MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	Tuesday, July 2, 2024	Agenda Item **2
Company	Dakota Electric Association	
Docket No.	**E111/M-23-420**	
	In the Matter of Distribution System Planning for Dakota Electric Association	
Issues	1. Should the Commission accept or reject Dakota Electric Association's 2023 Integrated Distribution Plan (IDP)? 2. Should the Commission require any additional information or adjust any of the IDP filing requirements for Dakota Electric Association? 3. Should the Commission take any other action related to Dakota Electric Association's IDP?	
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✓ **Relevant Documents**	**Date**
Dakota Electric – Report – 2023 Integrated Distribution Plan Report	November 1, 2023
Department of Commerce - Comments	April 19, 2024
Dakota Electric – Reply Comments	May 3, 2024
Dakota Electric – DEA Response to PUC IR 1	May 9, 2024
Department of Commerce – Reply Comments	May 24, 2024

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Acronyms

ADMS	Advanced Distribution Management System
Agi	Advanced Metering Infrastructure
AMI	Advanced Metering Infrastructure
Area EPS	Area Electric Power System
CAIDI	Customer Average Interruption Dura�on Index
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DSM	Demand-side Management
ECO	Energy Conservation and Optimization
ERA	Energy Improvements in Rural or Remote Areas
ERP	Enterprise Resource Planning
EV	Electric Vehicle
IDP	Integrated Distribution Plan
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IT	Information Technology
LCR	Load Control Receiver
MDM	Meter Data Management
MN DIP	Minnesota Distributed Interconnection Procedures
O&M	Operations and Maintenance
OAG	Office of the Attorney General
OMS	Outage Management System
SCADA	Supervisory Control and Data Acquisition
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TOU	Time of Use

1. Statement of the Issues

1. What action should the Commission take with Dakota Electric Association's 2023 Integrated Distribution Plan (IDP)?
2. Should the Commission adjust any of the IDP filing requirements for Dakota Electric Association's next IDP?

2. Introduction and Background

The purpose of the Commission's IDP filing requirements is to facilitate a utility's IDP filing that will meet the following planning objectives:

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.

On November 1, 2023, Dakota Electric Association (Dakota Electric or DEA) submitted its Integrated Distribution Plan (2023 IDP).

On November 15, 2023, the Commission issued a Notice of Comment Period asking parties to answer the following questions regarding the 2023 Dakota Electric IDP:

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:[1]
    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

[1] MN PUC, ORDER ADOPTING INTEGRATED DISTRIBUTION PLAN FILING REQUIREMENTS at 2 (February 20, 2019), Docket No. E111/CI-18-255.

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.

On April 19, 2024, the Department filed its initial comments with additional information requests and initial recommendations.

On May 3, 2024, DEA filed reply comments with responses to the Department's additional detail requests.

On May 24, 2024, the Department filed reply comments with final recommendations.

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

3. Summary of IDP

A. System and Financial Overview

i. Existing System Summary

Dakota Electric Association is a not-for-profit, member-owned electrical cooperative, serving the electrical needs of approximately 115,000 members in Dakota County, and portions of Scott and Goodhue counties. Dakota Electric ranks as Minnesota's second-largest electric distribution cooperative and is among the top 35 largest in the United States. It is also unique as the only electric cooperative utility that is rate regulated by the Commission. Dakota Electric purchases wholesale power from Great River Energy (GRE) and experiences summer peak demand of 450-500 MW, primarily due to air conditioning use in homes and businesses.[2] Dakota Electric also has an extensive demand-side management system and can control as much as 100 MW during the summer months and around 70 MW during winter months, which is about 20% or more of its total system demand.[3]

All of Dakota Electric's substations are outfitted with SCADA monitoring and control, a standard that will also apply to any future substations, and all feeders feature digital protective relaying monitored by the SCADA system at the substation. Distributed Energy Resource (DER) systems that are part of the C&I Interruptible – Rate 70 also has SCADA monitoring and control installed by Dakota Electric. The SCADA control system can remotely curtail or disconnect these DER

[2] DEA initial filing on November 1, 2023, at 3.
[3] DEA initial filing on November 1, 2023, at 5.

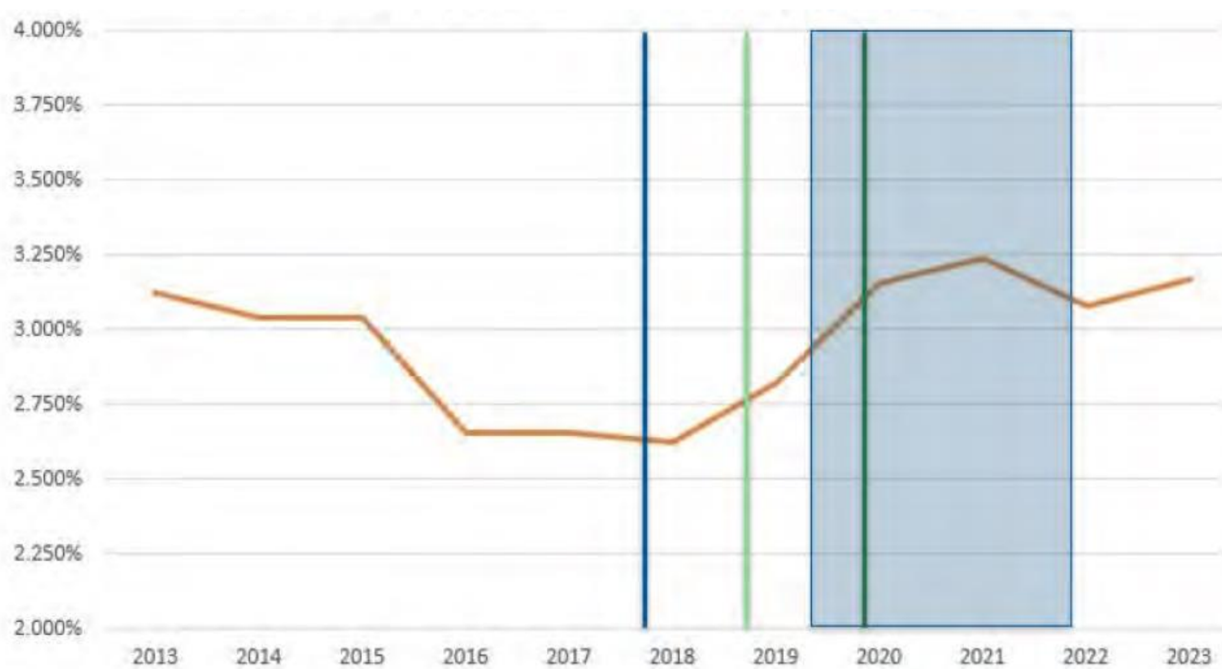
systems from the Dakota Electric system if necessary.[4] Working with the owners of these systems, DEA has the ability to support partial curtailment of DER output if needed, which is more flexible than shutting off the DER during system maintenance.

Dakota Electric has replaced over 125,000 meters and more than 50,000 load control receivers with devices that utilize the Advanced Grid Infrastructure (Agi) Radio Frequency (RF) mesh communication system.[5] By early 2024, all meters were to be replaced with AMI meters, except for about 165 members who have chosen to opt out of the advanced meters. Since the 2021 IDP report, Dakota Electric has begun using the internal switch in many single-phase residential meters to remotely disconnect and reconnect electrical service, which is safer than manually removing the meter.[6]

Increasing Distribution System Losses

The figure below provides recent trends in Dakota Electric's line loss data, showing an increase in distribution system losses starting from 2018 and losses remain close to 3 percent observed over the past decade.[7]

Figure 1: DEA's Distribution System Annual % Loss in the Past 10 Years



[4] DEA initial filing on November 1, 2023, at 95.
[5] DEA initial filing on November 1, 2023, at 96.
[6] DEA initial filing on November 1, 2023, at 97.
[7] DEA initial filing on November 1, 2023, at 10.

ii. Historic and forecasted budget overview, including a summary of how the utility develops their budget

DEA lists its capital spending for construction over a historical 5-year period (2018-2022) in Table 1, note that the capital projects listed in this table exclusively pertain to the distribution system, excluding any related to corporate building maintenance or internal software developments. [8]

Table 1: Historical Total Capital Spending in Thousands

	2018	2019	2020	2021	2022
Age Related Replacement	$4,195	$3,066	$5,771	$2,426	$3,108
System Expansion (Due to Capacity)	$716	$831	$694	$3,263	$2,772
System Expansion (Due to Reliability)	$1,220	$1,308	$1,025	$1,176	$1,225
New Members	$3,006	$4,302	$4,099	$4,561	$5,782
System Project (Driven by Mandate)	$1,263	$1,306	$1,107	$1,532	$1,659
Metering	$0	$103	$5,592	$12,381	$0
Grid Mod (Advanced Technologies)	$361	$1,057	$2,685	$3,348	$3,950
Annual Total	**$10,762**	**$11,973**	**$20,972**	**$28,687**	**$18,495**

DEA notes the significant increase in spending from 2020 is largely due to its AGi advanced metering project, where the cost of new meters is placed under the metering category and the cost of new load control receivers plus the RF Mesh system is included in the advanced technologies category.[9]

Table 2 shows a comparison between the forecasted spending for years 2021 and 2022 and the actual expenditures. DEA notes that the 2021 actual spending is higher than forecasts because of its ability to complete more of the AGi meter and load control receiver installations than expected. [10]

Table 2: 2021 & 2022 IDP Forecasted Capital Expenditures vs Actual in Thousands

	2021 Forecast	2021 Actual		2022 Forecast	2022 Actual
Age Related Replacement	$2,235	$2,426		$2,904	$3,108
System Expansion (Due to Capacity)	$3,348	$3,263		$3,045	$2,772
System Expansion (Due to Reliability)	$1,052	$1,176		$1,357	$1,225
New Members	$4,473	$4,561		$4,605	$5,782
System Project (Driven by Mandate)	$1,734	$1,532		$1,893	$1,659
Metering	$11,921	$12,381		$499	$0
Grid Mod (Advanced Technologies)	$2,972	$3,348		$4,169	$3,950
Annual Total	**$27,736**	**$28,687**		**$18,471**	**$18,495**

[8] Table 37 in DEA initial filing on November 1, 2023, at 123.
[9] DEA initial filing on November 1, 2023, at 124.
[10] DEA initial filing on November 1, 2023, at 125.

DEA also lists the forecasted 5-year construction capital spend for the requested categories, where the capital spending forecast for short term projects such as new services, road rebuilds by government, response to area load growth is based on historical spending and longer-term projects such as new distribution, substation, and age-related replacements are forecasted further out. DEA notes that new Energy Improvements in Rural or Remote Areas (ERA) projects that have been submitted but not finalized are not included in Table 3.[11]

Table 3: Five Year Forecast of Distribution System Spending in Thousands

	2023	2024	2025	2026	2027
Age Related Replacement	$3,806	$4,242	$5,646	$6,687	$5,137
System Expansion (Due to Capacity)	$4,650	$4,501	$3,982	$3,061	$3,256
System Expansion (Due to Reliability)	$1,736	$1,777	$1,775	$1,594	$1,594
New Members	$4,765	$5,510	$5,727	$5,666	$5,495
System Project (Driven by Mandate)	$1,970	$1,966	$1,413	$1,222	$1,622
Metering	$123	$216	$10	$10	$10
Grid Mod (Advanced Technologies)	$1,695	$1,376	$272	$257	$257
Annual Total	**$18,746**	**$19,588**	**$18,825**	**$18,496**	**$17,371**

Department Initial Comments

The Department reviewed DEA's annual spending projections provided in 2021 and 2023 IDP respectively and found forecasted total distribution system spending from 2023 through 2025 period increased by $13.23 million (30 percent), which were mostly driven by increase in three categories: Age-Related Replacements and Asset Renewal ($5.4 million), System Expansion or Upgrades for Capacity ($3.5 million), and New Customer Projects and New Revenue ($3.2 million). The Department also provided a high-level overview of financial data in DEA's 2023 IDP and found a 2.4% increase in DEA's projected distribution system spending for 2023-2027 compared with historical spending in 2018-2022.[12]

Table 4: Distribution System Spending Reported in DEA's 2023 IDP, Historical (2018-2022) vs. Budgeted (2023-2027)[13]

	Historical (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%

[11] Table 40 in DEA initial filing on November 1, 2023, at 127.
[12] Department initial comments on April 19, 2024, at 16-17.
[13] Table 36 in Department initial comments on April 19, 2024, at 16.

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%**

The Department suggests that DEA should quantify the effects of its grid investments on capacity, reliability, ratepayer impacts, and equity across various demographics, even though measuring these impacts can be complex.[14]

The Department recommends that the Commission direct DEA to provide a proposal for measuring the capacity, reliability, ratepayer, and equity impacts of its distribution grid investments in its next IDP. This proposal should specifically address the level of granularity at which DEA will evaluate these impacts for each budget category, indicating for each category whether DEA plans to measure these impacts at the level of the budget category, program, project, or at some other level of resolution, or not at all, and specifically accounting for the impact of any expected changes to IDP budget categories. (**Decision Option 7**)

Staff discusses this recommendation in the Joint Briefing papers.

Decision Option 7 is the Department's recommendation
Decision Option 8 is Staff's recommendation

iii. Summary of how the utility plans its system

Planning Process

Dakota Electric closely collaborates with Great River Energy (GRE), its wholesale power supplier, in planning and operating their electrical systems. This partnership is crucial as Dakota Electric focuses solely on distribution, relying on GRE to ensure the security and resilience of the transmission system that supplies their network.

The time required to integrate new distribution substations into the transmission system has significantly increased due to a higher volume of transmission connections. Previously, securing a transmission connection for a new load took 14-24 months, with local permitting as the

[14] Department reply comments on May 24, 2024, at 12.

primary delay. Now, due to multiple changes in the transmission system such as new substations, retiring generation units, and new transmission lines, the process can take 3-6 years. A local transmission provider now requires a minimum of five years' notice for any new substation interconnections.[15]

Demand Management/Load Management/Energy Efficiency

Dakota Electric has a demand-side management system that can control as much as 100 MW during the summer months and around 70 MW during winter months, including AC units, water heaters, irrigation, and other heating devices such as room heaters and hot tubs. [16] Additionally, some businesses possess full-capacity generation systems that can disconnect their entire load or the entire business campus and support it through their own internal generation system. DEA's demand-side management system controls over 45,000 air conditioners and heat-pumps, more than 7,000 water heaters, and other loads through installed load control receivers (LCRs). [17] As part of the AGi project, all existing LCRs are being replaced with new devices that utilize the same radio frequency mesh network as the AMI meters for communication.

DEA also works with GRE to operate and administer the Demand Management and Energy Efficiency programs. Dakota Electric has been using its AGi project systems, including the Meter Data Management (MDM) and advanced meters, to provide critical data on Demand Side Management (DSM) historical performance to GRE. This data helps GRE confirm past performance and supports future registration levels. Together, GRE and its member distribution cooperatives are exploring ways to enhance the benefits from demand response programs. Beyond demand response programs, GRE, in collaboration with distribution cooperatives and their member-owners, has developed a comprehensive portfolio of energy efficiency programs. These programs result in annual savings of over $15 million in energy and power costs for Dakota Electric's members.[18]

B. Roadmap for major initiatives (reliability improvements, DERMs, AMI, etc)

i. Reliability Improvements

Reliability is crucial for member equity and vital to identify the causes of outages and the characteristics that may lead to service inequities. DEA claims to be one of the most reliable electric utilities when comparing reliability key indices with other utilities. Though Dakota Electric has an overall strong system reliability performance, its operation staff observed periodically unacceptable number of outages (more than three separate outages a year).[19] DEA has started to track system-wide data on this topic using CEMI (Customers Experiencing

[15] DEA initial filing on November 1, 2023, at 100.
[16] DEA initial filing on November 1, 2023, at 4.
[17] DEA initial filing on November 1, 2023, at 5.
[18] DEA initial filing on November 1, 2023, at 101.
[19] DEA classified the level unacceptable to be as more than three separate outages in a year in DEA initial filing on November 1, 2023, at 13.

Multiple Interruptions) to identify members with a higher number of outages per year. The table below shows DEA's CEMI performance since 2020. [20]

Table 5: Dakota Electric CEMI Performance (2020-2022)

Year	$CEMI_4$	$CEMI_5$	$CEMI_6$	$CEMI_7$
2020	0.82%	0.34%	0.05%	0.01%
2021	0.14%	0.07%	0.01%	0.00%
2022	0.54%	0.06%	0.00%	0.00%

For the past three years from 2020 to 2022, Dakota Electric has the best CEMI performance in 2021 in most CEMI indices. In 2022, there were 0.54 percent, or approximately 620 members who had four separate outages during the years, compared to 0.14 percent in 2021.

Infrastructure Upgrades

Storms, animals, and nearby trees are often the key causes of outages. Before the 1980s, most areas used these overhead wires. However, since the 1980s, many communities have required new electrical services to be installed underground, enhancing reliability in newer developments. Older and rural areas in the service territory often experience more power outages due to aging overhead equipment and infrastructure installed when the homes were built. These areas, typically more affordable with lower-income communities, have less reliable electrical systems. Dakota Electric is working on identifying and upgrading these areas to underground systems where economically feasible to improve reliability.[21]

Dakota Electric identified a census track in Burnsville with reliability issues and classified as a Justice40 disadvantaged community[22]. The area, using outdated overhead wires and substation equipment, was part of a grant request under the Infrastructure Investment and Jobs Act (IIJA) to upgrade to underground wiring and replace 40-year-old substation equipment. However, the grant was not approved in October 2023, and Dakota Electric is considering resubmitting the request.[23]

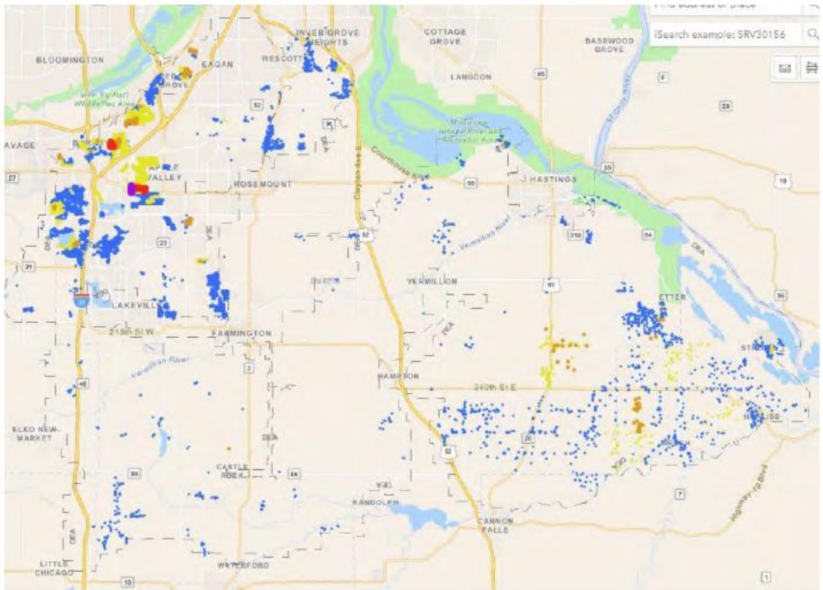
Vegetation Management

Additionally, rural areas with older overhead wires affected by vegetation also experience poorer reliability, and efforts are ongoing to address these issues. Below is a picture of outages on the Dakota Electric system caused by vegetation in 2022, where the blue color stands for a single outage, and other colors represent more outages with red representing 4 and purple

[20] Table 2 in DEA initial filing on November 1, 2023, at 13.
[21] DEA initial filing on November 1, 2023, at 14.
[22] A "Justice40 disadvantaged community" refers to a community identified under the U.S. Justice40 Initiative, aimed at directing 40% of certain federal investment benefits to areas facing significant economic, health, and environmental challenges.
[23] DEA initial filing on November 1, 2023, at 14.

representing 5.[24] Dakota Electric has implemented a vegetation management strategy and is starting to observe improvements in metrics related to these types of outages.

Figure 2: Outage Map in 2022 -Caused by Vegetation



ii. <u>Distributed Energy Resource Management System (DERMS)</u>

Dakota Electric has developed a GIS tool that enables the engineering department to quickly assess the remaining capacity of the distribution system for additional DER interconnections. This tool screens for capacity issues, allowing for quick reviews of DER interconnection applications.[25] Given the low penetration of DER, the current tool is adequate; however, as DER integration increases, Dakota Electric plans to adopt more advanced systems like Advanced Distribution Management System (ADMS) for comprehensive assessments.

Dakota Electric has submitted three applications for projects exceeding two million dollars through the US Department of Agriculture and the US Department of Energy. The third project is a part of the GRIP Round 2 funding opportunity through the US Department of Energy and involves implementing a Distributed Energy Resource Management System (DERMS) into their software tools. This system will enhance distributed energy resource management by allowing Dakota Electric to directly control member-owned thermostats, EV chargers, and other devices, building on their existing load control capabilities. The projected expenditure for this is approximately $2 million between 2025 and 2029, with up to 50% of the costs potentially covered by the grant.[26]

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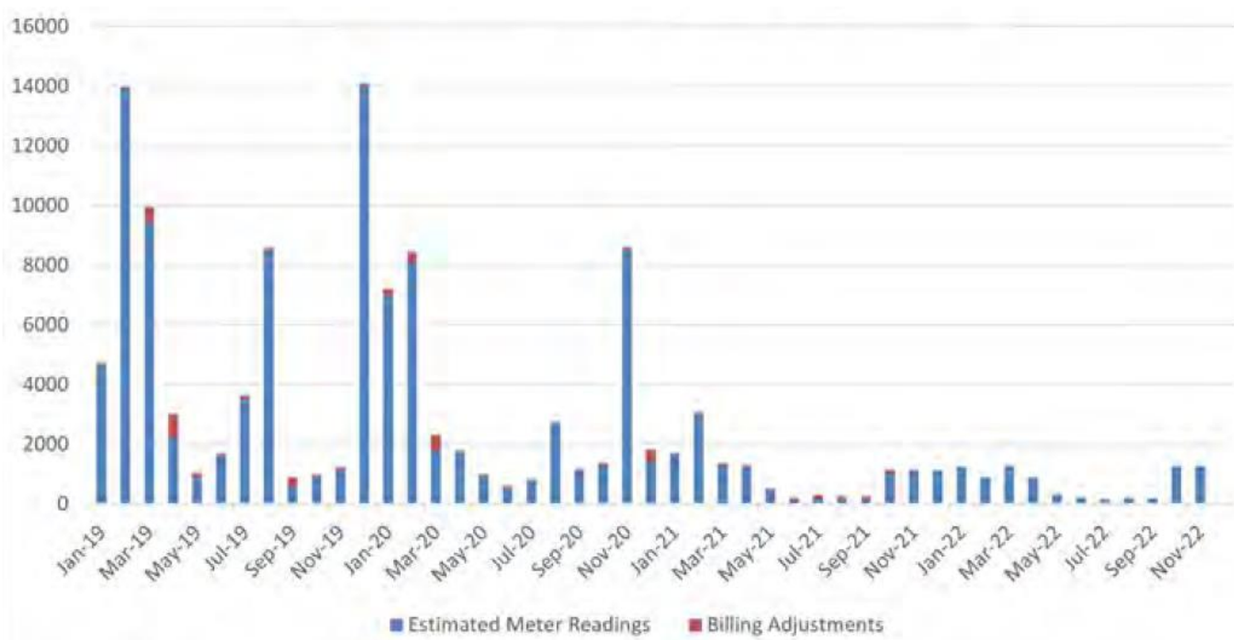
[24] DEA initial filing on November 1, 2023, at 14-15.
[25] DEA initial filing on November 1, 2023, at 89.
[26] Department initial comments, IR 11 on April 19, 2024.

iii. AGi Advanced Metering Project

The AGi Project, the largest in Dakota Electric's history, aims to enhance distribution operations and planning for decades. By early 2024, the installation of meters and load control receivers will be mostly complete, enabling the next phase of leveraging system data to improve operations and member value. The AGi system collects 15-minute internal data and will allow members to view and access this data to inform their energy usage decisions, potentially impacting future distribution planning and improving service quality.[27]

The figure below illustrates a rise in estimated meter readings during winter as members deactivate their off-peak sub-meters on air conditioning units, leading to zero usage estimates until power is restored in spring. The initial deployment of AMI meters, which started in July 2020 and finished by January 2022, shifted from manual to remote meter reading, achieving nearly 100% accuracy and availability of monthly meter readings.[28]

Figure 3: Estimated Meter & Billing Adjustments Before and After Agi Meters



iv. Operational Technology and Cyber Security

Over the next 5 to 10 years, Dakota plans to upgrade its Enterprise Resource Planning (ERP), GIS, outage management system (OMS), and SCADA systems, to bolster cybersecurity and functionality. These extensive updates require significant investment in time, resources, and funds, aiming to protect the system from cyber threats and improve operational efficiency.

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[27] DEA initial filing on November 1, 2023, at 43. Docket No. E999/CI-20-800.

[28] DEA initial filing on November 1, 2023, at 98.

Additionally, these upgrades may introduce advanced functionalities through an Advanced Distribution Management System (ADMS) platform.[29]

v. Energy Storage

Dakota Electric explored using a utility-scale energy storage system at a transmission-limited substation to enhance DER integration in its last IDP report. This system would store excess energy during peak production and release it during low production, potentially avoiding costly transmission upgrades. However, initial assessments deemed the costs high and the solution not economically viable across all scenarios, influenced by limited vendor availability and factors from their power supplier, GRE.[30] In addition to utility-scale energy storage system, Dakota is also exploring behind-the-meter (BTM) energy storage to enhance DER management by investigating member-focused solutions and expects more interests from members in the future.

vi. Electric Vehicles

Electric vehicles (EVs) present a significant load growth opportunity for Dakota Electric, influencing both member usage and the distribution system. Dakota has adapted by introducing specific rate programs to facilitate EV charging, especially for multi-family residences, and by developing innovative billing methods like the virtual metered EV rate to accommodate off-peak charging without additional meter installations. As of May 1, 2023, 1,033 members are enrolled in Dakota's EV charging rates, which constitute about 45 percent of its total members with EVs.[31] Additionally, the Cooperative is also planning infrastructure to support public fast charging, particularly along the I-35 corridor within their service territory. Lastly, Dakota Electric is considering the complexities of large fleet charging, recognizing its potential impact on the system and the need for tailored solutions based on operational patterns.

vii. Prairie Island Net Zero Initiative

Dakota Electric continues to collaborate with the Prairie Island Community on their Net Zero Initiative, which includes the construction of a 4.5MW solar facility set to become operational in early 2024. This facility will be the fourth utility scale solar generator in the Dakota Electric service territory and will be an important part of the Community's plans to meet their net zero objectives.[32]

viii. Comment Summary

The Department notes that DEA has not provided a comprehensive update on the costs and benefits of these investments in its IDP or reply comments. It suggests that DEA should offer a detailed quantitative accounting of costs and benefits of AGI projects to date, including any variations from initial projections. The Department emphasizes that including updated cost and

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[29] DEA initial filing on November 1, 2023, at 89-90.
[30] DEA initial filing on November 1, 2023, at 91.
[31] DEA initial filing on November 1, 2023, at 118.
[32] DEA initial filing on November 1, 2023, at 93.

benefit information in the IDP would align with the objectives of providing a current overview and ensuring consistency across filings.[33]

The Department recommends DEA should provide more complete quantification of the benefits and costs of all grid modernization projects anticipated to begin within a five-year interval, consistent with the IDP filing requirements in future IDPs. (**Decision Option 2**)

The Department noted that the Cooperative did not provide details for grid modernization, including timelines and cost-benefit analyses for projects like GIS, OMS, and SCADA systems, as required by the IDP filing requirements.[34]

The Department recommends DEA should include a formal Action Plan detailing the anticipated timing of grid modernization projects over the next five years. (**Decision Option 3**)

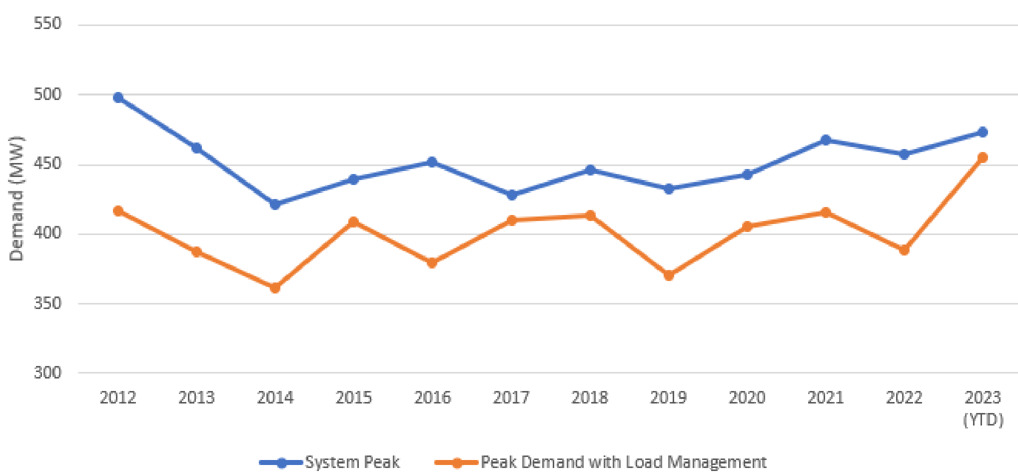
The Cooperative stated that they currently prioritized submitting grant applications over detailed discussions of cost recovery mechanisms with limited internal resources, as the potential grant outcomes are uncertain and could significantly benefit their membership.[35]

C. Forecasts – load, DERs, etc, and how the utility develops the forecast

i. Load Forecast

Through the demand-side management system, Dakota Electric has the ability to control 20% or more of its total system demand. Figure 4 represents the historical system peak demand on DEA's system based on data provided in the IDP report.[36]

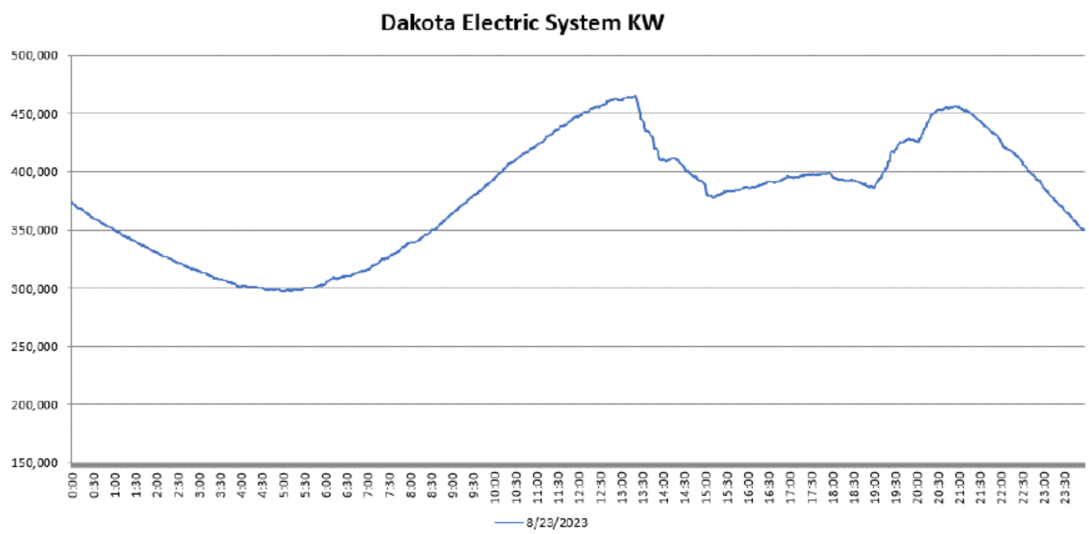
Figure 4: Historical System Peak Demand



[33] Department reply comments on May 24, 2024, at 11.
[34] Department reply comments on May 24, 2024, at 11.
[35] DEA reply comments on May 3, 2024, at 10-11.
[36] Data from Table 23. Historical System Peak Demand in DEA's initial filing on November 1, 2023, at 109. Note that demand values are reduced by any coincident DER generation amounts and do not reflect the maximum electrical load in the area.

Figure 5 shows the total Dakota Electric load curve for a peak summer day in 2023, which shows the effectiveness and robustness of Dakota's load management program. The Cooperative analyzed that the maximum load on the system could have easily exceeded 600 MWs without load management.[37]

Figure 5: Summer Peak Day (Aug 2023) with Load Management



ii. Electric Vehicle Forecast

Over the past five years (2018-2022), the number of electric vehicles participating in Dakota Electric's off-peak programs has surged from 269 to 1,207, representing an increase of more than 400%.[38] Dakota Electric developed four distinct classes for EV forecasts, including residential EV charging, light commercial and small businesses, retail charging, as well as fleet and over-the road charging. EV forecast for Dakota Electric's service area is based on the high growth rates from the Minnesota Department of Transportation's (MnDOT) 2022 EV forecast, which provides sales figures up to 2030. The figure below illustrates the projected number of EVs in Dakota Electric's service area. It features two lines: the top line represents the total forecasted EVs, while the second line shows those expected to participate in the off-peak rates.[39]

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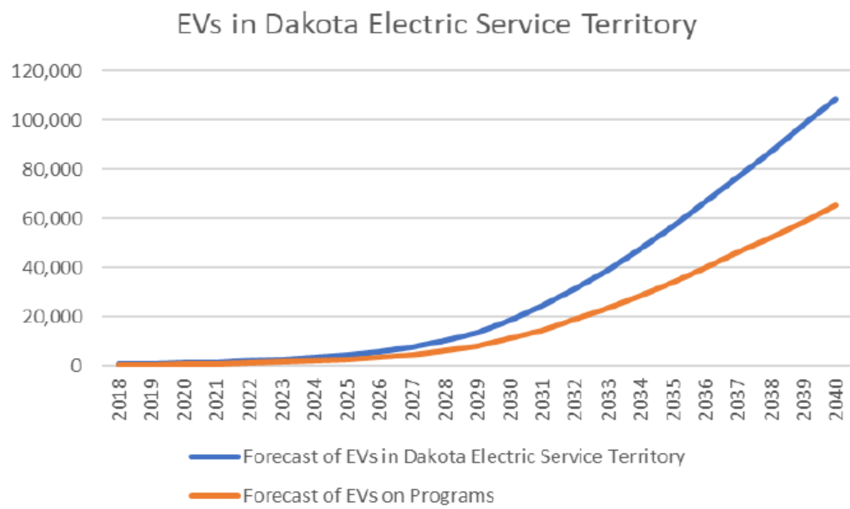
[37] DEA initial filing on November 1, 2023, at 6.
[38] DEA initial filing on November 1, 2023, at 29.
[39] Graph 8 in DEA initial filing on November 1, 2023, at 30.

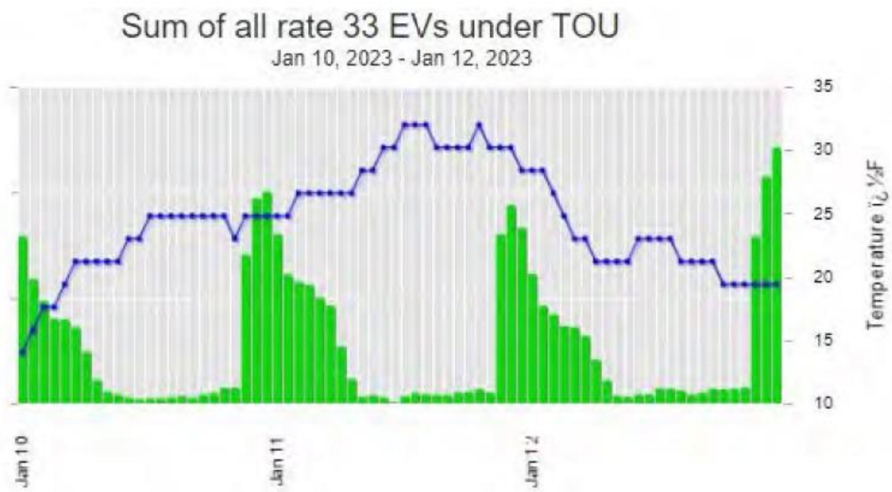
Figure 6: Forecast of number of EV Charging



To date, about 50%-60% of Dakota's members with EVs have participated in one of its lower cost EV charging rates programs. Starting in 2023, Dakota Electric has observed a steady increase in members joining its EV programs, with enrollment rising from about 1,000 to over 1,200 in the first half of the year and has updated its forecast to project over 20,000 EVs by 2030, doubling its previous estimate. With Dakota's AGi meter data, the Cooperative learned that most residential EVs only charge for about 2.5 hours per day and some only recharge their EV every 3 or 4 days.[40] The chart below presents the hourly energy usage profile for EV charging under Dakota's Time-of-Use rate (Rate 33), indicating that most EVs are recharged during the initial hours of the off-peak period.

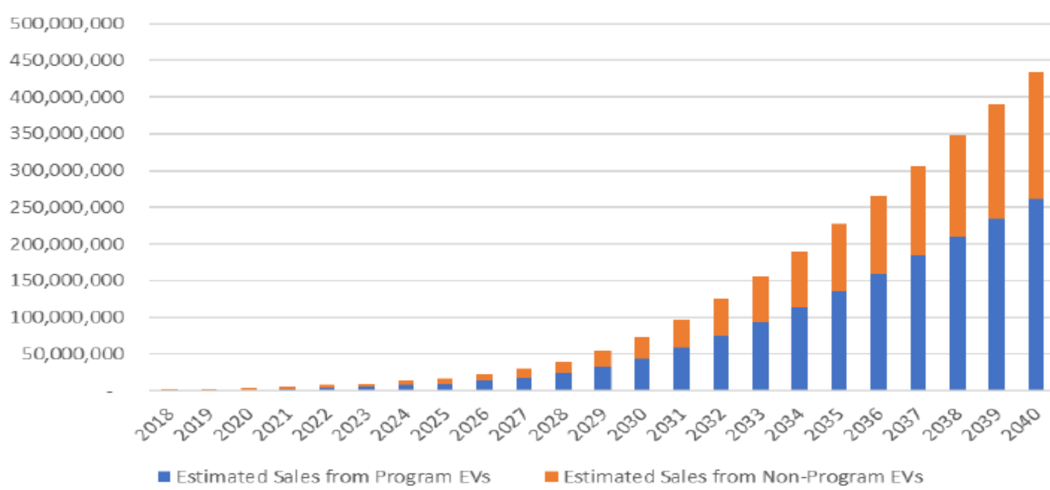
Figure 7: Daily Recharging Pattern for EVs on TOU Rate

[40] DEA initial filing on November 1, 2023, at 30-31.



Dakota Electric reports that EV charging typically boosts a household's electrical use by about 50%, increasing monthly consumption from 300- 400 kWh to 700 kWh. By 2030, the utility anticipates an increase of over 70 million kWh in electricity consumption due to EVs, not accounting for fleet charging and over the road vehicle charging due to limited data.[41] The figure below shows the electric usage forecast by EVs.[42]

Figure 8: Forecast of EV Electrical Consumption



iii. <u>DER Forecast</u>

Solar

Similar to the 2021 IDP solar forecast, Dakota used the U.S. Energy Information Administration (EIA) Solar energy growth forecast as the basis for forecasting its member owned solar interconnections with a Low, Medium, and High scenario. In the Low forecast Dakota Electric

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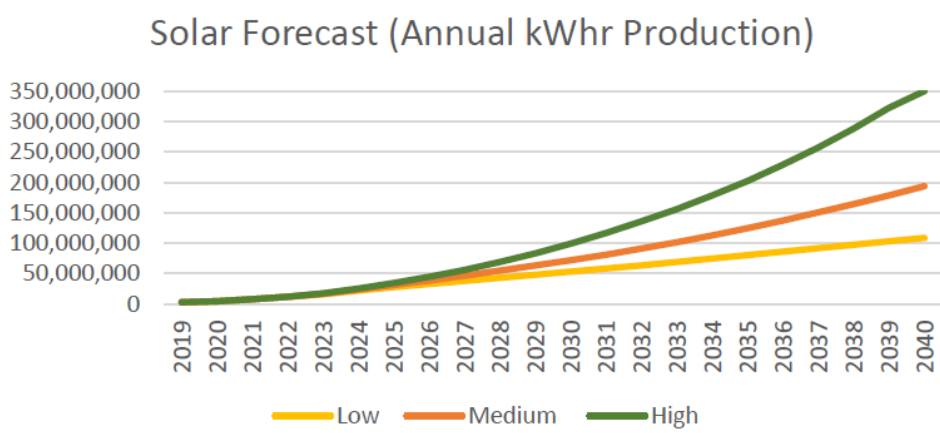
[41] DEA initial filing on November 1, 2023, at 33.

[42] Graph 10 in DEA initial filing on November 1, 2023, at 33.

expects continued market challenges and high costs due to supply chain issues. The Medium forecast predicts a return to lower, pre-COVID installation costs and improved supply chain conditions, with significant emphasis on the benefits of federal tax incentives. The High forecast anticipates robust, ongoing installations, considering the current stabilization in the number of installations as temporary.[43]

Using these assumptions for its analysis, Dakota forecasted the respective total energy generated by the member owned solar for each scenario until 2040.[44]

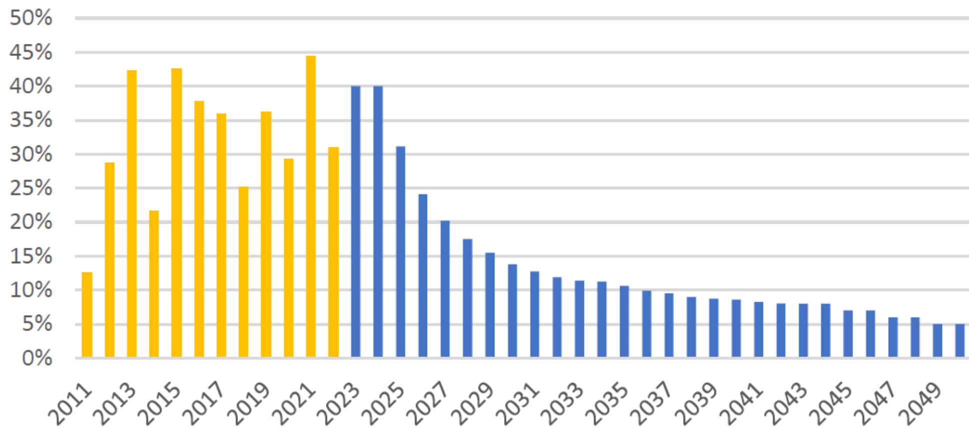
Figure 9: Forecast of Total Energy Production – Member Owned Solar



Dakota Electric expects the number of systems interconnections will continue at the current pace for the next 5 -10 years, which is in line with the Medium forecast, represented in Figure 10.[45]

Figure 10: Forecast (Medium) Annual % Growth of Member Owner Solar Systems

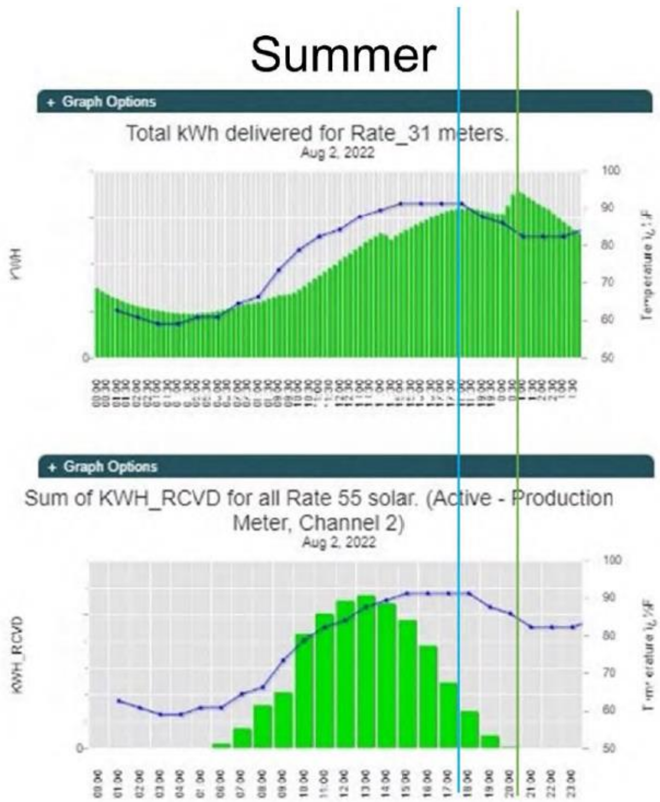
[43] DEA initial filing on November 1, 2023, at 35.
[44] Graph 12 in DEA initial filing on November 1, 2023, at 36.
[45]



The two graphs below illustrate Dakota Electric's residential load management on a hot summer day.[46] The top graph shows the overall load curve, displaying a dip in demand from 2 pm to 8:30 pm due to load control measures. The bottom graph compares the solar output to the distribution peaks, where the blue line indicates potential peak demand without load control. Notably, solar production is minimal at the time of the expected peak and nonexistent at the actual peak, highlighting the limited contribution of solar energy during critical demand times.

Figure 11: Solar Summer Production During Distribution System Demand

[46] Figure 13 in DEA initial filing on November 1, 2023, at 46.



Energy Storage System

In 2023, Dakota Electric has observed a significant increase in the installation of energy storage systems (ESS), with approximately 30 systems now interconnected or approved for interconnection, compared to less than 10 before 2022.[47] These systems are primarily used for emergency backup and are often installed alongside solar systems. Despite the high initial costs of ESS, federal tax incentives under the IRA, state grants, and increased competition are reducing the costs, which is expected to boost demand.

DER System Costs, Impacts, and Potential Barriers

Since 2018, Dakota Electric has significantly reduced the internal costs associated with processing distributed energy resource (DER) interconnection applications, achieving over a 70% decrease.[48] This reduction was partly achieved by implementing the NOVA application platform and streamlining work order processes to ensure each is handled just once, enhancing efficiency. Additionally, the cooperation and quality of applications submitted by DER customers and developer/installers has been crucial, as clean applications prevent the need for multiple site visits for testing, which further reduces costs. However, the average cost of a DER interconnection saw an increase in 2022, showing in the Table below, which was a result from

[47] DEA initial filing on November 1, 2023, at 41.

[48] DEA initial filing on November 1, 2023, at 42.

new developer/installers entering the service area whose applications often required multiple revisions and re-testing due to non-compliance with installation specifications.

Table 6: Interconnection Costs for Member Owned DER Systems[49]

Category	2018	2019	2020	2021	2022
# of Interconnections per year	40	98	138	371	322
Total DEA Costs	$57,437	$111,390	$146,066	$186,009	$175,627
Average DEA cost per DER	$1,436	$1,137	$1,058	$501	$545
Total Receipts	$4,700	$11,818	$23,924	$55,467	$53,180
Average Receipt per DER	$118	$121	$173	$155	$140
NET Total Cost to Dakota Electric	$52,734	$99,572	$122,142	$130,542	$122,447
Net Dakota Electric's Cost Per DER Interconnection	$1,318	$1,016	$885	$352	$380

Dakota Electric is adapting to the variability of DER generation by developing detailed system modeling and researching on Advanced Distribution Management System (ADMS) and similar tools for real-time operation support. This is crucial as the Cooperative contends that DER cannot reliably meet peak demand, often affected by environmental factors like cloud and snow cover. To mitigate these challenges, Dakota Electric collaborates with Great River Energy on programs that help members reduce energy costs during peak periods when solar output is minimal.[50]

Dakota Electric also identifies several barriers to DER interconnection, including the high costs of upgrading three-terminal transmission lines, stringent MISO transmission injection requirements, and challenges arising from the loss of native load due to energy efficiency and business closures. Additionally, while behind-the-meter (BTM) energy storage offers potential benefits, its high costs and insufficient economic incentives present further obstacles. These barriers necessitate strategic investments and regulatory adjustments to enhance DER integration while maintaining grid reliability and safety.[51]

Dakota provides a table that summarizes the total load control estimated by different programs in Table 7. Note that the actual load reduction achieved by Dakota Electric during any control period varies due to factors such as season, time of day, weather conditions, and length of the control period, with up to 80-100 MWs typically shed during peak mid-summer weekdays.

Table 7: Load Reduction Estimated by Program Type[52]

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[49] Table 6 in DEA initial filing on November 1, 2023, at 43.
[50] DEA initial filing on November 1, 2023, at 44-45.
[51] DEA initial filing on November 1, 2023, at 48.
[52] Table 36 in DEA initial filing on November 1, 2023, at 122.

Program	Number of Units	MW Connected	MW Reduction Summer	MW Reduction Winter
Air Conditioning	52,189	153	10-20	N/A
Heat Pump	2,765	10	3-5	2-8
Heat Device	3,331	29	N/A	5-10
Irrigation	377	24	0-12	N/A
Miscellaneous	738	4.7	1	1
Water Heat	7,372	33	4-8	5-10
C&I Interruptible Generation	127	85	50-65	30-50
Curtailment	20	9	2-5	2-5

iv. Department Comments

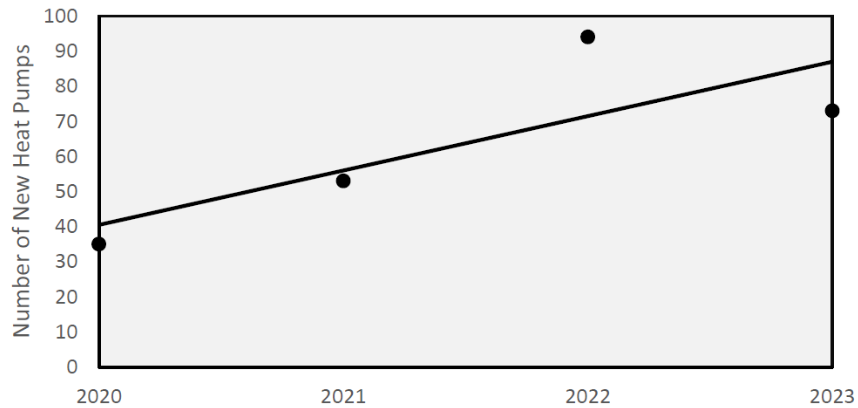
In general, the Department agrees with DEA'S analysis regarding DER scenarios and forecasts, including a proposed 8,760-hour modeling of the distribution system with higher penetration of DER integration, concerns about the correlated loss of DER solar, adoption of the Minnesota Department of Transportation (MnDOT)'s forecast, and suggests that DEA should continue to address these topics in future IDPs, including exploring how AMI meters can enhance understanding of EV impacts on the distribution grid.[53]

From Dakota's response to IR 14, the Department plotted the historical data in Figure 12, which showed that heat pump enrollment has doubled over three years from 2020 to 2023, mirroring the growth trend of EV adoption with a 349 percent increase over four years. The Department notes that if this rate continues, the number of heat pumps in DEA's service area could significantly increase by 2050 and requested DEA discuss in reply comments the extent to which the Cooperative has conducted surveying and/or targeted outreach to increase participation in its Load Management Program.[54]

Figure 12: DEA Load Management Program New Heat Pump Enrollment

[53] Department initial comments on April 19, 2024, at 18-19.

[54] Department initial comments on April 19, 2024, at 25.



Dakota Electric highlights that about 45 percent of its members are engaged in load management programs and is exploring ways to further increase participation despite industry reluctance towards targeted outreach due to concerns of perceived discrimination or preferential treatment. If deemed necessary by the Commission, Dakota Electric is open to considering targeted outreach in future program developments.[55]

D. Non-wires alternatives

Dakota Electric proposed two large distribution system projects for non-wire alternative analysis. The first is an updated analysis of determining if there was an alternative to a new substation near Elko-New Market and the second set of projects involves the replacement of aging substation equipment.[56]

Basic Requirements for Non-Wires Solutions

Dakota developed a list of requirements for non-wires solutions to ensure reliable electrical supply for its members. Any non-wired solutions must provide, at a minimum, the following:[57]

1. Provide Reliable Energy: Ensure consistent energy output on demand to prevent outages where the distribution system isn't upgraded.
2. Maintain Energy Supply: Offer sustained energy for the required duration to replace traditional infrastructure expansions.
3. Guarantee Quick Repairs: Quickly repair or replace failed components to maintain continuous energy supply and reliability.
4. Commit Contractually: Enter into agreements ensuring DER availability, especially during equipment failures, to keep power flowing consistently.

Project 1: Construction of a New Substation Near Elko-New Market

Dakota Electric's service area around Elko-New Market is currently served by an overloaded substation, necessitating a new substation by late 2024 to support a major new manufacturing

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[55] DEA reply comments on May 3, 2024, at 13.
[56] DEA initial filing on November 1, 2023, at 64-65.
[57] DEA initial filing on November 1, 2023, at 66.

plant and future growth. Dakota analyzed three potential non-wire solutions compared to a "traditional solution" of building a new 115kV substation under low and high load growth scenarios. The three alternative solutions include energy storage only, energy storage plus solar, and demand side management.[58]

The analysis is similar to the analysis conducted in the 2019 and 2021 IDP with updated prices and conclusions remain unchanged since 2021. Due to high land and battery costs, exceptional member compliance, and the intermittency of solar energy, each of these alternatives remains too expensive and unreliable compared to the traditional solution of installing a 115kV substation.[59]

Commission Staff created a high-level overview of the four scenarios in Table 8 which details the cost of each scenario at 5% discount rate under "low" and "high" load growth scenarios. Note that Option 1D is impractical for the fast growth scenario due to excessively high 24-hour load levels that cannot be sufficiently controlled within the 4-6 hour daily load control window.[60]

Table 8: Dakota NWA Options

Scenarios	Project	Low Growth NPV	Fast Growth NPV
Option 1A	Build New 115 kV Substation	$6,997,317	$6,997,317
Option 1B	Defer Substation using Energy Storage	$15,439,319	$23,662,986
Option 1C	Defer Substation using Solar and Energy Storage	$25,250,115	$40,524,315
Option 1D	Deferring New Substation with Demand-side Management	$14,813,626	

Project 2: Replacement of Aging Substation Equipment

Dakota Electric plans to replace aging substation equipment over the next 10 years to mitigate the increased risk of failure and long repair times due to supply chain issues. Dakota stated that the Cedar and Lakeville Substation projects, along with the Fisher Substation Rebuild were not suitable for Non-Wires Alternatives (NWA) analysis due to factors like land constraints and potential operational issues. Dakota Electric is open to using NWA for future projects where appropriate.[61]

Non-Wires Alternative Solution Considerations

Dakota Electric finds demand side management programs most promising as non-wire solutions, but these require large geographical areas and significant participation to ensure reliability. Due to less than 100% participation and eventual attrition, making such programs mandatory isn't viable. Additionally, the expected benefit from distributed solar systems hasn't

[58] DEA initial filing on November 1, 2023, at 70.
[59] DEA initial filing on November 1, 2023, at 72-84.
[60] DEA initial filing on November 1, 2023, at 81.
[61] DEA reply comments on May 3, 2024, at 5.

materialized, as the systems lack sufficient diversity and their output loss is concurrent, failing to offset distribution needs effectively. Furthermore, limited prior notification and long lead times for non-wires solutions complicate their implementation. While traditional equipment can be pre-ordered and stocked, non-traditional options like solar and ESS systems have not proven economically viable, resilient, or reliable enough to justify stocking due to similar supply chain delays.[62]

Through analyzing these non-wire solutions in Dakota Electric's 2019 IDP report, Dakota concludes that NWS are not a global solution to every distribution system problem.[63] Larger projects are more attractive to vendors due to economies of scale, whereas smaller projects incur high overhead costs and less vendor interest, making it challenging for smaller utilities like Dakota Electric to engage vendors, especially with the increasing number of non-wired projects being considered.

i. Comment Summary

The Department finds most assumptions reasonable but notes that DEA's cost estimates for solar are overly optimistic, suggesting a recalibration by averaging the “Utility=Scale PV” and “Commercial PV” forecasted costs based on more realistic figures from NREL's benchmarks for solar system costs.[64]

DEA did not provide response with respect to this concern in its reply comments.

The Department stated that DEA’s conclusion that the traditional approach of constructing a new substation is the most cost-effective for the Elko-New Market Area NWA analysis resulted from significant forecasted load growth and relative short deferral periods for each NWA solution from 3 to 5 years, which would reduce the potential benefit of an NWA solution.[65]

The Department requested further information from the Cooperative regarding their evaluation of Non-Wires Alternatives (NWA) for specific projects, noting that the provided details on the feasibility of NWA for the Cedar Substation, Lakeville Substation, and Fisher Substation Rebuild Projects are insufficient. Despite the Cooperative's explanation that these projects are unsuitable for NWA due to various logistical and operational constraints, the Department finds that the consideration of NWAs does not meet the required standards outlined in the IDP filing requirements. [66]

The Department recommends that the Commission direct DEA to provide in its next IDP a more detailed assessment of NWA suitability for qualifying opportunities. The Department clarifies that such an evaluation need not necessarily rise to the level of a full-blown cost-benefit analysis, but that it should be rigorous and quantitative to the extent possible rather than simply relying on expert judgement. The Department further expects the Cooperative to

[62] DEA initial filing on November 1, 2023, at 85-86.
[63] DEA initial filing on November 1, 2023, at 86.
[64] Department initial comments on April 19, 2024, at 7.
[65] Department initial comments on April 19, 2024, at 8.
[66] Department reply comments on May 24, 2024, at 12-13.

provide records of all data considered and analyses undertaken (i.e., at the screening stage) to determine whether a detailed NWA analysis in indicated. For all needs for which a detailed analysis is undertaken, the Cooperative should provide documentation of this analysis in its IDP. (**Decision Option 4**)

The Department asks for similar detailed explanations of benefit calculations used in NWA analysis for future IDPs and emphasizes the value of using multiple test cases in NWA analyses to capture diverse perspectives and seeks guidance from the Commission on the necessity of each Minnesota Test Case in future IDPs.[67]

The Department recommends that the Commission direct DEA to provide in its next IDP clarification about which categories of capital projects warrant detailed discussions of NWA viability and/or NWA analysis. The Department further requests that the Commission provide guidance whether the requirements of filing requirement E.1 are applicable to all project purposes or only certain project purposes. (**Decision Option 5**)

ii. Staff Analysis

DEA concludes from their NWA analysis that the traditional approach of constructing a new substation is the most cost-effective for the Elko-New Market Area, being less than 50 percent of the cost of the cheapest NWA option. Staff notes that the forecasted NWA costs could be exaggerated by significant increase in forecasted load growth and relative short deferral periods assumed. With different deferral period assumptions used in NWA analysis, DEA could expect a more economic favorable forecast.

E. Resiliency

The Cooperative approaches resiliency of the distribution grid through reliability investments. The Cooperative provided that, historically, the largest causes of outages were vegetation and weather-related incidents.

As a result, the Cooperative has focused on vegetation management, undergrounding, and age-related equipment replacements to design a resilient distribution system.

Table 9: Resiliency Initiatives

Vegetation Management	Tree trimming cycle on approximately 500 miles of line; increased budget project from $1.53 million in 2023 to $1.78 million in 2024.[68]
Strategic Distribution Line Undergrounding	Almost all new commercial and residential building have underground distribution lines.[69]
Age Related Replacement	Budget to replace aging equipment increased from $3.8 million in 2023 to $6.1 million in 2028.[70]

[67] Department reply comments on May 24, 2024, at 13.
68 DEA initial filing on November 1, 2023, at 127.
69 DEA initial filing on November 1, 2023, at 14.
70 DEA initial filing on November 1, 2023, at 127.

For overhead lines, the Cooperative is in the process of implementing a transition from wood to Fiberglass Reinforced Polymer Crossarms for grid hardening. The Cooperative is also working to increase main feeder size for underground construction to increase available capacity and provide additional operational flexibility. Increased main feeder size and operational flexibility is valuable in extreme heat situations with extended load durations.

Every year, the Cooperative monitors the distribution system using the SCADA system to review system non-coincident peak demand data for each feeder. As a result of these reviews, changes have been made to relocate load from one substation to another or from feeder to another to minimize customer outages during planned or unplanned substation or feeder outages.

i. Department of Commerce Initial Comment

In the Department's review of the Cooperative's resiliency efforts, the Department notes the Cooperative address's reliability seriously in its distribution planning efforts but does not make a clear distinction between reliability and resiliency. To help make this distinction, the Department offers the definition of resilience as "low-probability, high-consequence events […] and affect a significant number of customers, often spanning a wide geographic extent."[71]

Further, the Department notes the Cooperative has an "opportunity to track and report system resilience as a distinct concept from reliability to ensure that investments are appropriately targeted." To establish resiliency metrics, the Department notes DEA could utilize non-weather-normalized versions of metrics, including Major Event Days ("MEDs"), in its Minnesota Safety, Reliability, and Service Quality Standards ("SRSQ") Report. The Department notes that other jurisdictions track System Average Interruption Duration Index ("SAIDI") and SAIFI with MEDs as resilience metrics.

ii. Dakota Electric Association Reply

The Cooperative clarifies that it is not required to file service quality reports for Commission approval.[72] Nonetheless, the Cooperative provides the Commission with the SRSQ Report as an informational filing with the Commission.[73]

The Cooperative further notes that no current industry standards are available to measure resilience and Commission guidance may be warranted to track resiliency.[74] In the meantime, the Cooperative does participate in the Outage Data Initiative Nationwide.[75]

In response to the Department's request for the Cooperative to provide a discussion of how its AMI and AGi programs could be used to track system resiliency, the Cooperatives provides that

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[71] Department of Commerce Initial Comments at 30.
[72] Dakota Electric Reply Comments at 16.
[73] Dakota Electric Reply Comments at 16.
[74] Dakota Electric Reply Comments at 16.
[75] Dakota Electric reply Comments at 16.

the AGi project enables the Cooperative to identify outages efficiently and accurately. As a result, the Cooperative could configure this system to track resiliency data.[76]

The Cooperative responded to an Information Request from the Commission inquiring about equipment design standards to withstand extreme weather events by reiterating its asset health and technology investments. The Cooperative reiterates it continues to increase the number of underground distribution lines, its transition from wood to Fiberglass Reinforced Polymer Crossarms for distribution poles and increased main feeder size for underground construction. The Cooperative also provides it utilizes SCADA system information to relocate load from one substation to another or from one feeder to another feeder.[77]

iii. Department of Commerce Reply Comment

The Department appreciates the Cooperative's interest in tracking resiliency and its participation in the Outage Data Initiative Nationwide to standardize resiliency metrics. Further, the Department appreciates the Cooperative's tracking of normalized and non-normalized values of SAIDI, SAIFI, and CAIDI in its Annual SRSQ report. The Department believes isolating SAIDI, SAIFI, and CAIDI values during major events alone would more accurately capture resiliency.[78]

The Department agrees with the Cooperative that clarification and guidance from the Commission on how to resiliency should be tracked and reviewed is warranted.[79]

The Department recommends the Commission direct Dakota Electric Association to develop a suite of metrics to track resiliency, including SAIDI with MEDs and SAIFI with MEDs, and other metrics to the extent warranted. (**Decision Option 6**)

iv. Staff Analysis

Staff appreciates the provided definition of "resilience" from the Department which "focuses on low-probability, high-consequence events […] and affect a significant number of customers, often spanning a wide geographic extent."[80] Based on this definition, the Cooperative offers investments, such as the undergrounding of distribution lines, that can withstand low-probability, high-consequence events. The Cooperative's investments in vegetation management and age replacement investments also advance reliability and resiliency efforts.

Both the Cooperative and the Department agree that, while the Cooperative's investment do advance resiliency efforts, methods to measure the effectiveness of such resiliency investments are unknown. The Department's recommendation is for the Cooperative to produce resiliency metrics, including SAIDI with MEDs and SAIFI with MEDs, to begin to develop such metrics while the Cooperative works with the Outage Data Initiative Nationwide to standardize resilience

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[76] Dakota Electric Reply Comments at 13-14.
[77] Dakota Electric Information Request Response.
[78] Department of Commerce Reply Comments at 14.
[79] Department of Commerce Reply Comments at 14.
80 Department of Commerce Initial Comments at 30.

metrics. The Cooperative offers to track grid system resilience through its AGi system but requests further guidance on resilience metrics from the Commission.

Staff discusses the Department's recommendations in the Joint Briefing Papers.

Decision Option 6 implements the Department's recommendation
Decision Option 8 implements Staff's recommendation

4. Additional Comment Topics Summary

The Department recommends that the Commission accept Dakota Electric Association's 2023 IDP acknowledging that the Cooperative has addressed every IDP Filing Requirements and relevant requirements from past Commission Orders. (**Decision Option 1**)[81]

In Xcel's IDP proceeding, the Department supports Xcel's request to revise IDP filing requirements to eliminate the need for financial information to be reported in IDP-specific budget categories and suggests that the Commission consider implementing similar revisions with other utilities' IDP filings. Therefore, the Department seeks input from DEA and stakeholders on the possibility of revising IDP filing requirements in the Cooperative's reply comments.[82]

Dakota Electric supports the proposed revision to the IDP filing requirements, highlighting that their current tracking of expenses by project rather than IDP-specific categories aligns better with their regular planning processes and provides a more relevant comparison standard for the Commission and stakeholders.[83]

The Department requested additional information from DEA with respect to NWA, grid modernization, IRA incentives, load management, resiliency, and IDP budget categories to supplement its current IDP proceedings and concludes that DEA's response to be adequate. The Department also requested additional information to be provided at a later date in terms of beneficial electrification and resiliency and provides recommendations for enhanced information requirements. [84]

F. Beneficial Electrification and Related Issues

The Department stresses the need for the Cooperative to enhance their IDP submissions by including detailed plans and impact forecasts for beneficial electrification, especially considering its significance to state climate goals. The Department also points out the importance of incorporating the benefits of the Inflation Reduction Act (IRA) into future utility planning and filings, emphasizing the need for comprehensive planning to maximize these benefits across various electrification initiatives. Despite the reluctance of both DEA and the Commission to engage in targeted marketing programs, the Department also emphasizes the necessity of targeting specific customer groups, such as low- to moderate-income households,

[81] Department reply comments on May 24, 2024, at 4.
[82] Department initial comments on April 19, 2024, at 31.
[83] DEA reply comments on May 3, 2024, at 14.
[84] Department reply comments on May 24, 2024, at 4-9.

to effectively navigate and maximize the benefits of complex funding layers for electrification incentives.[85]

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 for space heating and electrification of water heating, and provide forecasts of expected grid impacts of the same. (**Decision Option 9**)

Dakota Electric supports engaging in beneficial electrification opportunities through the IRA and the Minnesota ECO Act, with plans to develop cost-effective programs in partnership with their power supplier, GRE. They are focused on maximizing federal, state, and utility incentives for their members. However, the Cooperative prefers to wait for clearer program details before making a supplemental filing, believing it's more resource-efficient to address these updates in the next IDP Report, which will allow them to better utilize resources and align with new incentive programs.[86]

Staff covered this area in the Joint Briefing Papers.

Decision Option 9 implements the Department's recommendation.
Decision Option 10 implements Staff's suggestion.

5. Decision Options

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

Modifications for Future IDPs

The Commission ay select any combination of DO 2-5, or none of the options

2. Direct Dakota Electric Association to provide more complete quantification of the benefits and costs of all grid modernization projects anticipated to begin within a five-year interval, consistent with the IDP filing requirements, in future IDPs. (The Department)

3. Direct Dakota Electric Association to include a formal Action Plan detailing the anticipated timing of grid modernization projects over the next five years in future IDPs. (The Department)

4. Direct Dakota Electric Association to provide in its next IDP a more detailed assessment of NWA suitability for qualifying opportunities. This assessment must be rigorous and quantitative to the extent possible rather than simply relying on expert judgement. The

[85] Department reply comments on May 24, 2024, at 15-18.
[86] DEA reply comments on May 3, 2024, at 14-16.

Cooperative shall file records of all data considered and analyses undertaken (i.e., at the screening stage) to determine whether a detailed NWA analysis is suitable. For all needs for which a detailed analysis is undertaken, the Cooperative shall provide documentation of this analysis in its IDP. (The Department)

5. Direct Dakota Electric Association to provide in its next IDP clarification about which categories of capital projects warrant detailed discussions of NWA viability and/or NWA analysis, and: (The Department)

    A. Clarify that filing requirement E.1 applies to all project purposes

    OR

    B. Clarify that filing requirement E.1 applies only to the following project purposes: *[identify the project purposes subject to this requirement]*

The Commission may select DO 6 ***AND/OR*** *7,* ***OR*** *DO 8, or none of the options. These decision options are explained the Joint Briefing Papers*

6. Direct Dakota Electric to develop a suite of metrics to track resiliency, including SAIDI with MEDs and SAIFI with MEDs, and other metrics to the extent warranted with its 2025 IDP. (The Department)

AND/OR

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

OR

8. Delegate authority to the Executive Secretary work with Dakota Electric Association and stakeholders to discuss metrics reported across distribution dockets, and delegate authority to the Executive Secretary to approve via notice a stakeholder agreement on metrics reporting if one is reached. At minimum, the proposal and metrics shall include the following components:
    a. Reliability metrics such as SAIDI, SAIFI, CAIDI, CEMI, and CELI
    b. Distribution spending by IDP budget categories
    c. Whether there is available hosting capacity for generation or load at the primary system level

d. Demographic data including race and income
e. Installed DERs, ECO rebates, DR customers enrolled in programs
f. Metrics reported at a feeder and/or census block group level

(Staff)

The Commission may select either DO 9 ***OR*** *DO 10, or neither. These decision options are explained the Joint Briefing Papers*

9. Order Dakota Electric Association to file a supplemental filing within [180 days] of the Commission's Order in this docket that proposes a plan to accelerate beneficial electrification for its customers, including a discussion of how to incentivize dual fuel adoption for space heating and electrification of water heating, and provide forecasts of expected grid impacts of the same. (The Department)

OR

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

The Commission may select DO 11 or DO 12, or neither. These decision options are explained the Joint Briefing Papers

11. Delegate authority to the Executive Secretary to work with Dakota Electric Association and stakeholders on ways to modify the IDP budget categories to allow for comparisons between utilities and comparison of historic to forecasted data. Delegate authority to the Executive Secretary to approve via notice a stakeholder agreement on amended filing requirements if one is reached. (Staff)

OR

12. Modify Dakota Electric Association's IDP filing requirements to amend requirement 3.A.26, 3.A.28, and 3.A.29 to remove the requirement that financial information be reported in IDP-specific categories as follows:

3.A.26 Historical distribution system spending for the past 5 years.~~, in each category:~~ Information shall be reflected in categories consistent with the Associations' cost recovery proceedings.

~~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~~
~~i. Electric Vehicle Programs~~
~~1) Capital Costs~~
~~2) O&M Costs~~
~~3) Marketing and Communications~~
~~4) Other (provide explanation of what is in "other")~~

~~The Company may provide in the IDP any 2018 or earlier data in the following rate case categories:~~
~~a. Asset Health~~
~~b. New Business~~
~~c. Capacity~~
~~d. Fleet, Tools, and Equipment~~
~~e. Grid Modernization~~

For each category, provide a description of what items and investments are included.

3.A.28 Projected distribution system spending for 5 years into the future ~~for the categories listed above~~ in categories consistent with the Association's cost recovery proceedings. ~~itemizing any non-traditional distribution projects.~~

3.A.29 Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Projects shall be reflected in categories consistent with the Association's cost recovery proceedings. ~~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~~
~~i. Electric Vehicle Programs~~
~~1) Capital Costs~~
~~2) O&M Costs~~
~~3) Marketing and Communications~~
~~4) Other (provide explanation of what is in "other")~~