, grid modernization efforts, and more. Later in the IDP, Minnesota Power describes the planning for a resilient future through financial planning, potential pilots, distribution forecasting, historical loading and preliminary hosting capacity data, and DER system impacts and benefits.

The Company approaches resilience investments through the following:

Figure 23: Minnesota Power Identified Resilience Investments[48]

Asset Renewal	Increased asset renewal budget from $18 million in 2024 to $52 million in 2028.
Upgrades to OMS and GIS	Positions the Company to receive real-time and accurate information regarding system outages.
Groundline Pole Inspection Program	Identifies aging distribution poles and applies chemical treatment to extend pole life 10 to 12 years.
Strategic Underground	Increase in strategic underground budget from $4.1 million in 2023 to $6 million in 2025.
Solar Photovoltaic Impacts	During system-wide outages, geographically dispersed solar arrays may be able to isolate and repower sections not directly affected by system outages.
Electric Vehicles	The Company is taking the first steps to learn about discharging EV back onto the distribution system.

In a response to a PUC Information Request on equipment design standards regarding modernizing infrastructure to withstand increasing extreme weather events, the Company reiterated that an increase in extreme weather events is one driver of the Company's commitment to asset renewal and grid modernization.[49] The Company specifically highlighted undergrounding distribution lines, upgrading its Outage Management System and building infrastructure to meet or exceed National Electrical Safety Code standards for heavy loading

[48] MP IDP at 13.
[49] Docket No. E-015/M-23-258, *In the Matter of Minnesota Power's Integrated Distribution Plan*, Minnesota Power Information Request Response (May 13, 2024)

requirements for ice and wind storms. Lastly, the Company provides it has developed standards for materials such as transformers, cables, and wire that provide additional capacity for increased demand in extreme heat and cold events.

B. Initial Comments

i. Department of Commerce

The Department identifies resilience as "low-probability, high-consequence events […] and affect a significant number of customers, often spanning a wide geographic extent." The Department views the Company's following investments as strategic actions to improve system resilience:

Figure 24: System Resilience Investments[50]

Asset Renewal	Increase in asset renewal investments from $18 million in 2024 to $52 million in 2028.
Upgrades to OMS and GIS	Positions the Company to receive real-time and accurate information regarding system outages.
Groundline Pole Inspection Program	Identifies aging distribution poles and applies chemical treatment to extend pole life 10 to 12 years.
Strategic Underground	Increase in strategic underground budget from $4.1 million in 2023 to $6 million in 2025.

C. Reply Comments

ii. Minnesota Power

In response to the Department's initial comment recommendation, the Company provided it currently files resilience and reliability metrics within the Safety, Reliability, and Service Quality filing on or before April 1 of each year.

iii. Department of Commerce

The Department clarifies its initial recommendation on how the Company should develop a suite a resilience metrics by including SAIDI with MEDs and SAIFI with MEDs.

The Department recommends the Commission direct Minnesota Power to develop a suite of metrics to track resiliency, including SAIDI with MEDs and SAIFI with MEDs, and other metrics to the extent warranted.

D. Staff Analysis

Staff analysis for this section is found in the Joint Briefing Papers.

5. Non-wires alternatives

The Company's five-year distribution capital plan includes four projects that are anticipated to have an individual total cost exceeding two million dollars. Any individual project over two

[50] Department Initial Comments at 31 – 34.

million dollars is required to go through a non-wires alternatives analysis. Non-wires alternatives are projects designed to address reliability performance or load-serving issues. Minnesota Power provides that NWAs are only viable when there is no significant asset renewal need being addressed and the operational characteristics of the non-wires solution adequately corresponds to the need.[51] Population growth is an important consideration for Minnesota Power because the population is expected to decline in the Company's service territory through 2053.[52]

The Company initiated a consultant-led Distribution Non-Wires Alternative Study to gain experience with the evaluation, development, and justification of non-wire solutions. Black & Veatch was selected as the consultant to assist the Company in developing a NWA benefit cost analysis framework.[53] More details about the selected vendor can be found in MP's IDP[54], otherwise, the report included four non-wires alternative projects:

Figure 15: Non-Wires Alternatives Projects[55]

Project Name	Project Description
Kerrick Area Non-Wire Alternative Solution Report	Replace backup distribution line connect with battery energy storage system.
Wrenshall Non-Wire Alternative Solution Final Report	Comparison of traditional reliability backup solutions with battery energy storage system
Silver Bay Non-Wire Alternative Solution Final Report	Comparison of traditional reliability backup solutions, a battery energy storage system, and a FLISR.
Cloquet Non-Wire Alternative Solution Final Report	Analysis to evaluate benefits of adding a FLISR

A. Initial Comments

i. Department of Commerce

Filing Requirements

The Department notes the Company did not satisfy filing requirement 3.E.2d, which requires the Company to discuss its NWA screen process. The Department claims these issues arose because the Company hired a contractor to perform the NWA analysis.

Further, the Department notes the Company has not complied with the January 9, 2023, Order, which requires the Company to begin a discussion on how to integrate NWA into all the Company's planning practice, and a discussion of how to improve the NWA analysis and better address costs. A lack of defined process leaves open the possibilities to ignore or delay NWA

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[51] *Id.* at 64 – 65.
[52] *Id.* at 66.
[53] MP IDP at 67.
[54] *Id.* at 67.
[55] *Id.* at 69 – 72.

implementation. Thus, not properly complying with Filing Requirement 3.E.2.b.[56] The Department requests the Company present such information in its next IDP.

Project Types Considered for NWAs

The Department notes the Company did not consider demand response or energy efficiency as a NWA solution because these types of projects were considered in other areas of MP's IDP. Further, the Company's IDP does not consider renewable generation isolated or with battery storage as a type of NWA solution.[57] The Department requests the Company consider these options as a NWA solution in its next IDP.

Benefit Categories

The Company did not elaborate on benefit categories that are challenging to monetize. Such benefit categories were not incorporated in different Minnesota Test Cases that are typically used by utilities for a benefit cost analysis.[58] The Department requests the Company include such information in its reply comments.

Key Assumptions

Minnesota Power provides a description of their key assumptions when calculating benefits and an overview of the process used to calculate benefits. However, the document does not outline how the specific litigation costs are assumed for each disbenefit severity category.

Further, the Department finds the calculation of "Avoided Capital Costs" benefit category should be modified for future NWA analysis. The Cost-Benefit Analysis should assume construction costs for the NWA solution at the beginning of the Cost-Benefit Analysis period of analysis, not at year 10 of the project. Calculating a year 10 benefit has the effect of discounting the value of the NWA solution because benefits at year 1- are significantly lower than the benefits at year one.[59]

NWA Studies Conducted

The Department notes that the full benefit cost analysis conducted for the four NWA solutions were not included in the IDP. Thus, providing the Department with insufficient information to determine the proposed impacts of each NWA project, or how each project was compared to a traditional solution's cost and benefits as well as a no-build solution. The Department requests such information be included in reply comments.[60]

B. Reply Comments

ii. Minnesota Power

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[56] Department Initial Comments at 6.
[57] *Id.* at 6 -7.
[58] *Id.* at 7 – 9.
[59] *Id.* at 9-10.
[60] *Id.* at 10 – 12.

Consider demand response, energy efficiency, and renewable generation as part of the NWA process

The Company will evaluate incorporating demand response, energy efficiency, and renewable generation into its NWA process for the 2025 IDP.[61]

Calculate NWA ratepayer disbenefit categories based on ratepayer cost of outages

The Company will evaluate incorporating ratepayer costs of outages into its NWA cost-benefit analysis for the 2025 IDP.[62]

NWA Process Details

The Company believes evaluating NWAs on a case-by-case basis is more cost-effective than establishing a blanket NWA process due to the small number of NWA studies in effect. Additionally, the majority of spending within the IDP relates to replacing aging assets because not all projects can effectively be replaced by NWAs.[63]

Calculated Benefits for all Minnesota Test Cases

The Company does not deem it feasible to provide these calculations in reply comments due to the scope of the request. The Company will evaluate incorporating calculated benefits for all Minnesota Test Cases into its NWA Cost-Benefit Analysis in its 2025 IDP.[64]

Recalculation of the Company's Cost-Benefit Benefits

The Department requested the Company recalculate its Cost-Benefit Analysis benefits starting with an "Avoided Capital Cost" benefit at the beginning of the Cost-Benefit Analysis period of analysis and present the results in reply comments. The table below provides the NPV and BCR with Avoided Capital Cost benefit moved up to the Beginning of the Cost-Benefit Analysis period.[65]

Figure 16: NWA Cost-Benefit Analysis Cost Ratios[66]

Project	Total NPV Net Benefits	Benefit Cost Ratio
Kerrick and Askvoc	$8,104,936.84	2.42
Wrenshall and Thomson	$33,341.95	1.00
Silver Bay 271 or 277	-$487,963.45	0.91
Silver Bay 271 and 277	-$4,776,425.46	0.51

Full Cost-Benefit Analysis for each NWA project

[61] MP Reply Comments at 4.
[62] *Id.* at 4.
[63] *Id.* at 5 – 6.
[64] *Id.* at 6.
[65] *Id.* at 6.
[66] *Id.* at 6 - 7.

The Company did not receive the full Cost-Benefit Analysis from its external consultant before the utility reply comment deadline.[67]

Planned 2023 to 2027 Budget allocations for all NWA projects

The Company provided that of the four NWA projects studied, the Kerrick Battery Energy Storage System is the only project that the Company is developing. The Company has a planning level estimate of $1.8 million in 2024 and $1.2 million in 2025.[68]

iii. Department of Commerce

NWA Process

The Department maintains its request that the Company present and discuss an NWA process even if such process is not as cost-effective as case-by-case analysis. The Department is unable to independently evaluate NWA suitability and request NWA studies in the IDP, and therefore, the Department finds a need for the Company to establish and provide a clear screening criteria rather than rely on the Company's own due diligence.

Providing Cost-Benefit Analysis for Programs

The Department appreciates that the Company included the cost-benefit analysis for the Central Area Non-Wires Alternative, but asks the Cloquet Non-Wires Alternative also be provided.

iv. Department Recommendations

1. Commission provide clarification as to whether the current NWA analysis conducted by the Company is compliant with the Filing Requirement 3.E.2.d and 3.E.2.b. If the Commission believes that the current analysis is not compliant, the Department recommends that the Commission require the Company to file a compliant NWA process in its 2025 IDP.
2. Commission require Minnesota Power to consider demand response, energy efficiency, and renewable generation as part of its future NWA process in its next IDP.
3. Minnesota Power calculate future NWA ratepayer disbenefit categories based on the ratepayer cost of outages rather than in the calculated categories of "Compliance Risk," "Power Quality Consequences," and "Improved Customer Satisfaction."
4. Commission direct Minnesota Power to provide the cost-benefit analysis for the Cloquet Area project be provided through a supplemental filing within 180 days of the Commission's final Order in this proceeding.

C. Staff Analysis

v. Department NWA Recommendation 1

[67] *Id.* at 7.
[68] MP Reply Comments at 7 – 8.

Staff believes the record supports compliance from the Company with these filing requirements because the Company has chosen to select NWAs in this case-by-case process. Further, the Company is able to provide the individual process used for each project but was unable to receive the cost-benefit analysis from the consultant prior to the deadline for utility reply comments. Below is a table with the relevant filing requirement with the Company's response.

Figure 17: Filing Requirement Decision

Filing Requirement	Filing Requirement Description	Minnesota Power Response
3.E.2.b.	A timeline is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation).	The Company's believes evaluating NWAs on a case-by-case basis. The Company is unable to provide the screening process because the Company had not received the full Cost-Benefit Analysis from the consultant before the reply comment deadline.
3.E.2.d	A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.	The Company believes evaluating NWAs on a case-by-case basis. The Company is unable to provide the screening process because the Company had not received the full Cost-Benefit Analysis from the consultant before the reply comment deadline.

If the Commission believes the Company has not complied with these filing requirements, then Staff provides (**Decision Option 8**). Staff further provides (**Decision Option 9**) to require the Company to present a compliant filing NWA process in its 2025 IDP.

vi. Department NWA Recommendation 2

The Department and Minnesota Power agree the Company will evaluate incorporating demand response, energy efficiency, and renewable generation into its NWA process for the 2025 IDP. **(Decision Option 10)**

vii. Department NWA Recommendation 4

The Department recommends that Minnesota Power provide the cost-benefit analysis for the Cloquet Area project through a supplemental filing within 180 days of the Commission's final order. The Company provided it was unable to obtain the full cost-benefit analysis for each NWA project from its external consultant before the utility reply comment deadline. The Cloquet Area NWA will be partially implemented in 2024 to adopt a FLISR solution. However, the cost-benefit score can be improved if voltage correction and power quality improvements are included in the NWA project. However, these improvements have not advanced out of the planning stage and the Company has not selected a vendor.

Based on the record, Staff is not persuaded that the full Cloquet Area cost-benefit analysis is necessary to determine whether Minnesota Power's IDP is complete, especially given the NWA project is in the initial planning stages. It is unlikely the Company would have the full implementation details to conduct a worthwhile cost-benefit analysis and such information may not be useful to determine if the Company's IDP is complete. Staff believes that it is appropriate for the Company to submit the Cloquet Area CBA if the Company proceeds with a NWA pilot approval request, or when it is available from the third-party evaluator. However, if the Commission agrees with the Department it may adopt (**Decision Option 11**).

6. Transportation Electrification Plan

The Company's filed TEP provides the Company's vision to support its service territory as more consumers adopt EVs in the five-year plan. The Company highlights its rebate offerings and installation of DCFC options.

A. Initial Filing

Minnesota Power continues its work on installing 16 Direct Current Fast Charging (DCFC) stations throughout their service territory as approved by the Commission.[69] The Company submitted a permanent Commercial EV rate[70] and will submit a program to support multifamily-dwelling units by the end of 2024. The Company noted that they expect modifications to timelines and proposals as the transportation electrification market rapidly shifts and grows, citing the forced cancellation of its Smart Charge Rewards pilot program as an example.[71] The Smart Charge Rewards pilot program was delayed indefinitely due to a lack of vendors that fit the Company's needs for the program.[72] The vendor originally selected discontinued their programming.

The Company continues to offer a residential EV tariff, charging rebates, a commercial EV tariff, and investments in charging through DCFC. The Company currently has 49 customers enrolled in its residential tariff offering.[73] Feedback from ratepayers suggests the necessity of a second metered service acts as a barrier to participation and installing a secondary meter is not possible for all customers due to upfront costs and access to off-street parking. The Company

[69] October 22, 2021 Order Approving Proposal as Modified, Authorizing Deferred Accounting, and Requiring Reporting, Docket No. E015/M-21-257

[70] EV Commercial Charging Rate Pilot Compliance Filing, In the Matter of Minnesota Power's Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot, Docket No. E015/M-19-337.

[71] MP IDP at Appendix E, p. 8.

[72] More information on the program can be found in Docket M-20-638. The Company's letter dated April 25, 2022 details the discontinuation.

[73] Docket Nos. 15-120; 19-337; 20-638; 21-257, Minnesota Power Electric Vehicle 2023/2024 Annual Report.

recommends its Residential Time-of-Day rate as an alternative to ratepayers as it does not have the requirement of installing a secondary meter.[74]

Alternatively, MP offers two EV charger rebates to help address these upfront costs as well. The Company offers a $500 rebate for the costs related to installing a second service meter for those enrolled in the Residential EV Tariff. The Company has issued 7 second service rebates over a 12-month period from 2022 to 2023, as well 18 rebates towards the purchase of a level 2 charger. In March of 2020, the Company implemented its Commercial Charging Rate Pilot of which nine customers representing 14 separate locations are enrolled in, the largest of which is Duluth Transit Authority.[75] In 2019 MP donated 20 Level 2 EV chargers to businesses in strategic locations across the Company's service territory to support expanded availability.[76]

The Company had to reissue a request for proposals to select a new vendor for their DCFC rollout due to initial vendor issues that delayed the project. Target locations for the DCFC network were identified based on gaps in existing public fast chargers, population clusters and proximity to major travel corridors as well as consideration of environmental justice areas of concern. The goal is to improve access to EV drivers as they travel throughout the state and reduce range anxiety, particularly for non-metro drivers. These barriers exist as there are only nine public DCFC stations in MPs territory and one operating in support of a fleet operator. All but one DCFC are enrolled in the Commercial EV Tariff.[77] As the DCFC program concludes, MP will investigate possible divestment strategies including sale to site hosts or third-party charging companies.[78]

According to the Minnesota Department of Transportation, there are an estimated 87 Level 2 charging ports within MP's territory and the Company expects to not only continue monitoring its growth and access, but to provide outreach and education to customers and the public regarding EV charging through its website, promotion at public events and awareness campaigns.[79]

MP stated they are actively engaging fleet operators to better understand customer interest in fleet electrification and is working to assist fleet managers in analyzing fleet conversions for its specific businesses. As a result of the Company's approved outreach budget, MP has supported two assessments and will work with customers to identify cost effective approaches as MP customer EV adoption increases. The Company is also working to electrify its own fleet with the goal of 50% electrification of their light duty fleet and 25% electrification of their medium and heavy-duty fleet by 2030.[80]

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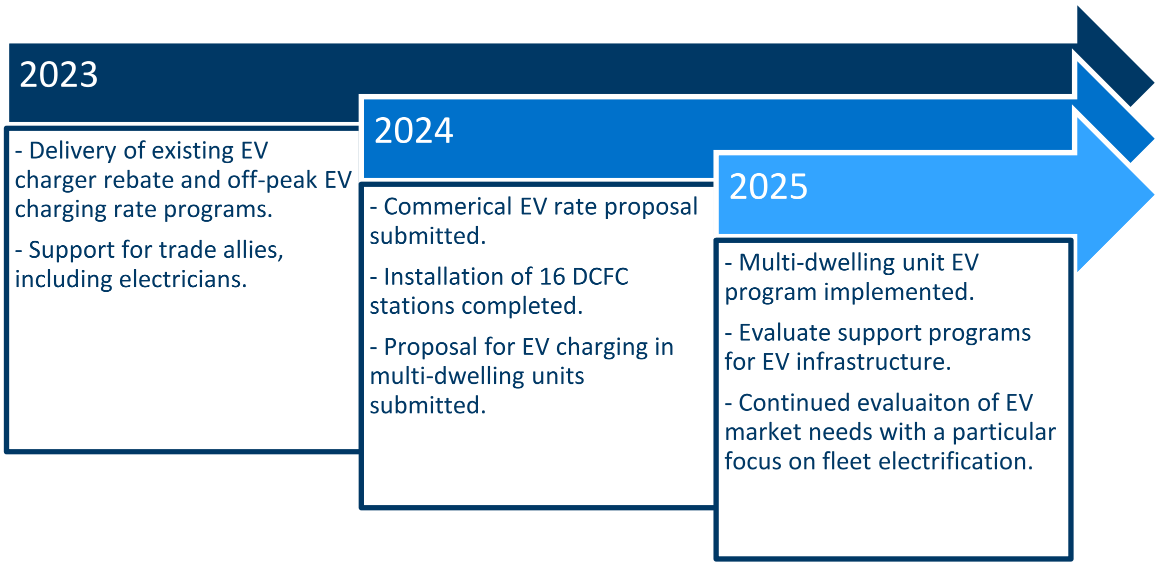
[74] MP IDP at Appendix E, p. 10.
[75] *Id.* at Appendix E, pp. 10-11.
[76] *Id.* at Appendix E, p. 12.
[77] *Id.* at Appendix E, p. 13.
[78] *Id.* at Appendix E, p. 17.
[79] *Id.* at Appendix E, p. 13.
[80] *Id.* at Appendix E, p. 16.

The Company provided an EV Initiatives Implementation Timeline below to visualize current and near future offerings.

Figure 18: EV Initiatives Implementation Timeline[81,82]



B. Initial Comments

i. Clean Energy Groups

The Clean Energy Groups (CEGs) recommended the Commission accept MP's TEP with requirements for subsequent filings to fill in perceived gaps in the plan. The CEGs recommendations include:[83]

1. An additional discussion of how MP is preparing for and supporting adoption of medium and heavy duty EVs;
2. A discussion of equity, specifically an analysis of the gaps regarding how MP's EV programs are serving those disproportionately impacted by mobile source pollution, renters, multifamily housing residents, communities of color, "low to moderate income customers"[84], and rural communities; and

[81] MP IDP at Appendix E, p. 9, Figure 2

[82] Commission Staff note that while the Company expects completion of the DCFC stations by the end of 2024, the Department believes the end of 2024 to be the earliest potential completion date based on the recent Company compliance filings in docket 21-257.

[83] Docket No. E-015/M-23-258, *In the Matter of Minnesota Power's Integrated Distribution Plan*, Clean Energy Group Initial Comment at 1 (April 5, 2024). (hereinafter "CEG Comment")

[84] Note on the use of quotations: while Fresh Energy, based on input from key partners, often uses the term under-

3. A discussion regarding the coordination between EVs, energy efficiency, and building electrification through their programs approved by the Commission and their ECO-initiated programs.

The CEGs laid foundational knowledge and background information on the impacts of transportation electrification on public health and the environment before providing a summary of state and federal policy landscapes. Compared to discussions in prior years, the CEGs highlighted the now finalized United States Environmental Protection Agency rules reducing emissions from the national new passenger cars and light trucks fleet and national new heavy-duty vehicle fleet. Both rules take effect with model year 2027 and are expected to electrify the American light and heavy-duty fleets faster than the previous policy landscape.[85]

The CEGs expressed concern that MP did not share how many of the 500 EV owners in the Company's service territory are on the TOD rate or if the rate is an attractive offering relative to the standard residential rate. Therefore, the CEGs requested MP share the number of customers enrolled on its Residential TOD rate that also have an EV. The CEGs also requested MP share any feedback it has received from customers on why EV drivers have or have not adopted the whole-home TOD rate in MP's reply.[86]

The CEGs also expressed concern regarding the cancellation of MP's Charging Rewards Pilot because MP has not provided a timeline for developing a future EV residential rate program. The CEGs noted that only 5.4% of MP's EVs are actively incentivized to charge off-peak at a time beneficial to the grid and expressed concern that enrollment in programs to incentivize managed charging is lagging behind EV adoption.[87] The CEGs believed this lag will only be exacerbated with no planned replacement of the Charging Rewards program. The CEGs therefore recommended MP provide an additional EV residential managed charging program in or before its next TEP (**Decision Option 14**) and requested MP comment on the availability of alternative technology providers in the market now that could offer a similar service to the original Charging Rewards Pilot provider.[88]

Due to a lack of information regarding medium and heavy-duty electric vehicles in the MP service territory, the CEGs requested MP provide an estimate of medium and heavy-duty EVs in the service territory as well as current or planned electric school buses.[89]

As in previous TEPs, the CEGs requested MP provide additional discussions regarding heavy duty electrification, equity, and coordination between transportation electrification, energy

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resourced to describe customers with fewer financial resources, the CEGs are using "low-to-moderate income" to align with the language of the Minnesota Statute 216B.1615 which directs what utilities' Transportation Electrification Plans should include, and which uses the term "low-to-moderate income." The quotations indicate a reference to that usage.

[85] *Id.* at 5.
[86] *Id.* at. 7.
[87] *Id.*
[88] *Id.* at 8.
[89] *Id.* at. 9.

efficiency, and building electrification through programs such as ECO. These requests are presented in **Decision Options 15, 16, and 17**.

ii. Department of Commerce

After reviewing MP's filing in its entirety, the Department concluded MP sufficiently addressed each of the TEP filing requirements and Commission Orders.[90]

The Department requested MP discuss in reply comments its strategy to increase off-peak charging among EV owners as well as an assessment of its residential TOD rate to promote off-peak charging.[91]

The Department noted the relative absence of discussion regarding electric school buses given the sizeable federal and state funding sources available to promote adoption and encouraged the Company to incorporate a discussion of school bus electrification into its support for fleet electrification.[92]

The Department highlighted the educational benefits of MP's DCFC project as it will nearly triple the number of fast charging stations in the MP service territory.[93]

The Department noted the absence of budgetary information for specific initiatives limits the insight into how ratepayer-funded investments are addressing transportation electrification holistically in the MP service territory. The Department noted that as an example, nearly all of MP's historical spending is represented in the "Other" category. Therefore, the Department requested additional information to differentiate the identified spending between rebates and labor costs. The information provided by MP's response is detailed below.[94]

Figure 19: MP 5 Year Historical Spending[95]

***Other expenses include rebate incentives and labor**

Budget Category	Capital	O&M	Marketing & Communications	Other*
Customer Programs			$10,808.24	$524,089.98

Figure 20: MP 5 Year Future Spending[96]

Budget Category	Capital	O&M	Marketing & Communications	Other*
Distribution	$2,602,161	$549,838		
Customer Programs			$275,000	$1,424,724

[90] Department Initial Comment at 36.
[91] *Id.* at 41.
[92] *Id.* at 44.
[93] *Id.* at 45.
[94] *Id.* at 46 – 47.
[95] MP IDP at Appendix E, p. 20.
[96] *Id.* at Appendix E, p. 21.

Figure 21: Detailed Historical Spending at Request of Department[97]

Budget Category	2019	2020	2021	2022	2023	Total
Labor & Overhead	$9,563	$41,810	$81,632	$93,079	$79,360	$305,444
Program Expenses	$97,897	$10,904	$79,117	$24,685	$16,853	$229,456
Total	$107,460	$52713	$160,749	$117,764	$96,213	$534,900

From the information provided, the Department determined spending overall remains relatively modest during the 5-year forecast period, with the exception of MP's DCFC project. The Department also noted increased spending from historical levels in the categories of rebates, education and outreach, and labor.

The Department requested that Minnesota Power discuss:[98]

- Company strategy to increase rebate uptake for home charging.
- Company strategy to increase off-peak charging among EV owners in its service territory, including its assessment of the effectiveness of the Residential TOD rate to promote off-peak charging as well as their plans to increase utilization of its home charger rebates.
- How planned increased spending for labor costs will be utilized to further transportation electrification.

C. Reply Comments

iii. Minnesota Power

Response to the CEGs

In response to the CEG's recommendation of a more robust discussion on equity and disproportionately impacted communities, the Company reiterated its use of the MPCA's environmental justice screening tool when selecting site locations for their DCFC buildout. The Company also noted its current evaluation of approaches to MDU charging access and a plan to bring forward a detailed proposal in late 2024.[99]

In response to the CEG's request for a discussion on coordination between EVs, energy efficiency, and building electrification, the Company discussed its cross promotion of programs to customers through a single department within its customer experience team. The Company noted that they did not include any efficient fuel switching measures in their 2023 Triennial[100] but stated the Company will continue to evaluate opportunities as guidance and processes evolve such as PEV rebates that can be incorporated into their ECO plans.[101]

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[97] Department of Commerce Initial Comment at 47.
[98] *Id.* at 51.
[99] MP Reply Comment at 2.
[100] Docket No. E015/CIP-23-93
[101] MP Reply Comment at 2.

In response to the CEG's request for a residential managed charging proposal by or before the Company's next TEP filing, the Company discussed its three rates offered for residential EV charging customers (EV Service Rate, Time of Day Rate, and Dual Fuel Rate) as well as their offered rebates. Due to limited resources and the number of existing residential EV rates, the Company is focused on accessible public EV charging and MDU charging. The Company noted it is in the early stages of evaluating its default TOD rate for residential customers. The Company felt it is premature to propose additional managed charging programs until more data can be collected on the default TOD rate.[102]

In response to the CEG's request for information on the number of EV customers on its Residential TOD rate as well as feedback from customers on EV driver adoption of the whole-home TOD rate, the Company responded that it is aware of 56 EV owners that currently participate in the whole home TOD rate but that the number is likely an undercount of total EV owners on the whole home TOD rate. Customer feedback included those who shift their EV, dishwasher, and dryer usage to the lower rate times of whole home TOD rates and feedback from customers who did not switch due to the low annual savings obtained by the TOD rate (estimated at $6/year for the customer).[103]

In response to the CEG's request for the number of medium and heavy-duty PEVs in MP's service territory, MP estimated there are 42 medium duty and 12 heavy duty PEVs in its territory based on the penetration rate of light-duty vehicles in the territory.[104]

In response to the CEG's request for alternative technology providers that could replace the Company's original technology provider selected for the since canceled Charging Rewards Pilot, the Company noted it has evaluated offerings from other vendors and found them to be an inadequate fit for the Company's needs and objectives, but the Company will continue to monitor the market for opportunities to provide a similar offering. The Company restated the availability of their other rate offerings to provide similar off-peak charging encouragement.[105]

Response to the Department

The Company did not discuss its strategy to increase off-peak charging through its other rates and programming in response to this Department request.[106]

In response to the Department's request for how MP plans to increase utilization of its home charger rebates, the Company cited a steady increase in participation in its EV charger and second service rebates over the three years of the program. MP noted access to public charging, vehicle availability and purchase price are the most prevalent market drivers and that the Company anticipates the programs will scale with PEV adoption.[107]

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[102] *Id.* at. 2 – 3.
[103] *Id.* at. 3.
[104] *Id.* at 4.
[105] *Id.* at 4.
[106] *Id.* at 10 -11.
[107] *Id.* at 11.

Figure 22: Minnesota Power Residential EV Charger Rebates[108]

Rebate Year	Number of Rebates Issued
Year 1	4
Year 2	25
Year 3	48

The Department also requested discussion on MP's planned increased spending for labor costs on transportation electrification. MP explained labor assumptions for 1.5 full-time employees per year in its budget with an increasing rate of 3% annually to account for inflation. These labor assumptions were consistent with the Company's EV portfolio filing[109] for programs delivered from 2021-2023. The Company also noted historical labor spending did not match the budgeted amount for reasons including turn over in positions, resources dedicating time to multiple programs and differences in budgeted assumptions and actual market labor rates. The labor assumptions do not reflect an increase in transportation electrification programming labor as the Company continues to project 1.5 full time allocated employees.[110]

iv. Department of Commerce

After review of Minnesota Power's Reply Comments, the Department concluded that the Company had generally responded sufficiently to the Department's reply comments and its request for additional information. The Department maintained its conclusion that the Company's TEP is reasonable and in the public interest, sufficiently addressing the TEP filing requirements.[111] (**Decision Option 12**).

v. Clean Energy Group

The CEGs continued to recommend requiring discussions on MP's support of medium and heavy duty EVs, equity and justice gaps, and coordination of EVs with energy efficiency, building electrification and ECO programming in the next TEP (**Decision Option 17**). The CEGs also requested the Commission require MP to propose an additional EV residential managed charging program that does not require installation of a second service or participation in a whole-home time of use rate by or before the Company's next TEP filing.[112]

In response to MP's acknowledged barriers and resource constraints, the CEGs acknowledged that a default residential TOD rate would likely incentivize beneficial, off-peak EV charging behavior once rolled out in full (expected by end of 2027). The CEGs expressed concern that this rollout will not occur for a few years and insisted that a new residential EV managed

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[108] MP Reply Comment at 11.
[109] Docket No. E-015/M-20-638
[110] MP Reply Comment at 11.
[111] Docket No. E-015/M-23-258, *In the Matter of Minnesota Power's Integrated Distribution Plan*, Department of Commerce Reply Comments at 4 – 5. (May 10, 2024) (hereinafter "Department Reply Comments")
[112] Docket No. E-015/M-23-258, *In the Matter of Minnesota Power's Integrated Distribution Plan*, Clean Energy Groups Reply Comments at 1 – 2. (May 13, 2024). (hereinafter "CEGs Reply Comments")

charging program, or pilot in the interim, could provide grid benefits and garner additional useful data and feedback when informing future EV charging programs. The CEGs also argued a new residential EV managed charging program would support more MP customers in acclimating to time of use rates.[113]

Further, the CEGs stated there is room for growth in customer adoption of TOU rates until the implementation of the default residential TOD rate and for innovation in shaping customer charging patterns to the benefit the electric grid and all utility customers. In defense of this position, the CEGs cited that at least 56 residential time of day customers own an EV and at least 17 percent of MP's light-duty EV customers on a managed charging program.[114]

The CEGs noted the number of EV drivers participating in whole home Time of Day (at least 56) compared to the Residential EV Service Rate (27) is double. The CEGs highlight customer feedback received by the Company[115] to reinforce CEGs concerns that some customers may want an EV-specific rate. The CEGs argues the customer feedback and rate participation levels suggest that installing a second service meter is a barrier to access with regards to cheaper off-peak EV charging rates, even with the available rebates from the Company, and supports the need for a new residential EV managed charging program that does not require a second service or switching to a whole home residential time of day rate.[116] Therefore, the CEGs recommend the Commission require MP to propose an additional EV residential managed charging program that does not require second service or participation in a whole-home time of use rate by or before its next TEP filing in 2025. (**Decision Option 14**)

The CEGs expressed support for the Company's efforts to increase access to public charging and MDU charging, recommending MP include some managed charging component into its MDU program via passive (time of use rates) and/or active management. The CEGs welcomed further discussion on these topics with MP staff in the coming months.[117]

D. Staff Analysis

Staff is encouraged by MP's plans to bring forward a new MDU program in 2024 that will lower cost barriers, improve MDU charging access and encourage beneficial electrification to its grid system. Ensuring that those who do not own single family homes have options to charge through work, street side parking, and public charging in important to ensuring equitable access to transportation electrification. In Docket 17-879, the Commission specifically found barriers to EV adoption include access and supply of to charging infrastructure. These types of programs will support reducing those barriers.

While Staff shares the CEGs disappointment in the challenges surrounding MP's residential managed charging pilot and subsequent cancellation, Staff does not believe an alternative

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[113] CEGs Reply Comments at 2 – 3.
[114] *Id.* at 3.
[115] Customer stated: "I have not changed to ToD rate since it only looks like a $6 annual savings while restricting myself to specific times to charge (unless I want to increase my cost vs. save)" citing MP Reply Comments at 3.
[116] CEGs Reply Comments at 3.
[117] *Id.* at 4.

residential EV rate program is needed at this moment due to the expected full implementation of the Company's new TOD Rate in 2027. Instead, Staff encourages Minnesota Power to explore possibilities for more active managed charging options that could be paired with the forthcoming universal residential TOD rate to increase load flexibility within charging periods.

Staff notes that MP did not separate out a discussion of electric school buses as requested by the CEGs when they requested more information regarding medium and heavy duty EVs in MP's service territory. Staff believe this information would also be helpful to the CEGs, the Commission, and the Company with recent changes to electric school bus funding opportunities for school districts and school bus fleet managers. Staff recommends the Commission require Minnesota Power to file additional information about electric school buses in its next TEP. **(Decision Option 18)**

Staff also note that while the CEGs expressed concern regarding off peak charging uptake by MP ratepayers, MP had a 100% increase in their residential EV tariff since last year with 88.5% off peak charging.[118] Last year was 81% off peak charging. Staff will continue to monitor annual reports to track participation and off-peak charging impacts.

Minnesota Power's next TEP will be filed with the IDP before November 1, 2025 unless the Commission alters that date. Staff recommends the Commission set the filing date for Minnesota Power's next TEP for November 1, 2025. (**Decision Option 13**)

Staff also notes (**Decision Option 12**) as there is separate statutory requirements (Minn. Stat. § 216B.1615 subd. 3) allowing specifically for Commission approval of the TEP.

7. Additional IDP Comment Topics Summary

A. The Inflation Reduction Act (IRA) and Utility Planning and Benefits

a. Department Initial Comments

The Department notes that the Company does not specifically reference the IRA in its IDP and only provides limited references to federal tax incentives. However, the Department acknowledges the short time period from the September 12, 2023, Order to the filing of the IDP on October 16, 2023. The Department requests the Company provide a description of how its distribution system planning will evolve to incorporate impacts from the IRA.

b. Minnesota Power Reply Comments

The Company actively engages with customers, stakeholders, and contractors to promote available tax credits and has offered to engage with the Department on the design and delivery of IRA rebate programs. The Company anticipates the combination of ECO and IRA programs will spur electrification and the Company will continue to refine its DER forecasts as more information becomes available and impacts of these rebates are experienced.[119]

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[118] Docket 15-120, Compliance Filing, June 3, 2024, p. 8; Docket 15-120, Compliance Filing, June 1, 2023, p. 8
[119] *Id.* at 9.

c. Staff Analysis

Staff believes incorporating impacts of the IRA into utility planning and benefits of the IDP will occur over time as only a short time has passed between the passage of the IRA and the Company's IDP filing. The Company provided it will continue to refine its forecasts as more information of IRA benefits and impacts becomes available and, therefore, Staff does not provide a recommendation at this time.

B. Beneficial Electrification

a. Department Initial Comments

The Department notes that while the Company is required to include information about distributed generation and EVs in its IDP, it is not obligated to address beneficial electrification. However, the Department requested in its initial comments that the Company provide a plan for accelerating beneficial electrification and to provide forecasts of its expected grid impacts because electrification of heating and cooling and other beneficial electrification is key to achieving the state's climate policy goals.

The Department notes a discussion about beneficial electrification, specifically various heat pump technologies, was absent in the Company's IDP. The Company does not provide a forecast for the adoption of heat pump in its service territory, but does provide the estimated number of heat pump incentives it expects to deliver in its 2024-2026 ECO triennial plan. The Department estimates an adoption rate of Minnesota Power's planned heat pump incentives corresponds to a heat pump adoption rate of 1.8% for space-heating heat pumps and 0.2% for water-heating space-heating heat pumps between 2023 through 2027.[120]

In the Department's reply comments, it reiterated its requests that the Company provide the same level of information about beneficial electrification as it did for distributed generation and EVs. Such information should include:

- Determine the number of beneficial electronification devices at a system level and, preferably, on a feeder level;
- Historical adoption rates, preferably at each feeder, and forecast beneficial electrification rates for at least a system wide level;
- Identify feeders at risk of not supporting increased adoption of beneficial electrification technologies;
- Discussion of how the IRA is impacting beneficial electrification implementation;
- A beneficial electrification plan should be reported in the IDP;
- Explore the benefits of offering fuel switching incentives in the proposed Beneficial Electrification Plan;

[120] *Id.* at 26 – 31.

- The Company should identify who its income-qualified customers are, and how to ensure equity in the distribution of incentives;

b. Minnesota Power Reply Comments

The Company appreciates the Department's interest in accelerating beneficial electrification and the desire to understand how the Company is planning for the related load growth. It is currently unknown how beneficial electrification will impact the grid because IRA rebate programs have not yet been implemented and the Company does not currently have any efficient fuel switching measures within its filed and approved ECO plan. The Company is unlikely to have significant data on the impacts of electrification prior to its next IDP due November 1, 2025.[121]

Further, the Company provided data on the number of customers who rely on natural gas, electric resistance heat, or other heat sources as their primary heating source.

Figure 25: Minnesota Power Residential Customers Primary Heating Fuel[122]

Fuel Type	Percentage of Customers
Electricity	20.34%
Natural Gas	57.15%
Propane	15.16%
Fuel Oil	7.36%

Figure 26: Minnesota Power Residential Customers Primary Heating Equipment[123]

Heating Equipment	Percentage of Customers
Central Furnace	59.83%
Heat Pump	4.04%
Steam or hot water system in radiators or pipes	25.25%
Built-in electric units installed in walls, ceilings, baseboard or floors	10.89%

c. Staff Analysis

The Department recommends the Company prepare a Beneficial Electrification Plan as a supplemental filing following the Commission's final order. Such a plan would include:

[121] MP Reply Comments at 5.
[122] *Id.* at 10.
[123] *Id.*

- A plan to accelerate beneficial electrification for its customers;
- A discussion on how to incentivize dual fuel adoption; and
- Provide forecasts of expected grid impacts of beneficial electrification.

Staff covered this area in the introductory briefing papers (**Decision Option 3** and **Decision Option 4**). In these Briefing Papers, (**Decision Option 5**) implements the Department's recommendation.

C. Budget Presentation Across Dockets

a. Department Initial Comments

The Department continues to note that the consistent presentation of budget information across utility proceedings could benefit the regulatory process. Further, the Department believes that finding an approach to integrate the IDP and IRP processes, and timing of filings, would benefit parties, the Department's review, and regulatory efficiency.[124]

b. Minnesota Power Reply Comments

The Company is supportive of a processual improvement between major filings to improve coordination between IDP, IRP, Transmission Planning, and Rate Cases. The Company looks forward to continued discussion on this topic.[125]

c. Staff Analysis

The Department recommends that the Commission clarify the role of the IDP. The Department and Company are in agreement to clarify and better align IDP filings, but neither party offered suggestions on how to accomplish this recommendation. Staff covers this area in the Joint Briefing Papers.

8. Decision Options

<u>IDP Acceptance</u>

The Commission must select DO 1 or DO 2

1. Accept Minnesota Power's 2023 IDP Report as in compliance with IDP reporting requirements. Acceptance of the 2023 IDP has no bearing on prudency nor certification under Minn. Stat. § 216B.2425, subd. 3. (Minnesota Power)

OR

2. Accept Minnesota Power's 2023 IDP report as in compliance with IDP reporting requirements contingent on the Company making additional filings as noted below. Acceptance of the 2023 IDP has no bearing on prudency nor certification under Minn. Stat. § 216B.2425, subd. 3. (Department)

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[124] *Id.* at 34.
[125] MP Reply Comments at 10.

a. Require Minnesota Power to file separate cost-benefit analyses for FLISR, the Smart Sensor Program, OMS, and GIS, through supplemental filings within 180 days of the Order. (Department)

Staff notes the Department determined Minnesota Power's NWA was not compliant with the filing objects, Staff listed all NWA related DOs together for clarity.

Modification for Future IDPs

The Commission may select DO 3 ***AND/OR*** *4,* ***OR*** *DO 5, or none of the options. These decision options are explained the Joint Briefing Papers.*

3. Require Minnesota Power in its next IDP to develop a suite of metrics to track resiliency, including SAIDI with MEDs and SAIFI with MEDs, and other metrics to the extent warranted. (Department)

AND/OR

4. Require Minnesota Power to provide a proposal for measuring the capacity, reliability, ratepayer, and equity impacts of its distribution grid investments in its next IDP. This proposal shall specifically address the level of granularity at which Minnesota Power will evaluate these impacts for each budget category, including for each category whether Minnesota Power plans to measure these impacts at the level of the budget category, program, project, or at some other level of resolution, or not at all, and specifically accounting for the impact of any expected changes to IDP budget categories. (Department)

OR

5. Delegate authority to the Executive Secretary to work with Minnesota Power and stakeholders to discuss metrics reported across distribution dockets, and delegate authority to the Executive Secretary to approve via notice a stakeholder agreement on metrics reporting if one is reached. At minimum, the proposal and metrics should include the following components:
   a. Reliability metrics such as SAIDI, SAIFI, CAIDI, CEMI, and CELI
   b. Distribution spending by IDP budget categories
   c. Whether there is available hosting capacity for generation or load at the primary system level
   d. Demographic data including race and income
   e. Installed DERs, ECO rebates, DR customers enrolled in programs, etc.
   f. Metrics reported at a feeder and/or census block group level

   (Staff)

The Commission may select either DO 6 ***OR*** *DO 7, or neither. These decision options are explained the Joint Briefing Papers.*

6. Require Minnesota Power to make a supplemental filing within [180 days] of the Order in this docket that proposes a plan to accelerate beneficial electrification for its customers, including a discussion of how to incentivize dual fuel adoption for space heating and electrification of water heating, and provide forecasts of expected grid impacts of the same. (Department)

OR

7. Delegate Authority to the Executive Secretary to work with Minnesota Power, the Department, and stakeholders to modify the IDP filing requirements to include discussions of the impacts of electrification where appropriate. Delegate authority to the Executive Secretary to approve via notice a stakeholder agreement on amended filing requirements if one is reached. (Staff)

<u>Non-Wires Alternatives</u>

The Commission must select either DO 8 ***OR*** *DO 9*

8. Accept Minnesota Power's current NWA analysis and find it is compliant with the Filing Requirement 3.E.2.d and 3.E.2.b. (Minnesota Power, Staff)

9. Find that Minnesota Power's current NWA analysis is not compliant with the Filing Requirement 3.E.2.d and 3.E.2.b. (Department)

OR

10. Require Minnesota Power in its next IDP to file a comprehensive NWA evaluation process. (Department)

The Commission may select DO 11 or 12, or neither option

11. Require Minnesota Power in its next IDP to consider demand response, energy efficiency, and renewable generation as part of its future NWA process. (Department)

12. Require Minnesota Power to provide cost-benefit analysis for the Cloquet Area project through a supplemental filing within 180 days of the Commission's Order. (Department)

<u>Transportation Electrification Plan</u>

The Commission should select DO 13 ***and*** *14.*

13. Approve Minnesota Power's 2023 Transportation Electrification Plan. (Minnesota Power, Department, Clean Energy Groups)

14. Require Minnesota Power to file its next TEP by November 1, 2025. (Staff)

The Commission may select any combination of DO 15-20, or none of the options

15. Require Minnesota Power to file a residential EV managed charging program that does not require second service or participation in a whole-home time of use rate on or before the date of their next Transportation Electrification Plan. (CEGs)

16. Require Minnesota Power to include a discussion of how the Company is preparing and supporting adoption of medium- and heavy-duty electric vehicles, specifically transit buses, school buses, and trucks in their future TEPs. (CEGs)

17. Require Minnesota Power to include a discussion of equity and an analysis of how the Company's EV programs are serving communities disproportionately impacted by transportation pollution including renters, multifamily housing residents, communities of color, "low-to-moderate income" customers, and rural communities in future TEPs. MP will also include a discussion on what gaps may remain. (CEGs)

18. Require Minnesota Power to include a discussion of their coordination between EVs, energy efficiency, and building electrification planning, including their Energy Conservation and Optimization programs in future TEPs. (CEGs)

19. Require Minnesota Power to include a discussion on electric school buses, including a count of any known electrified buses, with its next TEP. (Staff)