MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	September 1, 2022		Agenda Item 4*
Company	Dakota Electric Association		
Docket No.	**E111/M-21-728**		
	In the Matter of Distribution System Planning for Dakota Electric Association		
Issues	1. What action should the Commission take with Dakota Electric Association's 2021 Integrated Distribution Plan (IDP)? 2. Should the Commission adjust any of the IDP filing requirements for Dakota Electric Association's next IDP?		
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✓ **Relevant Documents**	**Date**
DEA – Initial Filing – Stakeholder Meeting Presentation	10/08/2021
DEA – Initial Filing – Integrated Distribution Plan	11/01/2021
PUC – Notice of Comment Period	11/15/2021
The Department – Letter (Guidance Document)	2/09/2022
The Department – Initial Comments	3/15/2022
DEA – Reply Comments	4/05/2022
The Department – Reply Comments	4/18/2022

I. Statement of the Issues

What action should the Commission take with Dakota Electric Association's 2021 Integrated Distribution Plan (IDP)?

Should the Commission adjust any of the IDP filing requirements for Dakota Electric Association's next IDP?

II. 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]

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 October 8, 2021 DEA submitted its Stakeholder Meeting Presentation.

On November 1, 2021 DEA submitted its Integrated Distribution Plan (2021 IDP).

On November 15, 2021 the PUC submitted a Notice of Comment Period asking parties to answer these questions regarding the 2021 Dakota Electric IDP:

1. Should the Commission accept or reject Dakota Electric's Integrated Distribution Plan (IDP)?
2. Does the IDP filed by Dakota Electric achieve the planning objectives outlined in the filing requirements as amended by the Commission's November 2, 2020 Order?
3. What IDP filing requirements provide the most value to the process, and why?
4. Are there filing requirements that are not informative and/or should be deleted or modified, and why?
5. Are there other issues or concerns related to this matter?

On February 9, 2022 the Department of Commerce filed its Guidance Document.

On March 15, 2022 the Department filed initial comments.

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

On April 5, 2022 DEA filed reply comments.

On April 18, 2022 the Department filed reply comments.

In Xcel Energy's 2017 and 2018 Transmission Cost Recovery (TCR) Rider petition, the Commission requested "the Commissioner of Commerce seek authority from the Commissioner of Minnesota Management and Budget to incur costs for specialized technical professional investigative services under Minn. Stat. § 216B.62, subd. 8, to investigate the potential costs and benefits of grid modernization investments proposed for recovery by Xcel in its next rate case or TCR filing and to assist the Department in providing recommendations to the Commission regarding any such investments."[2] On February 9, 2022, the Department filed a letter explaining its contract with Synapse Energy Economics, Inc. (Synapse) who performed an economic evaluation of all Xcel Energy's grid modernization investments. Synapse created a broad economic guide that gave a standard approach to evaluating utility grid modernization investments (herein, Guidance Document). The Department contended that the Guidance Document provides sufficient information for stakeholder understand and influence grid modernization plans.

The Department simultaneously filed this guide in other related dockets, including Xcel Energy's ongoing Transmission Cost Recovery Rider, and Xcel Energy, Minnesota Power, and Otter Tail Power's IDPs. The Department made similar recommendations across all four utility IDPs related to the Guidance Document and future grid modernization filings. The Guidance Document is referenced in portions of this briefing papers; however, Staff addresses the Department's recommendations for the Guidance Document in a separate set of briefing papers that covers all utility IDPs, also up for consideration at the September 1, 2022 agenda meeting. Summary of Dakota Electric's 2021 IDP

III. Summary of the Issues

The Department and Dakota Electric recommend the Commission accept Dakota Electric's 2021 Integrated Resource Plan while recognizing acceptance is not a determination of prudence of any proposed system modifications or investments. (**Decision Option 1**)

The disputed issue of the Department's Guidance Document and IDP filing requirement changes are addressed in separate briefing papers given these issues crossed all three IDP dockets.

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[2] Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements, September 27, 2019, Docket No. E002/M-17-797

Summary of Dakota Electric Association's 2021 IDP

A. Baseline System Data (System, Financial, and Distributed Energy Resources)

System

Dakota Electric Association is a not-for-profit electrical cooperative, serving the electrical needs of over 110,000 members in Dakota County, and portions of Scott and Goodhue counties. Specifically, Dakota is an electric distribution cooperative and purchases its wholesale power from Great River Energy (GRE). Dakota has a peak demand between 450-500 MW (mainly driven by summer air conditioning) and has a significant amount of demand-side management where DEA can control up 20-25% of the total system demand.[3]

Monitoring And Control

100% of Dakota Electric's substations are equipped with supervisory control and data acquisition (SCADA) monitoring and control and Dakota has been adding SCADA to downline regulators and key remote switches. DEA also includes SCADA monitoring on the 125 Distributed Energy Resources (DERs) that are on the member-owned generation systems on the Commercial and Industrial (C&I) Interruptible – Rate 70 tariff. These DERs represent a significant portion of DEA's load control.[4] Real time monitoring and visibility is limited beyond the substation level, but DEA has increased SCADA monitoring to roughly 15% of their feeders (up from 10% in the 2019 IDP) and has plans to increase that number.[5]

Financial

Dakota lists the Historical Capital Spending below, noting that these are these are estimate allocations of costs as it is difficult to determine what capital project belongs in which IDP category.

[3] P. 4-6, DEA Initial, 11/1/21
[4] P. 24, DEA Initial, 11/1/21
[5] P. 24, DEA Initial, 11/1/21

Table 17. Historical Total Capital Spending

	2016	2017	2018	2019	2020
Age Related Replacement	$3,032	$3,506	$4,195	$3,066	$5,771
System Expansion (Due to Capacity)	$1,330	$2,247	$716	$831	$694
System Expansion (Due to Reliability)	$1,884	$1,449	$1,220	$1,308	$1,025
New Members	$3,429	$3,603	$3,006	$4,302	$4,099
System Project (Driven by Mandate)	$1,121	$1,924	$1,263	$1,306	$1,107
Metering	$0	$0	$0	$103	$5,592
Grid Modernization (Advanced Technologies)	$973	$880	$361	$1,057	$2,685
Annual Total	**$11,769**	**$13,609**	**$10,762**	**$11,973**	**$20,972**

Note: All dollars are in Thousands

Dakota notes that the "Metering" costs are almost entirely the Advanced Grid Infrastructure (AGi) project, meaning the replacement of old meters with Advanced Metering Infrastructure (AMI). They distinguish this act as separate from the Grid Modernization (Advanced Technologies) category.[6]

Below is Dakota's projected distribution system spending through 2025. This includes costs regarding new meters and software, replacing older equipment, system expansion, and the AGi project.

Table 19. Five Year Forecast of Distribution System Spending

	2021	2022	2023	2024	2025
Age Related Replacement	$2,235	$2,904	$2,814	$2,741	$2,741
System Expansion (Due to Capacity)	$3,348	$3,045	$3,046	$3,319	$3,319
System Expansion (Due to Reliability)	$1,052	$1,357	$1,389	$1,306	$1,306
New Members	$4,473	$4,605	$4,153	$4,238	$4,378
System Project (Driven by Mandate)	$1,734	$1,893	$1,825	$1,789	$1,789
Metering	$11,921	$499	$10	$10	$10
Grid Modernization (Advanced Technologies)	$2,972	$4,169	$2,817	$464	$464
Other	$0	$0	$0	$0	$0
Annual Total	$27,736	$18,471	$16,055	$13,868	$14,008

Note: All dollars are in Thousands

The Metering expenses decreases by over 99% upon full installation of the AGi meters in 2023. The Grid Modernization category also decreases significantly by 2024 as AGi project concludes.

DEA stresses that for this is a rough 5-year forecast as much of their construction is reactionary in nature. Dakota Electric does not initiate the construction of new facilities until new load requires new distribution capacity for example. Local governments also may only have estimates regarding various projects and an undetermined timeline, both of which makes it difficult for Dakota to create

[6] P. 55, DEA Initial, 11/1/21

an accurate forecast.[7] This is also true for planned distribution projects (project greater than $100,000) – outside of substations, Dakota can only plan about a year at most and so has included projects planned to be completed in 2021 and those that have been proposed for 2022.

Load and Load Forecasting

Through Dakota's various demand-side management practices and load control, the Cooperative has been able to consistently reduce the system's peak demand, which they claim "saves [their] members significant money through avoided capacity costs with GRE."[8] The Cooperative states that the "amount of which is available to be controlled varies each control day depending upon many factors, such as the day of the week, the temperature of the proceeding day, etc."[9] Figure 1 represent the historical system peak demand on DEA's system which shows a consistent reduction in peak demand due to the Cooperative's load management.[10]

Figure 1 – Historical System Peak Demand

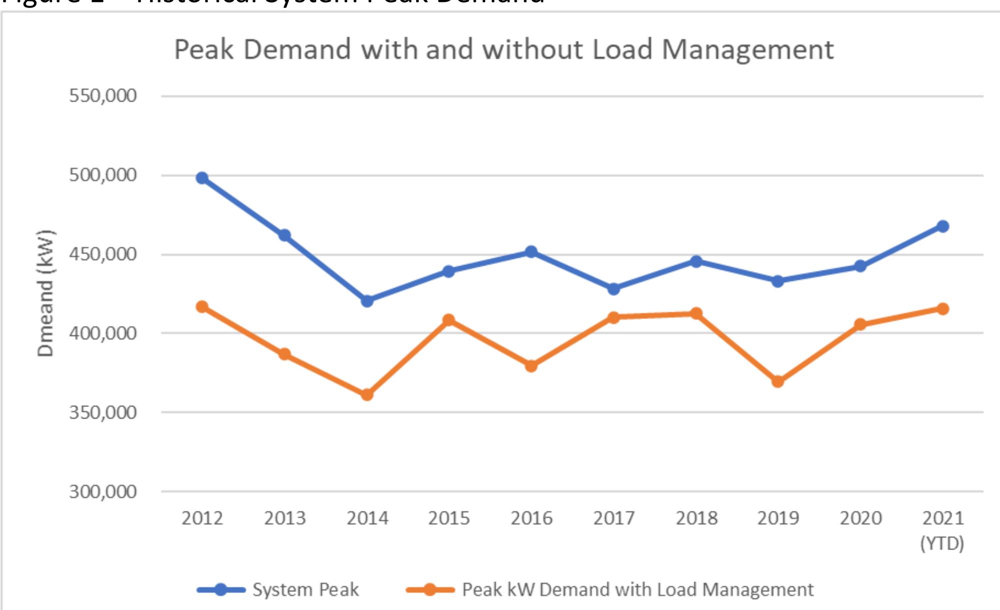
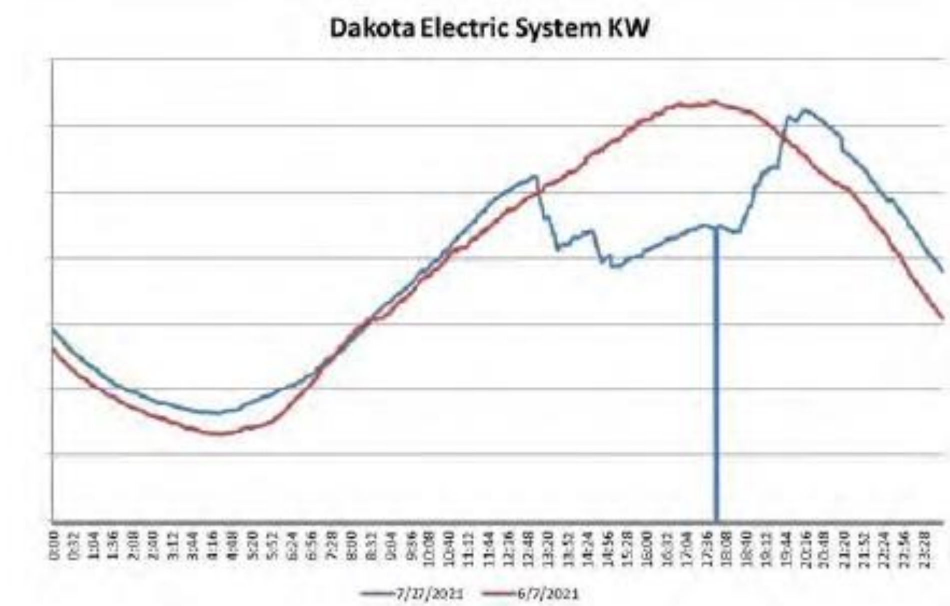


Figure 4 below exhibits the effect the Cooperative's demand management practices have on the peak demand for a typical summer day. The red line indicates a summer peak load day (June 7th) without any load control while the blue line indicates a summer peak load day (July 27th) with the Cooperative's load control in place.

[7] P. 59, DEA Initial, 11/1/21
[8] P. 40, DEA Initial, 11/1/21
[9] P. 9, DEA Initial, 11/1/21
[10] P. 39, DEA Initial, 11/1/21

Figure 4. Comparison of a 2021 Peak Day without control to a Peak Day with control



Dakota Electric manage several programs to reduce or control demand each of which can reduce demand by several megawatts depending on the season, as depicted in table 16.[11]

Table 16. Load Reduction Estimated by Program Type

Program	Number of Units	MW Connected	MW Reduction Summer	MW Reduction Winter
Air Conditioning	52,189	153	15-25	N/A
Heat Pump	2,765	10	3-5	2-8
Heat Device	3,331	29	N/A	5-10
Irrigation	377	24	0-15	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

Additionally, Dakota's energy efficiency programs saved 25,328 MWh in 2020.[12]

<u>Distributed Energy Resources (DER) Current State</u>

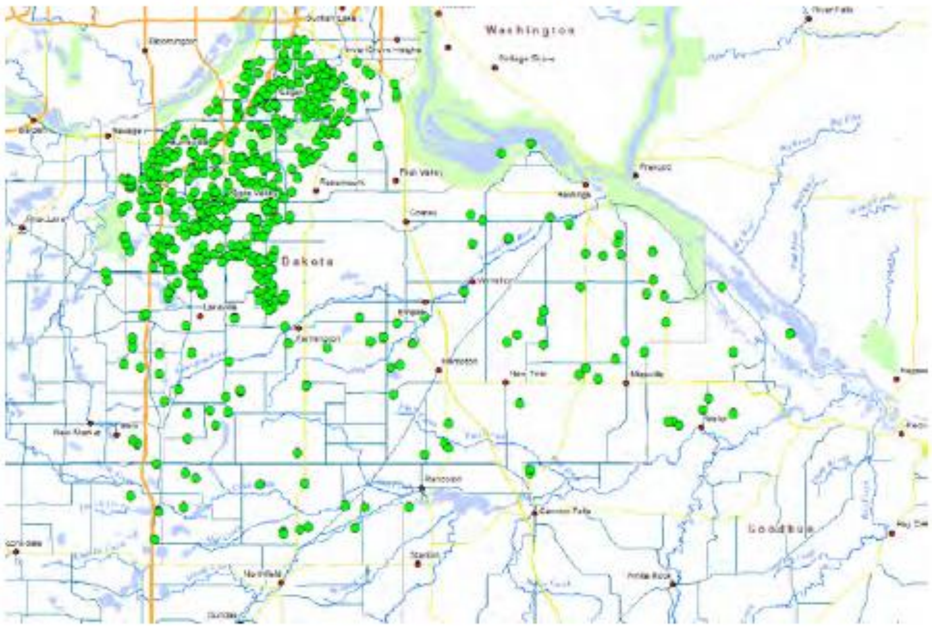
Dakota states that most of the distribution system has room for interconnecting additional DER without significant upgrades. The Cooperative highlights that 125 of their 178 feeders has at

[11] P. 49, DEA Initial, 11/1/21

[12] P. 49, DEA Initial, 11/1/21

least one solar system interconnected with five feeders having more than 10 solar systems interconnected. The average size of the behind the meter interconnection is 9 kW.[13]

Figure 25. Existing DER Generation Systems



DER Capacity and Voltage

Dakota does not currently have any "high" levels of DER penetration (defined by the Cooperative as being unable to connect small behind the meter (BTM) DER without expensive upgrades), although it does have three substations that have solar systems greater than 1MW connected to it and exceed the respective minimum loads. The Cooperative has also not encountered any significant voltage issues due to the DER systems.[14]

Potential Barriers to DER Integration

Dakota reexamines its 2019 engineering analysis which highlighted two points that the Cooperative expects will have the greatest impact on its ability to integrate larger DER generation without costly distribution system upgrades.[15] DEA kept these two factors and the other conclusions in mind as they analyzed and forecasted for the 2021 IDP.

- Less DER generation can be integrated on a circuit if the DER is not sized to the load
- Once reverse power flow into the transmission system is encountered, the ability to interconnect more DER on the distribution system is unknown and may be limited by transmission constraints.

The need to make costly upgrades to the distribution or transmission systems in order to accommodate additional DER in addition to the cost-recovery mechanism may be a potential

[13] P. 77, DEA Initial, 11/1/21
[14] P. 62, DEA Initial, 11/1/21
[15] P. 69, DEA Initial, 11/1/21

barrier. DEA points to the rural part of their service quality where an upgrade to the 69kV transmission line is needed to handle the consequential dangers if back feeding were to occur. Dakota says that transitioning this "three-terminal" transmission line to a "two-terminal" transmission line would be a multi-million dollar project. However, the Cooperative does investigate alternative routes to resolving the issues in their non-wires alternative section of the IDP.[16]

Dakota highlights that due to it being a distribution utility it is not familiar with the rules processes involved in the case where a transmission system receives back-feeding from the distribution substation although it does know that the transmission system is not built for this back-feeding.[17]

B. Hosting Capacity Data

Dakota Electric provided several spreadsheets of annual minimum load levels and annual daytime minimum load levels for the 165 feeders on the Cooperative's distribution system. An example of the spreadsheet is listed below, taken from Dakota's Appendix B. The data was captured from the Cooperative's SCADA system.

Substation	Feeder	Peak Load		Minimum		Daytime Minimum	
		8/2020-7/2021	6/2018-5/2019	8/2020-7/2021	6/2018-5/2019	8/2020-7/2021	6/2018-5/2019
Colonial Hills North (13)	Substation	16,675	19,828	4,764	4,832	5,899	6,523
	1			857	574	951	574
	3			164	197	301	339
	4			605	656	715	775
	8			1,011	597	1,011	867
	9			691	1,128	691	1,417
Colonial Hills South (13)	Substation	12,553	13,332	3,273	3,340	4,495	4,534
	2			263	759	394	1,312
	5			743	692	924	692
	6			356	399	498	515
	7			306	356	390	460
	10			630	694	833	841

Dakota identifies factors that affect the base data they have collected. The first is back-feeding feeders of the transmission system. Back-feeding is also one of the factors that can affect the interconnection and operation of a DER and so provides the minimum and maximum loading level for each of the substations. This information is one of the factors determining whether a transmission study is needed for new DER systems.[18]

Another factor is distribution switching – while modeled in a "Normal" state, Dakota states that the distribution system is rarely operating in a "normal configuration". The Cooperative

[16] P. 80, DEA Initial, 11/1/21
[17] P. 78, DEA Initial, 11/1/21
[18] P. 65, DEA Initial, 11/1/21

identifies several reasons why a feeder may have a partial or full transfer to another feeder: Emergency Switching (equipment failure), maintenance Switching, Switching for Road Construction, Distribution System Construction, and Load Control. Dakota reiterates that it has tried to provide the most useful minimum load data it could.[19]

C. DER Forecasting and Scenario Analysis

Dakota does not have personnel focused solely on forecasting and so used the U.S. Energy Information Administration (EIA) 2021 Annual Energy Outlook (AEO) for its forecasting.[20] DEA assumes that Minnesota will, on average, over 25 years, resemble the average of the US as a whole regarding DER development and used the data for the US average in its analysis. Additionally, Dakota did not forecast Demand Management because the Cooperative has already implemented significant Load and Demand-side Management.[21]

Dakota uses EIA's growth rate for its MEDIUM forecast. The LOW forecast reflects the potential impact of the loss of government incentives, through production tax credits and assumes limited increases in energy costs and limited reductions in the cost of solar installation. The HIGH forecast includes an adjustment in growth for years 2021-2028 above the EIA forecast levels. Dakota removed three existing utility scale solar systems because the Cooperative thought it distorted the forecasts in an unrealistic way.

Using these assumptions and growth rates for their analysis, Dakota forecasted the respective total behind the meter solar capacities for each scenario in 2020, 2030, and 2050.

Capacity for the Low, Medium and High Behind the Meter Solar Forecasts			
Forecast	**2020**	**2030**	**2050**
Low	3.5 MW	8.4 MW	16.8 MW
Medium	3.5 MW	13 MW	28 MW
High	3.5 MW	28 MW	62 MW

DEA believes that the number of systems interconnections in the medium forecast will stabilize over the next 10 years as the potential premises that solar can be installed saturates, represented in Figure 17.

[19] P. 67, DEA Initial, 11/1/21
[20] P. 70, DEA Initial, 11/1/21
[21] P. 70, DEA Initial, 11/1/21

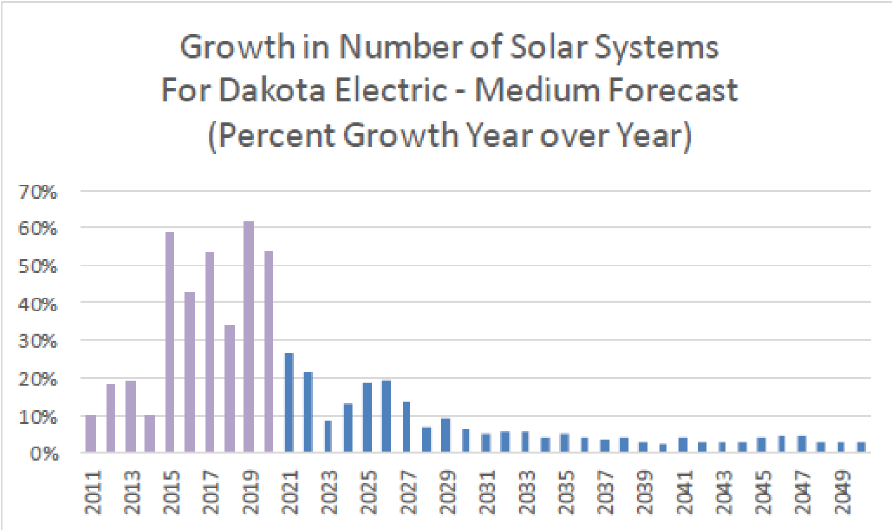
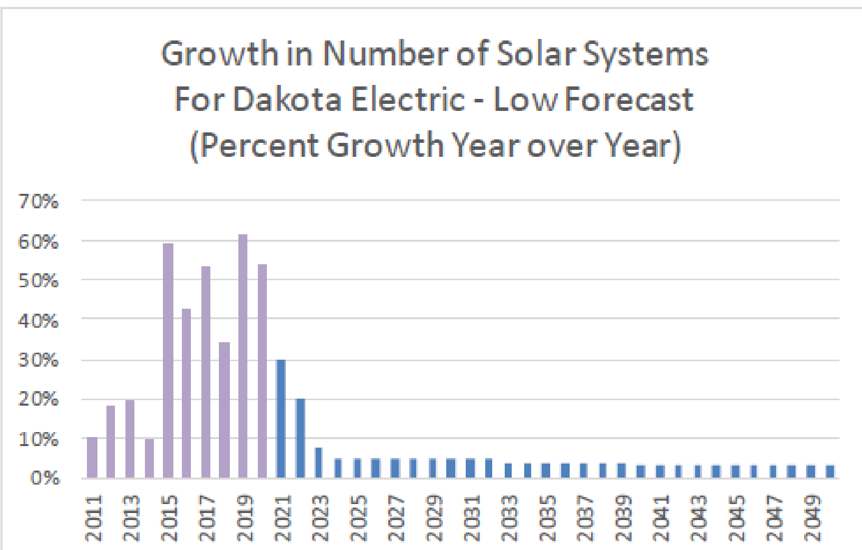


Figure 17. Medium DER Forecast of Annual Percent Growth in Solar Units

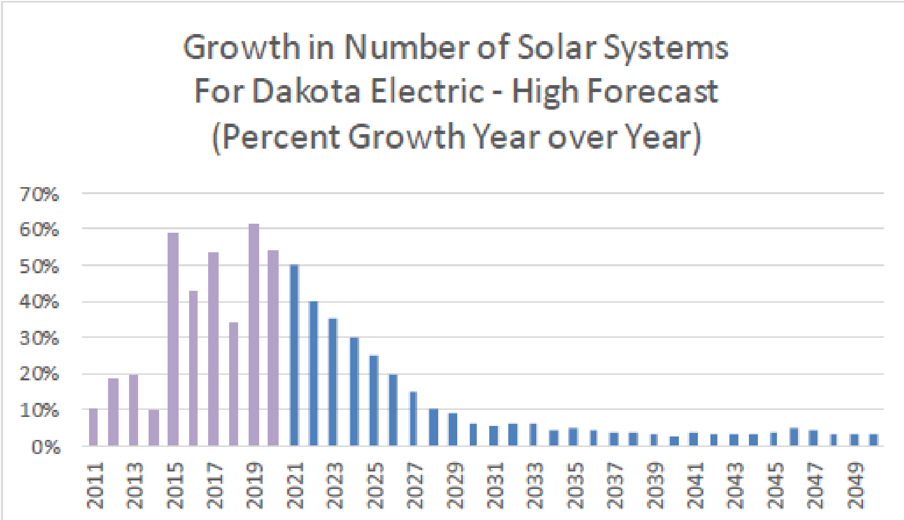
In the Low forecast scenario, due to the loss of government incentives, Dakota predicts that this could impact the economics of behind the meter solar and could see a smaller uptake in the near future relative to the medium forecast, depicted in Figure 20.

Figure 20. Low DER Forecast of Annual Percent Growth in Solar Units



In the High forecast scenario, DEA assumes that there will be higher levels of uptake in the 2021-2028 period and then fall back to the national average afterwards. However, due to the initial build-up the growth rate applied is working with a higher principle than the national average, resulting in capacity levels of 62 MW, depicted in Figure 23.

Figure 23. High DER Forecast of Annual Percent Growth in Solar Units



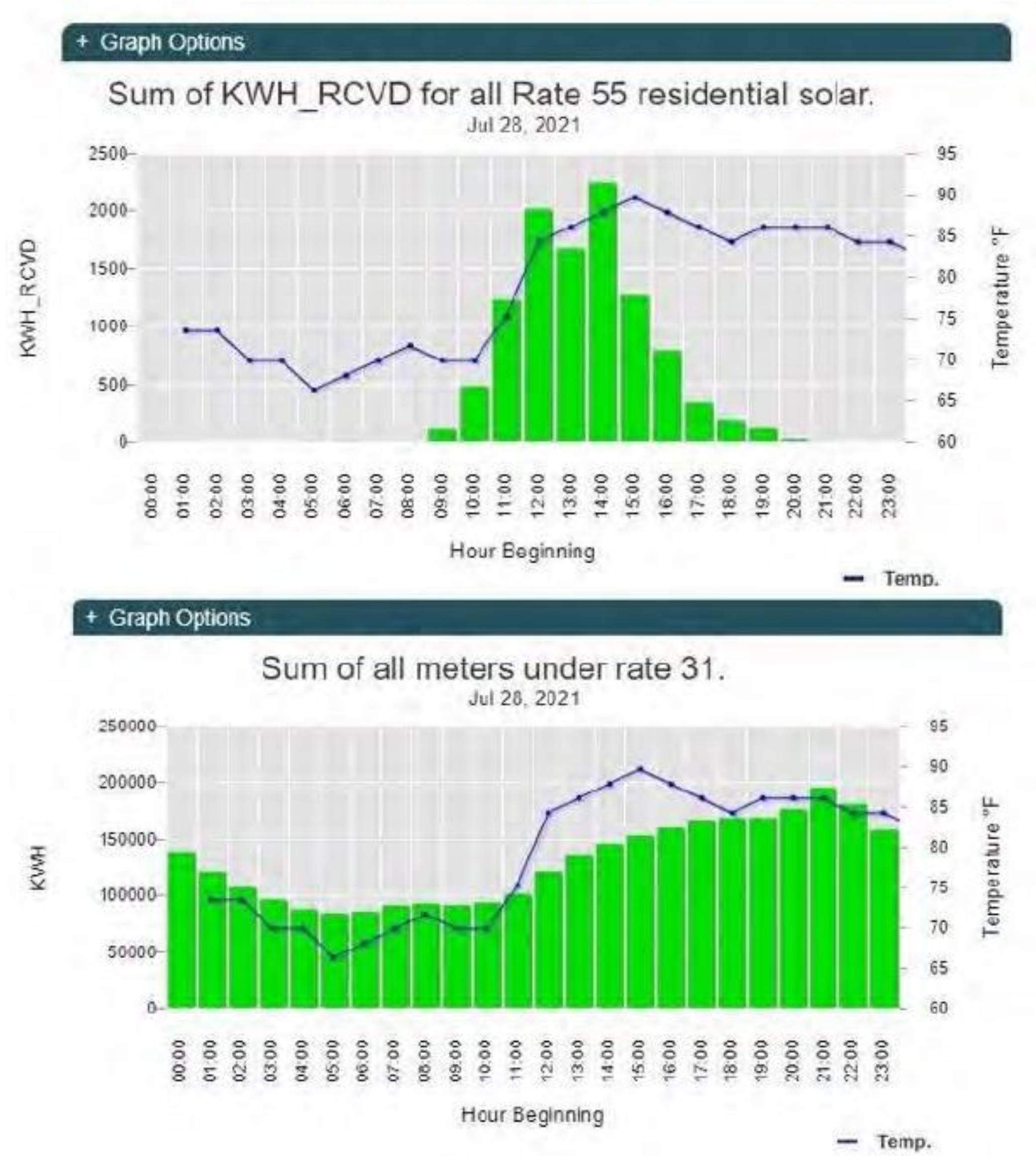
DER System Impacts, Costs, and Benefits

The Cooperative claims that "millions of dollars in power purchase costs are saved each year … through participation in demand side management programs" which has been the key DER benefit for Dakota.[22] Dakota says that while solar and wind DER has displaced some coal and natural gas, it is not evident that wind and solar DER benefit the distribution system infrastructure or operational costs. According to Dakota, the main reason is that these sources are too variable (cloud and snow cover) to be considered "firm" generation and that the generation does not match the native load.

Dakota used its AGi metering to map out the output of these solar system onto the peak electrical usage of a summer day and found that they do not align. Dakota found that peak solar output in the summer occurred around 3pm and was near zero around 8pm whereas peak demand was around 8-9pm and did not decline until around 10pm, depicted in figures 32 and 33.[23]

[22] P. 81, DEA Initial, 11/1/21
[23] P. 85-86, DEA Initial, 11/1/21

Figure 32 & 33. Solar Output vs Residential Energy Use – Wed. July 28, 2021



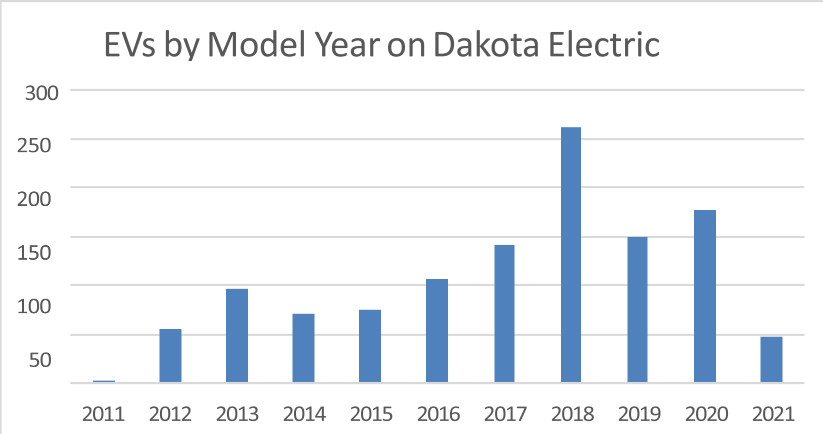
Impact of Electric Vehicles and TOU rates

Dakota has created a time of use (TOU) rate for electric vehicles and in the summer of 2021 started offering a TOU charging rate for non-residential and multi-family residential members. Dakota's TOU rate for electric vehicles has been relatively successful and the Cooperative is reviewing whether they should change the hours to soften the sharp rise in energy consumption they've observed between 9pm and midnight.[24]

The Cooperative does not track or forecast the number of EVs that are housed in its territory but using data from the MN Department of Public Safety DEA approximates that it has roughly 1,182 EVs located on its distribution system with the EVs by model year graphed below.[25]

[24] P. 87, DEA Initial, 11/1/21

[25] P. 58, DEA Initial, 11/1/21



Limitations and Issues with Incorporating DER into Future Planning Analysis

Using AGi metering, Dakota Electric has learned that present renewable energy systems have limited output that matches peak demand but has found that DER that is controllable, such as demand response, has been critical to being able to reduce the amount of capacity required by the distribution system.[26]

The two key concerns Dakota has regarding DER: 1) is the DER reliable and always available when needed, and 2) can distribution planning rely on DER owned and operated by other entities to delay or eliminate distribution projects, or can the DER be turned off and/or removed at any time without notice?[27] The Cooperative is questioning whether DER systems may hide loads that can cause complications upon failure to the DER system or an outage. Dakota looked at different scenarios to determine how to ensure DERs don't become a liability and may be used to enhance the system.

The Cooperative describes a "cold-load pickup", a situation after an outage where demand spikes to levels greater than before the outage due to the need to energize the motors and transformers on the system as well as due to a loss of diversity of electrical loads (water heaters, electrical heaters, air conditioning units all restart immediately upon restoration of power). This cold-load pickup coinciding with the delay time of DER output caused by the practice of IEEE Standard 1547-2018 that prevents quick interconnection with the distribution system after a prolonged outage, combine to create potential issues for the distribution system. This can also be exasperated by energy storage systems that begin recharging immediately as well.[28] Dakota notes that energy storage could help offset load immediately after power is restored if they use the energy already stored and has a planned delay for recharging.

Dakota hopes that information gathered through its AGi system, and its 15-minute interval data can help determine the potential demand levels post outage which could lead to a reduction in required safety margins and extra capacity needed to support the system post outage.[29]

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[26] P. 89, DEA Initial, 11/1/21
[27] P. 89, DEA Initial, 11/1/21
[28] P. 91, DEA Initial, 11/1/21
[29] P. 92, DEA Initial, 11/1/21

D. Long-Term Distribution System Modernization and Infrastructure Investment Plan

Energy Storage

Dakota is considering potentially adding utility-scale energy storage to support the interconnection of additional DER.[30] One use of the battery proposals would be to install the system at a substation where the transmission protective relaying can't support back feeding. This is an investment that the Cooperative is looking into as an alternative to replacing specific transmission substations which would cost $3-4 million. Additionally, DEA is considering the installation of utility operated energy storage system which would be charged with energy that would otherwise cause back feeding during the day and then discharge that energy in the evening. Dakota has not done a full economic analysis but believes the costs may be too high. Additionally, the Cooperative notes that this solution may impact their wholesale power supplier, GRE.

Electric Vehicles

As mentioned earlier, DEA has recently implemented an EV TOU rate for multi-family residential members. DEA believes this will support the Commission's objectives by increasing options and accessibility to EV rates and help optimize utilization of electrical grid assets and resources through the management of peak demands.[31]

Other Projects

Dakota continues to work with the Prairie Island Community to accomplish its Net Zero Project. The Cooperative is also putting significant resources into its cyber security efforts via its replacement of outdated software systems. GRE is also working to transform its core energy supply and expects to have 60% of its energy come from renewable sources.[32]

<u>Advanced Grid Infrastructure (AGi)</u>

The Commission approved Dakota Electric's AGi project and rollout in Docket No. E111/M-17-821. The Cooperative will have exchanged 99% of their over 120,000 meters with AMI metering by the end of 2021. The AMI metering has AGi Radio Frequency (RF) mesh communication system which provides 15-minutes interval data to Dakota Electric.[33] The last one percent are homes and businesses that are associated with larger capacity services and will be exchanged in 2022.

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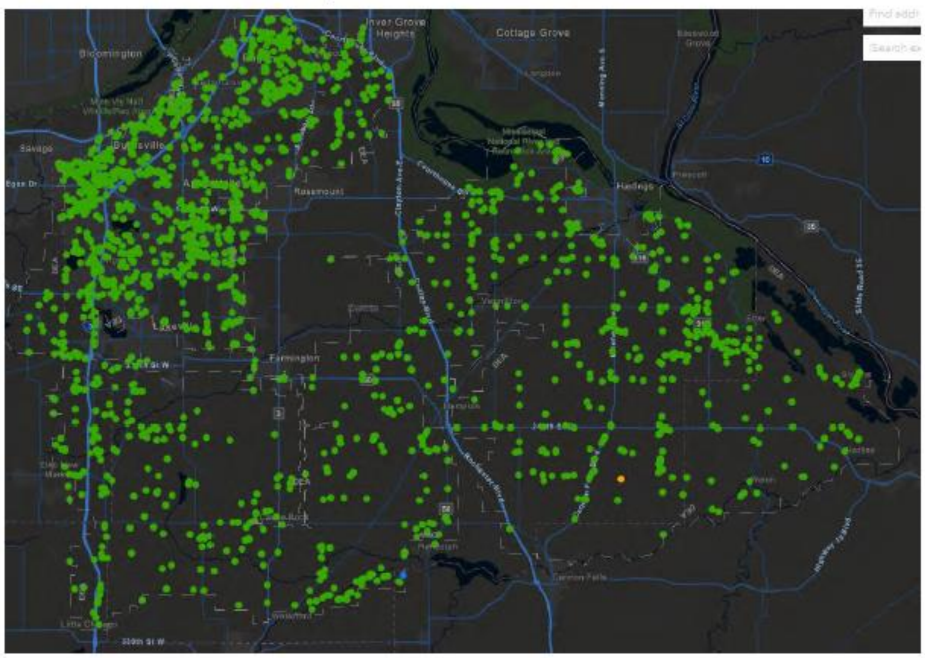
[30] P. 94, DEA Initial, 11/1/21
[31] P. 95, DEA Initial, 11/1/21
[32] P. 95-96, DEA Initial, 11/1/21
[33] P. 25, DEA Initial, 11/1/21

These meters are designed to send event data which informs DEA when there is a problem (e.g. high or low voltages, sags or swells, blinks, or outages). The Association's hope is that these smart meters will lead to resolving problems before they arise and quicken their response time when issues do occur.[34] Additionally, failed meters in the past weren't discovered until a meter reader physically interacted with the meter; now DEA can quickly identify failed meters and replace them much sooner. In addition to sending back alarms or notification for events, such as high or low voltage or high meter socket temps, each AGi meter provides various channels of 15-minute interval data.[35]

Dakota has 2,000 AMI meters being read every 5 minutes as opposed to the standard 4 hours in order to establish a bellwether system. This can help the Association catch issues early and improve the electrical reliability and quality of service to its membership.[36]

Figure 8. Bellwether Meters



One of the bigger benefits to the AGi project will be in calculating distribution losses. These losses were difficult to accurately determine due to having to manually read each meter every month which can be a temporally variable process but with AMI meters this reading can be done for all meters at the same time each month.[37] The system loss percentage has followed a 30-year downward trend and was determined to be 2.255% for the 2020 year.

Cost and Plans Associated with Obtaining System Data

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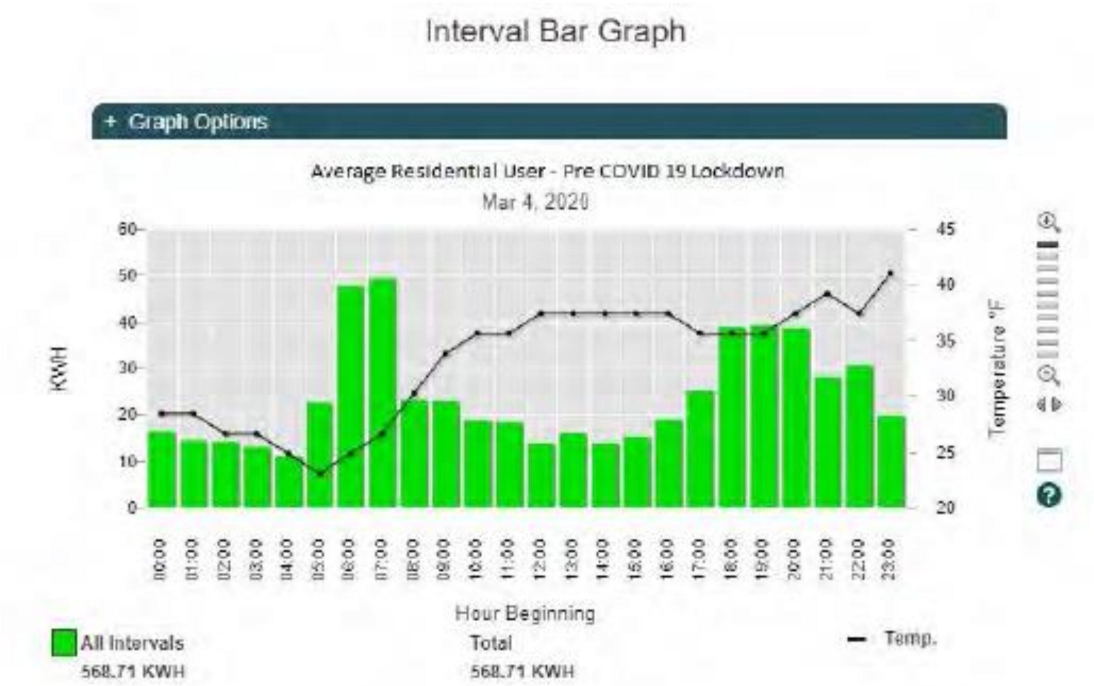
[34] P. 29, DEA Initial, 11/1/21
[35] P. 26, DEA Initial, 11/1/21
[36] P. 30, DEA Initial, 11/1/21
[37] P. 36, DEA Initial, 11/1/21

As a part of the AGi project, Dakota has also been installing production meters on DER installations to gather operational information about energy consumption and generation by the DER systems.[38] These production meters, in conjunction with the load shapes obtained by the AGi system, will inform Dakota on how best to utilize DER and in understanding DERs limitations.

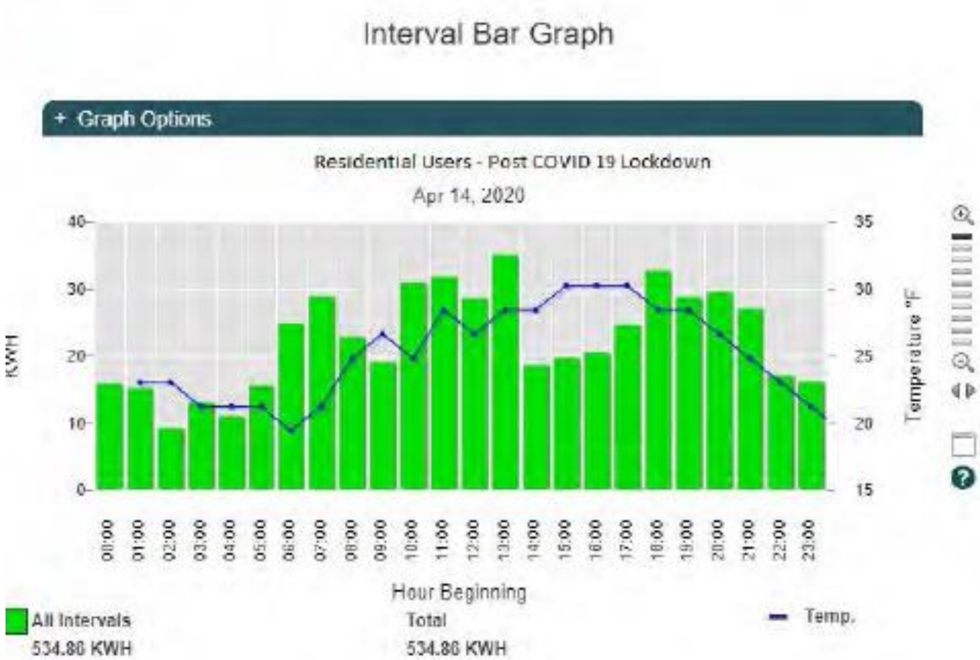
According to Dakota, AGi has already been useful – it was able to show how energy consumption changed throughout the pandemic which enabled Dakota to quickly respond to, and test for, potential impacts to the distribution system. As seen in the graphs below, energy consumption trends on an average day changed quite a bit as more people began working from home.[39]

Figure 36. Residential Electrical Usage Before and During Covid - 2020



[38] P. 98, DEA Initial, 11/1/21

[39] P. 99, DEA Initial, 11/1/21



Additionally, in 2022 Dakota plans to make a web-based portal for their membership that would allow access the 15-minute interval data gathered from their meter.[40] Once in place, Dakota believes that their members will be able to benefit by identifying potential issues with their service and ways to reduce their energy usage. The Cooperative believes the data will be detailed enough that their staff will be able to provide specific solutions to the improve individual household's electric service.[41]

AGi Costs and Benefits

The costs associated with the AGi are authorized for recovery through a separate monthly fixed charge rider based on actual costs incurred.[42] The AGi rate is updated each year until the project is complete whereupon the cost of the AGi will be rolled into base rates. The Cooperative expects several savings from the AGi project stemming for saved labor costs, customer related disputes, power quality complaints, as well as prevented issues discovered through data gathered, repairing systems before they fail, and identifying and resolving meter issues earlier than they used to.[43]

Dakota makes clear that member data is considered private, and the Cooperative will not disclose this information to third parties without member permission. However, Dakota will internally use individual data to monitor the quality of the power delivered to the member's service as well as aggregate data to aid in distribution planning.[44]

[40] P. 94, DEA Initial, 11/1/21
[41] P. 100, DEA Initial, 11/1/21
[42] P. 100, DEA Initial, 11/1/21
[43] P. 101, DEA Initial, 11/1/21
[44] P. 104, DEA Initial, 11/1/21

E. Non-Wires Alternative Analysis

Dakota Electric studied two projects as potential candidates for a non-wires alternative solution. The first is an updated analysis of determining if there was an alternative to a new substation near Elko-New Market, Minnesota and the other project review is the development and construction of new substation in southern Lakeville.

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:

1. Firm energy output when requested – the DER must be able to provide firm energy meaning most intermittent DER systems won't qualify.
2. Provide the firm energy for the duration of the need
3. Emergency repair / replacement of failed DER system components – repairs to the DERs must be made in an expedition manner to prevent putting the electrical energy supply to members in jeopardy
4. Enter into a contractual relationship to provide the service of the DER

Project 1 - Siting and Construction of New Substation Near Elko-New Market

Dakota analyzed three alternative solutions to a "traditional solution" of permitting and constructing a new 115kV substation under low and high growth (load) scenarios. The three alternative solutions include energy storage only, energy storage plus solar, and demand side management.[45]

This analysis is similar to the analysis conducted in the 2019 IDP with updated prices. The conclusions are no different now as they were in 2019. Through a combination of land costs, battery costs, extremely high member compliance, and the intermittency of solar energy, each of these alternatives are too costly and too uncertain over the traditional solution of installing a 115kV substation.[46]

Staff created a high-level overview of the four scenarios which details the cost of each scenario at 4% discount rate under "low" and "high" growth scenarios (energy demand growth).

[45] P. 111, DEA Initial, 11/1/21

[46] P. 125, DEA Initial, 11/1/21

Scenarios	Project	Low Growth NPV	Fast Growth NPV
Option 1A	Build New 115 kV Substation	$ 5,293,966	$ 5,293,966
Option 1B	Defer Substation using Energy Storage	$ 12,732,784	$ 19,697,463
Option 1C	Defer Substation using Solar and Energy Storage	$ 19,440,164	$ 31,154,269
Option 1D	Deferring New Substation with Demand-side Management	$ 6,151,144	

Note, the Cooperative did not run a scenario for Option 1D claiming "Option 1D is not practical for the fast growth scenario because the load growth and resulting load levels over the entire 24-hour period are too high."[47]

Project 2 Siting and Construction of a New Substation in Southern Lakeville

Dakota expects the reasons why Project 1 was cost-prohibitive would only be even more so in this project as the land in Lakeville is more expensive. Additionally, Dakota does not believe it has enough time to further explore and analyze other solutions to defer the initial substation installation. Dakota is working with GRE to develop programs to utilize behind the meter energy storage programs and hopes that this work will reduce the overall peak demands on the system.[48]

Non-Wires Alternative Solution Considerations

Through its work in analyzing these alternative solutions Dakota identified some key considerations they should observe in the future. First is that demand side or load management has the greatest potential but require a large geographical area that includes a significant number of services. The second is that solar DER cannot currently be counted as firm energy and therefore does not lend itself well to non-wires solutions. Additionally, the time it takes to obtain storage systems, which would make solar DER more viable, is too long if Dakota wants to be able to react quickly enough to situations that require distribution system adjustments or upgrades.[49] Dakota describes requesting responses from four vendors for a substation energy storage project and only receiving one response, believing that these vendors are busy with other projects and the Cooperative's projects may be too small in scale to divert focus from the other project the vendors' are working on.

Cost-wise it became apparent that non-traditional solutions do not necessarily compete at a specific cost threshold. Dakota states that "while economies of scale were important, the type

[47] P. 123, DEA Initial, 11/1/21
[48] P. 127, DEA Initial, 11/1/21
[49] P. 129, DEA Initial, 11/1/21

and capacity size of problem played a larger role in determining a non-traditional projects cost viability compared to traditional distribution projects."[50]

IV. Party Comments

The Department recommends that the Commission accept Dakota Electric Association's 2021 Integrated Distribution Plan with the understanding that acceptance of the IDP has no bearing on prudency or certification of specific proposed investments **(Decision Option 1)**.[51]

The Department reviewed the IDP against each planning objective and filing requirements as determined by the Commission's February 20, 2019 Order in Docket No. E111/CI-18-255 and later updated.

Planning 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

The Department did not find any section that discussed safety standards or how they affected the planning processes or risk management. However, the Department notes that they did not find anything wrong in Dakota Electric's Safety, Reliability, and Service Quality report.[52]

The Department points out that DEA will be replacing the GIS, OMS, SCADA, and other sub and supporting systems and may need extra care in ensuring protection against cyber security threat. The Department also notes that DEA did not provide what physical measures they are taking to ensure protection.[53]

The Department commends Dakota for being among the most reliable electric utilities in the United States due to far exceeding the average regarding SAIDI, SAIFI, and CAIDI measures.[54]

Table 4. 2020 Distribution System Reliability Indices[19] for Dakota Electric Association, Minnesota Utilities average[20], and United States Utilities average[21]

Reliability Performance Metric	2020 DEA	2020 MN Average	2020 US Average
SAIDI	19.5	84.7	116.0
SAIFI	0.31	0.90	1.013
CAIDI	63.7	94.6	114.5

Regarding whether investments have been fair and reasonable, the Department notes that it is developing a knowledge base in order to better evaluate this measure. The Department states that part of this knowledge base will be created by the utilities creating benefit-cost analyses in following their recommended Guidance Document.

[50] P. 129, DEA Initial, 11/1/21
[51] P. 26, Department of Commerce, Initial, 3/15/22
[52] P. 10, Department of Commerce, Initial, 3/15/22; Docket No. E111/M-21-202
[53] P. 10, Department of Commerce, Initial, 3/15/22
[54] P. 11, Department of Commerce, Initial, 3/15/22

The Department does not see a clear reasoning in how specific technology investment decisions relate to the Commission's objectives. The Department is considering recommending the Commission require that link in future IDP submissions but invites feedback from utilities.[55]

Planning Objective #2 - Enable greater customer engagement, empowerment, and options for energy services.

The Department notes that much of DEA's customer engagement, empowerment, and energy services options will be centered around the AGi project and that the Cooperative is "currently beginning to evaluate ADMS to integrate new capabilities provided by AGi equipment while replacing GIS, OMS, and SCADA technologies."[56]

The Department requests that in future filings regarding customer-facing utility offerings and programs that may be enabled by new investments in grid modernization technologies such as the AGi project or an ADMS project, Dakota Electric provides the following information:[57]

- Internal benefit-cost analyses for reference and investment case scenarios, including reasonably known and analyzed alternatives
- Assumptions and data supporting the projected customer participation rates
- Sensitivity analysis for varying rates of adoption of proposed programs; and
- Discussion of how the proposed customer-facing utility offerings and programs may interact with existing or proposed Conservation Improvement Plan or Next Generation Energy Act programs.

The Department states that this information is necessary for verification of the "reasonableness of the proposed incurred costs related to new customer-facing utility offerings and programs."[58]

The Cooperative is not necessarily opposed to this request but questions what the Department means by "customer-facing utility offerings".[59] The Department says that the recommendation is meant to support existing Commission-approved Filing Requirements, mainly IDP Filing Requirement 3.D.1 which relates to the grid modernization proposals.

The Department specifies that "services and technologies that provide customers with greater and more granular information regarding their energy use, allow for customer behavioral changes to result in reduced bills, and ease the interconnection and optimization of behind-the-meter DERs or enable beneficial electrification of equipment on a customer's property are examples of grid modernization proposals that the Department would consider to be customer-

[55] P. 12, Department of Commerce, Initial, 3/15/22
[56] P. 13, Department of Commerce, Initial, 3/15/22

facing."[60] The Department also states that it would be satisfied with being provided with the data and information used by DEA in its "regular business procurement practices" and "prudent reviews" that are sent to the Dakota Electric Board for approval.[61] Staff notes this request for more information is addressed in the Guidance Document briefing papers.

Planning Objective #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.

The Department created a table that compares the historical amount spent on the distribution system over the 2016-2020 period and what the Cooperative has budgeted for the 2021-2025 period.

Table 3. Comparison of Distribution System Spending Reported in DEA's 2021 IDP, Historical Actual (2016 – 2020) vs. Budgeted (2021 – 2025)

	Historical Actual (2016 - 2020)		Budgeted (2021 - 2025)		Δ	
IDP Budget Category	Spending (Millions)	% of Total Spend	Spending (Millions)	% of Total Spend	(Millions)	%
Age-Related Replacement and Asset Renewal	$ 19.57	28.33%	$ 13.44	14.91%	$ (6.14)	-31.35%
New Customer Projects and New Revenue	$ 18.44	26.69%	$ 21.85	24.24%	$ 3.41	18.48%
System Expansion or Upgrades for Capacity	$ 5.82	8.42%	$ 16.08	17.84%	$ 10.26	176.33%
Projects Related to Local (or other) Government Requirements	$ 6.72	9.73%	$ 9.03	10.02%	$ 2.31	34.36%
System Expansion or Upgrades for Reliability and Power Quality	$ 6.89	9.97%	$ 6.41	7.11%	$ (0.48)	-6.91%
Other	$ -		$ -		$ -	
Metering	$ 5.70	8.24%	$ 12.45	13.81%	$ 6.76	118.61%
Grid Modernization and Pilot Programs	$ 5.96	8.62%	$ 10.89	12.08%	$ 4.93	82.77%
Total Spending	**$ 69.09**		**$ 90.14**		**$ 21.05**	**30.47%**

The Department identifies that the AGi initiative is likely the cause for the increase in some of the categories but would like Dakota to provide more information regarding where exactly the AGi project is being categorized. Additionally, the Department states that there is "limited information that allows for rigorous assessment of the investment decision being made within each category" and that they are considering a recommendation requiring illustrative examples of detailed and completed BCAs for proposed projects within each category claiming that this information would help "the Department, the Commission, and stakeholders develop a deeper understanding of how DEA plans for and spends ratepayer funds on these myriad grid investments.[62] The Department requests that Dakota Electric provide additional information

[62] P. 15, Department of Commerce, Initial, 3/15/22

and/or discussion regarding how capital construction project alternatives are evaluated and funded.

Dakota responds reiterating that this budgeting process is subjective. Dakota states that the physical metering of the AGi project was categorized in the metering category, load control device installation costs were included under the Grid Modernization category, and communication costs for the AGi project were placed in the Grid Modernization category. The other AGi costs are included in the historical and forecasted capital costs for 2019-2023.[63]

Dakota Electric responds to the considered BCA request saying that while the request is well-placed, it assumes that there is time available for Dakota to complete an economic analysis of possible scenarios. It also assumes that the Cooperative has the time to "procure necessary materials and resources, both financial and human capital, to create a unique construction design before the necessary electrical service is required."[64] Dakota states that all of those assumptions are flawed – that they often only have weeks to respond to certain projects. Additionally, timely responses are necessary for both Commission's service quality rules as well as good business practice. However, Dakota does say they will conduct detailed cost-benefit analyses for large projects like the AGi project.

The Department appreciates Dakota's insight regarding traditional distribution infrastructure investments and retracted its recommendation of requiring a BCA for this manner.[65] Regarding the categorization questions, the Department says it is not raising the issue to make any implications other than to demonstrate the "difficulty faced by the Department in performing the rigorous analysis expected of it by the Commission in the absence of clear expectations regarding the quality and type of information that a utility is required to provide in response to IDP Filing Requirement 3.D to support the utility's grid modernization plans and proposals."[66]

Planning Objective #4 - Ensure optimized utilization of electricity grid assets and resources to minimize total system costs

The Department summarizes Dakota's development and execution of its Annual Construction Capital Budget where they include a 5-year forecast and only a one-year budget with specific projects due to the reactionary nature of the distribution system. Dakota stated that the one-year budget is reviewed for "ways to reduce, or delay, capital expenses prior to presenting the capital construction budget to senior management at Dakota Electric for further review, adjustments, and approval."[67] The Department finds that further discussion of this budget review process would be helpful in alleviating the information asymmetry and that "access to information regarding the considered alternatives and their associated benefits and costs, forecasting assumptions, and the assumed time period over which scenarios are compared"

[63] P. 19, DEA Reply, 4/5/22
[64] P. 20, DEA Reply, 4/5/22
[65] P. 26, Department of Commerce, Reply, 4/18/22
[66] P. 24, Department of Commerce, Reply, 4/18/22
[67] P. 14, DEA Initial, 11/1/21

would be required in order to "properly evaluate whether investments selected after this comparative analysis satisfy the Commission's Planning Objective."[68]

The Department notes that DEA has generally kept their expenditures close to what the Cooperative had estimated with a few exceptions in 2020. Dakota gave a reasonable explanation for why they spent more on the Age-Related Replacement and Asset Renewal category (replacing wooden line poles that were deteriorating more quickly than expected) but that they were unable to find a rationale for why less than estimated amounts were spent on the System Expansion or Upgrades for Capacity, Metering, or Grid Modernization and Pilot Programs IDP Budget Categories.[69] Additionally, the Department believes more transparency would be advantageous – it is currently difficult to understand why certain categories have projected increases in spending and it's also difficult to reconcile the Commission-ordered budget categories with DEA's internal budgets.

The Department requests that DEA provide a narrative explanation for the changes in spending for each IDP Budget Category compared to the 2019 IDP in Utility Reply comments and an explanation for how budgeted capital expenditures that are currently accounted for as System Expansion for Capacity and Reliability would be allocated between the IDP Budget Categories of System Expansion or Upgrades for Capacity and System Expansion or Upgrades for Reliability and Power Quality in the Cooperative's 2021 – 2025 proposed budget.[70]

The Department also suggest that the Cooperative utilize a "right-size analysis"; defined as "the process of matching utility investments to the need identified by the engineering analysis of the distribution system so performance and reliability of the distribution system is achieved at the lowest possible cost", to demonstrate that the budgeted projects are the "right size" monetarily.[71]

Dakota responds by reiterating that the budget categories have significant overlap and that it can be difficult to quantify or categorize a particular project and that they practice a "what basis" not a "why basis" for their financial records.[72] The Cooperative believes that further clarification about what should and shouldn't be included would be beneficial. The Cooperative continues – the spending in 2019 was lower than estimates by $2.3 million mainly due to weather events that caused construction delays, impacting new residential developments and governmental road rebuild projects. The AGi has an initial delay which caused underspending in 2019 but the AGi project accounted for 70% of the cost difference due to delays caused by Covid. DEA states that 90% of the cost difference in 2020 can be attributed to Covid-related delays.[73]

[68] P. 16, Department of Commerce, Initial, 3/15/22
[69] P. 17, Department of Commerce, Initial, 3/15/22
[70] P. 18, Department of Commerce, Initial, 3/15/22
[71] P. 19, Department of Commerce, Initial, 3/15/22
[72] P. 22, DEA Reply, 4/5/22
[73] P. 23, DEA Reply, 4/5/22

Regarding how budgeted capital expenditures are currently accounted for as "System Expansion for Capacity and Reliability" would be allocated between the IDP Budget Categories of "System Expansion or Upgrades for Capacity" and "System Expansion or Upgrades for Reliability and Power Quality" – the Cooperative apologize for the mis-categorization of its four projects over $100,000 in estimated costs being listed as "System Expansion for Capacity and Reliability".[74] DEA believes that the projects could be listed as either category and apologizes for any confusion.

The Department appreciates some of the nuance the Cooperative detailed but notes that the Cooperative "does not provide any indication of whether the costs were included in the reported planned investments for the Reliability category, Capacity category, both categories, or neither." The Department states that it is not intending to dictate how the Cooperative allocates its IDP budgets but "stresses the importance of consistency in application of a selection methodology among IDP iterations going forward."[75] The Department also notes that the Cooperative did not comment on its suggestion of a "right-size analysis" and reiterates its belief that a "right-size analysis" may be beneficial going forward and could lead to greater understanding.

Planning Objective #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**

The Department believes that the Cooperative generally provided relevant and sufficient information but emphasizes the need for additional information and transparency in some aspects of the IDP.[76]

IDP Notice Topic #3: What IDP Filing requirements provide the most value to the process, and why?

The Department identifies three themes regarding the IDP:[77]

1. distribution system planning should itself be cost-effective and lead to outcomes that are also cost-effective
2. distribution system planning reporting should correct a historic, long-term information asymmetry between regulators and utilities
3. IDP requirements between utilities should be consistent to the greatest extent practicable. IDPs should provide stakeholders with enough information to enable the evaluation of a utility's approach to distribution system planning

The Department then "[built] upon these themes by articulating a fourth which was also evinced in Xcel's IRP:

[74] P. 23, DEA Reply, 4/5/22
[75] P. 28, Department of Commerce, Reply, 4/18/22
[76] P. 20, Department of Commerce, Initial, 3/15/22
[77] P. 20, Department of Commerce, Initial, 3/15/22

4. utilities should undertake efforts to align the planning processes of integrated distribution system planning and integrated resource planning to the extent that such processes rely on tools, methods, data, and information (notably, forecasting of DERs) that can be shared in ways that lead to mutually beneficial outcomes for both processes and the consistent use of data and information in each process.

The Department understands that Dakota does not create IRPs but the Cooperative does "create detailed short- and long-term forecasts for energy consumption" from which GRE relies upon.

IDP filing requirement 3.C: Distributed energy resource scenario analysis

The Department points out that if Dakota's DER forecasts are used as part of GRE's IRP it would allow for both entities to better consider the impact of DERs on future resource acquisitions needs as well as identification of more cost-effective DER integration.[78] The Department charted out the incremental solar PV going back to 2015, noting that the growth rate for annual solar units installed as well as the total installed capacity "corresponds with DEA's "High" DER forecast case for 2022 – 2050."[79]

Table X. Solar PV Installations and Nameplate kW (AC) Capacity Increases, 2015 - 2021

	Solar PV System Installations			Nameplate kW		
Year	Annual	Cumulative	% Change	Annual	Cumulative	% Change
2015	20	53	60.61%	204.62	471.77	76.59%
2016	23	76	43.40%	291.51	763.28	61.79%
2017	41	117	53.95%	1,433.91	2,197.19	187.86%
2018	40	157	34.19%	2,406.02	4,603.21	109.50%
2019	97	254	61.78%	3,914.25	8,517.46	85.03%
2020	137	391	53.94%	1,035.11	9,552.57	12.15%
As of October 1, 2021	265	656	67.77%	2,022.43	11,575.00	21.17%
In queue as of Oct 1, 2021	153	809	23.32%	1,250.00	12,825.00	10.80%

IDP filing requirement 3.D

The Department refers to one of the Guidance Document's goals being to create a framework for grid modernization. Section 3.D requires utilities to provide a 5-year Action Plan as part of a

[78] P. 21, Department of Commerce, Initial, 3/15/22

[79] P. 21, Department of Commerce, Initial, 3/15/22

10-year long term plan for distribution system developments and investments in grid modernization. The Department points out that the filing requirements for Section 3.D of the IDP is similar to the requirements of the IRP's requirement that a "utility must identify resource options available to meet the service needs of its customers over the forecast period and supporting information."[80] Upon approving the resource plan, utilities complete a Certificate of Need (CN) which has its own set of filing requirements and evaluations criteria. The Department "contends that a meaningful connection between a utility's IDP and specific grid modernization proposals can and should be made in the same spirit of the IRP-CN connection".

IDP topic #4: are there filing requirements that are not informative and/or should be deleted or modified, and why?

Benefit-cost Analysis

The Department is not currently requesting changes to the filing requirements related to BCA information but point out that their Guidance Document details how they should be conducted so that the Commission and stakeholders can evaluate them.[81]

The Cooperative responds saying that focusing on the BCA process, "without consideration for other factors, ignores the fact that distribution planning is typically reactionary in nature and in response to member needs and creates an unnecessarily restrictive method to analyze the reasonableness of various projects."[82]

Miscellaneous

Redline Recommendation

The Department recommends that the Commission include DEA's IDP Filing Requirements in its Order in this and subsequent IDP proceedings, including a red-line version if modifications are made to DEA's IDP Filing Requirements.[83] The Cooperative also supports this recommendation as it will "ensure [they] provide the Commission with the information and data they need to review [their] filing."[84] Staff has created individual documents with for each set of utility IDP filing requirements and will file it as an attachment to the Order in this docket. Staff will also attach the current set of filing requirements to future notices for comment in this docket.

V. Staff Analysis

Both parties, Dakota Electric Association and the Department, agree that the Commission should accept Dakota's Integrated Distribution Plan (**Decision Option 1**).

[80] P. 24, Department of Commerce, Initial, 3/15/22
[81] P. 25, Department of Commerce, Initial, 3/15/22
[82] P. 15, DEA Reply, 4/5/22
[83] P. 26, Department of Commerce, Initial, 3/15/22
[84] P. 25, DEA Reply, 4/5/22

Staff notes that a significant portion of the record was spent discussing the merits, benefits, resource-requirements, and design of the Department's Guidance Document. Analysis will not be done on the Guidance Document in this briefing paper as it has been taken up in separate briefing papers also set to be heard on the September 1st, 2022 Agenda Meeting.

DER Scenario Analysis

Dakota Electric utilized the U.S. Energy Information Administration (EIA) 2021 Annual Energy Outlook (AEO) for its forecasting by creating a Low, Medium, and High scenario. The Department pulled data regarding the DER trends for the Cooperative and found that it's likely that Dakota will fall in the High category.[85] Dakota's assumption under the Low forecast, assumed the loss of government incentives for solar installations, causing a low growth rate in the 2020s. Staff notes that with the passing of the Inflation Reduction Act on August 16, 2022, the Investment Tax Credit (ITC) has been extended through 2025, making this scenario less likely for some DER.

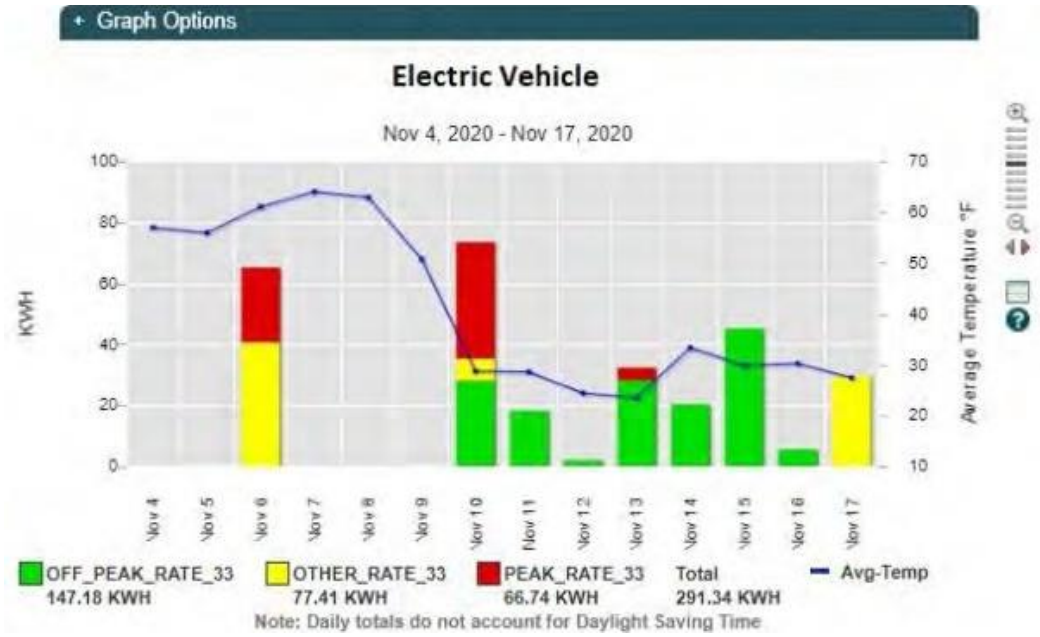
Advanced Grid Infrastructure (AGi)

Staff notes that the benefits resulting from the Advanced Grid Infrastructure project show potential. Data gathered from the project may allow for a safer and more reliable grid as Dakota is now able to be more responsive to outages or other issues. Dakota states that in the past, outages would not be discovered until a meter reader physically when out to check the meter and diagnose the issue.[86] Additionally, Dakota should see more labor efficiency as meter readers will not be needed for routine reading on the majority of their meters.

Another potential benefit of the AGi project is the member portal where their members can utilize information about their energy use and potentially make behavioral changes or notify Dakota when they see a potential issue.[87] This information can be used when considering DER installation, electrical improvements, or to better align their energy usage with a TOU plan. Dakota uses an example of a member realizing they were paying higher rates on the TOU plan and then shifting when they charge their electric car once they realized they were paying more.

[85] P. 21, Department of Commerce, Initial, 3/15/22
[86] P. 102, DEA Initial, 11/1/21
[87] P. 104, DEA Initial, 11/1/21

Figure 40. Electric Vehicle TOU Usage Example



VI. Decision Options

1. 1. Accept Dakota Electric's 2021 Integrated Distribution Plan. Acceptance is not a prudency determination of any proposed system modifications or investments. (*DEA, The Department*)

2. Dakota Electric shall file its 2023 Integrated Distribution Plan no later than November 1, 2023.