April 19, 2024

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

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Dakota Electric Association's 2023 Integrated Distribution Plan
Docket No. E111/M-23-420

Dear Mr. Seuffert:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

In the Matter of Distribution System Planning for Dakota Electric Association

Dakota Electric Association's Integrated Distribution Plan (IDP) was filed on November 1, 2023 by Adam Heinen, Vice President of Regulatory Services, and Craig Turner, Sr. Principal & Regulatory Engineer.

The Department makes recommendations and requests below and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Dr. Sydnie Lieb
Assistant Commissioner of Regulatory Affairs

SL/ar
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E111/M-23-420

I. INTRODUCTION

The Department provides the following comments on Dakota Electric Association's (DEA) Integrated Distribution Plan (IDP). Through these comments, the Department responds to the Notice of Comment (Notice) issued by the Commission on November 15, 2023.[1]

The IDP allows for greater transparency into the distribution system planning process used by utilities. Distribution plans cover utility infrastructure from the substation to the meter, as well as customer offerings in these areas. The need for integrated distribution system planning is a consequence of the increasing complexity of the distribution grid created by smart grid technologies, electric vehicles, and other distributed energy resources (DER). Due to the rise in these technologies, ratepayers will have an increasingly interactive role in distribution grid management, which further establishes the need for greater transparency in the distribution grid planning process. The Commission set forth five planning objectives for IDPs, with additional filing requirements to promote transparency in distribution system planning. The Commission's planning objectives for IDPs are to:

1. 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;
2. Enable greater customer engagement, empowerment, and options for energy services;
3. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
5. 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 a comprehensive analysis of ratepayer cost and value.

While the Department finds that DEA's IDP is largely compliant with filing requirements, the Department also identifies areas in which the IDP could be improved and offers recommendations (in bold, italicized text) for remedying them. The Department will provide a final recommendation regarding whether the Commission should accept DEA's IDP in reply comments once the Department reviews additional information from DEA and has the opportunity to consider stakeholder input.

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[1] *Notice of Comment Period – In the Matter of Distribution System Planning for Dakota Electric Association, Docket No. E111/M-23-420* (November 15, 2023). (eDocket No. 202311-200528-01). *Hereinafter* "Notice."

II. PROCEDURAL HISTORY

On September 9, 2022, the Minnesota Public Utilities Commission (Commission) issued its Order in Docket No. E111/M-21-728 (September 9, 2022 Order).[2] The September 9, 2022 Order accepted DEA's 2021 IDP[3] and required DEA to file its 2023 IDP no later than November 1, 2023.

On November 1, 2023, Dakota Electric Association (DEA or the Company) filed its IDP in Docket No. E111/M-23-420.[4]

On November 15, 2023, the Commission issued its Notice on the issue of whether the Commission should accept or reject Dakota Electric's 2023 IDP.[5] The Notice included the following topics open for comment:

1. Should the Commission accept or reject Dakota Electric Association's IDP?
2. Did Dakota Electric adequately address the Commission's IDP filing requirements and prior Orders, as outlined in Attachment A to this notice? Is additional information necessary for improved clarity?
3. Feedback, comments, and recommendations on the following areas of Dakota Electric's IDP:
    a. Non-wires alternatives analysis and potential pilot project
    b. Planned grid modernization initiatives
    c. Forecasted distribution budget
    d. Distributed Energy Resource (DER) scenarios and forecasts, including electric vehicle forecasts
4. Has Dakota Electric appropriately discussed its plans to maximize the benefits of the Inflation Reduction Act (IRA) and the IRA's impact on the utility's planning assumptions pursuant to Order Point 1 of the Commission's September 12, 2023 Order in Docket No. E,G-999/CI-22-624?
5. What should the Commission consider or address related to enhancing the resilience of the distribution system within Dakota Electric's IDP?
6. Other areas of Dakota Electric's IDP not listed above, along with any other issues or concerns related to this matter.

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[2] *Order, In the Matter of Distribution System Planning for Dakota Electric Association, Docket No. E111/M-21-728* (September 9, 2022). (eDocket No. 20229-188947-01). *Hereinafter* "September 9, 2022 Order."
[3] *2021 Integrated Distribution System Report, In the Matter of Distribution System Planning for Dakota Electric Association, Docket No. E111/M-21-728* (November 1, 2021) (eDocket No. 202111-179361-01*). Hereinafter* "2021 IDP."
[4] *2023 Integrated Distribution System Report, In the Matter of Distribution System Planning for Dakota Electric Association, Docket No. E111/M-23-420* (November 1, 2023) (eDocket No. 202311-200124-01*). Hereinafter* "IDP."
[5] The comment period was extended on January 19, 2024 and amended on January 22, 2024. *Amended Notice of Extended Comment Period – In the Matter of Distribution System Planning for Dakota Electric Association, Docket No. E111/M-23-420* (January 22, 2024). (eDocket No. 20241-202420-01).

III. DEPARTMENT ANALYSIS

The initial comments provided by the Department address DEA's IDP and the Commission's Notice Topics 1 through 6. Recommendations are offered in the corresponding sections and are summarized at the conclusion of this filing.

The comment sections and corresponding notice topics are presented below:

A. *IDP Compliance with Filing Requirements and Recommendations Concerning Acceptance (Notice Topics 1 and 2)*
B. *Non-Wires Alternatives Analysis (Notice Topic 3.A)*
C. *Planned Grid Modernization Initiatives (Notice Topic 3.B)*
D. *Forecasted Distribution Budget (Notice Topic 3.C)*
E. *Distributed Energy Resource (DER) Scenarios and Forecasts (Notice Topic 3.D)*
F. *The Inflation Reduction Act and Utility Planning and Benefits (Notice Topic 4)*
G. *Distribution System Resilience (Notice Topic 5)*
H. *Other Areas of DEA's IDP (Notice Topic 6)*

A. *IDP COMPLIANCE WITH FILING REQUIREMENTS AND RECOMMENDATIONS CONCERNING ACCEPTANCE*

Notice Topic 1: Should the Commission Accept or Reject Dakota Electric Association's IDP?

Notice Topic 2: Did Dakota Electric Adequately Address the Commission's IDP Filing Requirements and Prior Orders, as Outlined in Attachment A to This Notice? Is Additional Information Necessary for Improved Clarity?

DEA provided as an attachment to its IDP a table of the Planning Objectives and previous Commission Orders and the location within the IDP where information related to those can be found.[6]

The Department's review of DEA's IDP begins at a threshold question: did DEA provide information and analyses required by the Commission's IDP filing requirements and previous Commission Orders? The Department reviewed DEA's table and determined that the references provided to the contents within the IDP are appropriate. Further, at first pass, it appears that DEA has mostly addressed each of the IDP filing requirements, Commission Orders, and statutes. The Department provides its assessment of DEA's compliance with filing requirements with these comments as Attachment A.

Moreover, as required by the Notice, where DEA did not include the required information, the Company generally provided an explanation of why that information was not included in the filing. However, in several instances, the information provided by DEA did not fully address the filing requirement or prior Commission Order. Specific examples are indicated throughout the Department's comments.

[6] IDP Appendix E.

On March 25th, the Department submitted a series of Information Requests (IRs). DEA responses to Department IRs are included with these comments as Attachment B.

Throughout these comments the Department has also identified topics and Order Points where additional information would improve the ability to meaningfully analyze the IDP.

The Department will provide a final recommendation regarding whether the Commission should accept DEA's 2023 IDP in reply comments once the Department reviews additional information from DEA and has had the opportunity to review stakeholder input.

B. NON-WIRES ALTERNATIVES ANALYSIS

Notice Topic 3.A: Feedback, Comments, and Recommendations on Non-Wires Alternative Analysis.

DEA conducted a Non-Wires Alternatives (NWA) analysis of four different scenarios for one project. The Department analyzes DEA's NWA starting with a discussion of IDP filing requirements and order points, then discusses the NWA screening process and Cost Benefit Analysis (CBA) assumptions. The Department next discusses the NWA project that was analyzed by DEA. The discussion concludes with order point compliance to examine a solar battery storage project to avoid selling solar energy to the transmission grid.

1. Overview of Filing Requirements and Order Points

There are two primary IDP requirements pertaining to NWAs. First, IDP Filing Requirement 3.E.1 requires DEA to "provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value."[7]

Second, IDP Filing Requirement 3.E.2 sets forth the requirements for the information DEA must provide related to NWA analysis, which includes:

a. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
b. A timeline that 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)
c. Cost threshold of any project type that would need to be met to have a nontraditional solution reviewed
d. A discussion of a proposed screening process to be used internally to determine that nontraditional alternatives are considered prior to distribution system investments are made.[8]

[7] IDP Filing Requirement 3.E.1.
[8] IDP Filing Requirement 3.E.2.

In addition to the IDP filing requirements, Order Point 3 from the September 9, 2022 Order in DEA's 2021 IDP pertains to NWA analysis as follows:

- Order Point 3 requires DEA to "file, in its next IDP filing, a thorough discussion of the installation of a utility-operated energy storage system (which would be charged with energy that would otherwise cause back-feeding during the day and that would then discharge that energy in the evening) in light of recent state and federal infrastructure programs. The discussion must include how to calculate cost to benefits impacts and how such storage solutions affect its wholesale power supply contracts and obligations."[9]

2. Areas of Non-Compliance With IDP Filing Requirements and Order Points

The Department finds that DEA has not fully complied with IDP Filing Requirement 3.E.1. While DEA provided a thorough NWA discussion of the Elko-New Market Area in Section 4.d of the Company's IDP, with a budget of $4.5 million, there are three additional projects that were not discussed in Section 4.a, which was written in response to IDP Filing Requirement 3.E.1. The first project is the "Cedar Substation and Feeders" project, with a budget of $4.63 million. The project is needed to "…to provide increased capacity for the fast growing eastern Lakeville and northern Farmington areas."[10] This project status is listed under "In Progress Capital Construction Projects > $250,000," which likely precludes an NWA study, however the project was still not discussed, as required by Filing Requirement 3.E.1. There are two additional projects listed in Appendix D of the IDP that were not discussed in the NWA section. These projects include the "Increase Capacity at Lakeville Substation," coupled with the "Lakeville Feeders," project, which has a combined budget of $4.15 million. DEA states that "The driver for this expansion is new residential and commercial development in eastern Apple Valley and northeastern Lakeville."[11] DEA did provide an NWA analysis of this project in its 2021 IDP. Finally, DEA lists the "Fisher Substation Rebuild" project with a budget of $4.4 million. DEA states that "The Fisher Substation in Apple Valley was built around 1980 and the transformer and switchgear are now over 40 years old. Dakota Electric has initiated a substation rejuvenation project and the replacement of the two transformers and switchgear will be one of the first substations being targeted."[12]

The Department requests that DEA discuss in reply comments whether the Cedar Substation and Feeders Project, Lakeville Substation and Feeders Project, and the Fisher Substation Rebuild Project are suitable for current or future NWA analysis.

DEA is compliant with IDP Filing Requirement 3.E.2 and the September 9, 2022 Order. Project types that lend themselves to non-traditional solutions (IDP Filing Requirement 3.E.2.i) is discussed in IDP Section 4.e, where the Company discusses how demand-side management or load management

[9] September 9, 2022 Order Point 3.
[10] IDP Appendix C at 145.
[11] IDP Appendix D at 148.
[12] *Ibid.*

projects have the greatest potential for NWA solutions, but does not rule out other solutions. The timeline of NWA solutions (IDP Filing Requirement 3.E.2.ii) is discussed in IDP Section 4.f. The company does not discuss specific timelines for soliciting proposals, but provides a general discussion of the short turnaround time required to respond to new load growth, which is prohibitive to deploying NWA solutions, however this problem appears to also be applicable to traditional wired alternatives as well. The ability for DEA to respond in a timely manner is mitigated by pre-ordering existing equipment, whereas the uncertain economics and site-specific nature of NWA solutions do not lend themselves to pre-stock NWA equipment. The cost threshold for NWA projects (IDP Filing Requirement E.3.2.iii) is discussed in Section 4.g of DEA's IDP. The company does not set a specific cost threshold, but rather discusses the challenging economics of finding vendors who are willing to bid on smaller jobs with larger overhead. Finally, the Company discusses its screening process (IDP Filing Requirement E.3.2.iv) in IDP Section 4.h. The Company describes how projects with slower, more incremental load growth are more suitable for NWA studies. Further requirements are discussed in Section 4.b, where the Company discusses the performance requirements of NWA solutions, which include 1) Firm energy output when requested, 2) Provide the firm energy for the duration of the need, 3) Emergency repair/replacement of failed DER system components, and 4) Enter into a contractual relationship to provide the service of the DER.

3. Project Types Considered for NWAs

DEA does not specifically exclude any project types for NWAs. The company studies four different options to avoid the rebuild of a substation project in the Elko-New Market Area study, which includes solar, energy storage, and demand response, with behind-the-meter storage. Future NWA studies could also include power quality and reliability benefits, which were, for example, studied by Minnesota Power in its IDP.[13]

4. Benefit Categories

DEA does not provide a discussion of the benefit categories it has studied, or how benefits are calculated. The only reference to benefits is shown in a single line at the bottom of each table where discounted costs are calculated.

The Department requests that DEA discuss in reply comments which benefits are studied as part of its NWA process and which main assumptions are used to calculate benefits.

Benefit categories were not calculated based on the different Minnesota Test Cases that are typically used by utilities for CBA. The test cases include the Utility Test, Ratepayer Impact Test, Societal Test, and Minnesota Test, and are meant to illustrate project benefits from different perspectives and value systems. The present analysis appears to focus on the Utility Test only.

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[13] *2023 Integrated Distribution System Plan, Minnesota Power, In the Matter of Minnesota Power's 2023 Integrated Distribution Plan, Docket No. E015/M-23-258* (October 16, 2023) (eDocket No. 202310-199614-01).

The Department requests that DEA include calculated benefits for all Minnesota Test Cases, and to the extent practicable, present the results in reply comments.

5. *Key Assumptions*

The Department finds that most assumptions are reasonable. However, the Department notes that the cost of solar is overly optimistic. For example, the National Renewable Energy Laboratory (NREL) Q1 2023 Cost Benchmark Report lists a cost of \$1,761 / kW_{dc} for a 3 MW_{dc} solar system,[14] which converts to \$2,254 / kW_{ac} using the inverter load ratio of 1.28 assumed by NREL in its 2022 Baseline. In the same report, NREL lists a cost of \$1,161 / kW_{dc} for a 100 MW_{dc} solar system, which reflects a cost that is 52 percent higher than the cost assumed for the 100 MW_{ac} solar system cost assumed by DEA. DEA's 2025 "Moderate Technology" cost of \$981.7 / kW_{ac} is not appropriate because the solar system size modeled is too large compared to the 2 and 3 MW_{ac} systems proposed in the NWA study, regardless of the vintage year of data used for cost estimation. Instead, DEA could average the "Utility-Scale PV" and "Commercial PV" forecasted costs to obtain a more realistic cost estimate for future NWA analyses.

6. *NWA Studies Conducted*

DEA conducted an NWA analysis only for the Elko-New Market Area. The area is crosscut by Interstate 35, and currently has a 5 MW commercial load ready to be energized in 2025. DEA assumes a forecast of load growth from 5 MW in year one to 25 MW in year 40 in a "Slow Growth" scenario and growth from 7 MW in year one to 40 MW in year 40 in a "Faster Growth" scenario. Load growth scenarios are based on DEA's "best engineering judgment,"[15] but do not list specific assumptions that drive load growth.

The Elko-New Market Area is not the ideal project for NWA analysis. There are two existing substations in Castle Rock and Lake Marion that were studied to provide supplemental power to the growing area, which could potentially offset load growth, in lieu of building a new substation. DEA examined expanding the Lake Marion Substation capacity to supply the area, but determined that there would be no backup power source in the event of a substation failure, because the Castle Rock Substation would be unable to supply the Elko New Market Area. The lack of backup power options created the need for a redundant backup power solution studied in this section. However, based on DEA's load growth assumptions, the Company would prepare to build a new substation regardless of any NWA solution proposed in order to at least reserve the land before development prevents the siting of a new substation at a later point. Therefore, the large growth forecast and the inevitability of the substation construction both work against the potential viability of an NWA solution in this area, which supports DEA's assertion that areas of slower load growth are more suitable for NWA studies.

The context of the NWA analysis largely explains why none of the proposed NWA studies resulted in positive cash flows. DEA examines four different scenarios. These scenarios include 1A) The Traditional

[14] See https://www.nrel.gov/docs/fy23osti/87303.pdf
[15] DEA Response to Department IR 12. See Attachment B.

Solution, 1B) an Energy Storage Only Solution, 1C) an Energy Storage Plus Solar Solution, and 1D) a Demand Side Management Solution. The traditional solution of building a new substation is by far the cheapest solution, with a Net Present Value (NPV) of $6,997,317. The next lowest cost option is Scenario 1D, with a NPV of $14,813,626, which is over double the cost of the traditional solution. Below, Department Table 1 provides a summary of scenario costs. The unfavorable economics for each NWA solution studied results from both the need to build additional NWA solutions to keep up with the load growth forecast, as well as construction of a new substation, at a cost of $6,997,317. The deferral periods for each NWA solution are generally short, around 3 to 5 years, which further reduces the potential benefit of an NWA solution. Batteries in Scenarios 1B and 1D would also have to charge at night and discharge during the day. Under a different forecast, where the forecasted load was not expected to grow five-fold or more, an NWA solution with a longer deferral period could have more favorable economics.

Department Table 1: Summary of NWA Scenarios Studied for the Elko-New Market Area

Scenario	Net Present Value	Load Growth Assumption
1A: Traditional Solution	$6,997,317	Fast
1B: Battery Storage Only	$15,439,319	Slow
1B: Battery Storage Only	$23,662,986	Fast
1C: Solar Plus Storage	$25,250,115	Slow
1C: Solar Plus Storage	$40,524,315	Fast
1D: Demand Side Management	$14,813,626	Slow

7. Substation Energy Storage Project to Enhance DER Adoption

Order Point 3 of the September 9, 2022 Order is addressed in Section III.g of DEA's IDP. The Commission seeks to understand how an energy storage system could be implemented to absorb excess solar generation during the day, discharge at night, and prevent the distribution system from exporting power to the transmissions system. DEA states on page 55 of its IDP that land use requirements for energy storage solutions could be high, with a 3 MW 6-8 hour flow battery requiring up to an acre of land. The land requirements for an energy storage solution would likely prevent the Company from siting an energy storage project at the substation, with an additional risk of fire from the battery also making substation co-location not ideal.

DEA discusses several potential benefits of an energy storage solution. DEA expects that outage protection would not be possible due to the relatively small size of a battery. Further, even if the battery were to be used as a backup solution, the Company explains that differences in battery dispatch frequency could create unsafe conditions on interconnected distribution system wires. DEA generally concludes that participating in the Midcontinent Independent System Operator (MISO) market would also not be possible because the battery would not be guaranteed to be available when it would be required for dispatch, and thus a majority of benefits discussed would not be applicable. The Company estimates a cost to install a 3 MW / 18 MWh energy storage system at $8,006,754, and concludes that the energy storage project would not be economical.

C. PLANNED GRID MODERNIZATION INITIATIVES

Notice Topic 3.B: Feedback, Comments, and Recommendations on Planned Grid Modernization Initiatives.

1. Grid Modernization Scope and Analysis

Grid modernization can cover a whole suite of grid enhancements and is not clearly defined to explicitly include or exclude every grid enhancing technology proposed by a utility. Minnesota Statute §216B.2425, Subd.2(e) provides an overview of the goals of grid modernization, where a utility operating under a multi-year rate plan shall:

> [I]dentify investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.[16]

The Department proceeds with its analysis of grid modernization proposals based on Section 3.D of the IDP Filing Requirements, which describes the information to be included in the mandated Five-Year Action Plan. The following filing requirements for DEA's Five-Year Action Plan are emphasized for the Department's analysis:

- 3.D.1.a: Overview of investment plan: scope, timing, and cost recovery mechanism;
- 3.D.1.c: Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment;
- 3.D.1.g: Customer anticipated benefit and cost;
- 3.D.1.i: Plans to manage rate or bill impacts, if any;
- 3.D.1.j: Impacts to net present value of system costs (in net present value revenue requirements/megawatt/hour or megawatt); and
- 3.D.1.k for each grid modernization project in its 5-year Action Plan, Dakota Electric should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Dakota Electric shall provide all information to support its analysis.

[16] The Department notes that the statutory reference does not apply to DEA but provides a useful definition of grid modernization investments, generally.

To the extent practicable, the Department expects a discussion of the overall investment plan (Filing Requirement 3.D.1.a), a discussion of customer anticipated benefit and cost (Filing Requirement 3.D.1.g), a discussion of alternative investments that were analyzed (Filing Requirement 3.D.1.c), a discussion of a plan to mitigate bill impacts (Filing Requirement 3.D.1.i), a presentation of the net present value of system costs (Filing Requirement 3.D.1.j), and a cost-benefit analysis of each grid modernization project (Filing Requirement 3.D.1.k).

2. *Overview of DEA Grid Modernization Projects*

The DEA Grid Modernization budget spans two budget categories, including “Metering,” and “Grid Modernization and Pilot Projects.” The respective five-year budgets for each category are $3,857,914 (4.1 percent of total) for “Grid Modernization,” and $368,186 (0.4 percent of total) for “Metering.” The entire “Metering” budget category is dedicated to the installation of Advanced Metering Infrastructure (AMI) and Advanced Grid Infrastructure (AGi). Within the “Grid Modernization” category, $3,271,000 is allocated to “Advanced Tech,” $582,170 is allocated to “600 Series Misc Dist,” $75,000 is allocated to “Substations” and $70,256 is recovered through “Salvage.”[17]

3. *Advanced Metering Infrastructure and Advanced Grid Infrastructure*

The AMI Program is combined with the AGi program to deliver the smart meters and a communication network. The system consists of three main components, which all support each other to enable the full functionality of the system. The first component is the smart meter. DEA states that it has installed 125,000 smart meters and will have completed deployment of the last 1,000 meters in 2024. The second component is the AGi, which uses wireless radio frequencies to transmit data back to DEA. The third component is a Meter Data Management System (MDM), which DEA lists under the AGi Project. The MDM System is a DEA data repository and control system, which allows DEA to process and use the data it collects. The deployment of these three components allowed DEA to implement its full AMI rollout.

DEA states several benefits from the AMI program. DEA reported that it has significantly improved meter reading performance, with significantly reduced estimated bills. The program also allows DEA to remotely disconnect and reconnect meters, which saves truck rolls and reduces fees for members. The program also allowed for the creation of a Virtual Metered Electric Vehicle (EV) tariff,[18] which can detect if an EV is charging without the need for a separate meter. The AMI Program also provides a suite of data about real time conditions on the distribution grid, which allows DEA to more quickly identify outages and power quality issues. An example of the MDM System is shown in Department Figure 1, where DEA is able to track electric vehicle charging in real time.

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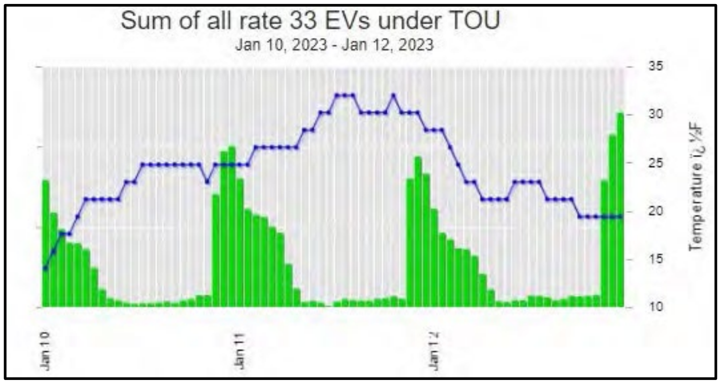
[17] DEA Response to Department IR 2.
[18] Docket No. E111/M-22-592

Department Figure 1: DEA MDM Summary of Electric Vehicle Charging on the Time of Use Rate



Source: DEA IDP Graph 9

Finally, as the AMI and AGi programs have already been approved by the Commission[19] and deployment has nearly reached completion. However, IDP Filing Requirement 3.D.1.k still requires the Company to report on costs and benefits of the program.

The Department requests that DEA discuss in reply comments the costs and benefits of its AMI and AGi Programs.

4. Load Control Receivers

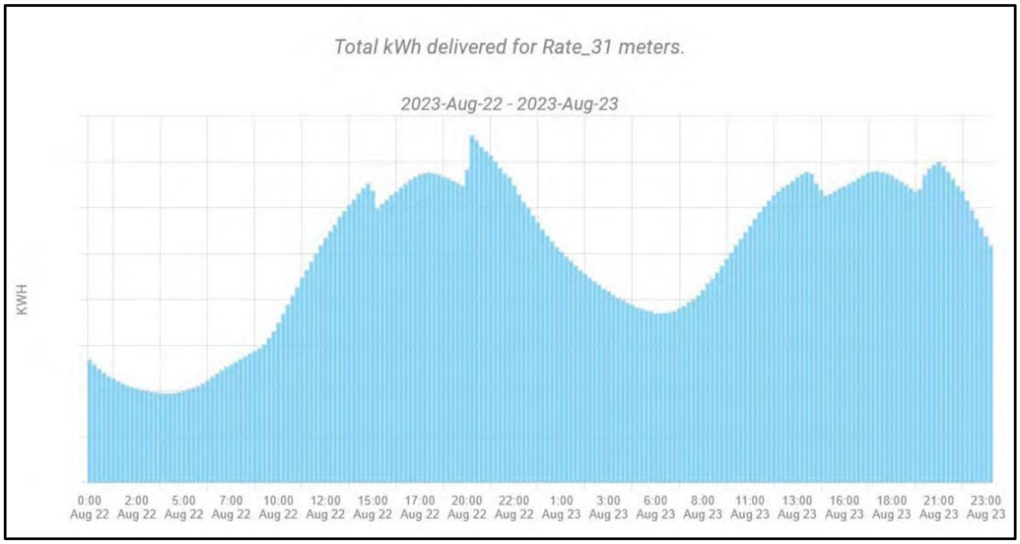
Load Control Receivers are also part of the AGi Program, but are included separately as the "Advanced Tech" budget line item in the "Grid Modernization and Pilot Projects" budget category. With a cost of $3,271,000, Load Control Receivers compose 83 percent of the "Grid Modernization and Pilot Projects" budget category. Load Control Receivers are used by the Company to reduce demand during peak periods, which lowers costs for members. Typically load control receivers are installed in a sub-panel connected to the main electric service at a building, and are able to temporarily turn off connected devices such as a central air unit, heat pump, water heater, or other large power using devices. Load Control Receivers primarily differ from more expensive separate metered services due to their inability to meter power, and instead only act as switches. As part of the AGi Program, 50,000 Load Control Receivers are to be installed alongside the 125,000 AMI meters. The deployment of the 50,000 Load Control Receivers does not represent a new capability for the Company but was rather initiated to replace the existing stock with better communications through the AMI program.

The main benefit of Load Control Receivers is to reduce peak system demand, which lowers ratepayer electric costs. An example of the effect of Load Control Receivers is shown in Figure 2. The figure displays two periods of peak system demand, where the unmitigated peak is avoided by temporarily turning off devices during peak hour periods. The result is two troughs on the graph where a higher peak would have occurred without use of load management. Further, DEA demonstrated its ability to

[19] Docket No. E111/M-17-821

stagger the onset of its demand response program, where the sharp peaks in the first load shedding event in Figure 2 are contrasted by the more gradual onset and restoration of load in the second peak.

Department Figure 2: Example of How Load Control Receivers are Used to Reduce Peak Demand



Source: DEA IDP Graph 3 at 6.

The remainder of the Load Control Receivers budget in the 2023 to 2027 DEA budget is due to a delay in the replacement of Load Control Receivers. The budget is forecasted to heavily decline after 2024. Finally, as the AGi program has already been approved by the Commission[20] and deployment has nearly reached completion, further discussion about the costs and benefits of the program are not warranted. However, IDP Filing Requirement 3.D.1.k still requires the Company to report on costs and benefits of the program.

The Department requests that DEA discuss in reply comments the costs and benefits of its Load Control Receiver Program.

5. Miscellaneous Grid Modernization Budget

DEA lists a cost of $582,170 for miscellaneous grid modernization projects, but does not explain the purpose of the funding.

The Department requests that DEA present in reply comments the purpose of its Miscellaneous Grid Modernization budget allocation and provide additional information, as available, which includes a discussion of the investment plan, a discussion of the cost recovery mechanism, an analysis of alternative investments, a discussion of customer anticipated benefits, a discussion to manage bill impacts, a presentation of the impact to the net present value of system costs, and a cost-benefit analysis, if available. If DEA is not able to provide the requested information, it should indicate when it expects to be able to provide the information.

[20] Docket No. E111/M-17-821

6. Grant Applications

On page 64 of its IDP, DEA discusses that it "…has also applied for, or is actively considering, grant and funding opportunities through the IIJA [Infrastructure Investments and Jobs Act] and IRA which may also involve projects in excess of $2 million." The Department requested clarification on the projects requested for funding in IR 11. The Company stated that it has submitted three grant applications in excess of $2 million, as part of a larger consortia with other electric cooperatives. One project is to install 20 MW of solar PV, which the Department does not consider to meet to the statutory definition of Grid Modernization. The second project is for grid resilience, which would upgrade single phase power lines and would employ a new software tool as part of the project. The estimated budget is $12 million between 2025 and 2029, with a 25 percent grant match, valued at three million dollars. The Department does consider this project to be Grid Modernization due to its utilization of new software solutions to manage the distribution grid. The project may also include Grid Modernization components as part of its single phase power line upgrades. The third project would fund a Distributed Energy Resource Management System (DERMS), which the Department also considers Grid Modernization. This third project would allow DEA control thermostats, EV chargers, solar PV arrays, and other loads. The budget for this project is up to two million dollars between 2025 and 2029, with a 50 percent match, valued at one million dollars.

Grant applications, while uncertain, do still represent tangible spending when a grant award is made and accepted. DEA has described a grant match obligation of $4 million, some of which the Department considers Grid Modernization, that is larger than the 2023 to 2027 "Grid Modernization and Pilot Projects" budget. The match obligations would need to be recovered from ratepayers, and thus these applications should also be discussed in more detail as part of DEA's IDP. Presumably, the Company may still be interested in implementing its grid resilience and DERMS projects even if grants are not awarded, and thus a discussion of these projects would allow stakeholders to determine their value.

The Department requests that DEA present in reply comments a discussion of its grid modernization projects submitted in grant applications, which includes a discussion of the investment plan, a discussion of the cost recovery mechanism, an analysis of alternative investments, a discussion of customer anticipated benefits, a discussion to manage bill impacts, a presentation of the impact to the net present value of system costs, and a cost-benefit analysis, if available.

D. FORECASTED DISTRIBUTION BUDGET

Notice Topic 3.C: Feedback, Comments, and Recommendations on the Forecasted Distribution Budget.

DEA's 2021 IDP projected total distribution spending of approximately $90.135 million between 2021 and 2025.[21] DEA's 2023 IDP increased that projection to $93.026 million between 2023 and 2027.[22] The table below provides a high-level overview of the projected spending levels DEA provides in its

[21] 2021 IDP Table 19 at 58.
[22] IDP Table 40 at 127.

2021 and 2023 IDPs, organized by the IDP Budget Categories required by IDP Filing Requirement 3.A.28. IDP Filing Requirement 3.A.28 requires DEA to provide information on "[p]rojected distribution system spending for 5-years into the future"[23] and references the IDP Budget Categories from IDP Filing Requirement 3.A.26, which are listed in the table below.[24]

Department Table 2. Comparison of DEA's Distribution System Spending Projections: 2021 and 2023 IDP

	Spending (Millions)		
IDP Budget Category	***2021 IDP (2021 - 2025)***	***2023 IDP (2023 - 2027)***	**Change**
Age-Related Replacements and Asset Renewal	$13.435	$25.518	**$12.083**
System Expansion or Upgrades for Capacity	$16.077	$19.450	**$3.373**
System Expansion or Upgrades for Reliability and Power Quality	$6.410	$8.476	**$2.066**
New Customer Projects and New Revenue	$21.847	$27.163	**$5.316**
Grid Modernization and Pilot Programs	$10.886	$3.857	**-$7.03**
Projects related to Local (or other) Government Requirements	$9.030	$8.193	**-$0.84**
Metering	$12.450	$0.369	**-$12.08**
Total Spending	**$90.135**	**$93.026**	**$2.891**

For each IDP Budget Category and overall, this table calculates the difference in projected spending between the 2021 IDP and the 2023 IDP.

These filings were made two years apart from one another (on November 1, 2021 and November 1, 2023), and overall distribution system spending projections increased from approximately $90.135 million to $93.026 million over that time period, a 3.2% increase. The budget categories of "Age-

[23] IDP Filing Requirement 3.A.28.
[24] The Department notes that DEA did not include any spending in IDP Budget Category "Other" in either its 2021 IDP or the 2023 IDP and so that Budget Category is not included in the Department's tables.

Related Replacements and Asset Renewal," "System Expansion or Upgrades for Capacity," "System Expansion or Upgrades for Reliability and Power Quality," and "New Customer Projects and New Revenue" are the main drivers of the increase, accounting for increases of $12.1 million, $3.4 million, $2.1 million and $5.316 million, respectively. These spending increases have largely been offset by decreases in spending in the other budget categories.

While the table above shows increases in total projected spending, it is important to note that this is not an apples-to-apples comparison given the periods analyzed in each filing (e.g., the 2021 IDP period covers years 2021 through 2025, whereas the 2023 IDP period covers years 2023 through 2027). To obtain a better apples-to-apples comparison between each filing, the Department reviewed the annual spending projections provided in each filing and was able to compare projected spending between the 2023 through 2025 period. The table below provides such a comparison.

Department Table 3. Comparison of DEA's Distribution System Spending Projections for the 2023 – 2025 Period: 2021 and 2023 IDP

	Spending (Millions)		
IDP Budget Category	***2021 IDP (2023 - 2025)***	***2023 IDP (2023 - 2025)***	**Change**
Age-Related Replacements and Asset Renewal	$8.296	$13.694	**$5.398**
System Expansion or Upgrades for Capacity	$9.684	$13.133	**$3.449**
System Expansion or Upgrades for Reliability and Power Quality	$4.001	$5.288	**$1.287**
New Customer Projects and New Revenue	$12.769	$16.002	**$3.233**
Grid Modernization and Pilot Programs	$3.745	$3.343	**-$0.402**
Projects related to Local (or other) Government Requirements	$5.403	$5.349	**-$0.054**
Metering	$0.030	$0.349	**$0.319**
Total Spending	**$43.928**	**$57.158**	**$13.230**

This table calculates the difference in spending reported in the 2023 IDP for each IDP Budget Category and overall, as compared to the 2021 IDP for 2023 through 2025. DEA's total planned distribution system spending over these three years increased by $13.23 million (30 percent). While proposed total spending for this three-year period is relatively similar in some categories, in both IDPs, the increase in total spending is primarily driven by the Budget Categories of "Age-Related Replacements and Asset Renewal," "System Expansion or Upgrades for Capacity," and "New Customer Projects and New Revenue" with increases of $5.4 million (65 percent), $3.5 million (35.6 percent), and $3.2 million (25.3 percent), respectively.

Finally, the Department reviewed the 2023 IDP's provision of information related to DEA's historical actual distribution system spending from the 2018 to 2022 period and compared it to DEA's projected distribution system spending from the 2023 to 2027 period. This high-level overview of financial data in DEA's 2023 IDP is summarized in the table below.

Table 4. Comparison of Distribution System Spending Reported in DEA's 2023 IDP, Historical Actual (2018 – 2022) vs. Budgeted (2023 – 2027)

	Historical Actual (2018 - 2022)		Budgeted (2023 - 2027)		Change	
IDP Budget Category	*Spending (Millions)*	*% of Total Spend*	*Spending (Millions)*	*% of Total Spend*	*(Millions)*	*%*
Age-Related Replacements and Asset Renewal	$18.566	20.43%	$25.518	27.43%	**$6.952**	**37.44%**
System Expansion or Upgrades for Capacity	$8.276	9.11%	$19.450	20.91%	**$11.174**	**135.02%**
System Expansion or Upgrades for Reliability and Power Quality	$5.954	6.55%	$8.476	9.11%	**$2.522**	**42.36%**
New Customer Projects and New Revenue	$21.750	23.93%	$27.163	29.20%	**$5.413**	**24.89%**
Grid Modernization and Pilot Programs	$11.401	12.54%	$3.857	4.15%	**-$7.54**	**-66.17%**
Projects related to Local (or other) Government Requirements	$6.867	7.56%	$8.193	8.81%	**$1.33**	**19.31%**
Metering	$18.076	19.89%	$0.369	0.40%	**-$17.71**	**-97.96%**
Total Spending	**$90.890**		**$93.026**		**$2.136**	**2.35%**

DEA's total budgeted distribution system spending is projected to be $93.026 million for the 2023 through 2027 period compared to the historical actual distribution system spending of $90.89 million for the 2018 through 2022 period, an increase of 2.4 percent. DEA has budgeted dollar increases in every IDP Budget Category except for "Grid Modernization and Pilot Programs" and "Metering," with decreases of $7.54 million (66.17 percent) and $17.71 million (97.96 percent), respectively. Significant budget increases are projected in the categories of "Age Related Replacements and Asset Renewal," "System Expansion or Upgrades for Capacity," and "System Expansion or Upgrades for Reliability and Power Quality," and "New Customer Projects and New Revenue," which are projected to have budget increases of $7 million (37.4 percent), $11.2 million (135 percent), $2.5 million (42.4 percent), and $5.4 million (24.9 percent), respectively. The percentage increase in "Age-Related Replacements and Asset Renewal" is driven by increases in materials cost, as well as a new set of projects aimed at rejuvenating aging substations. The percentage increases in "System Expansion or Upgrades for Capacity" and "System Expansion or Upgrades for Reliability and Quality" are driven by significant increases in materials costs. The percentage increase in "New Customer Projects and New Revenue" are driven by increases in the number of new services and cost increases due to material costs such as distribution transformers.[25]

The budget categories of "Age-Related Replacements and Asset Renewal," "System Expansion or Upgrades for Capacity," and "New Customer Projects and New Revenue," together, account for 77.54% of total planned distribution investment over the coming five years. DEA states that "only projects that require longer lead times, such as new distribution substations or projects which are driven by internal timelines, such as age-related replacements, can be forecasted further out."[26] DEA indicates that most of the distribution system construction is in response to requests for new services, road rebuilds by government, response to area load growth, or other requests which have short lead times; so much of the capital spending forecast is based upon historical spending within the internal financial categories. DEA further states that estimates made in the forecasted distribution budget may change, because the budget process for 2024 is open and has not yet been reviewed, and approved, by the Dakota Electric Board.[27]

E. DISTRIBUTED ENERGY RESOURCE (DER) SCENARIOS AND FORECASTS

Notice Topic 3.D: Feedback, Comments, and Recommendations on Distributed Energy Resources (DER) Scenarios and Forecasts

The Commission's Notice states that one of the topics open for comment is "Feedback, comments, and recommendations on the following areas of Dakota Electric's IDP, which includes Distributed Energy Resources (DER) scenarios and forecasts."

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[25] IDP at 130.
[26] IDP at 127.
[27] *Ibid.*

Regarding DER scenarios, DEA's petition states:

> Dakota Electric worked with Great River Energy on forecasting future member owned solar interconnections for the Dakota Electric system. As with the 2021 IDP solar forecast, we again used the EIA Solar energy growth forecast numbers as the basis for forecasting member owned solar interconnections. A low, medium, and high forecast were created.

DEA's petition states that:

> Dakota Electric expects the additions of member owned solar will continue at the current pace for the next 5 -10 years. This is in line with the Medium forecast.

The Department did not review the modeling processes that underlie DEA's DER forecasts, however, use of EIA data is a reasonable starting point. The results of DEA's DER solar forecasts are illustrated in Graphs 12 to 15 and Tables 3 to 5 of the IDP. In essence, DEA is forecasting a large amount of DER solar, particularly in the later years of the forecast, exceeding 100 MW and 12,000 units by 2036 under the medium forecast. The low forecast does not exceed 100 MW of DER solar until 2044 and the high forecast exceeds 100 MW of DER solar as early as 2032. The resulting forecast band presented by DEA appears to be reasonable at this time. In summary, DEA is forecasting a large amount of DER solar by early 2030s. The accuracy of DEA's forecast band can be tracked over time by comparing the forecast to actuals and any necessary improvements can be evaluated in the future.

Regarding the impact of the DER Solar DEA states:

> Along with the higher penetration of DER integration, Dakota Electric will need to develop 8,760-hour modeling of the distribution system and incorporate data from the AGi advanced meters within that modeling.

The Department agrees with DEA that 8,760-hour modeling of the distribution system will be necessary with the high penetration levels being forecasted.

In addition, DEA discusses concerns about correlated loss of output from the DER solar:

> Thus far, the data captured shows that even with many aggregated solar installations, there is a common loss of output due to snow cover in the winter and cloud cover in the summer.

The Department agrees correlated loss of DER solar is an issue to be considered. In addition, it is possible for the correlated loss of DER solar to be compounded by correlated addition of EV load:

> With the addition of electric vehicle charging, we have started to observe a shift in when peak demand occurs on the distribution system. With the need to environmentally condition the vehicles in the morning, especially

> during the winter season, the time of the monthly distribution peak demand has started to periodically occur in the early morning. Further, with EV charging, the evening peaks are starting to shift later in the day, coinciding when people begin charging their vehicles and when Dakota Electric's off-peak rates become available.

The Department recommends that DEA continue to follow and discuss these issues in future IDPs, including how AMI meters can be used to better understand the impacts of EVs on the distribution grid.

Regarding the EV forecast, DEA's Petition states:

> The following EV forecast for the Dakota Electric service territory was created using the growth rates in the MnDOT 2022 EV forecast (High). The MnDOT forecast provided EV sales numbers up to 2030. This forecast was then extrapolated through 2040. Below is a graph showing the Medium and High EV sales forecast. The High forecast was tapered off due to the number of annual sales of passage and light duty vehicles reaching 100% of all sales.

The Department concludes that it is reasonable for DEA to use the Minnesota Department of Transportation (MnDOT)'s forecast. In addition, the Department agrees that use of the high forecast is reasonable because DEA's metro service territory will likely have higher EV sales than rural areas.[28]

Regarding on-peak versus off-peak distribution, DEA states:

> For planning purposes, the amount of "off-peak" EVs is forecasted to remain around 60% of the total number of vehicles. Dakota Electric is optimistic that it can continue to convince our members to utilize our EV programs and, through existing, new, and future programs, reduce the impact of the EVs on the distribution system and wholesale power costs.

In absence of evidence to build a more detailed forecast, DEA's approach is reasonable at this time but DEA may be able to refine this aspect of the EV forecast in the future.

F. THE INFLATION REDUCTION ACT AND UTILITY PLANNING AND BENEFITS

Notice Topic 4: Has Dakota Electric appropriately discussed its plans to maximize the benefits of the Inflation Reduction Act (IRA) and the IRA's impact on the utility's planning assumptions pursuant to Order Point 1 of the Commission's September 12, 2023 Order in Docket No. E,G-999/CI-22-624?

Order Point 1 of the Commission's September 12, 2023, Order in Docket No. E,G999/CI-22-624 states in part:

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[28] See https://www.transportation.gov/rural/ev/toolkit/ev-benefits-and-challenges/individual-benefits

> *The utilities shall maximize the benefits of the Inflation Reduction Act in […] integrated distribution plans […]. In such filings, utilities shall discuss how they plan to capture and maximize the benefits from the Act, and how the Act has impacted planning assumptions including (but not limited to) the predicted cost of assets and projects and the adoption rates of electric vehicles, distributed energy resources, and other electrification measures.*[29]

1. *General IRA Discussion*

DEA provides limited references to the IRA and federal tax incentives in several contexts of its IDP. DEA's IDP references are limited to electric vehicles (EVs), solar, and energy storage, and do not fully address how the incentives have impacted DEA's planning assumptions and adoption rates. DEA's IDP also includes a reference to several planned projects that are the subject of pending IRA grants.

The Department notes the short time period from the September 12, 2023 Order to the filing of the IDP on November 1, 2023. The Department anticipates that future IDPs, as well as the other filings required to comply with Order Point of the September 12, 2023 Order, will likely become more comprehensive in response to the requirements.

i. *Solar Installations*

DEA's IDP generally discusses the increase in member-owned solar installations, which has occurred in the past five years.[30] Although the majority of member-owned solar energy is consumed by the member, there is a significant amount of energy, on average 30-40%, that is generated by the solar member owned solar systems and is immediately fed back into the distribution system and consumed by other homes and businesses. The net energy received by the distribution system, from net metered homes and business, is compensated by Dakota Electric at full retail rates.[31]
DEA has worked collaboratively with the Prairie Island Indian Community on their Net Zero Initiative, which includes the construction of a 4.5MW solar facility located on the Dakota Electric distribution system.[32] DEA states that it has expressed its "willingness to work with and aid the [Prairie Island] Community with any Federal grants and programs they may undertake as part of the IIJA or IRA."[33]
DEA notes that its DER forecasts for solar installations include the impacts of federal tax credits.[34]

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[29] *Order Setting Requirements Related to Inflation Reduction Act, In the Matter of a Joint Investigation into the Impacts of the Federal Inflation Reduction Act*, *Docket No. E,G999/CI-22-624* (September 12, 2023). (eDocket No. 20239-198869-01). *Hereinafter "*September 12, 2023 Order."
[30] IDP at 35.
[31] *Ibid*.
[32] IDP at 13.
[33] IDP at 93.
[34] IDP at 35.

ii. Energy Storage

DEA's IDP discusses the increase in member-owned energy storage systems that occurred in 2023. DEA is exploring ways to utilize member owned energy storage systems to help reduce power supply costs and provide financial benefits to the members who install qualified energy storage systems.[35] DEA is working, in conjunction with Great River energy, on ways to obtain value using energy storage. DEA states that "demand response is seen as one of the fastest ways to get value from energy storage. Providing ancillary services for the grid are possible, but, currently, the costs for behind the meter energy storage may not economically support that effort."[36] "DEA further states "continued evolution in battery technology, pending changes in certain wholesale power provision [. . .], and recent changes in legislation related to the IIJA and IRA will significantly impact the potential viability or planning process for energy storage solutions. Dakota Electric is incorporating these changes into its analysis of future storage projects."[37]

DEA's IDP discusses alternative non-wires options, including the construction of a solar energy system to provide energy to meet the energy requirement of the new loads, which are connected in the area in combination with an energy storage system to provide energy during times when the solar is unavailable.[38] Finally, DEA notes that tax credits contribute to lower installation costs for energy storage and are expected to increase demand for new installations.[39]

iii. Electric Vehicle Charging

DEA's IDP generally discusses its policy of working to assist municipalities in completing and submitting applications for new electric vehicle charging station grants offered by Great River Energy. DEA has helped members receive 50% of the available funds offered by Great River Energy. Also, DEA has worked with the State of Minnesota to identify public locations for EV charging stations that would be a good fit for the National Electric Vehicle Infrastructure (NEVI) plan and thereby qualify for federal funds.[40] In addition, DEA is working to increase options and accessibility for members to utilize EV rates and to help provide cost effective options for charging electric vehicles.[41] DEA implemented an EV time of use charging rate option in 2012 and continues to examine other rate options, which encourage members, who increasingly utilize the EV rate options, to charge their EVs during periods of lower cost energy.[42] The Department notes that DEA's discussion of EVs does not fully address how IRA incentives have impacted DEA's planning assumptions and adoption rates.

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[35] IDP at 41.
[36] *Ibid.*
[37] IDP at 91.
[38] IDP at 76-80.
[39] IDP at 41.
[40] IDP at 28-31, 92.
[41] IDP at 92.
[42] IDP at 23-25.

The Department requests DEA to discuss in reply comments how it anticipates IRA incentives to impact electric vehicle adoption.

The Department notes that, while DEA's IRA references appear to be limited to a discussion of EVs, solar, and energy storage systems, IRA incentives may address additional forms of DER and electrification measures. These additional forms of DER and electrification measures are included in the requirements in the September 12, 2023 Order. Specifically, incentives for heat pump air conditioners/heaters, heat pump water heaters, electric wiring and electric panel upgrades that facilitate electrification, among others, are relevant aspects of the IRA to include in a discussion of planning assumptions.

The Department requests that DEA include in reply comments a description of how its distribution system planning will evolve with the incorporation of additional impacts from the IRA.

2. *Beneficial Electrification*

The Department found that a discussion about beneficial electrification, specifically various heat pump technologies, is absent in DEA's IDP. Beneficial electrification is consistent with the state's Climate Action Framework,[43] which sets a goal to reach carbon neutrality by 2050. The state has also established a standard for 100% carbon-free electricity by 2040.[44] Beneficial electrification aligns with the state's goals, to the extent that beneficial electrification technologies are able to offset a fossil fuel-based heat source.

While Dakota Electric's service area contains a high number of homes on natural gas, there are opportunities for more favorable economics with other heating fuels. In Dakota County, where the majority of DEA's service area exists, 80.8 percent of homes rely on natural gas, 14.5 percent of homes rely on electric heat, and 5.0 percent home homes rely on other heating fuels, the majority of which is assumed to be propane.[45] Therefore, an estimated 19.2 percent of homes rely on expensive heating fuels, which are ideal for beneficial electrification applications to both reduce emissions and save ratepayers money. Out of 115,000 members, this percentage equates to approximately 22,080 members that rely on high-cost heating fuels.

The high heating cost homes in DEA's service area that do not use natural gas for heating presents a significant opportunity to add value to DEA's electric ratepayers. Typical fossil-fuel based heating systems are limited to a maximum efficiency that cannot exceed 100 percent, and in practice, most high-efficiency models are around 95 percent efficient. Electric resistance heat is 100 percent efficient. Heat pumps, rather than generating heat, instead move heat from one place to another, which allows

[43] State of Minnesota. *Minnesota Climate Action Framework Report*. N.D. Accessed at https://climate.state.mn.us/sites/climate-action/files/Climate%20Action%20Framework.pdf
[44] Minn. Stat. § 216B.1691, subd. 2g. https://www.revisor.mn.gov/statutes/cite/216B.1691#stat.216B.1691.2g
[45] US Census Bureau. (n.d.). Home Heating Fuel. Retrieved from: https://www.census.gov/acs/www/about/why-we-ask-each-question/heating/

them to reach efficiencies higher than 100 percent. Heat pump performance is sometimes measured by its Coefficient of Performance (COP), which is measured as the ratio of input electricity to the equivalent output electricity. For example, at a COP of 2.0, this would mean a heat pump would generate 2 kWh equivalent of heat for every 1 kWh that is used by the heat pump, and thus a higher COP means the heat pump is more efficient.

Table 5 below shows a comparison of heating costs by fuel source and by heat pump efficiency. Natural gas costs $8.84 / MMBtu, while propane costs $21.64 / MMBtu, fuel oil costs $21.66 / MMBtu, and electric resistance heat costs $36.34 / MMBtu. Natural gas is significantly cheaper than propane (59.1 percent), fuel oil (59.2 percent) and electric resistance heat (75.7 percent). Some of the homes in DEA's service area may not have the option to switch to natural gas, which leaves heat pumps as an attractive, if not cheaper solution than even natural gas. Heat pump water heater COPs were found in a real world application to have a COP range of 1.82 – 2.32.[46] Energy Star requires that certified cold climate heat pumps achieve a COP of at least 1.75 at 5 degrees,[47] while several models can achieve a COP well above 2.0 at 5 degrees.[48] While Air Source Heat Pump (ASHP) performance declines with temperature, a COP of 2.0 at 5 degrees on the Interruptible Tariff (Schedule 52) is close to the economic break even point compared to natural gas. This means that cold climate ASHPs will be cheaper to run than natural gas for a significant portion of the heating season if the ratepayer is on the Interruptible Tariff with a fossil fuel fuel backup heat source.[49] The Interruptible Tariff would require the installation of a Load Control Receiver (LCR), but DEA does not discuss whether there is an additional cost to install the LCR, and if so, what the cost is. A high cost of installation may make installation financially infeasible, but the rate does offer an option for natural gas customers to save money on heating costs after the installation of a heat pump. When compared to propane and fuel oil, a heat pump with a COP of 2.0 on the standard residential tariff offers a 16.0 percent savings. For any home that can switch from electric resistance heat, the savings would be 50 percent, while warmer temperatures offer even higher levels of savings, with COPs reaching as high as 3.5 at 47 degrees. Homes on propane or fuel oil would have an opportunity for even more fuel savings if they switch to the Interruptible Tariff, and could continue to heat their homes with their standard heat source when the electric heat source is interrupted by DEA. Additional Interruptible Tariff use would also expand DEA's demand response capabilities.

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[46] Shapiro and Puttagunta. (February 2016). *Field Performance of Heat Pump Water Heaters in the Northeast*. US Department of Energy. https://www.nrel.gov/docs/fy16osti/64904.pdf
[47] See https://www.energystar.gov/products/heat_pump_water_heaters/key-product-criteria
[48] See https://ashp.neep.org/#!/product_list/
[49] Note that the Dual Fuel Standard tariff requires that the meter be allowed to be interrupted for up to 300 hours per year, or 12.5 days, and the Dual Fuel Plus tariff requires that the meter be allowed to be interrupted for 1,000 hours per year, or 41.7 days.

Department Table 5: Comparison of Heating Cost by Fuel and Heat Pump Coefficient of Performance (COP)

Heat Source	DEA Rate	Fuel Cost	Normalized Fuel Cost ($ / MMBtu)	Heating Cost ($ / MMBtu)
Natural Gas (95% Efficiency)	-	$8.72 / MCF[50]	$8.40 / MMBtu	$8.84 / MMBtu
Propane (95% Efficiency)	-	$1.88 / Gallon[51]	$20.56 / MMBtu	$21.64 / MMBtu
Fuel Oil (95% Efficiency)	-	$2.85 / Gallon[52]	$20.58 / MMBtu	$21.66 / MMBtu
Electric Resistance - COP 1.0	Standard	$0.124 / kWh[53]	$36.34 / MMBtu	$36.34 / MMBtu
Heat Pump - COP 2.0	Standard	$0.124 / kWh	$26.67 / MMBtu	$18.17 / MMBtu
Heat Pump - COP 2.0	Interruptible	$0.063 / kWh	$18.46 / MMBtu	$9.23 / MMBtu

The average Minnesota home uses 59.3 MMBtu for space heating, 15.2 MMBtu for water heating, and 3.5 MMBtu for air conditioning.[54] A fully natural gas heated home is estimated to spend $659 annually, whereas a fully propane heated home is estimated to spend $1,532 anually and a fully electric resistance heated home is estimated to spend $2,707 annually. Compared to a full heat pump home with a heat pump space and water heater that average a COP of 2.0, the average annual cost would be $1,354, with a savings potential of $178 for propane and $1,354 for electric resistance heat. Note that most, if not all, cold climate heat pumps currently on the market cannot serve 100% of a Minnesota home's heating load,[55] and will likely be able to fuel switch economically from natural gas to meet 20 – 80 percent of a home's heating load, based on the Duluth climate.[56] Heat pumps will remain economical compared to electric resistance heat for the entire load they are able to serve.

DEA does not provide a forecast for the adoption of heat pumps in its service territory. The Company provided historical participation rates for DEA's load management program, which is assumed to be on the Interruptible Tariff. As of 2024, there were 2,748 heat pumps participating in the Load

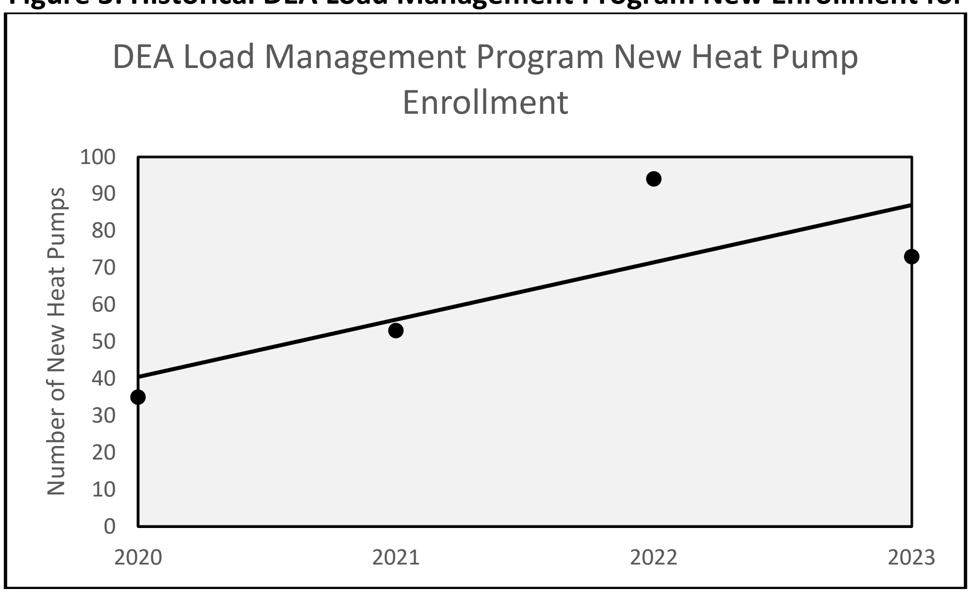
[50] 10 year average price of residential natural gas for December – February heating season: 2013 – 2022. Source: https://www.eia.gov/dnav/ng/hist/n3010mn3m.htm
[51] 10 year average price of residential propane for December – February heating season: 2013 – 2022. Source: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPLLPA_PRS_SMN_DPG&f=W
[52] [52] 10 year average price of residential propane for December – February heating season: 2013 – 2022. Source: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPD2F_PRS_SMN_DPG&f=W
[53] Based on the winter standard residential flat rate. See https://www.dakotaelectric.com/wp-content/uploads/2023/12/Residential-Tariff-Book-September-2022.pdf
[54] US Energy Information Administration. Residential Energy Consumption Survey (RECS) Dashboard. Source: https://experience.arcgis.com/experience/cbf6875974554a74823232f84f563253
[55] ASHP performance (COP) and output decline with decreasing temperature. Many Energy Star certified cold climate heat pumps have a similar rated output at 47 degrees to their output at 5 degrees, but output declines further at lower temperatures, and likely cannot meet 100% of building heating load without a backup heat source such as fossil fuels or electric resistance heat.
[56] A heat pump that can supply 100% of the heating load at 5 degrees will supply approximately 80% of a home's heating load in Duluth. See *Minnesota Energy Efficiency Potential Study: 2020-2029* at 104-105.

Management Program,[57] which allows DEA to turn off the device in order to reduce peak demand via LCR. This represents approximately 2.4 percent of DEA's members. DEA clarifies in IR 14 that it does not have data on the total number of heat pumps installed in its service territory, and there are likely many additional heat pumps installed that do not participate under the Load Management Program. DEA does not discuss a plan to increase enrollment in its Load Management Program.

The Department requests DEA to discuss in reply comments the extent to which the Company has conducted surveying and/or targeted outreach to increase participation in its Load Management Program.

DEA provided historical load management participation data in IR 14.[58] The enrollment in the program was 35 new heat pumps in 2020, 53 new heat pumps in 2021, 94 new heat pumps in 2022, and 73 new heat pumps in 2023. Further, not all of the heat pumps enrolled are likely to be cold climate ASHPs that have the benefits discussed previously. The Department plotted out the historical enrollment data in Figure 3. In the 3 years between 2020 and 2023, new heat pump enrollment approximately doubled (100 percent growth). The growth rate appears to follow a similar trend to the growth rate of EVs, discussed in IDP Section 2.b, where DEA stated that EV adoption grew from 269 vehicles in 2018 to 1,207 vehicles in 2022, which is a 349 percent increase in four years. While the current adoption rate is low and could maintain attrition from the current enrollment of 2,748 heat pumps, if the enrollment rate continues to double every three years, there could be a much higher number of heat pumps in DEA's service area by 2050.

Department Figure 3: Historical DEA Load Management Program New Enrollment for Heat Pumps



Source: DEA Response to IR 14.

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[57] DEA Response to IR 14.
[58] *Ibid.*

Without additional data and forecasting, it is not currently possible to predict how many heat pumps will be installed in DEA's service territory. Given that heat pumps can both reduce load when offsetting expensive electric resistance heating systems and increase load when offsetting non-electric fossil-fuel-based heating systems, it is important for DEA to forecast heat pump adoption to prepare for potential load growth or shrinking that results from heat pump installations.

The potential for beneficial electrification load growth is only enhanced by Inflation Reduction Act (IRA) incentives. DEA offers up to $1,000 to install an ASHP and $500 to install a heat pump water heater.[59] The IRA tax credit offers up to $2,000 for 30 percent of the cost to install an ASHP.[60] As an example, a 3-ton ducted ASHP that costs $7,000 would be eligible for a $3,000 incentive, which would cover 43 percent of the installation cost. The State of Minnesota has received over $148 million for home energy efficiency and home electrification[61] which can fund rebates up to $8,000 towards the installation of a heat pump for households at or below 80% of the Area Median Income, and $4,000 for households at or below 150% of the Area Median Income.[62] Further, the state is implementing a program to fund up to $4,000 for the installation of a heat pump for applicants of these programs.[63] Some of these programs can also potentially fund heat pump water heaters and clothes dryers.

Despite the unprecedented opportunities created by the IRA to install free or heavily discounted heat pumps, DEA has not presented any discussion about the topic. Many of these programs are scheduled for implementation in 2025, which means that DEA will be behind if it does not start planning for these new programs now. The rebate programs will require energy audits to first be performed that establish the need for heat pumps alongside other energy saving measures, such as insulation and air sealing. The implementation of these programs will require State Government and contracting partner coordination with DEA, at minimum, and at best, a proactive attempt by DEA to identify and enroll high heating cost homes into the many programs available for beneficial electrification.

The Department recommends the Commission order DEA to file a supplemental filing that proposes a plan to accelerate beneficial electrification for its customers, including a discussion of how to incentivize dual fuel adoption, and provide forecasts of expected grid impacts of the same.

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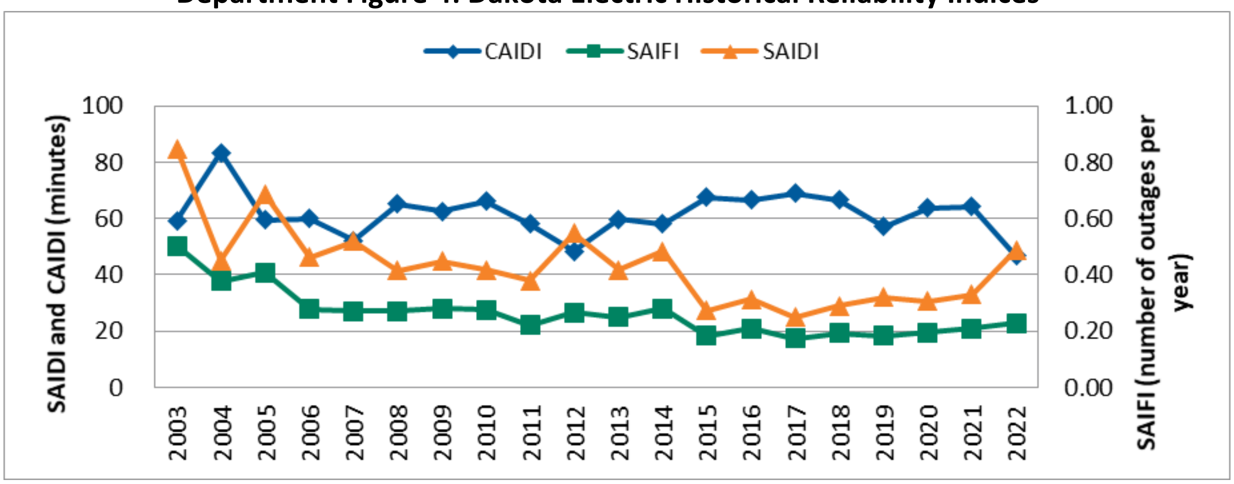
[59] See https://www.dakotaelectric.com/member-services/programs-rebates/for-your-home/energy-wise-rebates/
[60] See https://www.irs.gov/credits-deductions/energy-efficient-home-improvement-credit
[61] See https://www.energy.gov/sites/default/files/2023-07/IRA%2050121%20%26%2050122%20Home%20Energy%20Rebates%20State%20Allocations.pdf
[62] See https://mn.gov/commerce/energy/consumer/energy-programs/home-energy-rebates.jsp
[63] See https://mn.gov/commerce/energy/consumer/energy-programs/heat-pump.jsp

G. *DISTRIBUTION SYSTEM RESILIENCE*

Notice Topic 5: What should the Commission Consider or Address Related to Enhancing the Resilience of the Distribution System Within Dakota's IDP?

IDP Planning Objective 1 establishes that the purpose of the IDP is to "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."[64] DEA presents a robust discussion of system reliability throughout its IDP. DEA states that it is ranked among the most reliable electric utilities in the United States.[65] Each of the key reliability metrics tracked have generally trended downward since 2003, as shown in Figure 4.

Department Figure 4: Dakota Electric Historical Reliability Indices[66]



Source: DEA 2022 Safety, Reliability, and Service Quality Report[67]

While DEA has overall good reliability, the Company notes several areas where it continues to improve. Customers Experiencing Multiple Outages (CEMI) that includes four or more outages per year has varied from 1.22 percent in 2020, 0.22 in 2021 and 0.60 percent in 2022.[68] While DEA notes these metrics are favorable, there is still an opportunity for improvement. The company notes that older residential neighborhoods built before the 1970's tend to be more affordable, but also have lower reliability metrics because many of the power lines are overhead and are thus more subject to failure. These neighborhoods also have electrical infrastructure from around the same period, which requires

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[64] IDP Planning Objective 1.
[65] IDP at 4.
[66] IDP at 4: "The CAIDI, or Customer Average Interruption Duration Index, is a duration index which indicates the average annual minutes per outage for Members that actually lose power. The SAIDI, or System Average Interruption Duration Index, is a duration index which indicates the average annual minutes a Member was without power. The SAIFI, or System Average Interruption Frequency Index, is a frequency index which indicates the average annual number of times an average Member was without power."
[67] Docket No. E111/M-23-74
[68] IDP at 13-14.

replacement due to aging. The Company notes that it applied for IIJA funding to support reliability improvements in the Burnsville Community, which is also a Justice40 Community,[69] but the grant application was not funded.

The Company additionally addresses reliability concerns in more rural sections of its service territory where tree cover tends to create reliability problems due to long overhead lines. DEA states that it has "…embarked on an aggressive vegetation management strategy and is beginning to see improvement in metrics associated with [vegetation] outages."[70] The Department asked for additional information about the program in IR 4. The Company stated that, historically, vegetation- and weather-related incidents were the largest cause of outages. In 2020, the Company states that there was a backlog of 800 member requested tree tickets, and by the end of 2023, the backlog was reduced to 100. In addition, the Company enacted a regular tree trimming cycle on approximately 500 miles of lines. The result of this program is a decline in tree-related outages from 229 incidents in 2020 to 156 incidents in 2023. Spending on the program has climbed from $1.21 million in 2020, to 1.53 million in 2023, and the forecasted budget will increase to $1.78 million in 2024 and thereafter, a 47 percent increase over 2020 funding.

DEA is also slowly addressing strategic undergrounding of power lines. While older neighborhoods tend to have overhead power lines, DEA states that "Almost all new residential and commercial developments in Dakota Electric's service territory utilize underground cables for the electrical distribution system within development."[71] The number of miles of overhead power lines has slowly decreased, with the number of miles of underground power lines increasing at a faster pace, as shown in Figure 5.

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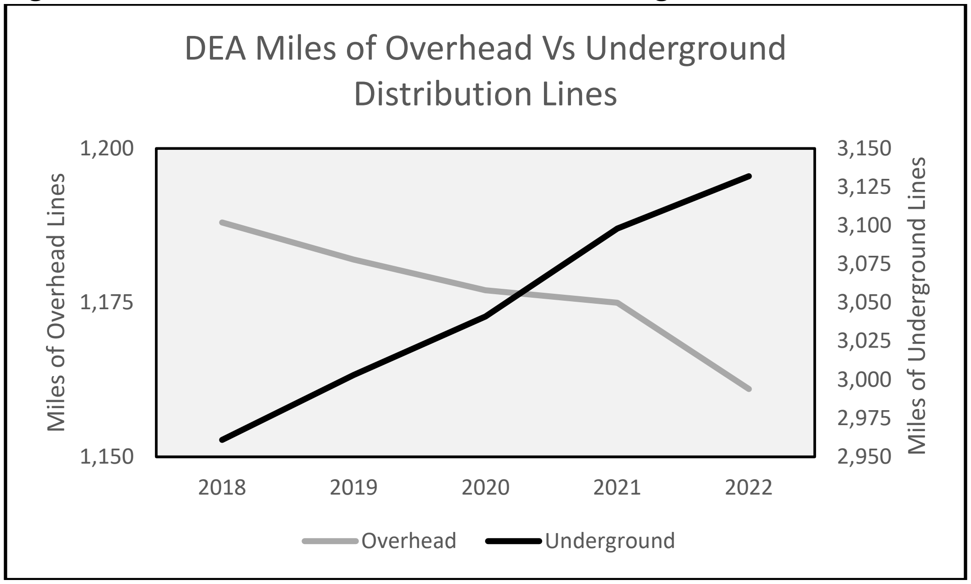
[69] Justice40 Communities are communities with a number of current or historical economic disadvantages that include disproportionate burdens for climate change, energy, health, housing, legacy pollution, transportation, water and wastewater, workforce development, or status as a Federally Recognized Tribe. The Biden Administration seeks to award 40% of the overall benefits of certain Federal climate, clean energy, sustainable housing, and other investments to Justice40 Communities. For more information, see: https://screeningtool.geoplatform.gov/en/methodology#5.04/34.11/-87.08
[70] IDP at 14.
[71] IDP at 113.

Department Figure 5: Number of Miles of Overhead VS Underground Distribution Lines Over Time



Source: IDP Tables 26 and 27

DEA is planning to further address grid reliability in its "Age Related Replacement" budget category. The budget is forecasted to increase from $3.8 million in 2023 to $6.1 million in 2028, which is the second largest cost category in DEA's budget. Replacing older infrastructure will additionally help DEA increase reliability.

DEA has clearly demonstrated that it takes reliability seriously. However, the Department observes an opportunity to track and report system resilience as a distinct concept from reliability to ensure that investments are appropriately targeted. Identifying the specific benefits derived from investments described in the IDP remains a challenge, and the development of resilience metrics to assess performance over time could provide additional insight and inform Commission and stakeholder understanding of how DEA's IDP aligns with IDP Planning Objective 1. Given DEA's significant and growing levels of investment for the stated objective, among others, to improve system resilience, the Department believes that resilience performance metrics can assist with the evaluation of investments.

DEA reports various metrics in its annual Minnesota Safety, Reliability, and Service Quality ("SRSQ") Standards Report, which includes standardized reporting metrics including System Average Interruption Duration Index ("SAIDI"), Customer Average Interruption Duration Index ("CAIDI"), Momentary Average Interruption Frequency Index ("MAIFI"), among others.[72] The reporting requirements for DEA's SRSQ Report include metrics using both weather-normalized and non-normalized data. Reliability reporting uses normalized data to exclude Major Event Days ("MEDs"), consistent with standardized reporting requirements and appropriate given that reliability "typically deals with routine, shorter-time events."[73]

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[72] Docket No. E111/M-23-74.

[73] National Renewable Energy Laboratory (NREL). *Measuring and Valuing Resilience: A Literature Review for the Power Sector*, August 2023 at 2. *Hereinafter* "NREL Report." Accessed at https://www.nrel.gov/docs/fy23osti/87053.pdf

In contrast, resilience "typically focuses on low-probability, high-consequence events […] and affect a significant number of customers, often spanning a wide geographic extent."[74] Thus, the likelihood and scope of the impact of the event are relevant to assess resilience. DEA reports non-weather-normalized versions of metrics, including MEDs, in its SRSQ Report and could provide the basis for the development of resiliency reporting metrics. The Department notes that other jurisdictions track SAIDI and SAIFI with MEDs as measures of resilience.[75] Further, the AMI and AGi programs offer DEA a higher resolution to track its resilience metrics.

The Department requests DEA to provide a discussion of how its AMI and AGi programs could be used to track and understand system resilience.

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

For reference in developing a suite of metrics, the Department offers reports published by Pacific Northwest National Laboratory and Sandia National Laboratories,[76;77] which provide a comprehensive discussion of resilience metrics. The Department encourages DEA to establish metrics and track performance across different customer groups and geographies, to the extent practicable, to gain insight into how major outage events affect different groups.

H. OTHER AREAS OF DEA'S IDP

Notice Topic 6: Other Areas of Dakota Electric's IDP Not Listed Above, Along With Any Other Issues or Concerns Related to This Matter.

The Department identifies one issue raised in its March 4, 2024 initial comments[78] filed in the ongoing Xcel Energy IDP proceeding that also pertain to DEA's IDP.

In the Department's initial comments in the Xcel IDP proceeding, the Department responded to Xcel's request to revise IDP filing requirements to removing the requirement that financial information be reported in IDP-specific budget categories.[79] Xcel's request was prompted by its observation regarding the manual work required to convert its internal budget categories to the IDP-specific budget

[74] *Ibid.*
[75] *See https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan-sept2023.pdf*
[76] Pacific Northwest National Laboratory and Sandia National Laboratories. *Resilient Electric Grid: Defining, Measuring, and Integrating Resilience into Electricity Sector Policy and Planning*. September 2023. Accessed at https://www.pnnl.gov/sites/default/files/media/file/MOD-Plan%20Resilience%20Paper%20Final.pdf
[77] Sandia National Laboratories. *Performance Metrics to Evaluate Utility Resilience Investments*. May 2021. Accessed at https://www.osti.gov/biblio/1821803/
[78] *Comments of the Minnesota Department of Commerce, In the Matter of Xcel Energy's 2023 Integrated Distribution Plan, Docket No. E002/M-23-452* (March 4, 2024) (eDocket No. 20243-204037-04). *Hereinafter* "March 4, 2024 Comments."
[79] March 4, 2024 Comments at 16.

categories and a desire from stakeholders to facilitate comparison of budget information across utility proceedings.[80] The Department expressed support for the alignment of the IDP process with other dockets, including cost recovery proceedings, which the removal of IDP-specific budget categories could facilitate. The Department also recommended the Commission consider implementing similar revisions with other utilities' IDP filings.

The Department continues to believe that consistent presentation of budget information across utility proceedings could benefit the regulatory process, particularly with cost recovery proceedings. The Department is interested in hearing from DEA regarding its challenges, if any, with providing its budget information in the IDP-specific budget categories, and what the impacts would be of aligning its IDP budget information with its internal budget categories.

The Department requests feedback from DEA and stakeholders regarding the potential revision of IDP filing requirements to remove the requirement that financial information be presented in IDP-specific budget categories.

IV. RECOMMENDATIONS

The Department appreciates the opportunity to comment on DEA's 2023 IDP and looks forward to the review of other stakeholder comments. The Department requests that DEA provide the following information:

- ***The Department requests that DEA discuss in reply comments whether the Cedar Substation and Feeders Project, Lakeville Substation and Feeders Project, and the Fisher Substation Rebuild Project are suitable for current or future NWA analysis.***

- ***The Department requests that DEA discuss in reply comments which benefits are studied as part of its NWA process and which main assumptions are used to calculate benefits.***

- ***The Department requests that DEA include calculated benefits for all Minnesota Test Cases, and to the extent practicable, present the results in reply comments.***

- ***The Department requests that DEA discuss in reply comments the costs and benefits of its AMI and AGi Programs.***

- ***The Department requests that DEA discuss in reply comments the costs and benefits of its Load Control Receiver Program.***

[80] *2023 Integrated Distribution System Plan, Northern States Power Company dba Xcel Energy, Docket No. E002/M-23-452* (November 1, 2023) (eDocket No. 202311-200132-09). Xcel IDP Main Report at 27.

- ***The Department requests that DEA present in reply comments the purpose of its Miscellaneous Grid Modernization budget allocation and provide additional information, as available, which includes a discussion of the investment plan, a discussion of the cost recovery mechanism, an analysis of alternative investments, a discussion of customer anticipated benefits, a discussion to manage bill impacts, a presentation of the impact to the net present value of system costs, and a cost-benefit analysis, if available. If DEA is not able to provide the requested information, it should indicate when it expects to be able to provide the information.***

- ***The Department requests that DEA present in reply comments a discussion of its grid modernization projects submitted in grant applications, which includes a discussion of the investment plan, a discussion of the cost recovery mechanism, an analysis of alternative investments, a discussion of customer anticipated benefits, a discussion to manage bill impacts, a presentation of the impact to the net present value of system costs, and a cost-benefit analysis, if available.***

- ***The Department requests DEA to discuss in reply comments how it anticipates IRA incentives to impact electric vehicle adoption.***

- ***The Department requests that DEA include in reply comments a description of how its distribution system planning will evolve with the incorporation of additional impacts from the IRA.***

- ***The Department requests DEA to discuss in reply comments the extent to which the Company has conducted surveying and/or targeted outreach to increase participation in its Load Management Program.***

- ***The Department requests DEA to provide a discussion of how its AMI and AGi programs could be used to track and understand system resilience.***

- ***The Department requests feedback from DEA and stakeholders regarding the potential revision of IDP filing requirements to remove the requirement that financial information be presented in IDP-specific budget categories.***

The Department makes the following initial recommendations:

- ***The Department recommends the Commission order DEA to file a supplemental filing that proposes a plan to accelerate beneficial electrification for its customers, including a discussion of how to incentivize dual fuel adoption, and provide forecasts of expected grid impacts of the same.***

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

V. GLOSSARY

AGi	Advanced Grid Infrastructure	**MAIFI**	Momentary Average Interruption Frequency Index
AMI	Advanced Metering Infrastructure	**MDM**	Meter Data Management System
ASHP	Air Source Heat Pump	**MED**	Major Event Day
CAIDI	Customer Average Interruption Duration Index	**Minn. Stat.**	Minnesota Statute
CBA	Cost-Benefit Analysis	**MISO**	Midcontinent Independent System Operator
CEMI	Customers Experiencing Multiple Outages	**MMBtu**	Million British Thermal Units
COP	Coefficient of Performance	**MW/MWh**	Megawatt/Megawatt-Hour
DER	Distributed Energy Resources	**NEVI**	National Electric Vehicle Infrastructure
DERMS	Distributed Energy Resource Management System	**NPV**	Net Present Value
EV	Electric Vehicle	**NREL**	National Renewable Energy Laboratory
ESS	Energy Storage System	**NWA**	Non-Wires Alternative
IDP	Integrated Distribution Plan	**PV**	Photovoltaic
IIJA	Infrastructure Investments and Jobs Act	**SAIDI**	System Average Interruption Duration Index
IRA	Inflation Reduction Act	**SAIFI**	System Average Interruption Frequency Index
kW/kWh	Kilowatt/Kilowatt-Hour	**SRSQ**	Safety, Reliability, & Service Quality
LCR	Load Control Receiver		

Filing Requirement	Heading	Description	Filing Section	Comments
3.A.1	Baseline Distribution System Data	Modeling software currently used and planned software deployments	6.a	Addressed
3.A.2	Baseline Distribution System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	6.b	Addressed
3.A.3	Baseline Distribution System Data	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	6.c	Addressed
3.A.4	Baseline Distribution System Data	Number of customer meters with AMI/smart meters and those without, planned AMI investments, and overview of functionality available	6.d	Addressed
3.A.5	Baseline Distribution System Data	Discussion of how Dakota Electric Association approaches distribution system planning in consideration of and coordination with Great River Energy's integrated resource plan, and any planned modifications or planned changes to the existing process to improve coordination and integration between the two plans from Dakota Electric Association's perspectiv	6.e	Addressed
3.A.6	Baseline Distribution System Data	Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology	6.f	Addressed
3.A.7	Baseline Distribution System Data	Discussion if and how IEEE Std. 1547-2018 5 impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability and advanced inverter functionality). 5 IEEE Standard 1547-2018, published April 6, 2018.	6.g	Addressed
3.A.8	Baseline Distribution System Data	Distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages)	6.h	Addressed
3.A.9	Baseline Distribution System Data	The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems	6.i	Addressed
3.A.10	Baseline Distribution System Data	Total distribution substation capacity in kVA	6.j	Addressed
3.A.11	Baseline Distribution System Data	Total distribution transformer capacity in kVA, if different from total distribution substation capacity and the reason for the difference.	6.k	Addressed
3.A.12	Baseline Distribution System Data	Total miles of overhead distribution wire	6.m	Addressed
3.A.13	Baseline Distribution System Data	Total miles of underground distribution wire	6.m	Addressed
3.A.14	Baseline Distribution System Data	Total number of distribution customers	6.n	Addressed
3.A.15	Baseline Distribution System Data	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category (including application review, responding to inquiries, metering, testing, make ready, etc).	6.o-p	Addressed
3.A.16	Baseline Distribution System Data	Total charges to customers/member installers for DER generation installations, in the prior year. These costs should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	6.i	Addressed
3.A.17	Baseline Distribution System Data	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	6.q	Addressed
3.A.18	Baseline Distribution System Data	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	6.r	Addressed
3.A.19	Baseline Distribution System Data	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	6.s	Addressed
3.A.20	Baseline Distribution System Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.) 21. Total number of electric vehicles in service territory	6.t	Addressed
3.A.21	Baseline Distribution System Data	Total number of electric vehicles in service territory	2.a-b, 6.u-v	Addressed
3.A.22	Baseline Distribution System Data	Total number and capacity of public electric vehicle charging stations	2.a-b, 6.u-v	Addressed
3.A.23	Baseline Distribution System Data	Number of units and MW/MWh ratings of battery storage	6.w	Addressed
3.A.24	Baseline Distribution System Data	MWh saving and peak demand reductions from EE program spending in previous year	6.x	Addressed
3.A.25	Baseline Distribution System Data	Amount of controllable demand (in both MW and as a percentage of system peak)	6.y	Addressed

Filing Requirement	Heading	Description	Filing Section	Comments
3.A.26	Baseline Distribution Financial Data	Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements (road-relocations, etc.) g. Metering h. Other The Company may provide in the IDP any 2019 or earlier data in the following categories: a. age-related replacements and asset renewal, b. system capacity expansion (capacity driven), c. system capacity expansion (reliability driven), d. projects to support new members (including metering, transformers and wires), e. system projects driven by governmental projects (road moves), f. grid modernization (advanced technologies)	6.z.aa-cc	Addressed
3.A.27	Baseline Distribution Financial Data	All non-Dakota Electric investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA and other) and location (i.e. feeder or substation).	6.z.aa	Addressed
3.A.28	Baseline Distribution Financial Data	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	6.z.bb	Addressed
3.A.29	Baseline Distribution Financial Data	Planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other	6.z.cc	Addressed
3.A.30	Baseline Distribution Financial Data	Provide any available cost benefit analysis in which the company evaluated a non traditional distribution system solution to either a capital or operating upgrade or replacement	6.z.dd	Addressed
3.A.31	Baseline Distribution Data (DER Deployment)	Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	6.z.ee	Addressed
3.A.32	Baseline Distribution Data (DER Deployment)	Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.	6.z.ff	Addressed
3.A.33	Baseline Distribution Data (DER Deployment)	Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues.	6.z.gg	Addressed
3.B.1	Preliminary Hosting Capacity Data	Provide an excel spreadsheet (or other equivalent format) by feeder of either daytime minimum load (daily, if available) or, if daytime minimum load is not available, peak load (time granularity should be specified)	5	Addressed
3.C.1	Distributed Energy Resource Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on the distribution system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Dakota Electric distribution system in the locations Dakota Electric would reasonably anticipate seeing DER growth take place first.	3.a-c	Addressed
3.C.2	Distributed Energy Resource Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	3.e	Addressed
3.C.3	Distributed Energy Resource Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.	3.d	Addressed
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 841 6 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators). 6 Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 162 FERC ¶61,127 (February 28, 2018)	3.e-g	Addressed

Filing Requirement	Heading	Description	Filing Section	Comments
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Dakota Electric shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Dakota Electric should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum: a. Overview of investment plan: scope, timing, and cost recovery mechanism b. Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.7 c. Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment. d. System interoperability and communications strategy e. Costs and plans associated with obtaining system data (EE load shapes, photovoltaic output profiles with and without battery storage, capacity impacts of demand response combined with EE, EV charging profiles, etc.) f. Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.) g. Customer anticipated benefit and cost h. Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties) i. Plans to manage rate or bill impacts, if any j. Impacts to net present value of system costs (in net present value revenue requirements/megawatt/hour or megawatt) k. For each grid modernization project in its 5-year Action Plan, Dakota Electric should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Dakota Electric shall provide all information to support its analysis.8 l. Status of any existing pilots or potential for new opportunities for grid modernization pilots 7 https://gridarchitecture.pnnl.gov/ 8 Nov 2, 2020, Order (19-674), Order Point 3	5	Addressed
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Dakota Electric shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10- year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Dakota Electric is currently using.	4.b-c, 5	Addressed
3.E.1	Non-Wires (Non-Traditional) Alternatives Analysis	Dakota Electric shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent five years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	4.a, 4.d.	See Department Comments Section III.B
3.E.2	Non-Wires (Non-Traditional) Alternatives Analysis	Dakota Electric shall provide information on the following: i. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) ii. A timeline that 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) iii. Cost threshold of any project type that would need to be met to have a non traditional solution reviewed iv. 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.	4.e-h	Addressed
September 8, 2022 Order (E111/M-21-728)	Order Point 3	Required Dakota to file, in its next IDP filing, a thorough discussion of the installation of a utility-operated energy storage system (which would be charged with energy that would otherwise cause back-feeding during the day and that would then discharge that energy in the evening) in light of recent state and federal infrastructure programs. The discussion must include how to calculate cost to benefits impacts and how such storage solutions affect its wholesale power supply contracts and obligations.	3.f-g	Addressed
June 7, 2023 Order (E111/CI-20-800)	Order Point 3	The Commission adopts and applies to Dakota Electric Association, Otter Tail Power, and Minnesota Power, the Dakota Electric Association proposal outlined in its June 30, 2021 Reply Comment to provide discrete sets of information on-demand, in the context of other existing DER interconnection tools and improvements being considered to maintain an orderly, efficient, and cost-effective deployment of DER in Minnesota. Utilities implementing this process shall make a compliance filing, to be filed with their IDPs, providing a narrative report on their implementation of this policy.	3.d	Addressed
September 12, 2023 Order (E,G999/CI-22-624)	Order Point 1: IRA Impacts	The utilities shall maximize the benefits of the Inflation Reduction Act in […] integrated distribution plans […]. In such filings, utilities shall discuss how they plan to capture and maximize the benefits from the Act, and how the Act has impacted planning assumptions including (but not limited to) the predicted cost of assets and projects and the adoption rates of electric vehicles, distributed energy resources, and other electrification measures.		See Department Comments Section III.F

Planning Objective	Description	Filing Pages	Comments
Objective 1	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		Addressed
	a. safety	56-57,88-89,98,147	Addressed
	b. security	48,56-57,89,93-94,98,147	Addressed
	c. reliability	1-2,4,8,13-16,17,28,50,63-65,84-85,88-94,123,127,145,147	Addressed
	e. resilience	78, 99	Addressed
	f. fair and reasonable costs	4-6,9,10,42-43,63-85	Addressed
Objective 2	Enable greater a. engagement	17-18	Addressed
	b. customer empowerment	13-16, 119-122	Addressed
	c. options for energy services	41-42, 119-122	Addressed
Objective 3	Move toward the following: a. create efficient, cost-effective grid	45, 115-116, 119-122	Addressed
	b. accessible grid platforms for new products and services	7,88-93	Addressed
	c. opportunities for adoption of new distributed technologies	33,41-42,88-93	Addressed
Objective 4	Ensure the following: a. optimized utilization of grid assets	45, 48, 104-108	Addressed
	b. minimize total system costs	47, 104-108, 110	Addressed
Objective 5	Provide the Commission with the following information: a short-term and long-term distribution plans	22-28, 31,45,88-93, 101-102, 126-133	Addressed
	b. a description of the costs and benefits of investments	59-62, 96-99, 126-133	Addressed
	c. an analysis of rate payer cost and value	96-99, 133	Addressed

Minnesota Department of Commerce
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Information Request

Docket Number: E111/M-23-420 ☐Nonpublic ☒Public
Requested From: Craig Turner, Sr. Principal & Regulatory Engineer DEA Date of Request: 3/25/2024
Type of Inquiry: General Response Due: 4/4/2024

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Diane Dietz, Peter Teigland, Ari Zwick
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Request Number:	**1**
Topic:	Information Requests
Reference(s):	2023 IDP

Request:
Please provide the Department a copy of DEA's past, present, and future responses to other parties' information requests in this proceeding.

Response:

Dakota Electric has not, to date, received information requests from other parties, but we will provide any, and all, information requests from other parties.

To be completed by responder

Response Date: April 4, 2024
Response by: Adam Heinen, Vice President Regulatory Services, and Alex Nelson, Electrical Engineer
Email Address: aheinen@dakotaelectric.com and anelson@dakotaelectric.com
Phone Number: 651-463-6258

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Request Number:	**2**
Topic:	Information Requests
Reference(s):	2023 IDP

Request:

Please provide all underlying working files used to create the figures and tables provided in DEA's 2023 IDP.

Where applicable, for any and all parts above, please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

Response:

Please see attached Excel files.

To be completed by responder

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Request Number: **3**
Topic: Total System Load Growth
Reference(s): 2023 IDP

Request:

Please present a forecast of total DEA service area load growth that covers at least the 2023 – 2027 planning period, if available.

Response:

Each year, Dakota Electric conducts long-range energy requirements (sales) forecasting as part of its regular budgeting process, and every two years (the most recent was conducted in 2022) Dakota Electric conducts a long-range load (kW or capacity) forecast. The results are show below:

Year	Energy Requirements (kWh)	Load (MW)
2023	1,858,400,461	457
2024	1,875,011,000	454
2025	1,905,081,000	469
2026	1,926,932,000	477
2027	1,945,526,706	484

Note: 2023 energy requirements are based on actual sales through August 2023.

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Request Number:	**4**
Topic:	Vegetation Management
Reference(s):	2023 IDP, Section 1.g

Request:

On p. 15 of its IDP, DEA states that it has "… embarked on an aggressive vegetation management strategy and is beginning to see improvements in metrics associated with these types of outages. The goal is to continue to reduce the overall impact of outages caused by trees." Please provide:

a) The historical and projected values for the metrics DEA tracks associated with this program,
b) The annual historical spending for the program,
c) The annual spending for the program included in the five-year forecast, and
d) How the program relates to DEA's efforts to maintain and enhance system resilience.

Response:

a) The historical and projected values for the metrics DEA tracks associated with this program,

Dakota Electric Association strives to deliver safe and reliable electric service to its members. Historically, vegetation and weather-related incidents were the largest cause of outages. In 2020, DEA executed a new vegetation management strategy focused on reducing the backlog of member requested tree tickets, reclaiming vegetation clearance for overhead lines, and reducing the number of tree related outage incidents. At the beginning of 2020, there was a backlog of over 800 member-requested tree tickets. At the end of 2023, the backlog of member-requested tree tickets was below 100. Prior to 2020, vegetation rights-of-way were not cleared on a trimming cycle. By the end of 2023, approximately 500 miles of line has been cleared and progress is being made toward a 5-year

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(continued)

tree trimming cycle. In 2020, DEA members experienced 229 tree related outage incidents. The number of tree related outage incidents has decreased annually since and was down to 156 incidents in 2023.

b) The annual historical spending for the program,

Dakota Electric spent $1.21 million in 2020, $1.21 million in 2021, $1.28 million in 2022, and $1.53 million in 2023 on external labor for vegetation management.

c) The annual spending for the program included in the five-year forecast, and

Dakota Electric has budgeted $1.78 million for external labor associated with vegetation management in 2024 and is forecasted to maintain funding at this level over the next 5 years.

d) How the program relates to DEA's efforts to maintain and enhance system resilience.

A properly executed vegetation management strategy reduces potential hazards to the public and improves system reliability. Possible injuries, damage to equipment, and potential fire hazards can be associated with poor vegetation management practices. Historically, vegetation has been the largest single contributor to outages and reducing the potential of tree related incidents will improve all three standard utility metrics (SAIDI, SAIFI, and CAIDI) commonly used to measure system reliability.

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Request Number:	**5**
Topic:	Grid Expansion Capacity
Reference(s):	2023 IDP, Section 2.a

Request:

On p. 24 of its IDP, DEA states "An engineering review of the expected capability of our existing infrastructure within the residential developments to support EV charging has occurred regularly over the past few years. While we continue to learn more, our engineers have found that the existing distribution system is ready to supply a large amount of level 2 EV charging with minimal modifications. In most cases, the backbone distribution system can support nearly double the amount of existing load." Please describe:

a) Whether the backbone distribution system can supply a doubling of EV load, or all load,
b) The estimated number of EVs that would trigger widescale capacity upgrades, and
c) The planning reserve margin for reliability that would trigger a capacity upgrade.

Response

a) Dakota Electric engineers believe, in general, our distribution system could handle doubling of existing EV load. Dakota Electric's engineers do not believe our distribution system could handle doubling of all load under current design.
b) Depending on where the EV load is located is a critical part that would determine what distribution system upgrades are needed. Estimating the quantity of EVs that would trigger widespread capacity upgrades has not been studied by Dakota Electric.

To be completed by responder

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(Continued)

c) From Dakota Electric's studies, design standards for transformer sizing, residential developments, and feeder sizing have been updated to prepare for projected EV load for new construction developments as new construction homes are typically equipped with EV charging infrastructure. Dakota Electric's engineers believe our historic design standards have positioned Dakota Electric well to accommodate EV loading. As noted on page 33 of the IDP Report, Dakota Electric's distribution transformers on average are loaded to 60%, thus there is some capacity for additional EV load. Dakota Electric continues to monitor loading directly related to EV load but has not set any standard regarding a planning reserve margin that would trigger capacity upgrades.

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Request Number:	**6**
Topic:	Multifamily EV Charging
Reference(s):	2023 IDP, Section 2.a

Request:

On p. 26 of its IDP, DEA states "Since a significant percentage of our residential members live in multi-family housing, working with the management companies to help them through the many issues involving adding EV charging to their facility is a top priority for Dakota Electric. Dakota Electric is working with management companies and considering various rate and rebate options and strategies that may be available to help incentivize development in multi-family facilities." Please describe any completed multifamily projects to date and provide a brief description of the project that includes:

a) The number of chargers installed,
b) The rated capacity of chargers installed,
c) Any cost recovery systems installed, and
d) Required upgrade costs and customer cost allocation.

Response

Dakota Electric does not currently have multi-family or commercial projects on our approved rate schedules. We continually engage with management companies, prospective members, and builders on this topic, and we are considering potential adjustments to programs and rate designs.

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Request Number:	**7**
Topic:	MnDOT High EV Prediction
Reference(s):	2023 IDP, Section 2.b

Request:

On p. 30 of its IDP, DEA states "Based on its review of EV data in its service territory, Dakota Electric believes that the statewide 2022 MnDOT high prediction is a reasonable star�ng point to forecast EV sales for the Dakota Electric service territory." Please provide a narrative description of why DEA believes the MNDOT high prediction is a reasonable basis for DEA's EV forecast.

Response:

Dakota Electric believes the MNDOT high prediction is a reasonable basis for DEA's EV forecast because the projections closely align with yearly EV growth in Dakota Electric's service territory. Using the MNDOT high prediction also allows engineers to calculate a 'worst case' scenario to begin reviewing and planning system upgrades. Dakota Electric has already updated and continues to review our design standards for residential developments, distribution transformer sizing, and conductor standards to accommodate forecasted EV load.

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Request Number:	**8**
Topic:	Solar Hosting Capacity Analysis
Reference(s):	2023 IDP, Section 3.d

Request:

In Section 3.d of its IDP, DEA describes its hosting capacity tool. Please describe what criteria DEA uses to determine if a transformer, feeder, fuse, substation etc. has reached its maximum hosting capacity.

Response:

Dakota Electric uses 100% of a device's nameplate capacity as its maximum hosting capacity for distribution transformers and sectionalizing equipment (*e.g.,* fuse, recloser). Dakota Electric's feeders are designed to interconnect with other feeders from other substations. Dakota Electric designs feeders to serve a normal maximum capacity of 50% of their rating so a feeder from a nearby substation could serve the entire load of another feeder without overloading any single feeder. This standard is what has enabled Dakota Electric to maintain high reliability and quality metrics. Dakota Electric employs this same standard for DER. Currently, Dakota Electric has not had any feeder level constraints for members. Dakota Electric would allow up to 100% of a substation transformer's nameplate rating of DER to interconnect; given the appropriate transmission back feeding approvals from Great River Energy and MISO. The ratings for maximum hosting capacity could change in the future given more DER penetration and analysis by Dakota Electric.

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Request Number:	**9**
Topic:	ESS to Control Transmission Backfeeding
Reference(s):	2023 IDP, Section 3.g

Request:

In Table 10 of DEA's IDP, DEA presents the estimated cost of an energy storage solution designed to prevent transmission back feeding. DEA states "the overall costs suggest that this is not an economic method for supporting additional DER integration with a distribution system that is limited in its ability to back feed the transmission system." Please describe:

a) The estimated benefits that would accrue from this project.
b) Any studies that DEA has completed to use behind the meter energy storage to increase hosting capacity.

Response:

a) Dakota Electric discussed the estimated benefits and issues of using ESS to control transmission back feeding on pages 56-61 of the IDP Report. Dakota Electric is unware of additional, quantifiable benefits outside of what was previously discussed in the IDP. Specific estimates of potential benefits and losses can also be seen in Tables 8 & 9 of the IDP Report.
b) Dakota Electric does not believe that behind the meter energy storage increases hosting capacity. Behind the meter energy storage would only increase the available hosting capacity if the energy storage system (ESS) limited its export to the grid. For example, assume a 20 kWac solar system was paired with a 10 kWac ESS for a total nameplate capacity of 30 kWac. If the DER implemented a control system so the maximum export capacity was 10 kWac to the grid, this would increase the available hosting capacity by 20 kWac. This does not increase the total hosting capacity; it only limits the capacity that the single DER takes up and allows a different DER an additional 20 kWac to interconnect. Dakota Electric has not done

To be completed by responder

Response Date: April 4, 2024
Response by: Adam Heinen, Vice President Regulatory Services, and Alex Nelson, Electrical Engineer
Email Address: aheinen@dakotaelectric.com and anelson@dakotaelectric.com
Phone Number: 651-463-6258

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Number: E111/M-23-420 ☐Nonpublic ☒Public
Requested From: Craig Turner, Sr. Principal & Regulatory Engineer DEA Date of Request: 3/25/2024
Type of Inquiry: General Response Due: 4/4/2024

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Diane Dietz, Peter Teigland, Ari Zwick
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(Continued)

additional studies but would welcome further discussion in the DGWG regarding hosting capacity & behind the meter storage.

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Request Number:	**10**
Topic:	AGi EV Benefits
Reference(s):	2023 IDP, Section 4.a

Request:

On p. 64 of its IDP, DEA states "The most recent example of using technology was leveraging our AGi advanced meters to provide a lower cost virtual metered EV charging option. This is just a small example of Dakota Electric's use of non-wires (non-traditional) methods to help our membership." Please describe the specific benefits of this program, both qualitative and quantitative, for ratepayers.

Response
Dakota Electric discussed the benefits and construction of the virtual EV charging rate at length in its approval request filed in Minnesota Public Utilities Commission Docket No. E111/M-22-592. Please refer to Dakota Electric's November 11, 2022 Initial Petition for further detail on this program. From a summary perspective, Dakota Electric provides the following excerpt from the Initial Petition:

> The petition implements a new pilot for virtual metered electric vehicle (EV) service. This new rate provides an option for members who are unable to utilize one of our existing EV rates and provides a financial incentive, through an energy credit, for those members to charge their electric vehicles during off-peak periods. Encouraging members to move EV charging from periods of peak demand to off-peak periods help lower wholesale power costs for Dakota Electric, which in turn translates into lower overall rates for all members. The energy credit maintains an on-peak/off-peak energy consumption relationship with the existing time-of-use residential electric vehicle rates (Schedule EV-1 or EV-1) approved in our most recent general rate case. The new rate will be open to all members who take power under the existing residential rate (Schedule 31). Under this new rate, if members adjust their charging schedules

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(Continued)

from charging during on-peak times to off-peak times, members will be rewarded with a rate credit for energy consumed during off-peak periods. This rate can only result in a credit for a member.

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Request Number:	**11**
Topic:	NWA Grant Applications
Reference(s):	2023 IDP, Section 4.a

Request:

On p. 64 of its IDP, DEA states "Dakota Electric has several projects planned for construction over the next 5 years which approach or exceed two (2) million dollars. Dakota Electric notes that it has also applied for, or is actively considering, grant and funding opportunities through the IIJA and IRA which may also involve projects in excess of $2 million. Since these potential investments are contingent upon a grant award, Dakota Electric does not provide additional discussion at this time." Please provide a brief description of these projects and the specific NWA solution they propose.

Response

Dakota Electric staff in charge of grant applications was on vacation during the response period and is still compiling this information. We will provide a response when available.

To be completed by responder

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Response:

Dakota Electric has three applications submitted for projects in excess of two (2) million dollars. All of the opportunities are part of consortia with other electric cooperatives. The first of these opportunities is submitted as part of the New ERA opportunity through the US Department of Agriculture. If awarded, this would enable Dakota Electric to add approximately 20 MW of photo-voltaic generation to our distribution system.

The second opportunity, part of the GRIP Round 2 funding opportunity through the US Department of Energy, is for projects to improve the resiliency of our existing system by upgrading single phase lines over five years. The specific projects would be determined as a result of a new software tool developed as part of the opportunity.

(Continued)

To be completed by responder

Response Date: April 8, 2024
Response by: Adam Heinen, Vice President of Regulatory Services, and Alex Nelson, Electrical Engineer
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The estimated spend for this would be $12 million between 2025 and 2029, with up to 75% of the cost covered by the grant.

The third opportunity, also part of the GRIP Round 2 funding opportunity, is to add a Distributed Energy Resource Management System (DERMS) to our suite of software tools. DERMS will further enable distributed energy resources by allowing direct control of member-owned thermostats, EV chargers, and other devices in addition to Dakota Electric's existing ability to control Dakota Electric owned load control receivers. The estimated spend for this is up $2 million dollars between 2025 and 2029 with up to 50% of the cost covered by the grant.

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Request Number:	**12**
Topic:	Lake Marion – Castle Rock Area Growth Scenarios
Reference(s):	2023 IDP, Section 4.d

Request:

On p. 70 of its IDP, DEA presents a "Slow Growth" and "Faster Growth" scenario for load growth in the Lake Marion – Castle Rock area. Please describe:

a) The underlying assumptions and data DEA used to develop its load growth forecasts.
b) Whether DEA believes that any of the NWA solutions studied in options 1A-D could become economical solutions if modeled load growth were curtailed to 10 or 15 MW.
c) Whether DEA believes that any of the NWA solutions studied in options 1A-D could become economical solutions with IRA or IIJA funding.
d) Any areas where DEA believes that the NWA solutions studied could prevent traditional wired distribution system upgrades.

Response:

a) Dakota Electric assumed an upfront load of 5 MW for Slow Growth and 7 MW for Fast Growth. The base 5 MW used is from a known commercial load that is planned to be operational in late 2024 and an additional load was added for the Fast Growth predicting expedited commercial growth in the area. After the initial 5 years, an average growth rate of approximately 3% was used for both forecasts. Existing information and best engineering judgement were used for these forecasts.
b) Considering the current costs of the NWA solutions that were studied, and the reliability concerns with the location of the load growth, Dakota Electric does not currently believe that an NWA solutions would become economically viable even with a lower growth rate.

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(Continued)

c) Dakota Electric notes that grant funding through the IRA and IIJA is extremely competitive and, even if awarded funding, there are many circumstances where an entity is required to fund the entire project upfront and receive government compensation at a later date. These facts not withstanding, Dakota Electric believes with funding from the IRA or IIJA, it may be possible for a solution to be economically feasible. However, it is important to reiterate that even with this funding, Dakota Electric would need to further investigate the operational and reliability risks involved with the NWA solutions because we have an obligation to provide safe, reliable, and affordable electric service.

d) Dakota Electric does not believe with current technology that the NWA solutions studied could replace traditional wired distribution system upgrades. These NWA solutions could potentially delay traditional upgrades but their associated costs along with operational and reliability concerns pose a greater risk than traditional system upgrades. Dakota Electric believes there are other use cases outside of the solutions studied where NWA solutions could potentially prevent traditional wired system upgrades.

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Request Number:	**13**
Topic:	NWA Option 1D – Deferring New Substation With Demand-Side Management
Reference(s):	2023 IDP, Section 4, Option 1D

Request:

In Section 4, Option 1D of its IDP, DEA describes its "Deferring New Substation with Demand Side Management" scenario. From Table 20, please describe:

a) Why a cost of $7 million is listed for the "Cost of Energy Storage Systems (500 kW)" line item, while Years 2 and 3 list a cost of $1,750,000, consistent with the $3,500 / kW criteria.
b) Why the "Cost of receiver controls (500 kW)" line item is only listed in Year 1.
c) Why the "Cost of Incentives for Members" line item is only listed in Year 1.

Response:

a) The $7 million line item should have said "Cost of Energy Storage Systems (2000kW)" instead of "Cost of Energy Storage Systems (500 kW)".
b) The "Cost of receiver controls (500 kW)" are the estimated costs associated with physically installing load control receiver devices at member homes. This is only listed in year 1 because it is assumed there is at least 500kW of load that could be managed in a targeted area, and Dakota Electric would strategically provide additional incentives for the first 500kW of load that would sign up for load management programs. There may be additional load management costs that occur outside of year 1 but they were not included in this analysis.
c) The "Cost of Incentives for Members" was only included in year 1 because it is directly related to "Cost of receiver controls (500 kW)" for the first 500kW of load that would sign up for Dakota Electric's load

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(Continued)

management programs. In this analysis, Dakota Electric did not provide additional incentives for load management outside of the first 500kW.

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Request Number:	**14**
Topic:	Heat Pump Adoption
Reference(s):	2023 IDP, Section 5.y

Request:

In Table 36 of DEA's IDP, DEA lists that it has 2,765 heat pumps enrolled in its controllable demand portfolio. Please provide:

a) Any data or estimates DEA has regarding the total number of heat pumps installed in the DEA service territory.
b) Historical data on the number of heat pumps enrolled in its controllable demand portfolio.
c) Any forecasts DEA has generated or relied on regarding heat pump adoption in its service territory.

Response:

a) Dakota Electric does not have data or estimates available regarding the total number of heat pumps in our service territory beyond those that are registered for our load management programs. Unlike loads such as an electric vehicle, heat pumps do not have a distinctive load profile that can be easily identified by our meter data management system.
b) The 2,765 heat pump figure is in error and represents the number of heat pumps reported in the 2021 IDP. The current figure, as presented in Appendix B of the IDP Report, for heat pumps is 2,748 and based on a snapshot of load control programs pulled from our GIS and billing system and does not necessarily match information and data used by Dakota Electric or Great River Energy for CIP program development. The information in the table below represents the number of heat pump installations that were

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(Continued)
associated with rebates for our load management program. This does not reflect prior installations that have left the program.

Year	Heat Pump Installations
2020	35
2021	53
2022	94
2023	73

c) Dakota Electric has not produced or relied upon any forecasts for future heat pump adoption in our service territory.

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Request Number:	**15**
Topic:	DML at Randolph Substation
Reference(s):	2023 IDP, Appendix B

Request:

On p. 139 of its IDP, DEA shows a daytime minimum load of -1,061 kW in 2022 and -1,108 kW in 2020 on the Randolph Substation. Please explain why the daytime minimum load is negative and how a negative daytime minimum load could affect the DEA distribution system.

Response:

A negative Daytime Minimum Load (DML) represents a larger amount of reverse power than load on the substation. These values also represent the maximum reverse power that was sent through the substation transformer and received on the transmission system. Dakota Electric has been approved by Great River Energy for a maximum of 2 MW back feeding to the transmission system. The cause of the large negative DML is a Utility-Scale Solar Array interconnected to the substation. Dakota Electric's distribution system could be affected by increased losses due to increased load flow in power flowing up through the feeder from the Utility-Scale Solar Array and then feeding out through the other substation feeders. Additional discussion on this can be found under section *1) e) Increasing Distribution System Losses* on page 10 & 11 of the IDP Report.

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CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E111/M-23-420

Dated this **19th** day of **April 2024**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, MN 55405	Electronic Service	No	OFF_SL_23-420_M-23-420
David	Amster Olzweski	david@mysunshare.com	SunShare, LLC	1151 Bannock St Denver, CO 80204-8020	Electronic Service	No	OFF_SL_23-420_M-23-420
Ellen	Anderson	ellena@umn.edu	325 Learning and Environmental Sciences	1954 Buford Ave Saint Paul, MN 55108	Electronic Service	No	OFF_SL_23-420_M-23-420
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Donna	Attanasio	dattanasio@law.gwu.edu	George Washington University	2000 H Street NW Washington, DC 20052	Electronic Service	No	OFF_SL_23-420_M-23-420
John	Bailey	bailey@ilsr.org	Institute For Local Self-Reliance	1313 5th St SE Ste 303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_23-420_M-23-420
Mark	Bakk	mbakk@lcp.coop	Lake Country Power	26039 Bear Ridge Drive Cohasset, MN 55721	Electronic Service	No	OFF_SL_23-420_M-23-420
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-420_M-23-420
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-420_M-23-420
Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services	3724 West Avera Drive PO Box 88920 Sioux Falls, SD 57109-8920	Electronic Service	No	OFF_SL_23-420_M-23-420

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Kenneth	Bradley	kbradley1965@gmail.com		2837 Emerson Ave S Apt CW112 Minneapolis, MN 55408	Electronic Service	No	OFF_SL_23-420_M-23-420
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_23-420_M-23-420
Sydney R.	Briggs	sbriggs@swce.coop	Steele-Waseca Cooperative Electric	2411 W. Bridge St PO Box 485 Owatonna, MN 55060-0485	Electronic Service	No	OFF_SL_23-420_M-23-420
Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company	215 South Cascade Street PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_23-420_M-23-420
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	60 S 6th St Ste 1500 Minneapolis, MN 55402-4400	Electronic Service	No	OFF_SL_23-420_M-23-420
Jessica	Burdette	jessica.burdette@state.mn.us	Department of Commerce	85 7th Place East Suite 500 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-420_M-23-420
LORI	CLOBES	lclobes@mienergy.coop	MiEnergy Cooperative	31110 COOPERATIVE WAY PO BOX 626 RUSHFORD, MN 55971	Electronic Service	No	OFF_SL_23-420_M-23-420
Douglas M.	Carnival	dcarnival@carnivalberns.com	McGrann Shea Carnival Straughn & Lamb	N/A	Electronic Service	No	OFF_SL_23-420_M-23-420
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_23-420_M-23-420

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC	26 Winton Road Meredith, NH 32535413	Electronic Service	No	OFF_SL_23-420_M-23-420
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_23-420_M-23-420
George	Crocker	gwillc@nawo.org	North American Water Office	5093 Keats Avenue Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_23-420_M-23-420
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-420_M-23-420
Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative	1302 S Union St Rock Rapids, IA 51246	Electronic Service	No	OFF_SL_23-420_M-23-420
Carlon	Doyle Fontaine	carlon.doyle.fontaine@senate.mn	MN Senate	75 Rev Dr Martin Luther King Jr Blvd Room G-17 St Paul, MN 55155	Electronic Service	No	OFF_SL_23-420_M-23-420
Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE	28477 N Lake Ave Frontenac, MN 55026-1044	Electronic Service	No	OFF_SL_23-420_M-23-420
Bob	Eleff	bob.eleff@house.mn	Regulated Industries Cmte	100 Rev Dr Martin Luther King Jr Blvd Room 600 St. Paul, MN 55155	Electronic Service	No	OFF_SL_23-420_M-23-420
Betsy	Engelking	betsy@nationalgridrenewables.com	National Grid Renewables	8400 Normandale Lake Blvd Ste 1200 Bloomington, MN 55437	Electronic Service	No	OFF_SL_23-420_M-23-420

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_23-420_M-23-420
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_23-420_M-23-420
Nathan	Franzen	nathan@nationalgridrenewables.com	Geronimo Energy, LLC	8400 Normandale Lake Blvd Ste 1200 Bloomington, MN 55437	Electronic Service	No	OFF_SL_23-420_M-23-420
Hal	Galvin	halgalvin@comcast.net	Provectus Energy Development llc	1936 Kenwood Parkway Minneapolis, MN 55405	Electronic Service	No	OFF_SL_23-420_M-23-420
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_23-420_M-23-420
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_23-420_M-23-420
Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy	408 St. Peter Street Ste 350 Saint Paul, MN 55102	Electronic Service	No	OFF_SL_23-420_M-23-420
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_23-420_M-23-420
Jared	Hendricks	jared.hendricks@owatonnautilities.com	Owatonna Municipal Public Utilities	PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940	Electronic Service	No	OFF_SL_23-420_M-23-420
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_23-420_M-23-420
Joe	Hoffman	ja.hoffman@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	OFF_SL_23-420_M-23-420
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_23-420_M-23-420
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Ralph	Jacobson	ralphj@ips-solar.com		2126 Roblyn Avenue Saint Paul, MN 55104	Electronic Service	No	OFF_SL_23-420_M-23-420
Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58501	Electronic Service	No	OFF_SL_23-420_M-23-420
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC	260 Salem Church Road Sunfish Lake, MN 55118	Electronic Service	No	OFF_SL_23-420_M-23-420
Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.	11 East Superior St Ste 125 Duluth, MN 55802	Electronic Service	No	OFF_SL_23-420_M-23-420
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_23-420_M-23-420
Brian	Krambeer	bkrambeer@mienergy.coop	MiEnergy Cooperative	PO Box 626 31110 Cooperative Way Rushford, MN 55971	Electronic Service	No	OFF_SL_23-420_M-23-420
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Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-420_M-23-420

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-420_M-23-420
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Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-420_M-23-420
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_23-420_M-23-420
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Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota	4808 10th Avenue S Minneapolis, MN 55417	Electronic Service	No	OFF_SL_23-420_M-23-420
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-420_M-23-420
Alex	Nelson	ANelson@dakotaelectric.com	Dakota Electric Association	4300 220nd St Farmington, MN 55024	Electronic Service	No	OFF_SL_23-420_M-23-420
Ben	Nelson	benn@cmpasgroup.org	CMMPA	459 South Grove Street Blue Earth, MN 56013	Electronic Service	No	OFF_SL_23-420_M-23-420
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-420_M-23-420
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	OFF_SL_23-420_M-23-420
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_23-420_M-23-420
David	O'Brien	david.obrien@navigant.com	Navigant Consulting	77 South Bedford St Ste 400 Burlington, MA 01803	Electronic Service	No	OFF_SL_23-420_M-23-420

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District	PO Box 248 Madison, SD 570420248	Electronic Service	No	OFF_SL_23-420_M-23-420
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Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute	1000 Vermont Ave, Third Floor Washington, DC 20005	Electronic Service	No	OFF_SL_23-420_M-23-420
David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_23-420_M-23-420
Michael	Reinertson	michael.reinertson@avantenergy.com	Avant Energy	220 S. Sixth St. Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-420_M-23-420
John C.	Reinhardt	N/A	Laura A. Reinhardt	3552 26th Ave S Minneapolis, MN 55406	Paper Service	No	OFF_SL_23-420_M-23-420
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_23-420_M-23-420

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Noah	Roberts	nroberts@cleanpower.org	Energy Storage Association	1155 15th St NW, Ste 500 Washington, DC 20005	Electronic Service	No	OFF_SL_23-420_M-23-420
Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative	P.O. Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_23-420_M-23-420
Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	OFF_SL_23-420_M-23-420
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_23-420_M-23-420
Dean	Sedgwick	Sedgwick@Itascapower.com	Itasca Power Company	PO Box 455 Spring Lake, MN 56680	Electronic Service	No	OFF_SL_23-420_M-23-420
Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology	120 Tredegar Street Richmond, VA 23219	Electronic Service	No	OFF_SL_23-420_M-23-420
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_23-420_M-23-420
Patricia F	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.	180 N LaSalle St Ste 3700 Chicago, IL 60601	Electronic Service	No	OFF_SL_23-420_M-23-420
Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-420_M-23-420

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.	254 E Hacienda Ave Campbell, CA 95008	Electronic Service	No	OFF_SL_23-420_M-23-420
Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy	305 Saint Peter St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_23-420_M-23-420
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, CA 94105	Electronic Service	No	OFF_SL_23-420_M-23-420
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_23-420_M-23-420
Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-420_M-23-420
Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	No	OFF_SL_23-420_M-23-420
Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger	396 Hayes Street San Francisco, CA 94102	Electronic Service	No	OFF_SL_23-420_M-23-420
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-420_M-23-420
Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-420_M-23-420

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_23-420_M-23-420
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_23-420_M-23-420
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_23-420_M-23-420
Lise	Trudeau	lise.trudeau@state.mn.us	Department of Commerce	85 7th Place East Suite 500 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-420_M-23-420
Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities	208 S Walnut Ave PO BOX 800 Owatonna, MN 55060	Electronic Service	No	OFF_SL_23-420_M-23-420
Jenna	Warmuth	jwarmuth@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802-2093	Electronic Service	No	OFF_SL_23-420_M-23-420
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_23-420_M-23-420
Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC	W234 N2000 Ridgeview Pkwy Court Waukesha, WI 53188-1022	Electronic Service	No	OFF_SL_23-420_M-23-420
Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_23-420_M-23-420