DAKOTA® ELECTRIC ASSOCIATION

Your Touchstone Energy® Cooperative

November 1, 2021

William Seuffert, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101-2147

Subject: ***Dakota Electric Association 2021 IDP Report***

In the Matter of Distribution System Planning
for Dakota Electric Association
Docket No. E-111/M-21-728

Dear Mr. Seuffert:

On February 20, 2019, the Minnesota Public Utilities Commission (Commission) issued an *Order Adopting Integrated Distribution Plan Filing Requirements* (February Order) in Docket No. E111/CI-18-255. This February Order outlined, in relevant part, the following distribution system plan requirements for Dakota Electric Association® (Dakota Electric® or Cooperative):

> 1. Filing Date: Require Dakota Electric to file biennially with the Commission beginning on November 1, 2019 an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above.

On November 2, 2020, the Commission issued an *Order Accepting Integrated Distribution Plan and Modifying Filing Requirements* (November 2 Order) in Docket No. E111/M-19-674. Ordering Point No. 5 stated:

> The Commission delegates authority to the Executive Secretary to convene a process to engage representatives from each of the rate-regulated utilities and stakeholders to review and discuss the Commission's IDP orders for the next round of IDP reports to help ensure that data included in future IDPs is efficiently gathered and presented.

Dakota Electric notes that we previously submitted two informational letters regarding the required stakeholder meeting in Docket No. E111/M-19-674, the 2019 IDP proceeding. Our July 23, 2021 letter included the invitation we sent to potentially interested stakeholders and the draft agenda for the stakeholder meeting. On September 1, 2021, we submitted another letter containing the final agenda for the stakeholder meeting. Dakota Electric held a stakeholder meeting on September 15, 2021 where it presented the preliminary findings of its IDP Report. This meeting was attended by other utilities and stakeholders that participated in the 2019 IDP process. We filed our presentation material on September 16, 2021 in Docket No. E111/M-19-674 and in this docket on October 8, 2021.

<u>Dakota Electric Compliance</u>

Dakota Electric submits its 2021 IDP Report in response to the Commission's February 20 Order in Docket No. E111/CI-18-255 and its November 2 Order in Docket No. E111/M-19-674.

This filing responds to requirements identified above and in the Commission's previous IDP orders. Dakota Electric has undertaken a substantial effort (through internal staff and consultants) to prepare this second biennial Integrated Distribution Plan. The attached plan covers the detailed filing requirements outlined in the Commission's February 20 Order and November 2 Order.

Conclusion

Dakota Electric looks forward to comments from interested parties and continuing refinement of this, and future, Integrated Distribution Plans.

Sincerely,

/s/ Craig Turner

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Craig Turner
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/s/ Adam J. Heinen

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Certificate of Service

I, Melissa Cherney, hereby certify that I have this day served copies of the attached document to those on the following service list by e-filing, personal service, or by causing to be placed in the U.S. mail at Farmington, Minnesota.

Docket No. *E-111/CI-21-728*

Dated this 1st day of November 2021

/s/ Melissa Cherney

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Melissa Cherney

Dakota Electric Association Integrated Distribution Plan (IDP) Report

November 2021

Provided in response to the Minnesota Public Utilities Commission dockets

E-111/CI-18-255 & E-111/M-19-674 & Filed in E-111/M-21-728

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Abbreviations and Common Terms

To assist the reader of Dakota Electric's Integrated Distribution Planning (IDP) report, the following is a list of common terms and abbreviations that are used throughout this report. Other abbreviations may also be explained within the report.

Advance Grid Infrastructure (AGi): This is Dakota Electric's grid modernization project that involved the installation of digital two-way communicating meters and load management infrastructure, integrated with a meter data management system. Additional details can be found in Minnesota Public Utilities Commission (Commission) Docket No. E111/M-17-821.

Advanced Metering Infrastructure (AMI): This is the system which includes an RF mesh communication network coupled with digital meters which are connected to the network. The digital meters are able to communicate energy information back to the Dakota Electric headquarters in support of energy billing and identification of metering and power quality issues.

Behind-the-Meter (BTM): Refers to a device that is located on the load (consumers) side of Dakota Electric's main service's electric meter.

CAIDI: Customer Average Interruption Duration Index. This is a term used by electric utility to report on the average outage duration that any given customer would experience. CAIDI is equal to SAIDI divided by SAIFI. This index is typically calculated per year.

Demand-side Management (DSM): Also known as Load Management or Load Control. It is a program where Dakota Electric can turn off and on different types of loads using communication systems such as the AGi RF mesh or start/stop member-owned generation using the SCADA system.

Distributed Energy Resources (DER): A Distributed Energy Resource is any resource on the distribution system that produces electricity. For the purposes of this report, DER includes energy efficiency and Demand Side Management.

DER Generation: For the purpose of this report, DER generation refers to a distributed energy resource that produces electricity. This term includes energy storage systems but does not include energy efficiency and Demand-side Management.

Energy Storage Systems (ESS): A system which can store energy to be released for use later, typically using a battery, which is charged by either the distribution grid or distributed generation source.

Electrical Vehicle (EV): A vehicle which uses batteries to provide energy to the vehicle engine.

Kilo-Watt (kW): This is a measurement of either capacity available or demand requirements.

Load Control Receiver (LCR): A device installed at a home or business which has a relay (switch) that can turn on or off an appliance upon receiving a command from the utility's Demand-side Management system.

Meter Data Management (MDM): Is a computer system and database which takes in the data from the AMI meter and stores that information. The MDM provides Dakota Electric with a platform to use the data provided from the AMI meter for billing, identifying metering issues and to identify power quality issues. As part of the overall AGi project, Dakota Electric also has integrated the load control receivers (LCR), so that they also provide information to the MDM database platform.

Non-wires Solutions (NWS): Also referred to as non-wires alternative. This is a type of distribution system solution that is different than the traditional wired solution commonly used today.

Operational Management System (OMS): System that supports the efficient management of the electrical distribution system topology and restoration of outages

Supervisory Control and Data Acquisition (SCADA): This is a computer system for gathering and analyzing real-time data. SCADA systems are used to monitor and control a plant or equipment in industries such as energy, oil, telecommunications and gas refining and transportation.

SAIDI: System Average Interruption Duration Index. This is a system wide average outage duration for an average customer. This index is typically calculated per year.

SAIFI: System Average Interruption Frequency Index. This is a system wide average number of interruptions that an average consumer would experience. This index is typically calculated per year.

Introduction

This Integrated Distribution Planning (IDP) report was authorized by the Minnesota Public Utilities Commission (Commission) in its February 20, 2019 Order (IDP Order) in Docket No. E002/CI-18-255. The Commission's IDP order was updated on November 2, 2020 in Docket No. E111/M-19-674. This report is organized following the sequence provided by the Commission in its IDP Orders. The format used in this report poses the Commission's question or request for information and is then followed by the information or response. The Commission's IDP Order requires each regulated electric utility in Minnesota to file an IDP every two years.

This the second IDP report submitted to the Commission, with the first being submitted on October 31, 2019 in Docket No. E111/M-19-674. Dakota Electric Association's (Dakota Electric) approach and philosophy in the IDP when responding to the questions contained within the Commission's IDP Order is to provide information looking at the big-picture, engineering perspective. In some areas, Dakota Electric has added additional information to help the reader understand the topic or provided additional data to help illustrate the issues. Dakota Electric strived to be responsive to the questions and issues raised within the Commission's IDP Order and its order from the first IDP.

1. Integrated Distribution Planning

Before reviewing or studying an IDP it is important to ask the question, what is Integrated Distribution Planning? The general intent of the IDP reporting process is to provide more transparency into the distribution planning process and provide information on expected or potential distribution system developments for an electric utility. The overall understanding of what an Integrated Distribution Plan includes can be quite different, depending upon with the audience. The IDP Order provided several planning objectives for future IDP reports and included specific data requests and questions which must be answered within the report.

The IDP report also serves as an educational platform which allows Dakota Electric to educate parties on how we conduct distribution planning and provide insight into Dakota Electric's future vision for the electrical distribution system. The creation of this report and the continued bi-annual process for future reports is expected to support a greater amount of interaction between Dakota Electric and stakeholders.

From the Commission's IDP Order, the Commission provided the following IDP report objectives:

> ***Planning Objectives:*** *The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to:*

- *Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;*
- *Enable greater customer engagement, empowerment, and options for energy services;*
- *Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;*
- *Ensure optimized utilization of electricity grid assets and resources to minimize total system costs, and,*
- *Provide the Commission with the information necessary to understand Dakota Electric's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of rate payer cost and value.*

From Dakota Electric's perspective, the IDP Order seeks information that focuses on the integration of DER at Dakota Electric in the past, present, and future. Within this IDP report, Dakota Electric provides discussion on topics such as:

- future modernization plans and capital spending;
- Dakota Electric's forecasted penetration levels for DER systems;
- discussion about possible issues which could occur that would affect higher DER levels of integration; and
- information being learned using Dakota Electric's new AGi metering system.

Dakota Electric crafted its report in a manner that it hopes is helpful to the Commission and responsive to any requests or questions that it may have. Since this is the second IDP Report, Dakota Electric expects future changes and process improvements going forward and is prepared to provide any clarification or additional information requested by the Commission or other parties.

2. Background Information

Dakota Electric Association is a not-for-profit electrical cooperative, serving the electrical needs of over 110,000 members. Dakota Electric was formed in 1937 by local citizens to provide electricity to the homes, farms, and businesses of Dakota County. Dakota Electric has grown since its founding to be a highly reliable supplier of electricity to members located in Dakota County and portions of Scott and Goodhue Counties.

Figure 1. Dakota Electric's Service Territory.

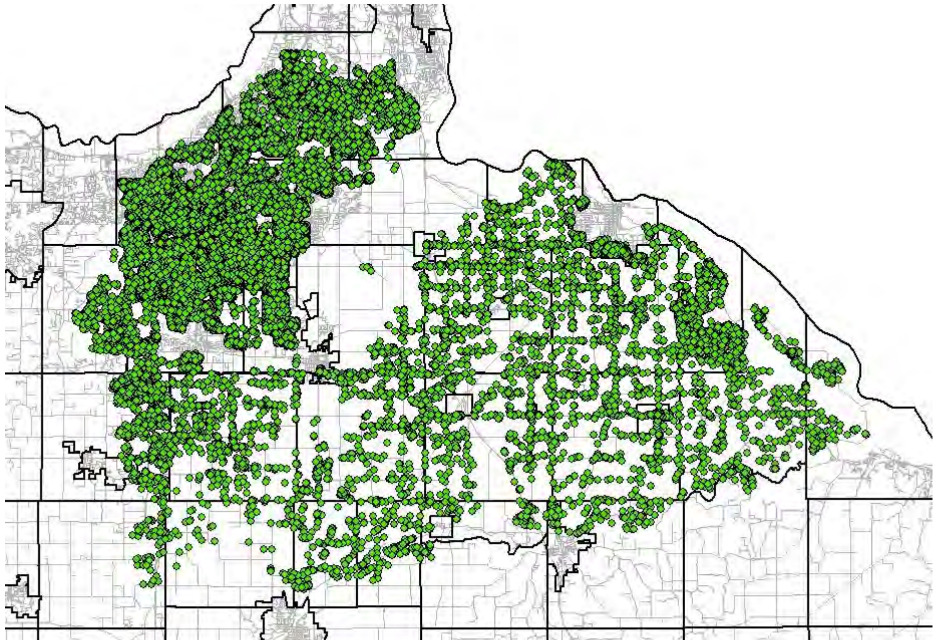

Figure 1 shows Dakota Electric's services within its service territory. Our 500 square mile service territory is located mostly within Dakota County, Minnesota and each of the small green dots represents a member's service.

As shown in Figure 1 above, most of the electric services are concentrated in the northern, suburban portion of Dakota County. This area includes the cities of Apple Valley, Burnsville, Eagan, Lakeville, Farmington, and Rosemount. Except for the service territory around the City of Hastings, much of the remaining service territory is less populated and more rural, similar to Dakota Electric's original service territory characteristics.

As a not-for-profit, member-owned cooperative, Dakota Electric is focused on providing safe, reliable, and economical electrical energy to our members. Member-owned and member-focused is in the promise of the Dakota Electric's service statement. This focus drives everything Dakota Electric does as a cooperative. Dakota Electric is the second largest electric distribution cooperative in Minnesota and ranked among the 25 largest electric distribution cooperatives in the nation. Dakota Electric is also the only electric cooperative utility rate regulated by the Commission.

Dakota Electric purchases wholesale power from Great River Energy (GRE), a generation and transmission (G&T) cooperative, that is headquartered in Maple Grove, Minnesota. The Dakota Electric distribution peak demand has been between 450-500 MW in recent years and occurs in the summer months. This summer peak electrical demand is driven mainly by air conditioning of homes and businesses.

In the 1970's, the Minnesota Legislature determined that the orderly development of economical statewide electric service required granting electric utilities exclusive service rights within designated service areas.[1] Because of assigned service territories, the utilities have agreed to supply electricity to anyone obtaining electrical service within their service territory. This is known as the utilities' requirement-to-serve.

While each electric utility has individual requirements and processes for connecting new electrical services, they all have a requirement-to-serve. This requirement-to-serve includes the installation and maintenance of distribution facilities with enough capacity to supply the electric needs of customers within their assigned service territory. Included in this requirement-to-serve is an expectation that the utility is able to extend service to new areas within its service territory in an acceptable amount of time.[2]

The requirement-to-serve drives the utilities to ensure that they not only have sufficient facilities to meet the expected electrical demands of their existing members, but also have options to supply the electrical demands during reasonable expected failures of existing equipment or during periods of maintenance when equipment is required to be out of service. Consumers expect a few short electrical outages due to storms and other events.[3] Electrical outages due to not planning and/or building sufficient facilities would not be acceptable to the consumers and may be considered a failure to provide safe and reliable service, which is required by Minnesota Statute. The risk of not being able to reliably serve the consumer's electrical requirements is a key issue with incorporating non-wires solutions and other new forms of energy solutions.

3. Reliability

Coupled with the requirement-to-serve, the reliability of the electric supply is equally as important to the members of Dakota Electric. The reliability of the electric service supplied by Dakota Electric ranks as among the most reliable electric utilities in the United States. When comparing Dakota Electric's reliability key indices with other utilities, few perform better. Graph 1 is taken from our most recent annual Service Reliability and Service Quality (SRSQ) report filed with the Commission and is a historical look at Dakota Electric's reliability indices.

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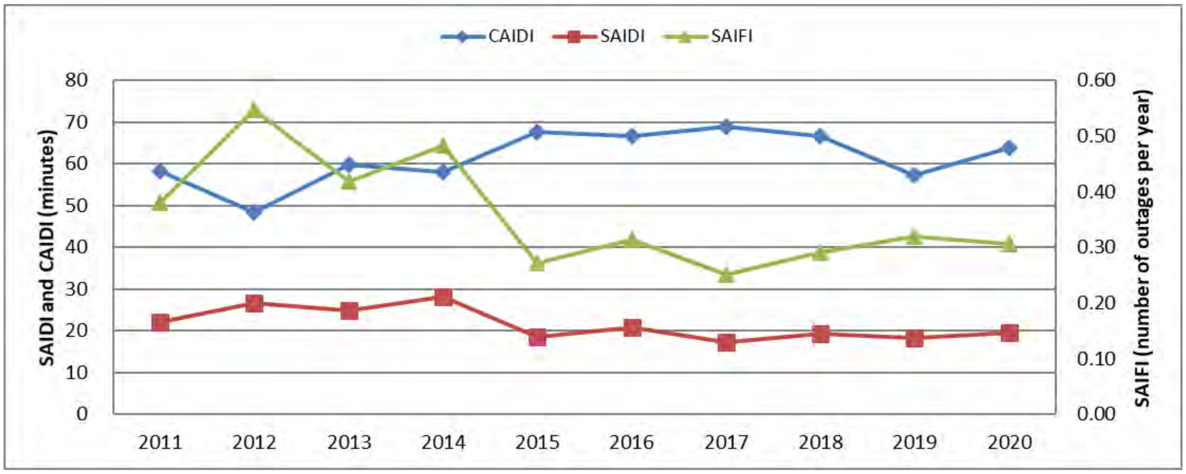
[1] Minnesota Statutes 216B.37 & 216B.39

[2] This expectation is included in Minnesota Statute 216B.04, which states:

> Every public utility shall furnish safe, adequate, efficient, and reasonable service; provided that service shall be deemed adequate if made so within 90 days after a person requests service. Upon application by a public utility, and for good cause shown, the commission may extend the period for not to exceed another 90 days.

[3] Dakota Electric provides information on customer outages and other service quality related metrics in its annual Service Reliability and Service Quality filing (SRSQ).

Graph 1. Historic Reliability Indices for Dakota Electric



The SAIDI, or System Average Interruption Duration Index, is a duration index which indicates the average annual minutes a Member was without power.

The SAIFI, or System Average Interruption Frequency Index, is a frequency index which indicates the average annual number of times an average Member was without power.

For 2020, each of these metrics were within the internal performance targets for Dakota Electric.

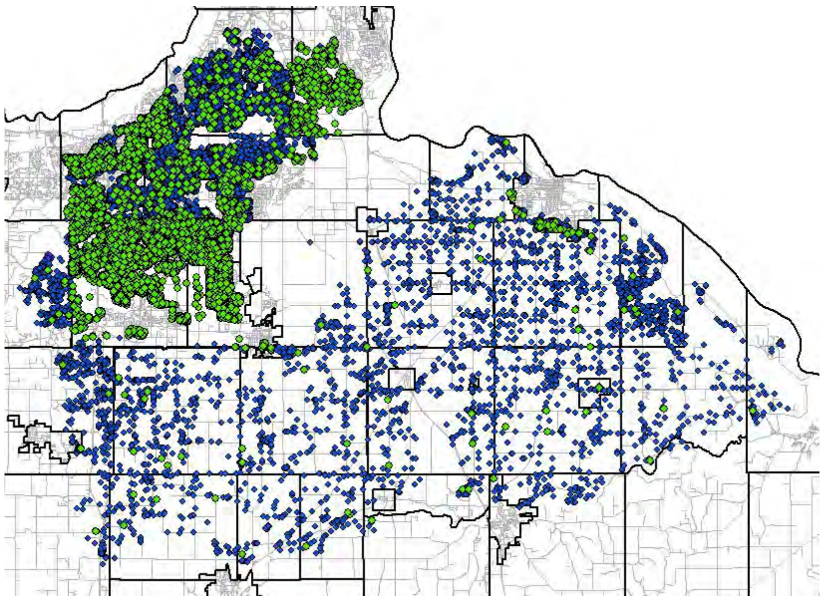
4. Demand-side Management

Dakota Electric has an extensive demand-side management system and can control (shed) around 100 megawatts (MW) during the summer months and around 70 MW during winter months. The load control consists of AC units, water heaters, irrigation, and other heating devices such as heaters and hot tubs. In addition, some of the businesses have full capacity generation which can disconnect the entire load of the business or the entire business campus and carry that load on their own internal generation system. Without this demand-side management system, the Dakota Electric system's peak electrical demand would be greater, and the power costs charged to our membership would be higher. Dakota Electric, in coordination with GRE, Dakota Electric's power supplier, operate the load management system to reduce Dakota Electric's electrical peak demands when GRE's peak demand is the greatest. Most of the time this corresponds to when Dakota Electric's system would have naturally experienced its peak demand. The load management system saves the Dakota Electric membership millions of dollars in wholesale power costs each year.

The demand-side management system includes over 45,000 air conditioners and heat-pumps, over 7,000 water heaters, and various other loads under control system. Dakota Electric has installed load control receivers (LCRs) at each of these loads to allow positive control of the loads. As part of its AGi project, all of Dakota Electric's existing LCRs are being exchanged with new devices, this exchange of LCRs is expected to be completed in 2023. The new LCRs use the same radio frequency mesh network as the AGi meters use to communicate.

Figure 3 shows the location of installed load control receivers. The new AGi LCRs are shown in green and the legacy LCRs are shown in blue.

Figure 2. Map of Load Control Receiver Installations



Through the demand-side management system, Dakota Electric has a significant amount of load which can be controlled. Dakota Electric is unique among utilities with the ability to control a large percentage (20-25%) of its total system demand. Within the IDP report, the demand-side management system may also be referred to as the demand response or load management system.

The following figures are some typical summer peak load curves, one with load management controlling the peak load on 7/26, the second showing a comparison of a peak non-controlled day in June vs a peak control day in July and a peak Sunday on 7/25, without any load management initiated. Notice the significant differences between the different days with load control. The amount of load 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. This figure illustrates the robustness and importance of Dakota Electric's load management programs.

Figure 3. Summer Peak Day with Load Management

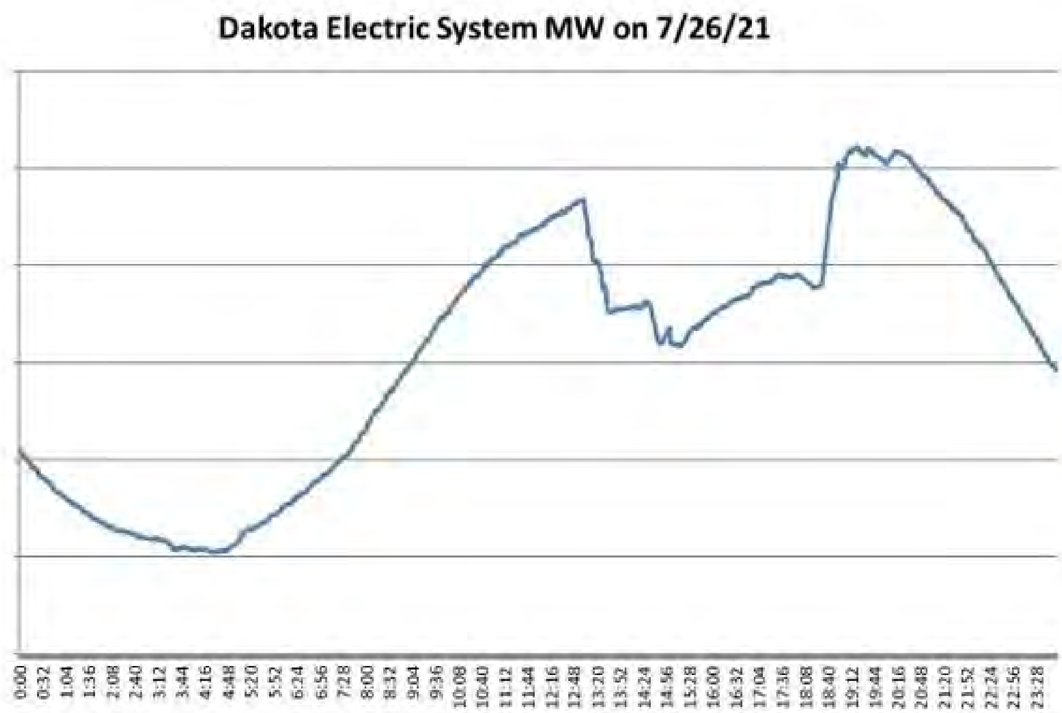


Figure 4. Comparison of a 2021 Peak Day without control to a Peak Day with control

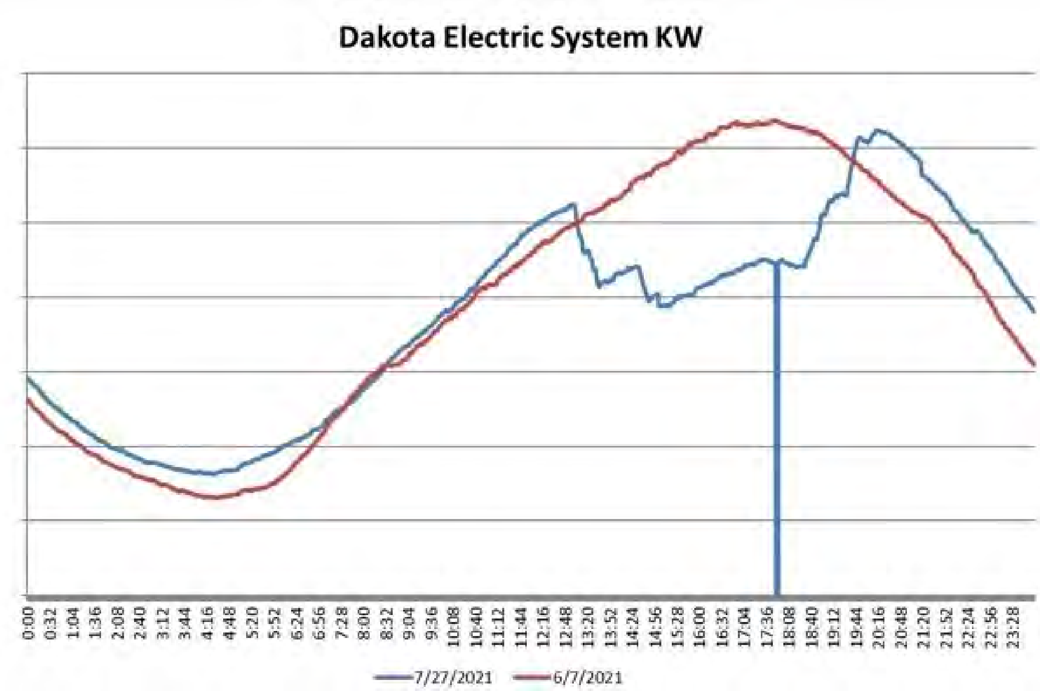
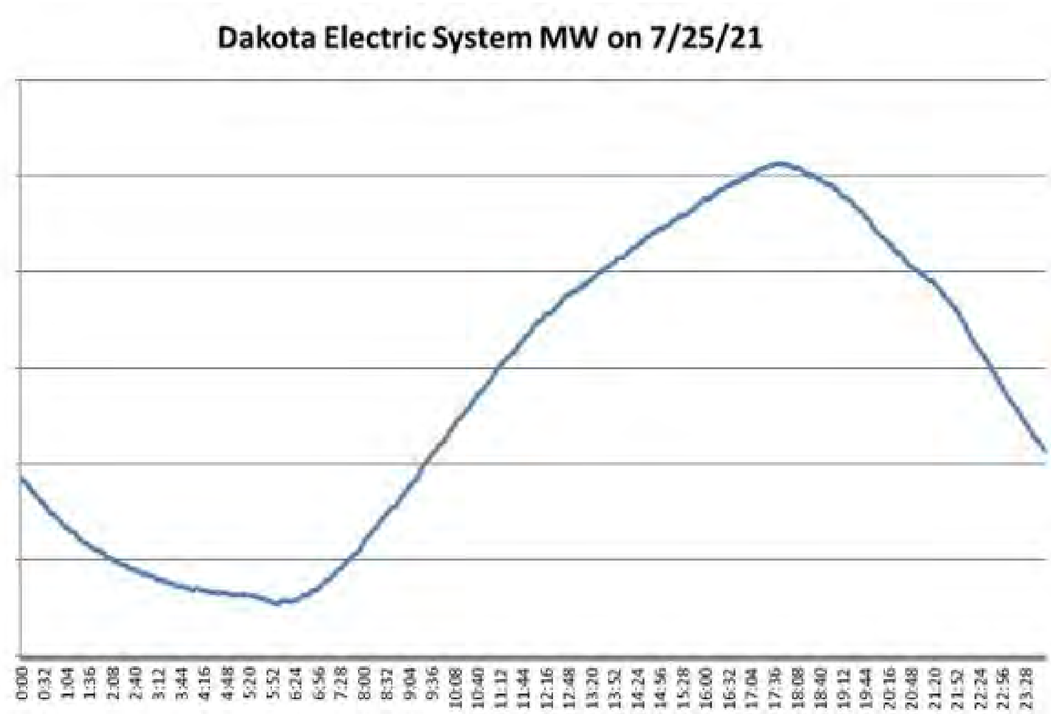


Figure 5. Summer Day (Sunday) without Load Management control



5. Annual Construction Capital Budget Development

Much of Dakota Electric's capital construction budget is driven by the peak electrical demands of its member loads and expected member loads. Dakota Electric must maintain enough electrical distribution facilities to supply the peak demands of the membership, every second of every day. If there is an event, whether it be storms or normal equipment failures, the members expect Dakota Electric to be able to quickly restore electrical service to their home or business.

Understanding the potential electrical demand for individual distribution transformers, which supply each of the services, all the way up to demand on the main circuits and substations is very important. While it would be easy to over-forecast capacity needs, this would result in excess capacity and increased costs for the members. On the other hand, under-forecasting will lead to overloaded equipment, equipment failures, and outages for the members. Forecasting demand on the distribution level is a process of balancing between spending too much and accepting too much risk.

Dakota Electric has Supervisory Control and Data Acquisition (SCADA) monitoring and control installed at all the substations, including monitoring each of the substation feeders, in our service territory. SCADA provides remote control and real-time data about the voltage and power flows on different distribution system elements. Outside of the distribution substation fence, Dakota Electric has limited SCADA capability. The Cooperative is, however, continuing to install remote monitoring and control devices on down line equipment.

To develop the peak loading on the substation and feeders, historical loading levels are captured by the SCADA system and used to create a forecast of the peak loading for each of the feeders. The forecasting process is manually done by looking at each of the feeders' load levels during several historical peak days over the prior 12-24 months. The historical peak numbers must be screened to eliminate maintenance, construction, and emergency peaks which occurred due to load being temporarily moved between feeders.

Each year, as part of the annual budget cycle, individual capital construction projects are identified. The capital construction budget includes any construction of distribution facilities. This may be distribution substations, feeders, residential and commercial developments, rebuilding of distribution lines in support of road construction, rebuilding of electrical service to member homes and replacement of equipment such as switches, poles and transformers. The capital construction budget does not include expense spending for maintenance and operational items such as tree trimming, underground locating service, power quality investigation and outage restoration. The capital construction budget also does not include headquarter building capital items and software systems such as customer information systems or financial accounting and reporting systems.

The development of the annual capital construction budget starts in early September with the development of an engineering model of the existing distribution system. The engineering model is based upon a data extraction from the Graphical / Geographic Information System (GIS) which contains the electrical wire connectivity information and billing data reflecting each member's monthly electrical usage.

For each of the feeders, (the main circuits coming out of the distribution substation), maximum expected electrical load levels for the coming year are developed. These values are developed based upon the past year and recent prior years historical maximum loads for each of the feeders. Using these historical values, and expected growth for each feeder, the maximum expected demands for the coming year are developed. These estimated maximum feeder demand values are then combined with the existing member metered load values within the base engineering model to "allocate" the maximum demands across each of the feeders within the model. The result is an engineering model of the existing electrical configuration, but with the loads distributed along each of the feeders to represent levels reflective of the next year's forecasted load levels.

At the same time the base engineering model is being created, Dakota Electric employees contact the cities and counties to acquire information about possible road reconstruction projects. These projects may require the existing distribution wires or underground cables to be moved and/or replaced. As part of these discussions, Dakota Electric also learns about potential larger residential and commercial developments which could be submitted by developers, and approved for construction, by the cities. Information about these larger proposed residential and commercial developments are incorporated within the maximum feeder forecasted demands to ensure there is enough feeder capacity to supply the new developments as homes and businesses are built. A large percentage of the annual capital budget is driven by local construction requirements.

Costs for each of the capital projects are estimated and added to the initial capital construction budget. It is important to understand that no detailed design for these projects is created at this point; therefore, the project estimates are high-level estimates with a large margin for error. Required projects, such as road reconstruction and new developments, typically are not yet fully designed and the impact to existing Dakota Electric facilities can only be estimated. There is also a reasonable chance that the proposed project may be canceled and/or the scope of the project modified before it is constructed. The actual impact of a road reconstruction or new development project is not known until some point in the following year. For example, Dakota Electric does not receive confirmation that a road reconstruction will go forward until the project is released for bidding by the road contractors. This notice to Dakota Electric for these types of projects is typically received less than a few months before Dakota Electric must have the modifications completed. The time available for Dakota Electric to design and order necessary distribution material is normally very short in duration. Hence, high-level estimates are normally used for these types of required projects when developing the initial capital construction budget.

Once the preliminary capital budget is estimated, the model of the distribution system, as it is expected to look during the next year, is studied to identify voltage, capacity, and other issues which must be resolved. For each of these identified issues, a potential solution is developed and added to the capital budget. By mid-October, Dakota Electric has developed a draft capital budget for the next year, including all the known required projects, including projects required to support new loads. During October, other capital construction budget categories are forecasted using historical data. Categories forecasted by historical data are reactionary in nature as the individual projects within those categories are triggered by the members or replacement of equipment that fails during the year. These historically forecasted categories include:

- Miscellaneous Distribution Equipment: this includes street lighting that is not part of new developments, capacitors, regulators, sectionalizing equipment, and overhead and pad-mounted switches.
- Service Rebuilds: includes conversion of members electrical service from overhead wires to underground cables that is requested by the members during the year.
- Pole Replacements: These are triggered by Dakota Electric's annual pole inspection where around 10% of the system's poles are physically inspected. Poles that fail the testing are replaced within the year the testing occurred.

Additional projects that are next added into the draft capital construction budget are project categories provided by internal Dakota Electric departments based upon their review of various issues. These project categories include:

- New residential and commercial services (e.g., wires, meters, streetlights): The number of new residential and commercial services is forecasted for the next year along with the estimated costs to interconnect those services.
- Underground cable replacement and Transformer replacements: The underground cable and transformer replacement categories are dependent upon past failure rates;
- ; and
- Substations: The substation category is the one category which needs to be planned a few years in advance as the lead time for permitting and construction is longer than one year. While substations are planned for multiple years prior to construction, the actual timeline of the substation project is adjusted each year based upon actual and forecasted load growth on each of the substations.

By the middle to end of October, Dakota Electric has a draft capital construction budget with estimated dollar amounts for each of the categories. The draft capital construction budget is then 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. In late November, upon senior management approval, the final version of the capital construction budget is presented to the Dakota Electric board for a final round of review, adjustments, and approval.

While the capital construction budget includes a 5-year forecast, the budget is only approved for the next year by Dakota Electric's Board. Only a one-year budget with specific projects is possible, due to the reactionary nature of the distribution utility business model. This business model is reactionary because individuals and developers typically do not inform Dakota Electric of their building plans that will occur multiple years in the future. In addition, cities and counties do not commit to a firm timetable for roads that will be added or reconstructed multiple years in advance. Further, site specific changes to the distribution system, such as additions of new solar, energy storage systems, or electric vehicles are unknown to Dakota Electric even during the annual capital construction budget process. Distribution planning can develop a framework for longer term changes to the distribution system; however, the actual construction of electrical infrastructure must wait until it is required and is incorporated into the annual capital construction budget.

6. Energy Supply Options for our Members – Wellspring®

Dakota Electric was one of the first utilities in the nation to provide its membership with the ability to have a renewable energy option for the electrical supply to their home or business. In 1998, Cooperative Power (one of the predecessor organizations to GRE) contracted for the purchase of energy and the installation of wind turbines in southwestern Minnesota. This was the start of the Wellspring Renewable® (Wellspring) energy option for Dakota Electric members. As the program has grown, the option for our membership to purchase solar, in addition to wind, has been added. While there are some differences between the commercial and residential Wellspring programs, their purpose and rate calculation are similar. The residential program has no upfront capital commitment required from our membership and allows fractional energy purchase options for energy used by the home. There is also only a 12-month commitment required to join so there are no long-term commitments. The commercial program requires commitment by August 31 each year, but it also allows the member to lock-in rates for a longer period.

Appendix C includes additional information about the Wellspring option for our residential members.

7. Stakeholder Engagement

As part of the IDP report development, the Commission encouraged Dakota Electric to engage with its stakeholders.[4] As a cooperative utility, Dakota Electric regularly engages with stakeholders in an attempt to improve processes and operations. Dakota Electric is governed by a Board made up of members, which is elected by the membership. This provides direct and immediate feedback for the staff from the membership. It is also a part of Dakota Electric's normal business practice to engage with its members. This two-way communication between the membership and Dakota Electric results with Dakota Electric being naturally and consciously responsive to the members.

Dakota Electric also routinely interacts with the municipal agencies within the electrical service territory. Dakota Electric is proud to annually host the "Energy Trends Expo," a free event for cooperative members interested in up-and-coming electric technologies and energy efficiency. While solar energy and electric vehicles have been the primary topics at past Energy Trends Expo, there have been other topics explored such as: home automation, in-home energy storage, and home energy audits.

The Energy Trends Expo includes a vendor showroom which provides a place for attendees to speak directly with solar installers, educational and trade organizations, and other companies presenting electrically related technology or services. The Minnesota EV Owners car club volunteers have provided an outdoor display of electric vehicles for members who wish to "kick the tires" when learning about electric vehicles.

Unfortunately, as a result of the Covid-19 pandemic, Dakota Electric was unable to host the Energy Trends Expo in 2020, but it returned in September 2021. The Expo was well attended, and our member were able to meet with vendors and attend presentation regarding development in the electric industry. The following are photos from the 2021 Expo.

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[4] January 8, 2021 Commission Stakeholder Discussion.

There are many other ways which Dakota Electric reaches out and engages our members (stakeholders). Over the past couple of years, Dakota Electric has engaged with many members, including municipalities, about certain energy efficiency and sustainability goals and programs.

The following is a list of these programs:

- Cities installing electric vehicle chargers - Dakota Electric has provided rebates for municipalities that have installed Level 2 charging equipment. Rebates have been provided to Burnsville, Apple Valley, and Eagan. Further, Dakota Electric has offered support for cities pursuing funding opportunities offered by the Minnesota Pollution Control Agency for the installation of new charging equipment.

- Sustainability Commissions - Many of the cities Dakota Electric serves have a sustainability commission focused on achieving specific municipal goals. Dakota Electric had staff present at these commissions and participated in workshops which aim to assist the cities in meeting their goals.

- Wellspring for Cities - Cities have becoming increasingly interested in powering their facilities with renewable energy. GRE's Wellspring program has been a cost-effective solution to achieve municipal goals of offsetting all, or a portion of, a community's carbon emissions. As noted above, the Wellspring program allows any member, regardless of their service type, to obtain some, or all, of their energy from renewable energy sources. Appendix C has additional information about the Wellspring program. Dakota Electric notes that starting January 1, 2022, Burnsville and Eagan are moving all of their municipal electrical load supplied by Dakota Electric to the Wellspring renewable energy option for the next 10 years. These cities are leveraging the Wellspring program to meet their sustainability goals, without requiring the large upfront expenditure of building their own renewable energy plant.

- Lakeville Fleet Study - The City of Lakeville studied their fleet vehicles usage patterns to understand which vehicles may be suitable for replacement with electric vehicles. Sawatch Labs provided the tools and analysis of the data that was collected. Dakota Electric and Xcel Energy worked together to study over 35 of the city's fleet vehicles.

- Healthy Buildings Webinar - Dakota Electric's business account executives held a webinar in December 2020 focusing on healthy buildings as the Covid pandemic was peaking and Minnesota was entering the coldest months of the year. The speakers at the webinar included a Mechanical Engineering Professor from the University of

Minnesota and a local building-controls vendor. The facilities staff from the municipalities we serve were invited and many attended. The post-webinar survey indicated the participants found value in the discussion.

- Greensteps Cities data collection - Many of the cities Dakota Electric serves participate in Minnesota Greensteps Cities.[5] Dakota Electric supports the cities' participation in this program through the collection of various pieces of information related to the cities' sustainability efforts.

Furthermore, specifically for the IDP report, Dakota Electric took steps to engage with other parties that are not necessarily members. We refer to these parties as "external stakeholders" in this report and, given the evolving nature of distribution planning, Dakota Electric believes these parties are also important and provide important input into our planning process.

8. IDP External Stakeholder Outreach

In its November 2, 2020 Order Accepting the Dakota Electric 2019 Integrated Distribution Plan and modifying filing requirements the Commission delegated to the Executive Security authority to convene a process to engage representatives from each of the rate-regulated utilities and stakeholders to review and discuss the Commission's IDP orders for the next round of IDP reports to help ensure that data included in future IDPs is efficiently gathered and presented. On January 8, 2021, the Commission held a stakeholder discussion regarding Integrated Distribution Planning (IDP). As part of the conclusion to this stakeholder discussion, the Commission drafted a next steps which stated in part, "*Individual utility stakeholder meetings are encouraged to continue the relevant discussions in preparation of the 2021 IDPs*."

In response to this directive, Dakota Electric provided notice to participants in its last IDP, relevant state agencies, and other Minnesota regulated utilities regarding a planned stakeholder workshop. Dakota Electric hosted an online stakeholder workshop on September 15, 2021 to present preliminary findings for the IDP. The meeting was facilitated by Kristi Robinson of Star Energy (Alexandria, Minnesota). The agenda for the meeting included the following:

- DER forecasts for the Dakota Electric system;
- Overview of the proposed five-year distribution system investments and capital budget;
- Key initiatives that Dakota Electric has planned and is monitoring over the next five years;

[5] https://greenstep.pca.state.mn.us/.

- Anticipated capabilities of system investments, including an AGi project update showing how AGi is helping Dakota Electric and its membership; and
- Presentation on solar and energy storage integration with Dakota Electric's system.

The following stakeholders attended the meeting:

Fresh Energy;
Minnesota Public Utilities Commission Staff;
Department of Commerce;
Minnesota Power;
Otter Tail Power; and
Xcel Energy.

The presentation covered background information on Dakota Electric's business model, existing load management programs, trends in electric vehicles and distributed solar, current capital spending, and forecasts of potential loads and impacts on the distribution system. The meeting agenda and final presentation materials were filed as part of this docket on October 8, 2021 and on September 16, 2021 in Docket No. E111/M-19-674.

9. Discussion on how IDP meets the Commission's Planning Objectives

Dakota Electric has structured this IDP report to provide answers to the questions asked by the Commission. As such, the information provided is in line with the issues and objectives which the Commission is most interested in. The following are the Commission's Planning Objectives:

- *Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;*
- *Enable greater customer engagement, empowerment, and options for energy services;*
- *Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and,*
- *Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and,*
- *Provide the Commission with the information necessary to understand Dakota Electric'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.*

For reference, Dakota Electric included a table in Appendix F which identifies page numbers where there is discussion and/or information provided for each of the Commission's planning objectives. The following discussion provides a brief summary of the discussion within each section of the IDP report.

<u>Section A:</u> Dakota Electric responds to the Commission's request for information and foundational data about the general operation of the utility. Year over year comparisons of the data provides the Commission with a view into the operation of Dakota Electric. For example, looking at distribution system losses, and the continued reduction in overall energy lost, shows how Dakota Electric continues to identify ways to improve efficiency and reduce the cost of distributing energy for our members. The DER interconnection information shows how the number of DER systems being interconnected with the Dakota Electric system continues to increase and how only a small portion of the cost of labor required to support the interconnection of DER is being compensated by the DER. This section also shows how the Cooperative is using data from its new AGi meters to better understand when our members use electrical energy. These data support better utilization of electrical grid assets and help Dakota Electric maintain and enhance the safety, security, reliability, and resilience of the electrical grid. Looking at the AGi data figures provided in Section A and other sections show how Dakota Electric is already using data provided by the new AGi grid platform to enable greater customer engagement and illustrates examples of how well the load management system is operating.

<u>Section B:</u> Dakota Electric provides minimum load information by substation and feeders as requested by the Commission. This information can be used to see the remaining level of minimum load on each substation. These data are used before interconnection of additional DER to the distribution system to determine how this DER may impact the transmission system. Before a substation is allowed to back feed the transmission system, additional engineering and operational coordination with the transmission provider is required. In some cases, back feeding of the transmission is not allowed without significant, expensive transmission upgrades.

<u>Section C:</u> This section continues the work started by Dakota Electric in its 2019 IDP report. In the 2019 IDP Report, Dakota Electric learned that if DER systems are sized to match up with the load, and are dispersed, that around 100 MWs of DER can be integrated with the distribution system. This could be accomplished at a reasonable cost for rebuilding the electrical system to accommodate the integration of the DER. The 2021 IDP report continues this work by forecasting the integration of behind the meter DER solar systems and found that even under the High forecast, by 2050, the expected solar generation capacity is less than 100 MWs. The 2021 IDP Report also pointed out the significant issues involved with back feeding of the transmission system at several of the Dakota Electric substations.

<u>Section D:</u> Dakota Electric provides information about the long-term distribution modernization plans and how the AGi project is a key foundational component of these plans. The AGi project supports the Commissions objectives by:

- Improved safety and reliability through the ability of each of the meters to report events, such as high temp in the meter socket or "last gasp" outage notifications;
- Enhances the reliability, security, and resilience of the energy supply for our membership through improved coordination of backup power supply options;
- Greater customer engagement and empowerment by providing 15-minute interval usage data to the member and allows them to better understand how they are utilizing electrical energy;
- Support additional options for energy services through better understanding of how different classes of members are using energy and empowers the membership to utilize new technology;
- Provides an accessible grid platform to help Dakota Electric develop new products (rates), and, services, and adoption of new technologies;
- Improved efficiencies and helps optimize the utilization of the electric grid access and minimize total system costs through information provided by meters and load control devices. The load control devices will alert Dakota Electric to non-functioning devices which are not able to control loads as intended. The meters will alert us when they malfunction and need to be replaced; and
- Helps optimize the utilization of grid access though the management of distribution peak demands.

Section E: Dakota Electric provides an analysis of potential non-wired solutions versus traditional wired solutions for meeting the electrical needs of our membership.

a. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives

Dakota Electric continues to look for ways to improve our performance and the value received by our membership. The launch and rollout of our AGi system is already providing benefit to Dakota Electric and its membership. Prior to the launch of AGi, when a member called in to question their bill, the Cooperative had little information available to identify issues. Now, with the 15-minute interval data, our Member Services Representatives can show the member how, and when, they used energy and, in some cases, help the member identify what is causing the higher than expected usage. This allows the member to better manage their electrical usage. The information provided by the electrical meter and load control receivers can potentially identify safety issues or equipment problems that may be impacting energy consumption (e.g., failing air conditioner). Dakota Electric is encouraged by the early results of its AGi rollout and is optimistic that these granular data will allow us to further improve and streamline our customer service experience.

b. Member Equity and Equality with Distribution Planning

Dakota Electric participated in each of the IDP stakeholder meetings for the other regulated electric utilities and observed that other utilities were asked about how the utility's distribution planning process takes into account social, economic, and equity issues. These are important issues and Dakota Electric is committed to furthering these objectives and addressing them where necessary. Dakota Electric was an active participant in the Commission's investigation into diversity in the industry[6] and is committed to these goals.

Dakota Electric is unique among Minnesota regulated utilities in that it is a cooperative. Under the cooperative structure, Dakota Electric is member owned. Unlike an investor owned utility, our members have a direct say in the operation and direction of the cooperative by electing the Board of Directors. Dakota Electric's business model is also based on a one member, one vote principle, so all our members, regardless of size, economic, or social status, have equal representation. This business model also guides our system operation goals and approach.

Dakota Electric strives for a highly reliable electrical service for all our members, regardless of size or other characteristics. We strive to achieve a homogeneous supply of electricity and service for our membership. For example, as engineers review the distribution system, they use the same design standards for all parts of the service territory. Although, as noted above, Dakota Electric's overall system performance and reliability is strong, and consistently amongst the best in the industry, our operations staff did observe members who experienced an unacceptable number of outages (classified as more than three separate outages in a year). Dakota Electric has been active in targeting these members with higher levels of outages and attempting to remedy these issues. Dakota Electric believes that all members deserve, and expect, safe and reliable electrical service. It is our expectation that this proactive approach will further decrease the number of outages for members and improve overall service.

The issue of electric reliability at an individual member level has also been discussed recently at the Commission. In response to directives in the annual SRSQ, Dakota Electric has started tracking system-wide data on this topic. In recent years, the Commission has started using CEMI (Customers Experiencing Multiple Interruptions) to track instances were individual members are experiencing multiple outages per year. Dakota Electric uses CEMI as part of its process of identifying members with higher number of outages per year. CEMI is a useful metric from an equity standpoint because it is based strictly on the number of outages per member/customer in a year and it is not weighted against revenues, sales, or demand.

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[6] Docket No. E,G999/CI-19-336.

Table 1. Dakota Electric CEMI Performance (2016-2020)

Year	$CEMI_4$	$CEMI_5$	$CEMI_6$	$CEMI_7$
2016	0.75%	0.21%	0.11%	0.06%
2017	0.38%	0.11%	0.00%	0.00%
2018	0.51%	0.18%	0.02%	0.00%
2019	0.30%	0.10%	0.03%	0.00%
2020	0.82%	0.34%	0.05%	0.01%

The information in Table 1 above shows Dakota Electric's CEMI performance since 2016. Overall, Dakota Electric's data is favorable and, in 2020, it shows that less than one percent, or approximately 500 members had four separate outages during the years. That being said, Dakota Electric is committed to improving and maintaining these performance metrics because all our members expect, and deserve, the same level of service and reliability.

c. Suggestions for improvements for the IDP filing

The IDP report structure, as designed, touches on many parts of a utility's operations and is not limited specifically to distribution functions. As evident in the stakeholder meetings for the upcoming IDPs of other utilities, and other regulatory dockets, there appears to be push by stakeholders for expanded information and analysis in the IDP report. This is only the second IDP Report, so Dakota Electric fully expects that, over time, the requirements of the IDP will change and the types of information requested may also change or expand. The feedback of the Commission and other parties to help the utility better understand where to focus our limited resources in the next IDP report cycle is particularly helpful.

Although the IDP process remains in its infancy, Dakota Electric believes it is important to discuss how the Commission plans to use the IDP going forward. If the Commission envisions the IDP becoming something similar to the Integrated Resource Plan (IRP) process, but for distribution planning, then there are planning and resource considerations that Dakota Electric will need to consider. Dakota Electric notes that this decision does not need to be made in this docket, but it may be worthwhile to consider the future of these filings so Dakota Electric can effectively manage resources to the benefit our members and the Commission.

After comparing the 2019 IDP report to the 2021 IDP report, Dakota Electric observed several questions and requirements that resulted in the same or substantially similar response to what occurred in the 2019 IDP. Since the IDP is a new process, and to aid in review by the reader and the Commission, Dakota Electric has included all the information within this report, even if there was little or no change from the previous IDP. In future IDP filings, the Commission may wish to discontinue or streamline information reporting that does not change between reports; however, Dakota Electric does not believe this is necessary at this time.

Section A. Baseline Distribution System and Financial Data

1. System Data: Modeling Software

Section A.1. Modeling software currently used and planned software deployments.

Dakota Electric continues to use the Milsoft Windmill® (Milsoft) software for modeling the distribution system. Dakota Electric maintains the real-time and normal system connectivity and equipment information within an ESRI© based GIS, which includes the Outage Management System (OMS). The OMS is the software which is used to maintain the near-real time connectivity for the Dakota Electric system and provides real-time outage predictions and coordination support. Dakota Electric periodically extracts the configuration and equipment data from the GIS system and creates a engineering study model to be used with the Milsoft software.

2. System Data: SCADA Penetration

Section A.2. Percentage of substations and feeders with monitoring and control capabilities, planned additions.

100% of Dakota Electric's substations are equipped with SCADA monitoring and control. Any future substation which Dakota Electric builds, will also be equipped with SCADA monitoring and control. In addition, all our feeders have digital protective relaying and are monitored at the substation by the SCADA system.

As noted in the introduction to this report, Dakota Electric is currently adding SCADA monitoring and control to some of our downline regulators and key remote switches that are installed away from the substation and located on feeders. DER that is part of the C&I Interruptible – Rate 70 also has SCADA monitoring and controlled installed by Dakota Electric. The Cooperative includes monitoring on this equipment since these members represent a significant portion of our load control, and it is important that we are able to monitor these members for compliance with control events. There are presently more than 125 of these member-owned generation systems on the C&I Interruptible – Rate 70 tariff.

In addition, there are a few DER installations greater than 1 MW in size which are monitored. The SCADA control system has the ability to remotely curtail or disconnect these DER systems from the Dakota Electric system if necessary. Based on a literature review and discussions with the DER vendors, Dakota Electric's ability to curtail these large DER systems appears unique in the industry. Dakota Electric has worked with the owners of these systems to provide this capability to support partial curtailment of DER output if needed. This function provides Dakota Electric with the ability to allow the DER to continue operation, at a lower output level, versus simply shutting off the DER during system maintenance system or during emergencies and other continencies. This arrangement provides Dakota Electric with operational flexibility and DER generators with economic benefits.

3. System Data: SCADA Intervals

Section A.3. A summary of existing system visibility and measurement (feeder-level and time) interval and planned visibility improvements; include information on percentage of the system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual).

With 100% SCADA monitoring at each of our substations, and on all the feeders leaving the substations, Dakota Electric has full visibility at the substation level. SCADA scans each of the monitoring points within a substation every few seconds. Except for short periods when the systems are down for maintenance, the analog data gathered approximately every minute is stored in Dakota Electric's iHistorian and is available for retrieval and analysis.[7] The feeder analog data includes phase amps and feeder measurements of kW and kVARs. The substation bus phase voltage is also monitored and stored within the iHistorian system.

At the time this report was filed, once the feeder leaves the substation, there is limited real-time monitoring and visibility. There are several places where a voltage regulator or a remote operated switch has SCADA monitoring installed, but most of the distribution system is presently not monitored in near real-time. Dakota Electric would estimate that we have less than 15% of our feeders with some type of SCADA monitoring of the downline feeder devices. The Cooperative does note, however, that we are in the process of installing more SCADA on downline devices.

With the implementation of the AGi system, Dakota Electric will have meters on all the services, except those members who have opted-out of having a communicating meter. The AGi meters provide 15-minute interval data. Dakota Electric also has sub-metering on the off-peak, TOU EV, and DER production meters which also provide 15-minute interval data.

4. System Data: AMI Infrastructure and Meters

Section A. 4. Number of customer meters with AMI/smart meters and those without, planned AMI- investments, and overview of functionality available.

The Commission approved Dakota Electric's AGi project and rollout in Docket No. E111/M-17-821. Dakota Electric has over 120,000 meters and over 50,000 load control receivers which are all being replaced with devices which use the AGi Radio Frequency (RF) mesh communication system. Dakota Electric's AGi project to install AMI metering for all member services is nearly

[7] iHistorian is the Dakota Electric software system which stores and supports retrieval of the data collected by the SCADA system.

complete. By the end of 2021, 99% of all meters will be exchanged for AMI meters and will be providing 15-minute interval data to Dakota Electric.

The remaining meters will be exchanged in 2022. These last remaining meters are associated with approximately 1,000 member homes and businesses that have larger capacity services, which use a 320-amp meter. At the time this report was being prepared, the meter manufacture is completing development of a 320-amp single phase meter, with an internal meter switch. The standard 200-amp meter, which Dakota Electric has installed, has the internal meter switch. Dakota Electric waited to install meters for services with higher capacity metering and use the new 320-amp meter being developed with the internal meter switch, because the new internal switch allows Dakota Electric to remotely turn off the flow of energy through the meter. This is a safer way to disconnect service to a home or business versus manually pulling the meter from the meter socket. When pulling the meter from the socket there is a chance of creating an electrical arc which can cause serious injury to the person who is manually removing the meter.[8]

At this time this report was prepared, just over 125 members have elected to opt-out of having an AGi meter installed at their home. These members are paying the Commission-approved opt-out monthly rate and have Dakota Electric manually read their meter each month. Each of these homes are not providing interval data into the meter data management system, so overload analysis of the equipment supplying their home, and power quality monitoring, will not be available. Since these meters will only be read one per month, there will also be limited information available for engineering models and engineering analysis.

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 15-minute interval data. The meters are programmed to provide various channels of interval data.

Single-phase meters provide the following information for each 15-minute interval

1) kWhr (Delivered);
2) kWhr (Received);
3) Voltage – latest 1-minute average voltage;
4) Minimum and maximum voltage within the 15-minute interval;
5) Temperature of the meter base;
6) Current (Meter's A leg); and

[8] This danger is underlined by the fact that Dakota Electric does not allow anyone, except trained employees or Dakota Electric contractors, to manually remove meters. Dakota Electric provides this service to members, free of charge, if given sufficient notice and the request occurs during regular business hours. This was discussed in our March 29, 2021 comments in Docket No. E111/M-21-203.

7) Current (Meter's B leg).

Multi-phase meters provide the following information for each 15-minute interval

1) kWhr (Delivered);
2) kWhr (Received);
3) kVARhr (Lagging);
4) kVARhr (Leading);
5) kVAhr (Total);
6) Voltage, A phase maximum within the 15-minute interval;
7) Voltage, A phase minimum within the 15-minute interval;
8) Voltage, A phase latest 1-minute average;
9) Voltage, B phase maximum within the 15-minute interval;
10) Voltage, B phase minimum within the 15-minute interval;
11) Voltage, B phase latest 1-minute average;
12) Voltage, C phase maximum within the 15-minute interval;
13) Voltage, C phase minimum within the 15-minute interval;
14) Voltage, C phase latest 1-minute average;
15) Current, A phase;
16) Current, B phase;
17) Current, C phase;
18) Meter base temperature;
19) Harmonic Distortion – Voltage phase B (VTHD); and
20) Harmonic Distortion – Current phase B (ITHD).

In addition to the 15-minute interval data, daily register values are also provided. The register values are used for billing and validation of the interval values and include the following information:

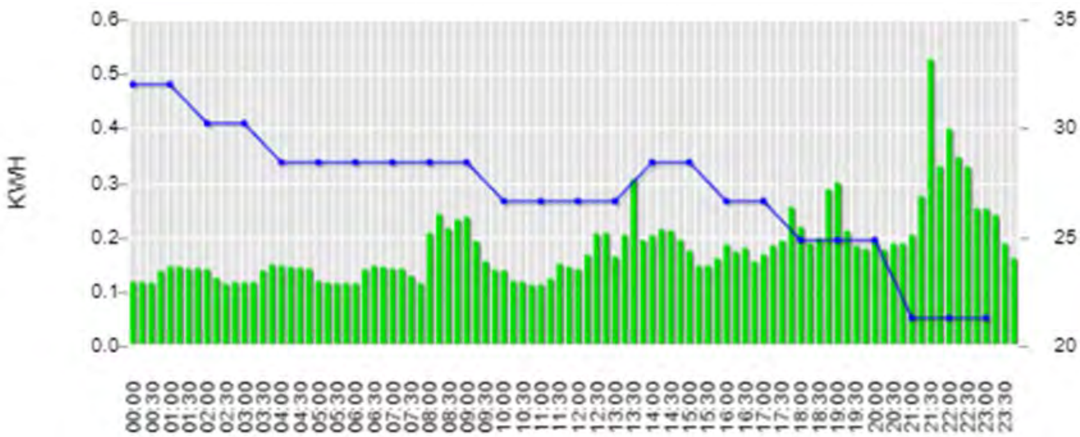
1) kWhr (Delivered);
2) kWhr (Received);
3) kW (Delivered) highest daily 15-minute kW for energy delivered;
4) kW (Received) highest daily 15-minute kW for energy received;
5) kVARhr (Lagging) - only on Multi-phase meters; and
6) kVARhr (Leading) – only on Multi-phase meters.

The AGi meters are standard utility meters with a communication card added to the meter. The manufacturer (Aclara) builds the meters in their factory and communication cards are supplied by ITRON, which is the company supplying our metering communication system. Aclara then adds the communication card to the meter and sends the assembled meter to Dakota Electric.

Dakota Electric procured the Aclara I-210+C model as the standard meter for metering residential homes. The meter is a digital meter which records the electrical usage of the home. The meter records 8 channels of information. Every 15 minutes, the channels record these 8 channels of information. Every 4 hours this information is sent to Dakota Electric over the RF Mesh communication system. All residential meters used by Dakota Electric are programmed to record the same data. Dakota Electric describes each of these channels separately below.

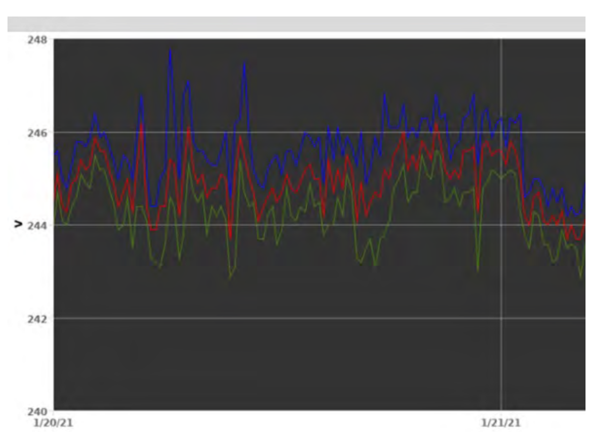
> <u>Channel 1 is kWhr delivered.</u> This is the energy used in the prior 15 minutes and is the primary information used for the monthly bill. This information is returned every 4 hours. The plot below shows billing information for an anonymous Dakota Electric home.

Figure 6. Example graph showing 15-minute usage data from AGi meter



> <u>Channel 2</u> is kWhr received. For most homes the values recorded in this channel are zero, but for homes with solar or other DER generation sources this channel is used to record energy sold back to Dakota Electric.

Figure 7. Example plot showing meter voltage



Channel 3,4,5 record the voltage supplied to the service. Every 15 minutes, the average voltage, maximum voltage and the minimum voltage are being recorded. These values are used to ensure the voltage remains within tolerance for the service. A plot of this information is included.

Channel 6 record the meter temperature. Every 15 minutes, the temperature of the meter socket is recorded. Dakota Electric uses this information to identify any "hot sockets" where there could be arcing or other electrical issues occurring.

Channel 7 & 8 record the current (amps) at the meter. Every 15 minutes, the current flowing through each 120V leg of the meter is recorded. Dakota Electric uses this to help identify open neutrals or other potential electrical issues with the service.

Although not currently charged to residential members, the meters also record the kW demand delivered. Only one value per day is recorded for the peak electric demand of the home from the prior day. This value is returned after midnight, as part of the early morning data read process from each of the meters.

In addition to these interval data, the meters are designed to send event data to Dakota Electric to inform us when there is a problem with the electrical supply to the member or a failure within the digital meter or the communication card. Events alerting us to high or low voltages, sags or swells,[9] blinks, or outages are sent back to the Dakota Electric Control Center. The Control Center and our engineers use these events to track service quality and identify problems. The goal is to then quickly resolve any issues identified. In the past, our members had to call about service quality issues, but with the new smart meters, we hope to identify and resolve these issues before the member calls us or, if they do contact us, we already have information available to discuss with the member.

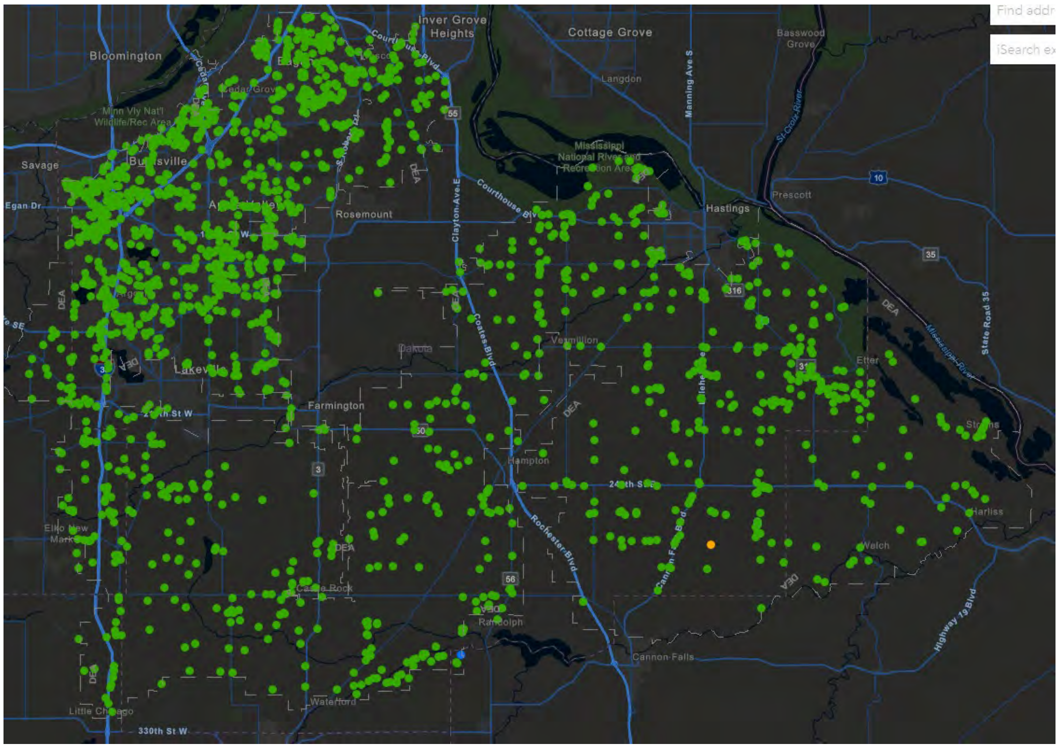
In addition, the events being reported from the meter will inform Dakota Electric if the meter has failed and is no longer metering the energy being used. Historically, Dakota Electric would not discover a meter failure until the meter reader went out and attempted to read the meter. This could result in periods of no metering and estimated billing. With the new AMI, Dakota Electric can identify if the meter has failed and quickly replace it to ensure the most accurate metering of the home's usage.

Dakota Electric has around 2,000 of the standard AMI meters, being read every 5 minutes, instead of the default read every 4 hours. These meters are referred to as bellwether meters and each feeder has several located along the main part of the feeder. The voltage information

[9] A sag or swell is a short duration excursion in the voltage which is above or below the normal ANSI range of voltage.

from these meters are made available to the System Control Center, which allows them to view and monitor the quality of the distribution system voltage. Below is a screenshot showing the bellwether meter display. The green dots represent voltages which are within normal ranges, a yellow dot represents lower than normal voltage, a red dot represents very low voltage, and a blue dot represents high voltage.

Figure 8. Bellwether Meters



The foundational purpose of these data being returned from the meter is to provide Dakota Electric with accurate billing determinants and to improve the electrical reliability and quality of service for our membership. Now that the majority of our meters have been upgraded, Dakota Electric is working on a web portal so that each member will have direct access to their own information. At the time this report was prepared, the portal is expected to be available to our membership in 2022. Per Dakota Electrics privacy policies, members will not have access to other member data and individual member data will not be supplied to any third party, unless authorized by the member.

5. System Data: Coordination of System Planning

Section A.5. Discussion of how Dakota Electric Association approaches distribution system planning in consideration of and coordination with GRE's integrated resource plan, and any planned modifications or planned changes to the existing process to improve coordination and integration between the two plans from Dakota Electric Association's perspective.

Planning Process

Dakota Electric works closely with GRE in many aspects of the planning and operation of the electrical systems. GRE organizes and supports committees and groups which include both GRE employees and employees of the member distribution cooperatives. These groups provide education, coordination and communication between the organizations. Since Dakota Electric is a distribution-only cooperative, and only responsible for a portion of the overall delivery of electricity to its members, it is paramount that we communicate and plan cooperatively with GRE, our wholesale power supplier. GRE is responsible for the security and resilience of the transmission system which is supplying the Dakota Electric distribution system.

Engineers from each of the organizations are involved during the planning process to create Long-Range Transmission and Long-Range Distribution studies. The reports are shared between GRE and Dakota Electric for review before plans are finalized. When new distribution substations are proposed by Dakota Electric, GRE review the proposal and both GRE and the Cooperative look at all possible options before any plans are finalized. GRE contacts Dakota Electric, and other distribution cooperatives, during the transmission planning process to review any transmission issues within cooperative service territories and all possible solutions are discussed amongst the parties. As part of this review process, it is not unusual for discussion of alternatives to the identified transmission issues to occur, including potential non-wired alternatives (NWA). When a transmission modification or addition is selected, and it impacts Dakota Electric, we are involved in the design and permitting process as needed.

Demand Management / Load Management / Energy Efficiency

GRE works closely with all its member distribution cooperatives to implement demand management / load management of distribution loads. Since the merger of Cooperative Power Association and United Power Association in 1998, GRE and Dakota Electric have worked together to operate and administer the Demand Management and Energy Efficiency program. Since the start of the State of Minnesota conservation improvement program, GRE, and its predecessors, has helped administer the planning and regulatory filings for Dakota Electric's DSM programs, and there are no plans to modify this arrangement with the recent passing of the ECO bill. In addition to these efforts, GRE provides support and coordination for many different energy efficiency programs. Dakota Electric notes that even with the assistance from GRE in these matters, we remain the point of contact with our members on DSM and conservation programs.

Many of the load management programs offered by Dakota Electric would not be possible without the support and coordination of GRE and its member cooperatives. In GRE's 2018 IRP report, GRE voiced continued support for demand response activities. Together, GRE and its member distribution cooperatives continue to look for ways to improve the benefits derived from demand response programs.

Beyond demand response programs, GRE has a large portfolio of energy efficiency programs. The energy efficiency programs have been created through joint development with the distribution cooperatives and their member-owners. On an average basis, both the demand response and energy efficiency programs reduced Dakota Electric's energy consumption by approximately 255,000,000 kwh in 2020.[10] This represents a savings to Dakota Electric's members of between $17 million and $20 million in energy and power costs annually.

6. System Data: DER Considerations in Load Forecasting

Section A.6. Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology.

Dakota Electric in conjunction with GRE, completes a long-range load forecast every two years and that looks beyond the next 10 years. The long-range load forecast uses historical monthly and annual energy usage by member category. For the long-range load forecast historical growth patterns for DER penetration and generation levels are naturally included using the historical monthly and annual energy usage by member category for the forecast. Some manual adjustment of the long-range energy forecast was done to reflect the expected increases in DER penetration and increased EV sales.

For short-range load forecasting, Dakota Electric projects one year into the future and uses the prior year's peak feeder and substation loads. The prior year's actual peak demands include reductions to potential peak demands through the operation of the demand response system. Presently Dakota Electric's peak demands are occurring during the hottest days of the summer. Depending on the area supplied by the feeder, the time of day for the peak will be different, but currently almost all the feeders experience their peak demand during the summer months. Each fall, Dakota Electric reviews feeder loadings for the prior summer season and develops a forecasted peak loading for the next summer. Dakota Electric includes the potential for new loads that may be added to an individual feeder in that feeder's forecasted peak loading.

Typically, Dakota Electric does not receive advanced notice of DER generation being added to a feeder, so new DER additions are not included in the annual feeder and substation load forecasts. Since most of Dakota Electric's feeders peak around 6-7 pm in the summer, the addition of new DER generation has not impacted the summer peak demand levels. As DER penetration increases, Dakota Electric notes forecasting and understanding the impact of DER on feeder peak loading may become more important. Dakota Electric is using the data from the

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[10] Dakota Electric 2021 Environmental Brochure.

AGi production meters to provide insight into the operation and performance of the member owned DER systems.

Dakota Electric is currently researching how to forecast larger DER generation on the feeders. Since Dakota Electric does not control or maintain these DER generation units, there is a possibility that the DER may not be available during one or more of the summer peaks. With more DER generation being added to the distribution system, the risk increases that multiple units clustered in the same area, will experience an outage due to storm damage (hail or high winds), or multiple equipment failures. Currently, since the DER generation systems do not greatly impact the peak feeder demands, Dakota Electric sizes a feeder to support the feeder load in the event that DER generation fails to operate normally. With the addition of energy storage, a portion of the members load may not be normally supplied by the distribution system during peak load periods and as such the traditional methods to measure peak demands may need to be supplemented through utilization of the data provided by the production meters. Dakota Electric will need to develop new study methods and planning standards to help properly anticipate and manage the risk of a DER failure. Understanding the total load behind the meter, using the main meter coupled with the data from the DER production meter is critical to knowing the potential magnitude of load which could be placed upon each of the circuits.

Dakota Electric has a large portion of peak load which is managed by our load management system. Given this large concentration, Dakota Electric includes the operation of load management within the feeder load forecasting process. Since Dakota Electric uses the prior peak summer loads as the starting point for the substation and feeder load forecast, the operation of load management is naturally included within those historical numbers. A typical load control day starts control around 2 pm and continues until around 9 pm. The load control, in effect, is reducing the normal feeder peak load which for Dakota Electric typically occurs around 6 pm. Because of load control's reduction in feeder peak demands, the actual feeder peak occurs on days without load control or, most commonly, just before the load control starts on a peak day. For example, if the load control starts at 2 pm on a peak day for most of the feeders, the load between 1:30 and 2 pm is when the historical feeder peak tends to occur. For feeders which supply large data centers or other industrial users which have a flat usage pattern, the 1-2pm peak is very similar to what the peak load on that feeder would have been without load control. For these industrial feeders, the DER load management has little effect upon the forecasted peak load.

For the rest of the feeders, the potential feeder peak is reduced by the operation of DER load management. The actual peak (reduced by load management) is used as the basis for the forecasted feeder peaks. If the Dakota Electric load management system failed to operate over any peak summer day, the actual peak load could be greater than the forecasted value for some of the feeders. Acknowledging this concern, Dakota Electric uses multiple methods to control the members' load management systems. Within these control systems, backup methods are available. Dakota Electric's load management is accomplished using two separate systems; one is using the SCADA system to control the member-owned generation units, and the other uses a commercial pager system to trigger the load control receivers to shed their loads. Dakota Electric has purchased, permitted, and installed a second pager system to control the load control receivers in the event of a commercial pager system failure. As existing load control receivers are replaced with the new AGi receivers, they will be using the same RF Mesh system which the AGi meters are utilizing. Over time this will eliminate the use of the pager systems for load control.

7. System Data: System Planning Impacts of IEEE Std. 1547-2018

Section A.7. Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability and advanced inverter functionality).

Dakota Electric does not see immediate changes in the distribution system planning process resulting from the new IEEE Standard 1547-2018. Once inverters which are designed to meet the new IEEE 1547-2018 requirements are available, Dakota Electric plans on utilizing some of the advanced feature to help maintain system voltages within the ANSI ranges. Over the next year, Dakota Electric is planning on developing standard settings for these new inverters. Use of the Volt / Var and possibly volt / watt configurations within the inverter are expected to help reduce potential high voltage issues resulting from operating with higher penetration levels of DER integration.

With the variable nature of DER generation, the energy output cannot be counted upon to be available 100% of the time to offset an individual member's electrical demand. Therefore, it cannot be assumed the DER will be providing energy coincident with peak loads. The expectation is that once the overall level of DER penetration increased, the aggregate output from many DER generators would provide a reliable partial reduction in electrical demand at a substation level. Dakota Electric has been using its AGi metering data to see if the aggregated output from solar DER systems provides a reliable level of energy. The data captured in 2021 shows that even with a large number of aggregated solar installations, there is a common loss of output due to snow cover in the winter and cloud cover in the summer. This loss of output is especially coincidental when cold fronts come across Minnesota and are typically associated with snowfall. Dakota Electric will continue to monitor this relationship in the future to see if any changes occur.

8. System Data: Distribution System Annual Loss Percentage

Section A.8. Distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages).

For Dakota Electric, system losses are determined by comparing total energy purchased to total energy sold. The energy purchased is measured by meters installed by GRE.

Historically, Dakota Electric maintains records of monthly energy purchases from GRE, the monthly energy sales to its members, and energy which is used for Dakota Electric facilities, referred to as “own use.” Dakota Electric calculates the energy losses by subtracting energy sales, and “own use” energy, from the monthly energy purchases from GRE. These energy loss values are then converted to a percentage of the total energy purchases from GRE.

Table 2. 2020 Monthly Loss Percentage

2020 - Months	System Loss Percentage
January	-0.591%
February	-6.149%
March	2.829%
April	0.971%
May	5.973%
June	12.012%
July	11.122%
August	-1.277%
September	-21.952%
October	4.568%
November	0.907%
December	12.252%
12-Month Average	**2.255%**

In table 2, the obvious observation is that the calculated monthly percent losses vary greatly from month to month. The reason for this variability is due to timing of the readings of substation meters versus the member service locations.

The energy which Dakota Electric provides to its members is metered at over 120,000 meters for each of its approximately 110,000 members. Historically, these meters are manually read each month, by meter readers which travel to each meter. These readings do not correlate with the GRE monthly substation readings.

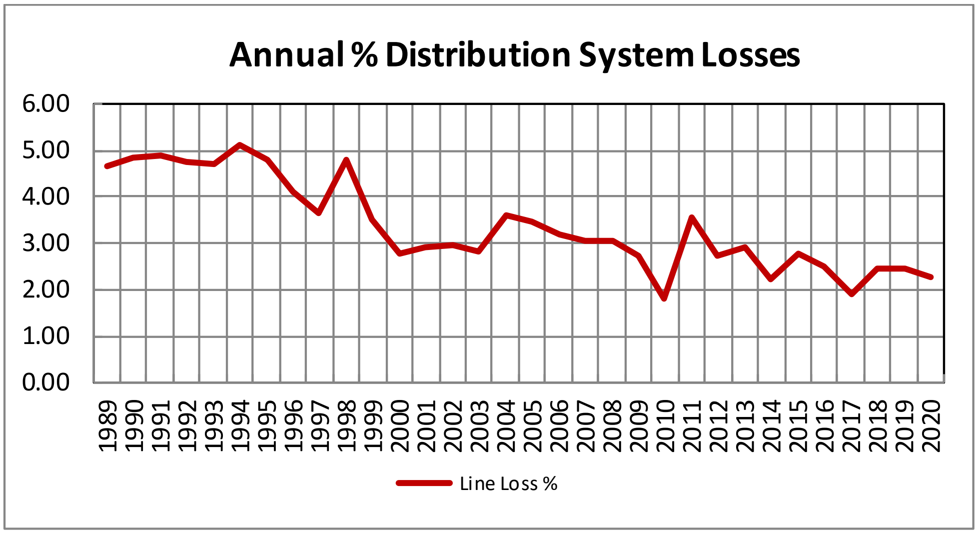
Generally speaking, this process involved Dakota Electric reading approximately one-fourth of our member meters each week; as such, there is some amount of energy recorded for the present month that was consumed in the prior month. For the services which are read during the first week of the month, three-fourths of the energy recorded on the meter was consumed in the last three weeks of the prior month.

There are certain instances, like seen for June in the above chart, where actual monthly energy consumption is greater than the usage in the prior month resulting in calculated losses that are greater than actual. This is due to the power purchases from GRE being greater in June than May and the members meter reading reflecting only a portion of the increased June usage. The reverse is true in September, when the September GRE purchases are less, but the members September meter readings include portions of the higher August usage.

The AGi project includes the installation of meters which are remotely read and support daily meter readings; this is one of the significant benefits of the AGi project. From these data, meter readings which are coincident with GRE's monthly meter readings can be used for the purpose of calculating distribution losses. Once the AGi metering system is fully installed, and assuming few members choose to opt-out of the metering system, accurate monthly energy losses will be able to be calculated. If too many Dakota Electric members choose to opt-out of allowing the installation of an AGi meter, the benefits from coordinated meter reading values could be greatly reduced. With the implementation of the AGi project, Dakota Electric will, in theory, be able to read all its meters at the same time each month and will have an improved knowledge of the system losses over a given period of time. At the time this report was filed (November 1, 2021), the installation of AMI meters was not complete system wide. For the next IDP report, due in November 2023, Dakota Electric anticipates being able to more accurately calculate monthly distribution system losses.

For accounting and analysis purposes, Dakota Electric uses the 12-month, 3-year and 5-year averages of the monthly distribution losses. Graph 2 shows the 12-month average losses for the last approximately 30 years. The 12-month average losses can be affected by the meter reading alignment issues between GRE and Dakota, but the 12-month averages are less effected due to the similar seasonal issues seen each year.

Graph 2. Dakota Electric Historical Distribution System Energy Loss



As shown in Graph 2, the Dakota Electric distribution system energy losses over the past 30 year, have improved significantly. This was accomplished through various changes including: purchasing more efficient equipment (such as distribution transformers), changes in how the system voltage is managed during light loading periods, addition of improved control systems for distribution capacitors, and replacement of existing distribution system components (such as wires and cables with larger capacity).

More efficient transformers are designed so the energy required to energize the transformer is less, which results in lower losses because less energy is required to support the transformers operation over the 24 hours of each day. This energy required 24/7 for a transformer is referred to as the transformer No-Load Losses.

The modification to the system voltages was the result of the initiation of automatic voltage controls which raises the voltage during the high load periods and allows the voltage of the system to be lower during the lighter load periods, such as over-night periods. The lower voltage helps to further reduce transformer No-Load losses because the lower the voltage, the lower the energy required to energize the transformer. During the higher load periods, the higher voltage reduces the losses in the wires and cables when the current is the highest. The losses in a wire or cable are based on the equation I^2R where the "I" in the equation is the current and losses increase with the square of the current. Using this relationship, balancing the voltage between the transformer No-Load losses and the losses in the wires is a continual process.

In the early 2000s, Dakota Electric implemented a new capacitor control system to help maintain the distribution system voltage. This new control system together with the automatic voltage controls helped maintain more consistent distribution voltages, which in turn helped support reduced system losses. Capacitors, by their nature, help raise voltages in the area they are installed and can help maintain a more consistent voltage level across the circuit.

Dakota Electric continues to evaluate the loading on distribution circuits and periodically identifies wire and cable which are heavily loaded and could improve system performance if replaced with a larger size to reduce system losses. While it is not common that sufficient benefits, from an economic standpoint, occur simplify from reduced system losses to pay for replacing wire and cable, in special cases, when coupled with reliability and capacity needs, Dakota Electric has observed sufficient benefits to justify replacement of existing wire and cable with larger sizes to reduce systems losses along with the other benefits.

9. System Data: Maximum Hourly Coincident Load (kW)

Section A.9. The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems.

Table 3 below shows coincident demand on the Dakota Electric distribution system at the time of peak system demand for Dakota Electric (1) and at the time of peak demand for GRE (2). The peak demand (kW) at the time of GRE's system peak is reduced through the operation of the Dakota Electric load management (demand-side management) system. Without the operation of the load management system, the peak demand at the time of the GRE peak would be greater.

Since each of the Dakota Electric distribution substations experience their peak demands at different times of the day and different days of the year, the non-coincident sum of the substation peak demands is much greater than the coincident peak for the Dakota Electric system. Distribution planning studies must consider this diversity of demand, and the distribution system must be built to support the non-coincident demands for each of the feeders and substations.

Table 3. Historical System Peak Demand (3)

Year	(1) System Peak Demand (kW)	(2) Peak kW demand with Load Management Active
2012	498,320	416,863
2013	462,059	387,091
2014	420,679	361,159
2015	439,376	408,662
2016	451,613	379,487
2017	428,248	410,169
2018	445,681	412,520
2019	433,148	369,675
2020	442,762	405,812
2021 YTD	467,944	415,665

(1) This is the peak hourly demand on the Dakota Electric distribution system. This peak demand typically occurs just before the start of load control on a peak day. The values are obtained from GRE's monthly billing summary reports.

(2) This is the peak hourly demand on the Dakota Electric system coincident with GRE's peak demand. This demand value is lower as Dakota Electric is controlling loads during the time of this peak.

(3) Both of the demand values are reduced by any coincident DER generation amounts and do not reflect the maximum electrical load in the area.

Figure 9 is a load shape for a typical summer peak day with load control in 2021. You can clearly see the reduction in electrical demand due to the load control. This day was selected to because on this day the load control was stopped earlier than normal due to GREs load across its footprint already being lower. For Dakota Electric's system, this resulted a higher electrical demand due to the control being suspended earlier. This demand, at the end of a load control period, which is higher than other periods of time during that day, is referred to as a "rebound peak". If not coordinated, rebound peaks can cause system overloads and/or low voltage. As such overall coordination of load control is important to help limit the size of "rebound peaks" and avoid potential reliability issues in the immediate period after control.

Figure 9. Summer Peak Day with Load Management

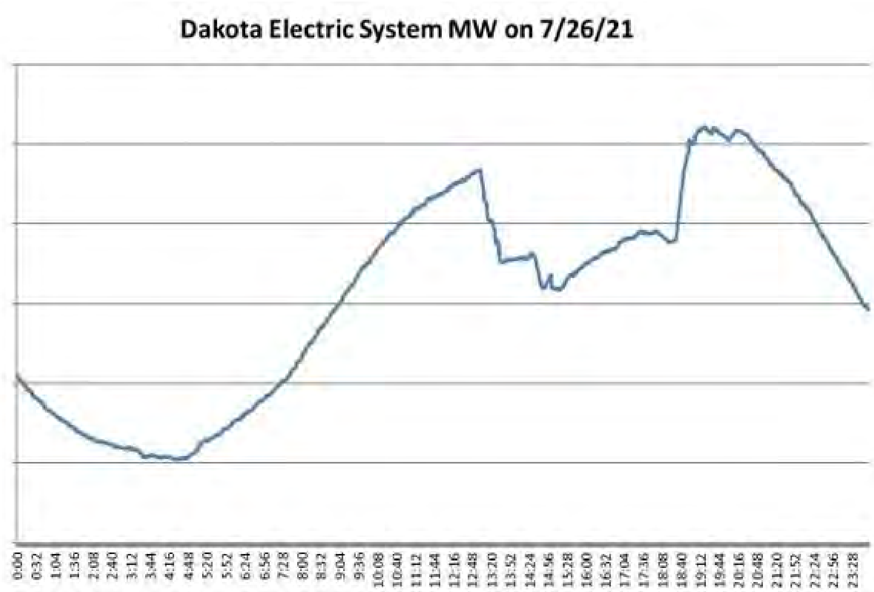


Figure 9 highlights the success of Dakota Electric's demand-side management and load control programs and how they effectively decrease peak demand on our system. This decrease in peak demand saves our members significant money through avoided capacity costs with GRE.

10. System Data: Total Distribution Substation Capacity

Section A.10. Total distribution substation capacity in kVA.

Table 4 below lists the total substation capacity for each of the past 10 years as of January 1st of that year.

Table 4. Historical Total Distribution Substation Capacity

Year	Total Distribution Substation Capacity (kVA)
2012	1,064,700
2013	1,078,700
2014	1,084,300
2015	1,085,200
2016	1,110,200
2017	1,110,200
2018	1,135,200
2019	1,135,200
2020	1,158,100
2021	1,172,500

11. System Data: Total Distribution Transformer Capacity

Section A.11. Total distribution transformer capacity in kVA, if different from total distribution substation capacity and the reason for the difference.

The total distribution transformer capacity is the sum of the kVA ratings for all the distribution transformers which provide electrical service to each of the homes and businesses on our distribution system. The total kVA capacity is similar to the total substation capacity, but the kVA capacity is less for the total distribution transformers as they are directly wired to supply specific homes and businesses. In addition, due to the nature of the distribution transformer, they can be periodically heavily loaded. The heavier a transformer is loaded, the shorter the life of the transformer, which is due to the heat created within the transformer from the electricity flowing through the unit. However, since the distribution transformers are physically small, the transformers can more easily dissipate the heat and withstand greater loading without experiencing loss of life. Distribution transformers also have flexibility compared to other types of transformers because they do not need to maintain spare capacity to carry the neighboring load upon a failure of the neighbor's transformer.

In comparison, each substation transformer is much larger and is less able to dissipate the internal heating from the flow of electricity. This fact means that they are not able to be as heavily loaded as distribution transformers. Furthermore, the substation transformers must be sized larger, so they have spare capacity available to allow the load from neighboring substations to be switched over during contingencies, emergencies, or maintenance activities. As such, under normal daily conditions, the substation transformers are not as heavily loaded as smaller distribution transformers.

The data in Table 5 below is from Dakota Electric's GIS system. The number of transformers represents the number of separate physical transformer tanks. For some multi-phase commercial services, individual single-phase units (transformer tanks) can be connected to form a multi-phase bank of transformers. For example, three single-phase transformers can be wired together to form a 3-phase bank.

Table 5. Total Distribution Transformer Capacity

Year	Number of Transformers	Total Transformer Rated kVA
2017	23,051	1,031,293
2018	23,271	1,055,552
2019	23,278	1,057,624
2020	23,420	1,059,892
2021	23,725	1,087,151

12. System Data: Total Overhead Distribution Miles

Section A.12. Total miles of overhead distribution wire.

The total miles of overhead distribution line were calculated using Dakota Electric's GIS. For purposes of Table 6 below, only the length of the line, not the total amount of wire footage used to create the line, is listed.[11] The amount of overhead line continues to decrease as urban areas expand and the existing wires are replaced by underground cables.

Table 6. Miles of Overhead Line

Year	Miles of Overhead Lines
2016	1,197
2017	1,195
2018	1,188
2019	1,182
2020	1,177

13. System Data: Total Underground Distribution Miles

Section A.13. Total miles of underground distribution wire.

Almost all new residential and commercial developments in Dakota Electric's service territory utilize underground cables for the electrical distribution system within the development. The miles of underground cables continue to increase as new developments are added to the system.

Table 7. Miles of Underground Cable

Year	Miles of Underground Cables
2016	2,898
2017	2,937
2018	2,961
2019	3,003
2020	3,041

[11] For example, three-phase line includes four strung conductors. A three-phase line that extends for one mile has four miles of wire footage.

14. System Data: Total Number of Distribution Customers

Section A.14. Total number of distribution customers.

Table 8 below lists the total number of services connected with the Dakota Electric distribution system at the end of each year.

Table 8. Total Number of Services

Year	Number of Member's (Services)
2016	105,867
2017	107,201
2018	108,274
2019	109,089
2020	110,760

15. System Data: DER Generation Installation Total Costs

Section A.15. Total costs spent on DER generation installation in the prior year. These costs should be broken down by category (including application review, responding to inquiries, metering, testing, make ready, etc.).

For calendar years 2018-2020, the following are the direct labor and material expense incurred in support of the interconnection and installation of DER generation. This data shows that the testing costs per interconnection has reduced over time, due to changes in whom Dakota Electric sent to the site to witness the testing and, with the AGi project the elimination of the need to replace the main service meter. This reduction in testing costs was achieved with over 30% more completed DER integrations.

Table 9. Cost Incurred from Interconnection & Installation of DER Generation

Category	2018 Expenses	2019 Expenses	2020 Expenses
Application Review	$57,437	$71,395	$105,228
Responding to Inquiries		$14,351	$17,568
Make Ready		$1,732	$2,071
Testing		$23,912	$21,199
Total Costs (1)	**$57,437**	**$111,390**	**$146,066**

(1) Total costs do not include the cost of the production meter which is provided by Dakota Electric at no additional cost to the member.

16. System Data: DER Generation Installation Charges

Section A.16. Total charges to customers/member installers for DER generation installations, in the prior year. These costs should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.).

For calendar years 2018-2020, the following are the charges invoiced to members for the interconnection and installation of DER generation.

Table 10. Total Charges to Members for DER Generation

Category	$ Paid		
	2018	2019	2020
Application Fees	$4,700	$10,946 (1)	$23,054
Metering	$0	$0	$0
Testing	$0	$0	$0
Make Ready	$0	$872	$870
Total	**$4,700**	**$11,818**	**$23,924**

(1) 2019 Application fees is calculated from the number of applications in the 2019 Commission DER report since the NOVA on-line portal was not fully functional during the entire year.

a. DER Average Cost Per Application

Using the costs and charges from the answers to questions 15 and 16 and utilizing the number of units interconnected from question 19, Dakota Electric calculated the average costs for handling DER applications.

Table 11. Average Costs for DER integration

Category	2018	2019	2020
# of Interconnections per year	40	98	138
Total DEA Costs	$57,437	$111,390	$146,066
Average DEA cost per DER	$1,436	$1,137	$1,058
Total Receipts	$4,700	$11,818	$23,924
Average Receipt per DER	$118	$121	$173
NET Total Cost to Dakota Electric	$52,734	$99,572	$122,142
Net Cost Per DER	$1,318	$1,016	$885

Looking at Table 11, you can see that Dakota Electric has worked to reduce the internal costs of interconnecting DER systems. In 2018, the cost per DER installation for the entire Dakota Electric membership was an average of $1,318. By 2020 this average was reduced to $885 per interconnection.

17. System Data: DER Generation System Total Capacity Interconnected in 2020

Section A.17. Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

For calendar years 2018-2020, the following are the aggregate nameplate capacity of the different DER generation systems that completed interconnected to Dakota Electric's distribution system.

Table 12. Total Nameplate Capacity of DER Generation Interconnected by year

Year	Solar	Solar/Storage	Storage	Wind	Gas Engine	CHP
2018	2,406 kW	0	0	0	500 kW	0
2019	3,914 kW	0	5 kW	0	0	0
2020	1,035 kW	0	0	0	270 kW	0

Note: 2018 includes a single 2,000 kW solar installation and 2019 includes a single 3,000 kW solar installation

18. System Data: Number of DER Generation Systems Interconnected in 2020

Section A.18. Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

For calendar years 2018-2020, the following are the total number of DER generation systems, by type, that completed interconnected to Dakota Electric's distribution system.

Table 13. Number of DER Generation Systems Interconnected by year

Year	Solar	Solar/Storage	Storage	Wind	Gas Engine	CHP
2018	39	0	0	0	1	0
2019	97	0	1	0	0	0
2020	137	0	0	0	1	0

19. System Data: Total DER Generation Systems Interconnected

Section A.19. Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

Table 14 reflects the number of DER generation systems interconnected to the distribution grid as of October 1, 2021 and the total nameplate capacity of those units.

Table 14. Total Number of DER Generation Systems Interconnected

	Solar	Solar/Storage	Storage	Wind	Gas Engine	CHP
Number of	656	3	2	10	127	0
Total Capacity kW	11,575	27	20	205	85,176 (1)	0

Note (1) Engine Prime Rating

20. System Data: Queued DER Generation Systems

Section A.20.Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

The following table reflects the number of DER generation systems in the interconnection queue as of October 1, 2021.

Table 15. Number of DER Generation Systems in Interconnection Queue

Solar	Solar/Storage	Storage	Wind	Gas Engine	Hydro	CHP
153	0	3	0	1	0	0

21. System Data: Total Electric Vehicles

Section A.21. Total number of electric vehicles in service territory.

Dakota Electric is not informed about all the electric vehicles (EVs) which are housed within the service territory, but Dakota Electric does have special electric vehicle charging rates.[12] On May 27, 2021, Dakota Electric filed its Annual EV Informational Letter with the Commission in Docket No. E111/M-12-874. Based on the information in this letter, as of May of 2021, members have enrolled 559 plug-in electrical vehicles on Dakota Electric's EV charging rates

Figure 10 below is shows EV model year data released by the Minnesota Department of Public Safety based upon vehicle registration data for the Dakota Electric service territory. Commission Staff created a dataset, using this data, which reflects which distribution utility

[12] The Commission recently approved two new EV pilots for Dakota Electric in Docket No. E111/M-21-127. These pilots are for Commercial members and Multi-Family Residential members.

each EV vehicle registration address is associated with. This information is based upon data as of spring 2021. Using this data, Dakota Electric has approximately 1,182 EVs located on its distribution system.

Figure 10. EVs by Model Year, on the Dakota Electric System

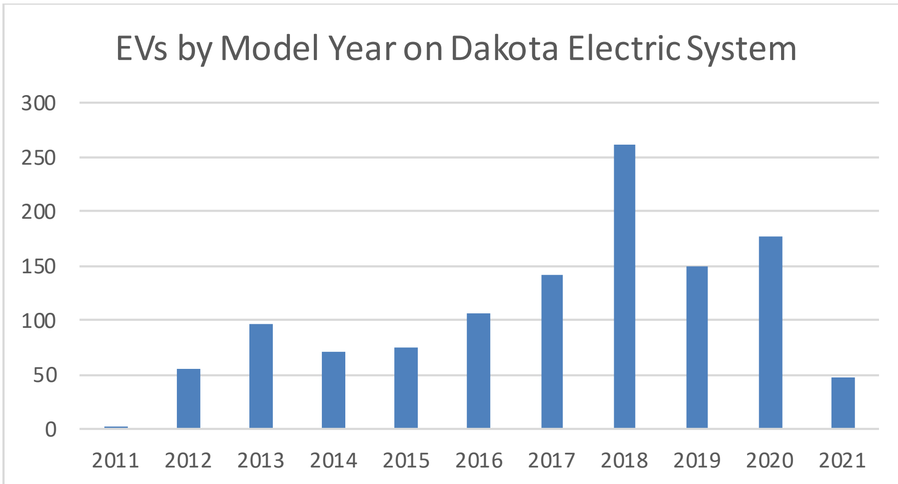
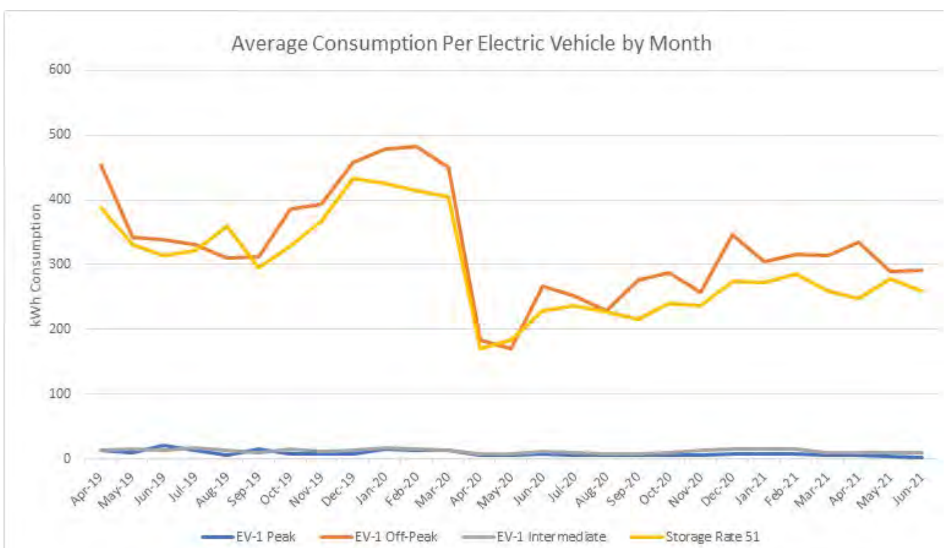


Figure 11 below is an interesting chart showing the general energy usage of the electric vehicles on the Dakota Electric's electric vehicle rates, before and after the COVID shutdown. This shows the COVID shutdown had a demonstrable impact on EV related energy use.

Figure 11. Electric Vehicle energy usage April 2019-June 2021



22. System Data: Public Electric Vehicle Charging Stations

Section A.22. Total number and capacity of public electric vehicle charging stations.

Dakota Electric is not informed about the installation of all electric vehicle charging stations within the service territory. One of the best resources where members can be directed to is the *www.plugshare.com* site which graphically shows electric vehicle charging station locations.

23. System Data: Battery Storage

Section A.23. Number of units and MW/MWh ratings of battery storage.

At the time Dakota Electric filed this report, it is not aware of any battery storage units interconnected with the distribution system that export power. All the energy storage systems which have provided applications are being utilized for backup protection. Some of the energy storage systems are designed to support the entire home during an electrical outage, while others only support critical circuits during an outage. Another possible use of one or more of the battery energy storage systems is to support charging of the electrical vehicle from energy produced by the member's solar system.

Dakota Electric has eight systems, five of them are installed and operating and three which are approved and awaiting installation and testing. Each of these systems are coupled with solar installations and are either DC or AC coupled. Most of the energy storage systems are coupled with the solar to allow the solar to continue generating during an outage and prolong the benefits of the backup system.

The smallest ESS system is rated at 4.5kW (8.6 kWhr) and the largest is rated at 10 kW (27 kWhr). The total ESS rating for all the systems combined is 67.5kW (169.4 kWhr)

Dakota Electric is aware that there are many energy storage systems which are installed as UPS system, with no exporting capability, but the size or number of these systems is not known.

24. System Data: Energy Efficient Program

Section A.24. MWh saving and peak demand reductions from EE program spending in previous year.

Dakota Electric's energy efficiency programs resulted in 25,328 MWh of savings in 2020.

25. System Data: Controllable Demand

Section A.25. Amount of controllable demand (in both MW and as a percentage of system peak).

The actual amount of demand available to control by Dakota Electric depends upon the season, weather, and many other factors. Later in Section A.31 of this report, Dakota Electric provides detailed information about the amount of DER interconnected to Dakota Electric system by substation and feeder. Within the IDP process, DER is defined to include controllable loads; as such, the information regarding the amount of connected controllable loads are listed in Section A.31.

The actual amount realized when the "control button is pushed" is different (lower) than the sum of the connected kW values. For each type of load, there are different factors impacting the actual amount of realized load reduction when the control button is pushed.

<u>Air Conditioning</u>

Air conditioning (AC) typically provides load reduction during hotter summer months and, for any given day during this period, the number of AC units turned on will vary. For residential AC, Dakota Electric has observed that for some homes it can take one or two hot days, which heat up a home, before they use their AC unit. For example, during a 90F-day in May, most of the AC units in our service territory are not operating and the resulting load reduction due to control is less. However, for a 90F day in later June, July, or August, most of the AC units in our service territory will be operating and we can see a greater reduction in load during control these months. Humidity and the length of hot days in a row will also affect the amount of AC run time, this is due to buildings retaining heat, which leads to members turning down the temperature in their homes. On a typical hot summer day, Dakota Electric forecasts approximately 15-25 MW of actual load reduction from controlling AC units. The amount of demand reduction, per individual AC unit, is decreasing as older units are replaced with more efficient units. It is important to note that there is an implicit overall reduction in electrical demand from these more efficient units because they are more energy efficient.

Using the new AGi system, we graphed the average residential usage on the home's main meters. Figure 12 and 13 are 1-hour main meter usage graphs, for the average residential member. Figure 12 includes members with off-peak usage that is sub-metered. Figure 13 are the members without sub-metered off peak usage. Members which have sub-metered off-peak usage have more electrical appliances under controls, such as water heaters along with the AC units. Comparing interval data in Figures 12 and 13, we can clearly see the difference when comparing interval data for a hot summer day of an average residential home with no metered off-peak versus a home with metered off-peak usage. In Figure 12, you can clearly see the reduction in demand during the evening control hours (15:00-20:00) for the homes with sub-metered off-peak energy.

Figure 12. Residential usage with off-peak)

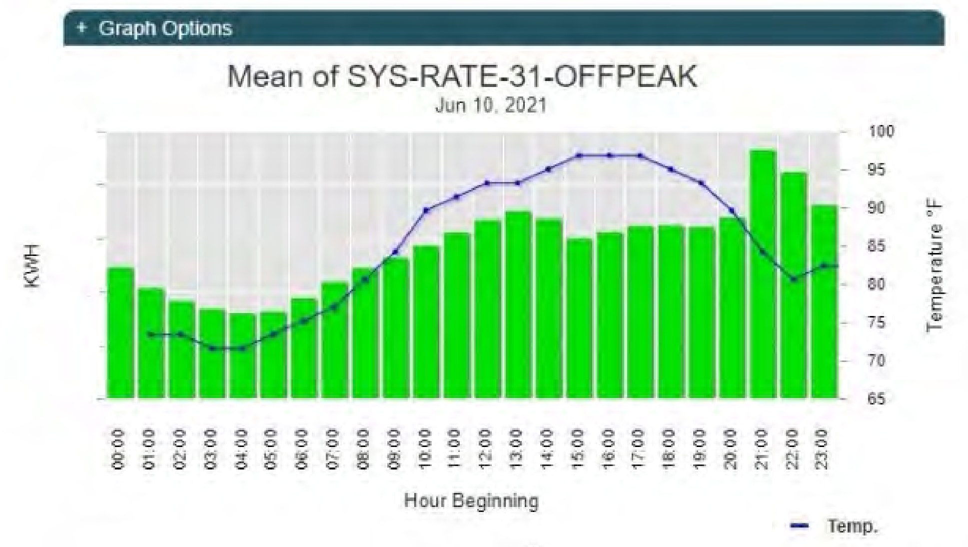
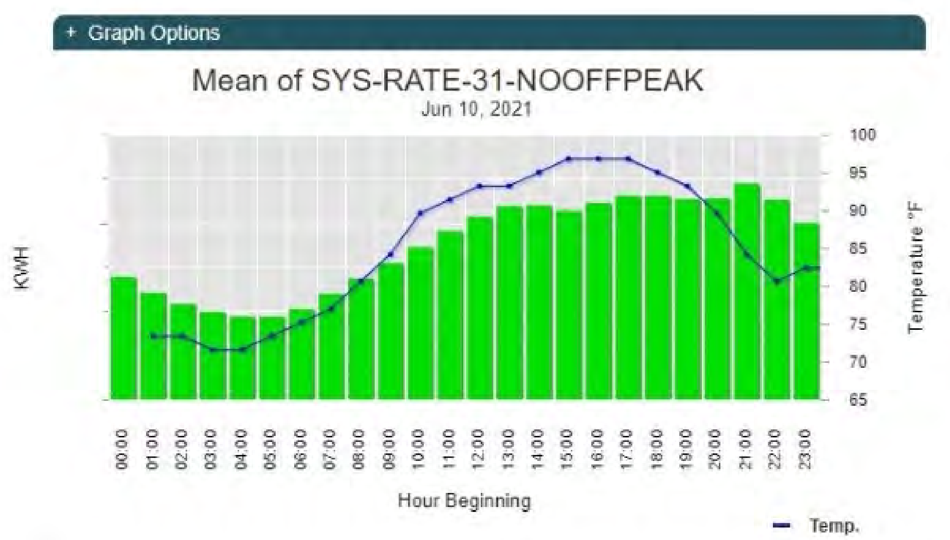


Figure 13. Residential usage (no off-peak)



Heat Pump

During the summer months (cooling periods), heat pumps operate the same as an air conditioner. During the winter months (heating periods), heat pumps operate just like during the cooling months except they heat a property; the main difference is that their run time is affected by coldness of the ambient air. Dakota Electric projects between 2-8 MW of demand reduction from controlling heat pumps on a cold winter day.

Heat Devices

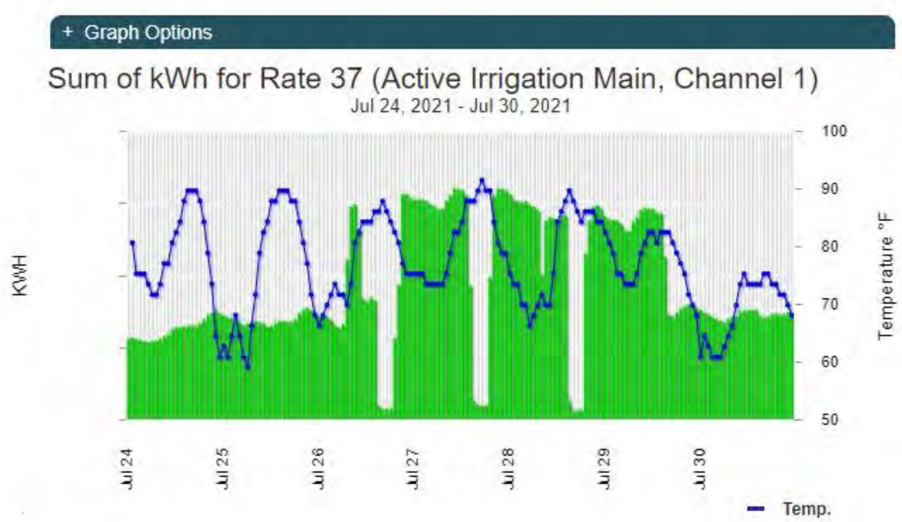
Heating devices can include methods such as in-floor heating, electric strip heaters, or infrared heating. The use of these devices is variable as the heating device can be the main heat for a residence or supplementary heating for a room or garage. The expected amount of load reduction is between 5-10 MW due to the variable nature of how these devices are used.

Irrigation

Irrigation is primarily used for agriculture and is configured to allow Dakota Electric to shed these loads during peak load periods. As with other loads, irrigation usage is dependent upon the weather, so the available load control is variable. In some instances, there is minimal load reduction from irrigation, while in other instances there can be between 10-15 MWs of load reduction. It is important to note that Irrigation is often used to distribute nutrients to the crops and may be operated even in naturally wet conditions.

Figure 14 below shows the control of the irrigation systems on the Dakota Electric system during July 2021. The impact of load control is evident in the solid drop in the electrical demand associated with each control.

Figure 14. Irrigation usage on days with load control



Miscellaneous and Water Heat

The miscellaneous category includes items such as hot tubs and other electric appliances. Water Heat is a combination of peak shaved water heaters and off-peak water heaters. Peak shaved water heaters are controlled for a few hours each control period. Off-peak water heaters are only heat water during the nighttime (off-peak) hours. There is over 30 MW of connected load in these categories. Depending upon the season, and the time of day, the amount of load reduction available from this category is between 5-10 MW.

C&I Interruptible Genset
This category includes member-owned generation systems where the entire building's electrical load is seamlessly transferred from the distribution system to the member's generation system. This control category is only available to Dakota Electric's larger commercial and industrial members. The load kW values in this category are actual summer peak demand values from the member's meter. These numbers do not reflect the total capacity of the member generation. The load kW values listed in this category are closer to the actual load reduction that is expected. The difference between the total number in this category and the actual load reduction experienced is due to the members' peak load not being coincidental with the control period. For a typical hot summer day, the C&I Interruptible generators can shed between 50-65 MW of load from the system. During the winter, the amount of load reduction from this category is a bit lower due to lower electrical demands.

Curtailment
This category is the maximum estimated amount of load that commercial members have contracted to shed from the distribution system during system load control periods. The commercial members who are on this program rate contract to shed their electric demand down to a pre-determined level (PDL). The amount listed is the difference between the PDL and the actual monthly peak kW demand. For this category approximately 2-5 MW of actual load reduction is expected.

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

Note: The load reduction numbers listed above are estimates. The actual amount of load reduction during any control period is variable and driven by many factors including: season, time of day, weather (both day of the control period and the weather on the days preceding the control period), and length of control period.

26. Financial Data: Historical Distribution System Spending

Section A.26. Historical distribution system spending for the past 5-years, in each category:

- *a. Age-Related Replacements and Asset Renewal*
- *b. System Expansion or Upgrades for Capacity*
- *c. System Expansion or Upgrades for Reliability and Power Quality*
- *d. New Customer Projects and New Revenue*
- *e. Grid Modernization and Pilot Projects*
- *f. Government Mandates Projects related to local (or other) government-requirements (i.e. road-relocations)*
- *g. Metering*
- *h. Other*

Table 17 below shows Dakota Electric's capital spending for construction over a historical 5-year period (2016-2020) by various categories. The capital projects included in this table only projects related to the distribution system. For example, a project related to maintenance of our corporate building or internal software projects are excluded in these construction capital projects.

As previously explained in the 2019 IDP report, Dakota Electric does not track construction projects using the categories requested in the list at the beginning of this section. At Dakota Electric, a code is applied to the construction work order which corresponds to the type of construction activity. For example, projects associated with new services are part of the 100 series codes, new or modified main lines are 200 and 300 series, respectively, and substation work is the 700 series. Dakota Electric uses these classifications for budgeting and project cost tracking.

Table 17 [13], is an engineering estimate of the breakdown for the requested categories using the actual total capital spending over the most recent 5-years.

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 Electric notes that the estimated allocation of these costs to the various categories is difficult and results in a rough estimate of costs. The coding system, which Dakota Electric uses for budgeting and tracking capital construction, tracks what was constructed, rather than why it was constructed. Converting what was constructed, especially for historical construction projects, into categories which are based upon why each project was constructed, is a subjective process. In the interest of transparency, Dakota Electric provides notes and discussion below about how it decided to assign spending from the tracking code categories into the various construction categories.

For some of the activities which are tracked by Dakota Electric's coding system, such as installations for new development and service connections, the relationship to the above categories was quite clear. For other activities, such as underground cable replacement or overhead line replacement, the category assignment was less straight forward. The difficulty associated with assigning costs is illustrated with the following example. Dakota Electric decides to replace an overhead line. The line is old and, because of its age, is weaker and considered a reliability risk. Due to these factors, the line was replaced. Since the line has deficiencies that fall into two categories, should this be placed into the Age-Related replacement category or the Reliability replacement category. For overhead lines, Dakota Electric placed most of these costs in the age-related category as these projects are primarily selected by age to improve reliability.

[13] The costs shown in Table 17 do not reflect the Contribution-In-Aid-of-Construction (CIAC) which was paid by the entity involved with requesting the project. Section A.27 provides the CIAC information by category and year.

Turning to underground cable replacements, the selection of these projects was by the number of failures (outages) experienced by the cable. The underground replacement projects are selected not by age but by the need to improve reliability. However, since the underground cable replacement project does not increase system capacity, these projects were also included in the age replacement category. Dakota Electric placed these projects in this category because the underground cables replaced tended to be among the older underground cables on the system.

Projects which were driven by member requests, such as conversion of the electrical service to their homes from overhead wire to underground, were included in the System Projects (Driven by Government) category as that appeared to be the best fit for those projects.

The information in Table 17 clearly shows the impact of Dakota Electric's AGi advanced metering project. This is illustrated by the significant increase in spending in 2020 related to new meters and load control receivers. The cost of the new load control receivers is included the advanced technologies category, and this includes costs associated with the RF Mesh system and new load control receivers which were replaced in 2020.

Dakota Electric also increased spending in 2020 on replacement of aging equipment. Part of this increased spending was focused on replacement of sections of our system where the wooden line poles are greater than 60 years old. Dakota Electric inspects all of its poles every 10-11 years and found through this process that poles which have been in service for 60 or more years fail routine inspection at a much greater percentage.

27. Financial Data: Investments in Distribution System Upgrades

Section A.27. All non-Dakota Electric investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA and other) and location (i.e. feeder or substation).

Table 18 shows all the Contribution-In-Aid-of-Construction (CIAC) collected by Dakota Electric for each of the requested areas over the period 2016 to 2020. Dakota Electric does not keep track which feeders or substations these costs are associated with.

Table 18. Historical Contribution-In-Aid-of-Construction

	2016	2017	2018	2019	2020
Age Related Replacement	$150	$105	$0	$316	$126
System Expansion (Due to Capacity)	$1	$5	$0	$0	$0
System Expansion (Due to Reliability)	$0	$0	$0	$0	$0
New Members	$1,458	$1,344	$1,301	$1,982	$1,419
System Project (Driven by Mandate)	$246	$121	$890	$164	$149
Metering	$0	$0	$0	$0	$0
Grid Modernization (Advanced Technologies)	$0	$0	$0	$0	$0
Annual Total	**$1,854**	**$1,575**	**$2,191**	**$2,462**	**$1,694**

Note: All dollars are in Thousands

28. Financial Data: Projected Distribution System Spending

Section A.28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects.

The following are the forecasted 5-year construction capital spending for the categories requested. As discussed in Section A.26, the allocation of the forecasted capital spending in the following table has been done using similar engineering estimation process.

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

Table 19 includes the AGi project budgeted capital spending for 2021-2023. For the years 2021-2022, the cost of the AGi meters is included in the new Metering category and for the years 2021-2023, the cost for the load control receivers is included in the Grid Modernization category.

When looking at the construction capital spending forecast, it is important to understand how Dakota Electric selects projects for construction and how that process works. Dakota Electric completes a 5-year capital construction forecast to help identify periods of expected high or low future capital spending. Dakota Electric has a limited labor pool to accomplish projects and peaks in the capital spending require increases in labor while, on the other hand, valleys in capital spending create an under-utilized labor pool. The 5-year capital construction budget forecast attempts to identify these periods of high and low spending and, if possible, it allows Dakota Electric to consider shifting spending to other years to help reduce capital budget swings. It is important to note that the majority of individual projects are not identified or approved by the Dakota Electric board beyond the next calendar year.

Dakota Electric provides a discussion for each cost category below and how the 5-year budget forecast is accomplished for these categories. It is important to note that Dakota Electric does not initiate the construction of new facilities until new load requires new distribution capacity. Therefore, while there are forecasted dollars in categories such as new consumers or main lines, the actual dollars spent will depend upon the actual need for distribution system capacity changes. The numbers for these categories are based on Dakota Electric's current growth expectations.

<u>Substation</u>

Substation projects are one of the few projects that must be planned beyond the standard year ahead time frame. New substations require permitting and interconnection with transmission and typically have a lead time of 2-3 years (or more in certain instances) from initial planning to completion. Some pieces of substation equipment, such as the substation transformer have longer lead times and must be specified and procured for a specific substation project. Individual substation projects are normally the largest single capital project within the annual capital budget and, necessarily, have the greatest impact upon the total budget. Forecasting substation projects to avoid multiple substation projects occurring in the same year, is important to avoid budget volatility, and accompanying impact on labor resources, as discussed earlier in this section.

<u>Reliability and Age-Related Replacement Projects</u>

Each year, during the budget cycle, capital dollars for reliability and age-related replacement projects are generally identified, but specific projects are not. Actual projects are based upon historical reliability performance and the worst performing sections of line are targeted for replacement. The group in charge of these projects is given a spending budget and then decides which sections of the system are replaced. This category is affected annually by the number of other identified projects in the capital budget, such as expected new services and government mandated projects. If there is a high number of these other projects, the available labor pool is less resulting in fewer reliability and age-related replacement projects being completed. However, if the failure rate of the existing underground cables or overhead lines tracks higher than average, more dollars are budgeted, and labor is allocated to this category.

<u>Road Rebuild Projects</u>

Local governments in our service territory provide multi-year forecasts of their respective road reconstruction projects. These projections are helpful for Dakota Electric to estimate its overall capital construction budget. However, the issue Dakota Electric faces is that the road reconstruction projects on the list provided are only in the concept phase. When a project is in the concept phase, it has not gone through the public hearing stage and is not fully scoped or designed. Dakota Electric is only able to roughly estimate the impacts to the distribution system and potential costs. The schedules provided by local governments for these projects are also only estimates. There are also many factors that can cause the actual road reconstruction to be canceled, greatly modified, or as routinely occurs, be delayed by one or more years. Dakota Electric becomes aware of when a project will occur when the project is released for bidding to contractors. When this occurs, Dakota Electric only has a couple of months (sometimes weeks) to work with the chosen contractor to prepare designs, order supplies, and start modifications to the distribution system in support of the road rebuild.

Technology Projects

Capital dollars for technology projects, such as adding remote control and monitoring to field equipment, are also forecasted for future years. Similar to age related equipment replacements, these specific projects are not identified.

29. Financial Data: Planned Distribution Capital Projects

Section A.29. Planned distribution capital projects, including drivers for the project (e.g. see list in 19), timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should include:

- *a. Age-Related Replacements and Asset Renewal*
- *b. System Expansion or Upgrades for Capacity*
- *c. System Expansion or Upgrades for Reliability and Power Quality*
- *d. New Customer Projects and New Revenue*
- *e. Grid Modernization and Pilot Projects*
- *f. Projects related to local (or other) government-requirements*
- *g. Metering*
- *h. Other*

After the discussion at the Commission's January 8, 2021 stakeholder meeting, it is understood that the focus of this question is on larger capital projects. For the 2021 IDP report, Dakota Electric is using a threshold of $100,000 to define a project for inclusion in this listing.

As discussed in other sections of this report, Dakota Electric does not generally commit to projects beyond a year, except for projects (*e.g.,* substations) which have longer permitting or require equipment with longer lead times. Dakota Electric's planned projects include what has not yet been completed in 2021 and what is proposed for 2022. Dakota Electric is including in this report the projects which are part of the 2021 budget, are being built in 2021 due to member needs, and are listed in the initial draft of the larger capital projects contained within the proposed 2022 capital construction budget. Within the 2021 project listing, each project is noted by whether:

- the project was budgeted, planned, and constructed;
- the project was budgeted for, but will not be constructed in 2021;
- the project was not planned, and budgeted, but conditions occurred during 2021 which caused these projects to be designed and constructed.

Projects for connecting new, larger commercial services have not been included within this listing of capital projects as much of the cost for adding a new commercial service is for the transformer and other equipment required to supply that individual member's electrical needs.

Appendix D – 2021 Capital Construction Projects > $100,000 has the list of construction projects for 2021 that are considered larger projects.

Appendix E – 2022 Proposed Capital Construction Projects > $100,000 has the list of proposed construction projects for 2022 that are considered larger projects. This list of projects is preliminary and has not been approved by the Dakota Electric Board. The review and approval for the projects is scheduled for the November 2021 Board meeting.

30. Financial Data: Cost Benefit Analysis - Non-Traditional Distribution System Solution

Section A.30. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement.

For over 30 years, Dakota Electric has used load management to help manage its system peak demands and reduce the demand charges from the power supplier. This non-traditional solution reduces demand during peak load period and is also available to reduce system demand during system contingencies. Dakota Electric's proactive use of load management has saved members millions of dollars since their inception and currently represents a roughly $15 to $20 million saving per year, not including additional savings such as avoided generation. Furthermore, the reduced demand associated with energy efficiency has allowed Dakota Electric to defer or eliminate the need to construct additional distribution resources.

31. DER Deployment: Current DER Deployment

Section A.31. Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.).

Appendix A – DER Summary Report provides a list, by substation and feeder, of the existing DER deployment as of August 2021. The listing is by type and overall kW. The values provided for the load control receiver loads are based upon information gathered during the initial load control receiver installation and *do not* include reductions in these kW control values due to replacement of the appliance with a more efficient unit. The actual amount of load control is much less than the sum of these load control receiver loads values as these numbers are not diversified and assume that all controlled devices are running 100% of the time. As previously discussed, the actual available load control value is dependent upon the current weather, season, and other factors.

Dakota Electric's distribution system is considered, and operated as, one planning area and is maintained by a single service/work center located in Farmington, Minnesota.

32. DER Deployment: High DER Penetration

Section A.31. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.

Dakota Electric does not have any areas which it believes are considered "high" behind the meter DER penetration and does not have any areas forecasted to have high levels of behind the meter DER penetration. DER penetration is considered high by Dakota Electric when it is unable to add additional small behind the meter DER without expensive upgrades of the distribution system.

Dakota Electric does have three substations where Dakota Electric has interconnected solar systems greater than 1MW. These larger solar systems are close to, or greater than, the minimum load of the substations they are connected to. Additional smaller behind the meter DER is still able to interconnect on these substations, but there is limited space available before expensive upgrades to the distribution and/or transmission system are required.

33. Areas with Abnormal Voltage or Frequency

Section A.33. Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues.

Dakota Electric has not encountered significant issues with extended abnormal voltages due to the operation of DER systems. With the limited penetration of DER installations on our system, most of the Dakota Electric distribution system still has load levels which are significantly greater than the total DER generation levels. There are, however, a few feeders where large DER generation is greater than the native load. At one of those installations, during initial start-up operation, high voltage did occur on several occasions and the DER was immediately, and automatically, tripped off-line by the protective relaying. In this instance, the inverters did not have the power factor settings required by Dakota Electric and the vendor had to modify the settings to meet the Dakota Electric requirements. The 98% lagging power factor setting was programmed into the inverters and they now maintain a lower voltage level. Since then, Dakota Electric has not experienced additional voltage issues.

Since frequency is regulated by the Eastern Interconnection, and is maintained at the transmission level, Dakota Electric does not have any areas with existing or forecasted abnormal frequency issues.

Section B. Preliminary Hosting Capacity Data

1. Feeder Load Levels

Section B.1. Provide an excel spreadsheet (or other equivalent format) by feeder of either daytime minimum load (daily, if available) or, if daytime minimum load is not available, peak load (time granularity should be specified).

Attached as *Appendix B – Substation and Feeder Minimum Loading Levels* is a spreadsheet showing annual minimum load (kW) levels and annual daytime (10am-4pm) minimum load levels for each of Dakota Electric's feeders for the 12 months between August 1, 2020 and July 31, 2021. The spreadsheet also includes, for comparison, the 2019 IDP values reported for the 12 months between June 1, 2018 and May 31, 2019.

Extracting and identifying daily (365) minimum values for each of the more than 165 feeders on the Dakota Electric system was not practical, as that would require significant resources and effort to identify, and remove, any abnormal operational conditions from each day of the year for each feeder. As such, the annual minimum loading levels for each feeder and substation are presented in Appendix B.

The base information was gathered by Dakota Electric's SCADA system from feeder and substation monitoring equipment. All of Dakota Electric's substations and feeders are monitored by the SCADA system. Data may not be available for short periods of time when either the entire SCADA system is taken out of service for database or software work or when the monitoring equipment within a substation is taken out of service for modifications or maintenance activities.

The demand (kW) values for each of the feeders are saved into a historical database by the SCADA system at a frequency of once every minute. The one-minute intervals are averaged over a 15-minute period as part of the process to extract the data from the historical database. The 15-minute periods allow for more reasonable amount of data to process for the analysis and, more importantly, the 15-minute periods reduce the effect of minute to minute swings in the feeder loading.

The exported data from the SCADA historical database is the actual operational loading on each of the feeders. Thus, the values include times when:

- the feeder or portions of the feeder are out of power (*e.g.,* storms, equipment failure),
- switching events which transfer load to another feeder or add load from another feeder; and
- periods of load control and other activities.

The historical pieces of feeder data were extracted into a spreadsheet for each of the substations and then programmatically and manually cleansed to improve the usefulness of the minimum load data. It is important to note that the loading on the feeders and substations are affected by many different factors. Dakota Electric provides the following discussion for certain factors that affected the base data and how the data were cleansed.

<u>Back-feeding Feeders</u>
Since back-feeding of the transmission system is one of the conditions which can affect the ability to interconnect and operate a DER, Dakota Electric included in the spreadsheet the minimum and maximum load levels for each of the substations. This additional information was provided as the overall substation minimum loading and is one of the key items to decide whether transmission studies are required for the interconnection of new DER systems. It is important to note that summing the non-coincident minimum or maximum values for each of the feeders on a substation is not the same as the coincident substation minimum values. The sum of the non-coincident feeder minimums does not equal the substation minimum as the feeders do not each reach their minimum values at the same time.

<u>Distribution Switching</u>
The distribution system configuration is in an ever-changing state. The configuration which is considered "Normal" is when all the switches and other distribution connections are in their normal state. In this normal state, the members' services are supplied by their normal feeder and substation. This normal state is what is modeled and studied during the annual and long-term planning processes. This normal state is also used for DER integration studies. The cleansed minimum feeder and substation load levels reported in this IDP still reflect the transferring of some loads between feeders and substation due to distribution switching. Therefore, a minimum load level could be the result of an "Abnormal" condition when a portion of the feeder's normal load is being switched to another feeder for a period of time.

Despite being modeled in a normal state, it is important to note that the distribution system is seldom operating in a "normal" configuration. It is not uncommon for one or more areas of the distribution system, at a given time, to have distribution switching occurring where some of the electrical services are transferred (switched) to another feeder or substation. There are many reasons why a distribution operator will transfer a portion of a feeder, or an entire feeder, to another source. Some of these include:

- <u>Emergency Switching</u> – Emergency switching is due to an equipment failure. Equipment failures may occur due to storm damage, equipment malfunction, vehicles leaving the roads and damaging poles or other equipment, animals, or other unexpected occurrences. Emergency switching is unplanned, but is typically for a short duration, as the failed equipment is quickly repaired or replaced, and the system is then switched back to normal.

During these events, the feeder's load can be greatly reduced, or in the event of a total feeder or substation outage, the loading can be reduced to zero. When reviewing historical data, the problem is that the SCADA system does not record a perfect zero number when a feeder or substation is out of power. The sensors are not perfectly accurate, and when the feeder is out of service, the sensors report a small value. Typically, in the range of -10 to +10. This small value is due to static electricity affecting the de-energized sensor leading to a small positive or negative value being recorded in the historical database. These very small values were manually removed from the historical data set to avoid them masking the minimum load value reported. As a result of this cleansing process in 2019, Dakota Electric identified a few feeders, which have a high penetration of DER integration, that do have actual negative current flow and back feed into the substation. The process to programmatically remove the near zero values from the minimum load also removed all negative values from the 2019 data set. The minimum load for these feeders is thus reported as "< 0." The 2021 process maintained the negative values to show the feeders which have back-feed the substation.

- <u>Maintenance Switching</u> – Periodically, pieces of equipment are de-energized and taken out of service for maintenance and testing. Switching due to system maintenance is normally planned for times when the overall impact to the distribution system is lower than some of the other drivers (*e.g.*, weather). Typically, these maintenance activities are planned for lightly loaded periods, so a feeder or a portion of a feeder could be switched during a minimum loading time, and the feeder's recorded minimum load value would be lower than its normal configuration. For the feeder receiving the switched load, the feeder's minimum load value recorded may have been greater than if recorded when the feeder was in its normal switched state.

- <u>Switching for Road Construction</u> – Much of the distribution system is located along roads and the electrical cables, poles, and wires are typically installed within the road right-of-way. The distribution facilities in the road right-of-way can be affected as the road is improved by the addition of traffic signals, addition of turn lanes, widening of the road to add lanes, and other projects. Many times, a section of a feeder (distribution line) must be de-energized, and possibly moved or rebuilt, to allow space for the road to expand. Road construction typically requires the distribution feeder to be switched to an abnormal configuration for weeks or months. Road construction schedules are driven by weather and most often occur during the summer months and can be concurrent with peak system loading. When possible, Dakota Electric works with the road contractor to reduce the amount of time the feeder is out of service and, if possible, move the time frame of the outages to off-peak months. Switching for road construction is one of the more disruptive activities for the Dakota Electric distribution system.

- <u>Distribution System Construction</u> – As parts of the distribution system require replacement or reconfiguration, other parts of that circuit may need to be de-energized or switched to another source to allow the construction to proceed. This process is similar to switching in support of road construction, but, in this case, Dakota Electric has more control of the project schedule because Dakota Electric is initiating the work. Dakota Electric normally targets this planned construction during periods when the feeder is lightly loaded.

- <u>Load Control</u> – Some of the substations and feeders have significant levels of demand-side management available. These feeders and substations are often at their minimum load levels during demand-side management control periods. Most of the feeders which have a high percentage of demand-side management will have the same or similar minimum load levels for the daytime minimum as the overall minimum reported load levels

Dakota Electric worked to provide the most useful minimum load data. As previously discussed, the minimum feeder load levels may include the feeder load level at times when some of the load was switched to another feeder. Dakota Electric does not keep records of when sections of a feeder are switched over to other feeders or substations. To keep this type of record would involve significant resources and there is no process or monitoring available to keep recording the amount of energy switched during the “abnormal state” configuration. It is important to understand that distribution switching occurs as a result of planned and emergency switching. Attempting to keep a detailed record of each incident of load transfer between feeders would be unreasonably time consuming and may negatively affect the restoration of service during storms and other unplanned outages.

Section C. DER Scenario Analysis

Section C.1. In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on the distribution system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Dakota Electric distribution system in the locations Dakota Electric would reasonably anticipate seeing DER growth take place first.

1. Summary

This section of the IDP report reviews the future ability to integrate DER systems onto the Dakota Electric distribution system. The discussion is broken into the following areas:

- Review of the 2019 IDP DER integration study results;
- Methodologies Used to Create 2020 DER Forecasts;
- DER Behind the Meter Solar Forecasts;
- Processes and Tools for DER Adoption Scenarios;
- Potential Barriers to DER Integration;
- DER System impacts, Costs and Benefits;
- FERC order 841 and 2222 discussion; and
- Limitations and issues with incorporating DER into future planning analysis.

2. Review of 2019 IDP DER Integration Study Results

In the 2019 IDP report, Dakota Electric completed studies to identify what levels of DER penetration the existing distribution system could support. These studies were also designed to identify the level(s) of DER generation integration above which would necessitate expenditures to augment the distribution system.

The conclusions from Dakota Electric's 2019 report are reproduced below.

> *Dakota Electric concluded that limiting factors may start to occur when the aggregated capacity amount of DER systems reaches 20% of the circuit's annual peak load. The engineering modeling also showed that limiting factors on circuits may not occur until the aggregated capacity amount of DER systems reached as high as 50% of the circuit's annual peak load.*
>
> *These basic studies show that DER generation rated to around 20% of the daytime minimum load of each of the Dakota Electric circuits could be installed without significant distribution infrastructure changes. This would amount to around 100 MW of DER generation capacity. This assumes the DER is sized to the existing load at the point*

the DER is interconnected. It is possible that DER capacities up to the distribution system daytime minimum load levels could be achieved without significant distribution infrastructure changes, if the DER systems are sized to the existing loads and are also distributed across the distribution system. That could potentially amount to approximately 200 MW of integrated DER generation on the Dakota Electric system. Conversely, if the DER is not sized to the load or is concentrated in a few areas, there could be costly distribution infrastructure changes required at much lower levels of DER integration.

Dakota Electric notes the following key points from the 2019 engineering analysis. The two conclusions with emphases added are, in Dakota Electric's estimation, the most important conclusions and are expected to have the greatest impact on our ability to integrate larger amounts of DER generation without costly distribution system upgrades.

- *Clustering of small DER systems can cause high voltage.*
- *Clustering of DER generation on one phase, can cause voltage and current imbalances on the distribution system, impacting system losses and voltage regulation*
- *The farther from the substation the DER is interconnected the greater chance of issues with the integration and operation of the DER generation.*
- ***Less DER generation can be integrated on a circuit if the DER is not sized to the load****.*
- *Larger DER systems can quickly take up the available capacity on a substation causing reverse power flow limitation to occur.*
- ***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****.*
- *Concentrated amounts of DER generation may cause overloading of smaller distribution wires and cables; the standard size residential development underground cable is #2 AL which could be overloaded with 850 kW of aggregate DER.*

Dakota Electric considered these conclusions when beginning its analysis and forecasts for the 2021 IDP.

3. Methodologies Used to Create 2022-2050 DER Forecasts

Section C.2. Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion.

Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.

It is important to note that Dakota Electric does not create Integrated Resource Plans as we obtain all our energy from GRE and we do not have generation facilities. Dakota Electric does, however, create detailed short-term or long-term forecasts for energy consumption. Every two years, GRE works directly with all its member Cooperatives, including Dakota Electric, to develop an updated long-range load forecast. Dakota Electric has direct input into this forecast. Dakota Electric uses this forecast as a basis for its internal short-term forecast and budgets.

Since Dakota Electric does not have personnel focused solely on forecasting, or the software and associated economic data to support the creation of long-term forecasts of DER integration, Dakota Electric looked to others who have spent considerable time to incorporate multiple economic variables into their forecasts. The U.S. Energy Information Administration (EIA) 2021 Annual Energy Outlook (AEO) is an independent analysis and includes a forecast of future of DER in the United States. Since the AEO is a well-known independent forecast conducted by a government agency, Dakota Electric concluded that the EIA's 2021 DER forecast was reasonable to use as the basis for the Dakota Electric DER forecast for this IDP report.

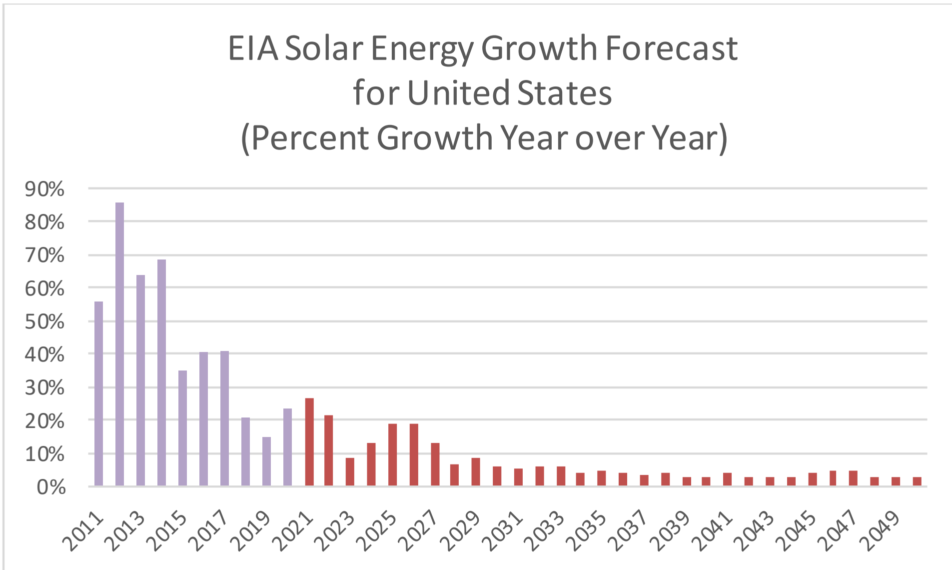
The AEO forecasts the annual solar energy production through 2050 at the national level. Over the next 25 years, Dakota Electric assumed that Minnesota will have a similar growth pattern as the rest of the nation for renewable energy. There will be periods when Minnesota's renewable energy growth differs from the national growth curve, but over the forecast period, it is reasonable to assume Minnesota's growth in DER adoption will be similar to the rest of the nation.

Dakota Electric reviewed the AEO and concluded that the annual percentage increases, forecasted in the EIA report, provide a solid foundation for a Dakota Electric forecast. The 2021 IDP DER forecast focused on the growth of solar DER generation. Of the different types of DER, solar appears to be the type of DER which is expected to be the dominant type for the near future. Dakota Electric did not consider energy storage in its forecast because energy storage does not create energy and it is a significant net user of electricity due to the round-trip efficiency of the energy storage system.

Dakota Electric did not forecast Demand Management because Dakota Electric has already implemented a significant amount of Load Management or Demand-side Management. Given this, there is a very low probability that Dakota Electric will have the ability to increase the penetration levels of demand management.

The method used to develop the three scenarios for the growth of solar on the Dakota Electric system was to take the EIA solar energy production forecasts, year-over-year, and calculate the annual growth percentages in solar energy production. Figure 15 below shows the EIA annual percentage growth in solar energy production. This figure reflects the natural reduction in year-over-year percentage growth as the total base value increases, it does not reflect a reduction in new production.

Figure 15. EIA Solar Energy Growth Forecast for USA



Starting from the Dakota Electric installed 2020 base for behind the meter solar systems, including both residential and commercial solar installations, the annual percentage in growth from the EIA forecast was applied to the existing Dakota Electric base. The three existing utility scale solar systems, which Dakota Electric and GRE developed, were not included in the base capacity. Dakota Electric removed these systems because their large size in relationship to the existing behind the meter solar capacity, and the resulting overall effect on the forecast from these large systems included in the initial base generation capacity would create a distortion in the DER growth forecast.

For the Dakota Electric MEDIUM forecast the EIA growth rates was applied without modification. The MEDIUM forecast is considered the reference or base forecast.

For the LOW forecast, the annual percentage growth values were adjusted down from the EIA reference values, except for the first two years (2021 and 2022). For these two years, the growth percentages were adjusted up to reflect actual applications and experience. After 2024 the annual growth percentages were adjusted down from the EIA forecast. The LOW forecast reflects the possible effects from the loss of the Production Tax Credit (PTC) for DER installations and the potential effect of metal prices and other economic conditions, such as supply chain issues, reducing the ability to sustain continued cost reduction for solar systems.

For the HIGH forecast, the first few years (2021-2028) have annual percent growth rates adjusted up from the EIA reference values. Dakota Electric made this adjustment to reflect the high level of solar applications we are experiencing and the expectation that those high levels would continue. After 2028, the EIA percentage growth forecasts are the best information we have available, but with the increased base capacity from the higher forecasts in the first few years, this results in a much higher level of DER integration throughout the forecast.

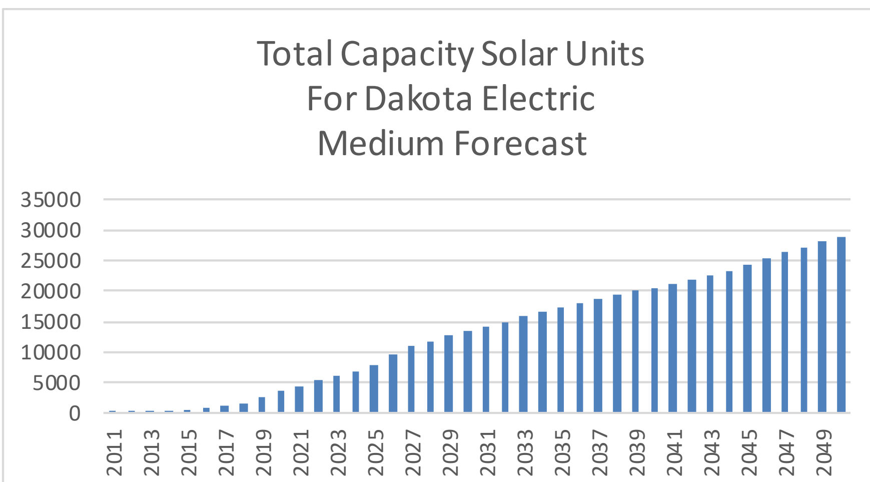
4. DER Behind the Meter Solar Forecasts (2022-2050)

As noted above, the DER forecast focused on the growth of behind the meter solar DER generation. Of the different types of DER, solar appears to be the DER type which is expected to be the dominant type for the near future.

a. Behind the Meter Solar - MEDIUM (Base) Forecast (2022-2050)

The MEDIUM forecast for behind the meter solar energy system capacity on the Dakota Electric system is shown in Figure 16, below. The total capacity of behind the meter solar generation is forecasted to be around 13 MWs in 2030 and over 28 MWs in 2050. This is from an existing base of 3.5MWs in 2020.

Figure 16. Medium DER Forecast of Solar Capacity Quantity (kW)



The historical and forecasted percentage growth in the number of behind the meter solar systems interconnecting with Dakota Electric for the MEDIUM forecast is shown in the following figures. Dakota Electric believes that the number of premises where solar can be installed will become saturated over the next 10 years, so the level of new behind the meter solar installations will stabilize over time.

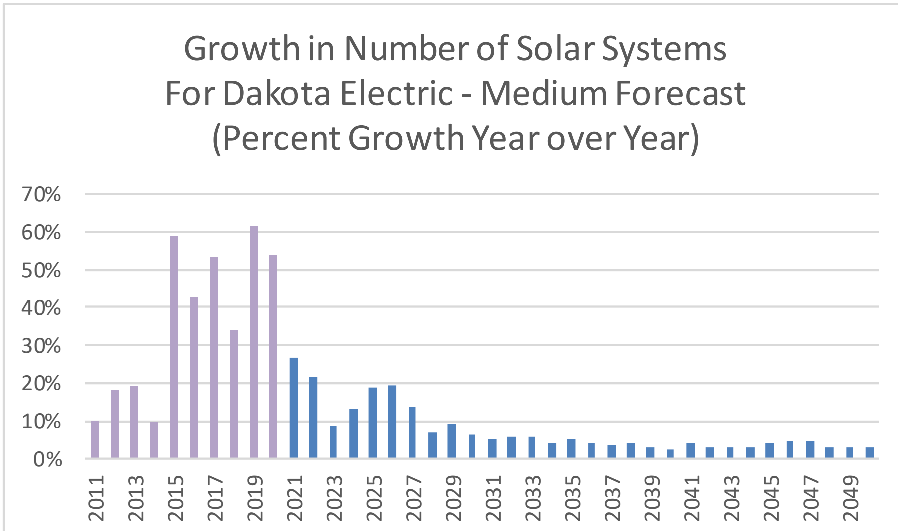


Figure 17. Medium DER Forecast of Annual Percent Growth in Solar Units

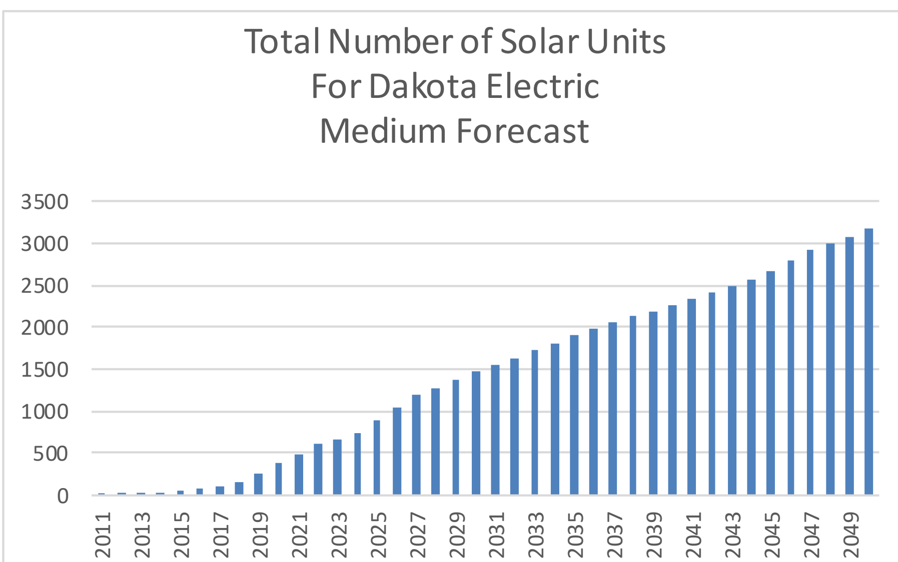


Figure 18. Medium DER Forecast of Total Number of Solar Units

b. Behind the Meter Solar - LOW Forecast (2022-2050)

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 installations (material and labor). Together, these factors, may impact the economics of adding behind the meter solar system and have a damping effect upon additional installations. Even with these negative economic factors, the total forecasted capacity in the LOW forecast is still 8.4 MW in 2030 and 16.8MWs in 2050.

Figure 19. Low DER Forecast of Solar Capacity Quantity (kW)

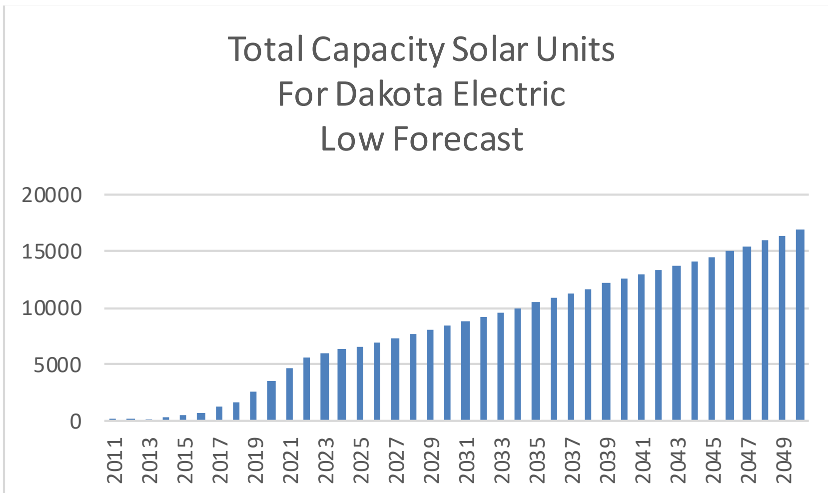


Figure 20. Low DER Forecast of Annual Percent Growth in Solar Units

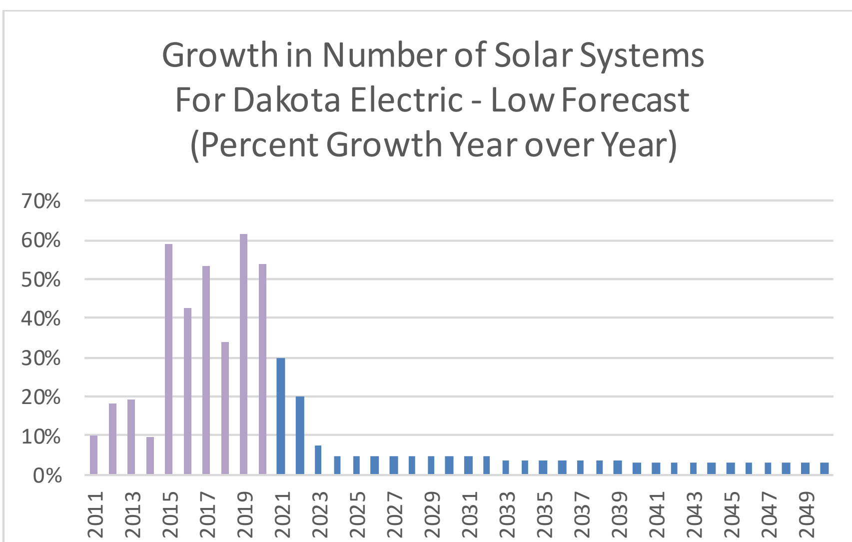
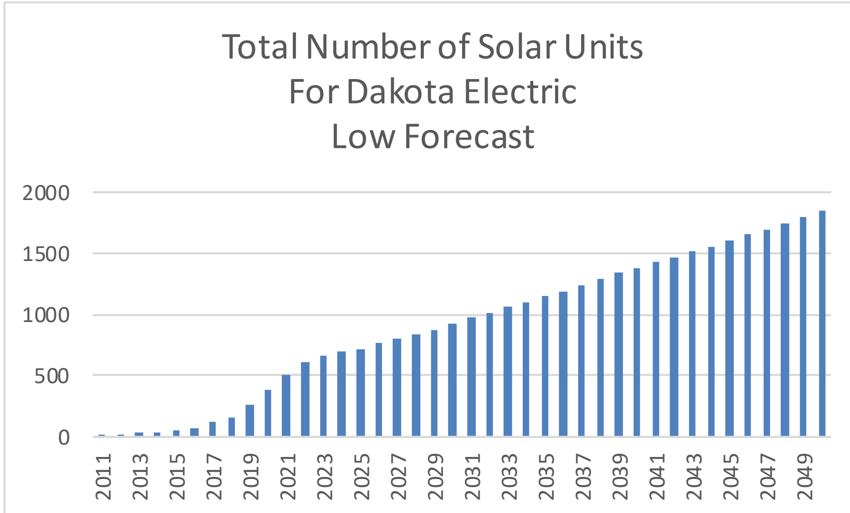


Figure 21. Low DER Forecast of Total Number of Solar Units



c. Behind the Meter Solar - HIGH Forecast (2022-2050)

The HIGH forecast includes an adjustment in growth for years 2021-2028 above the EIA forecast levels. This adjustment reflects the lower installed base for Dakota Electric of behind the meter solar systems and the potential for significant residential solar installations for the next ten years. The remainder of the HIGH forecast is in line with the EIA reference forecast. The 2030 installed capacity forecast is over 28MW and in 2050 the installed solar capacity is forecast is around 62MW.

Figure 22. High DER Forecast of Solar Capacity Quantity (kW)

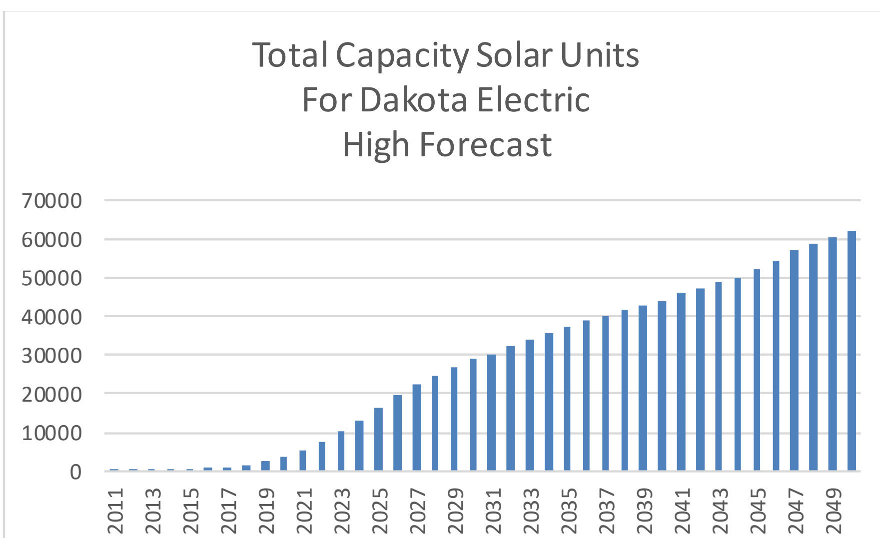


Figure 23. High DER Forecast of Annual Percent Growth in Solar Units

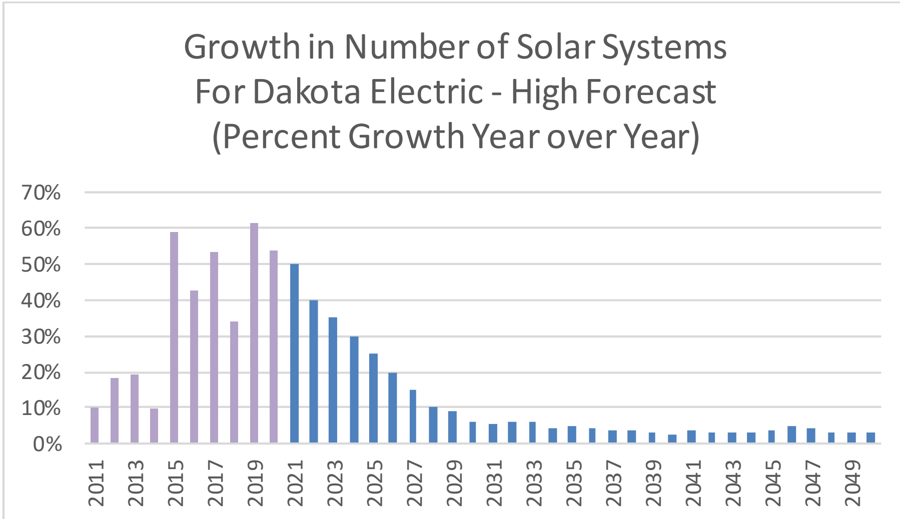
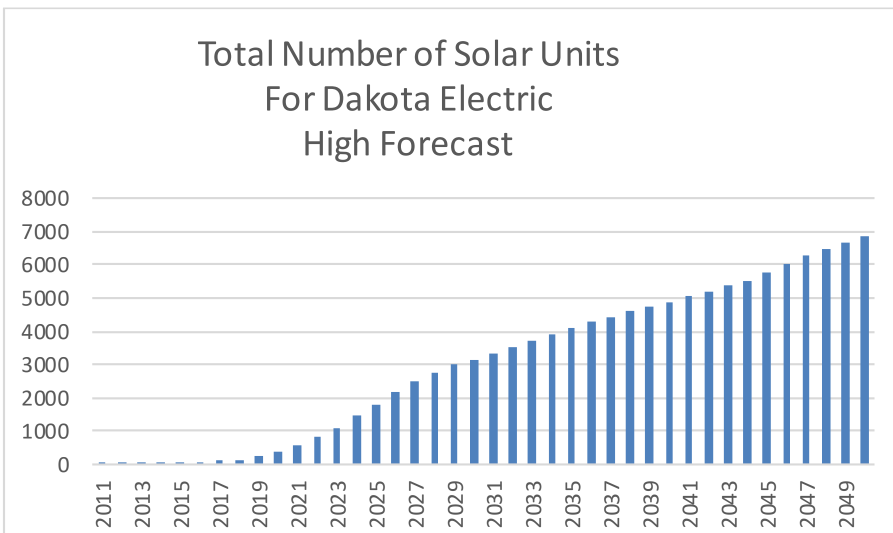


Figure 24. High DER Forecast of Total Number of Solar Units



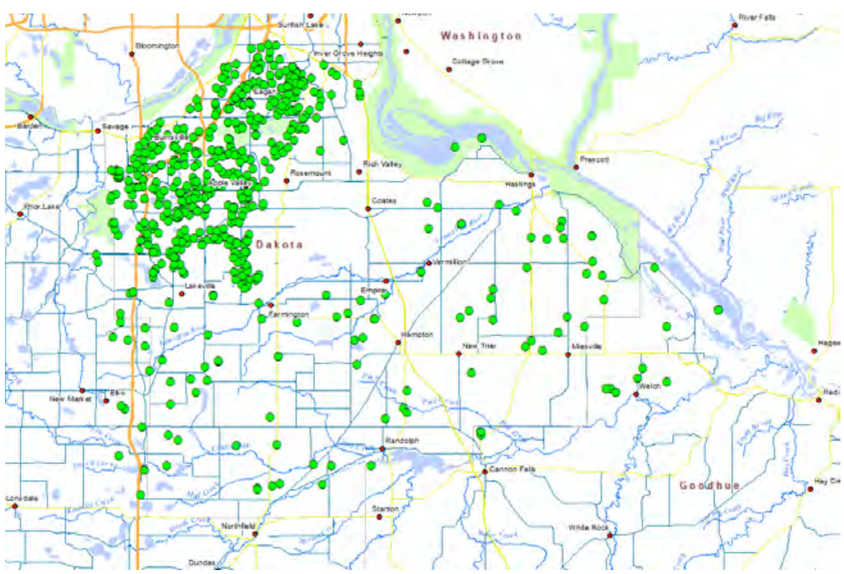
5. Processes and Tools for DER Adoption Scenarios

Section C.3. Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER adoption integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.

In most parts of the Dakota Electric distribution system there is available room for interconnecting more DER systems without a significant need to upgrade the distribution or transmission system. If the DER is sized to the load and the installations are not clustered, then continued integration of DER generation will be able to continue without significant distribution system upgrade costs. This is true on most of the system but not at in all locations. As discussed later in this section much of the rural portion of the Dakota Electric service territory is supplied by a single 69kV transmission system which is not able to support substation back feeding without costly transmission modifications and additions.

Figure 25 below, is a plot of currently integrated DER system. The plot shows a dispersed interconnection of DER across the Dakota Electric service territory. 125 of our 178 feeders have at least one solar system interconnected. Only 5 feeders have more than 10 solar systems interconnected. The average size of the interconnected behind the meter solar systems is 9 kW. As illustrated in the map below, the DER generation systems are spread evenly across the Dakota Electric distribution system, relative to the density of services. The northwestern part of the Dakota Electric system is suburban and has the highest density of homes and businesses, as well as DER systems.

Figure 25. Existing DER Generation Systems



6. Potential Barriers to DER integration

There are two known barriers which may have the greatest effect on limiting higher levels of DER integration on the Dakota Electric system. The first is the interaction between the distribution system and the transmission system. Any excess energy, which flows out of the distribution system is regulated by the rules of the transmission system. Since Dakota Electric is a distribution only utility and does not own or operate transmission, Dakota Electric does not have the right to flow energy from the distribution system onto the transmission system. Also, as with the distribution system, the transmission system was not designed and built to support energy flowing out of the distribution substations. In some cases, there are physical constraints on the transmission system for distribution substations to back feed the transmission system. In these cases, it can be extremely expensive to upgrade the transmission system to support reverse energy flow from the distribution substation.

The transmission system is operated, such that all users of the transmission system are required to pay for their use of the transmission system. Energy which back feeds the transmission system from a distribution substation is using the transmission system. As a distribution cooperative, Dakota Electric is not familiar with the rules for how these situations are accounted for both from an engineering and accounting perspective. Dakota Electric has inquired about these issues and has not received definitive response or guidance on these issues.

Costs to upgrade the distribution system, and in some cases the transmission system, to support the two-way flow of electricity will likely continue to increase as more and more DER is interconnected. These increasing costs may become a financial barrier for integration of additional DER on the distribution system. Dakota Electric notes that some of these cost considerations are currently being discussed in the Commission's Distributed Generation Working Group (DGWG).[14]

a. Transmission Back-feeding Constraint

As shown in the 2019 IDP Report, when Dakota Electric started exceeding the minimum substation load, and began back feeding the transmission system, integrating additional DER could become an issue. In the best-case scenario, the transmission system is physically capable of handling some back-feeding and does not require any physical modifications. For a vertically integrated utility, the accounting for this energy exchange between the distribution part of the utility to the transmission part of the utility is all handled within the utility. Dakota Electric does not have that luxury. For Dakota Electric, any energy exchange between the distribution system and the transmission system is between two utilities. In the case of Dakota Electric, this is further complicated

[14] Docket No. E999/CI-16-521.

because it involves a MISO control area-to-control area energy exchange. How this energy exchange is accounted for monetarily, and handled, within the transmission part of the market, is still being developed. At this point, Dakota Electric is not compensated for any energy which is sent back into the transmission system.

There are also some substations that before any back feeding of the transmission is allowed, very expensive upgrades to the transmission protection system are required to allow safe back feeding.[15] The costs for these upgrades are in the millions of dollars. For example, four of Dakota Electric's substations are supplied by the same 69kV transmission line. This transmission line has three existing transmission sources and is referred to as a "3-terminal" line. Most transmission lines have only two sources. For a 3-terminal transmission line, the ability for each of the sources feeding the transmission line to quickly identify when there is a fault on the line, is more difficult than for a typical two source transmission line. If each of the three transmission line sources are not opened expeditiously, the safety of the public is compromised and the overall effect of the fault on the rest of the transmission system is negative. The protection settings on 3-terminal lines are specially analyzed and calibrated to ensure a safely operated system.

When a substation, which is connected to a three terminal transmission line, back feeds the transmission line, that substation becomes a new fourth source into the transmission line. The back feeding (fourth source) from the substation causes the protective relaying on the transmission line to become unable to identify (see) faults. If one or more of the sources cannot see, or identify, a fault, it may not quickly trip and interrupt the flow of energy into the faulted transmission line. In the event that the transmission line falls to the ground, it is critical that ALL sources supplying electricity into the transmission line are quickly interrupted. A transmission line with four sources is unable to be quickly, and safely, cleared for a fault on the transmission line, which is a significant safety hazard.

The bottom line is that any of the Dakota Electric substations supplied by a three terminal transmission line are not allowed to back feed. If any back feed from the distribution substation is allowed, the transmission line must first be converted to a two-terminal line through construction of a transmission switching station(s). The construction of a transmission switching station is very expensive and would likely be in the multi-million-dollar range.

[15] Additional information is available in the Dakota Electric September 15,2021 IDP Stakeholder presentation, Slide 50, showing protective relaying zones for a 3-terminal transmission line with and without a back-feeding substation and the hole in protection which is created by the back-feeding substation.

In the case of the 69kV line feeding the four Dakota Electric substations, the fix is to add breakers and associated relaying to the transmission system to segment the transmission line. These fixes would be required at each distribution substation that is back feeding the transmission line. These new transmission segments would then create the ability to monitor and quickly open that segment of the transmission line to safely clear the fault. The problem with this fix is the high cost (millions of dollars) to install the additional breakers. In most cases, additional transmission substations are required to be sited and built.

There is another potential solution that may also address the back-feed issue. Dakota Electric is investigating the cost of installing energy storage systems at one or more of the substations associated with the 69kV line discussed in the previous paragraphs. Conceptually, the energy storage will capture excess DER generation which otherwise would back feed the transmission system. The energy storage would then hold this excess generation and release the energy later when the load on the substation is able to absorb the stored energy, thus mitigating the back-feed issue. However, this is likely still a costly and time intensive solution. In terms of timing, Dakota Electric notes that the current lead time for utility scale energy storage systems is well beyond 14 months. Dakota Electric is investigating these costs and potential methods to pay for this type of installation.

Generally speaking, the thought is the energy storage solution will allow additional behind the meter DER to installed beyond when the minimum load of the substation is exceeded by connected DER systems. This solution will allow additional DER generation to interconnection to the substation, but only to a point. Eventually, there will be insufficient load, regardless of battery storage, to absorb the excess energy generated by the DER. At this point, upgrading the transmission or curtailment of the DER operation would be required.

b. Cost Recovery for Distribution and Transmission Upgrades

The current method for cost recovery of distribution and transmission upgrades is based upon the first DER application which causes the need for the upgrade to pay the entire cost of the upgrade. With this cost-causation method of paying for system upgrades, there is no approved method for Dakota Electric to spread the costs over current and future DER systems. Expensive upgrades, such as what is required for the transmission system, can become a significant barrier for future DER integration. Dakota Electric notes that these cost issues are being discussed in the Commission's DGWG.

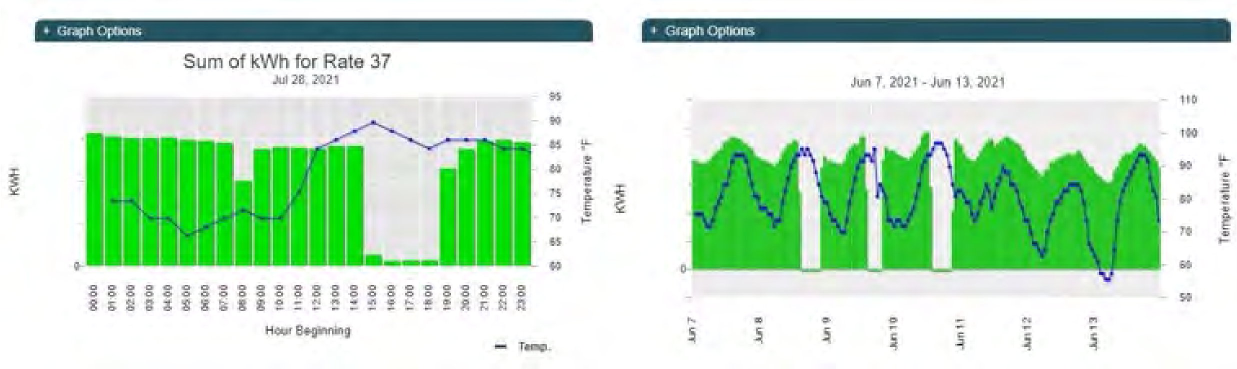
7. DER System impacts, Costs and Benefits.

The 2019 IDP Order defines DER as:

> *"supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter." This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles (EV), demand side management, and energy efficiency (EE).*[16]

The benefits of DER integration to the distribution system have been touted by certain parties. There is no question that energy efficiency and demand side management benefit our membership through reduce energy purchases and power cost reductions. Dakota Electric, in conjunction with our power supplier GRE, has a robust and extensive demand side management program. Millions of dollars in power purchase costs are saved each year by the Dakota Electric membership through participation in demand side management programs. The key component of Dakota Electric's use of DER for demand-side management is the operation of the resource in a controlled manner by Dakota Electric. When Dakota Electric is able to control, or manage the DER, it results in a known and expected demand reduction. Failure of the demand-side management to shed load when triggered, would not only be very costly, but equipment overloads and potential damage to the distribution system could result. Figure 26 below shows two examples of positive impacts when control is requested. The first graph is a virtual meter showing the aggregation of all the controlled irrigation systems and the second is a large load with has a member owned generation system.

Figure 26. Examples of Positive Load Control



The distribution system benefits from variable DER generation, namely solar and wind, are not evident yet. DER generation systems with variable output do reduce burning of coal and natural gas and result in reduced direct emissions. However, in terms of construction and daily operation of the distribution system, Dakota Electric has not experienced reductions in required

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[16] February 20, 2019 Order in Docket No. E111/CI-18-255

distribution system infrastructure or in operational costs. The main difference between the benefits received from demand side management and those derived from solar or wind generation is a difference in availability when needed. For demand side management, when the load is peaking and load control is triggered, the load being controlled is shed, so there is a direct, tangible reduction in demand when needed. For variable generation such as solar to be effective in augmenting or replacing wires, the output must always be available when the load is on the system. Solar generation has gaps in output and, thus, there are times when the load is placing demands upon the distribution system which are not being met by the solar generation. To account for issues with generation gaps, the general thought is that diversity through multiple solar systems in different locations will improve the aggregated output of the system as a whole and provide "firmer" output. This "firmer" output could then be counted upon and reliably replace distribution system facilities.

Using its new AGi metering system, along with the Meter Data Management system (MDM) Dakota Electric can create virtual meters which are the aggregation of many individual meters. Figure 27 below shows the sum of the energy produced by approximately 400 roof top solar systems interconnected across the Dakota Electric system. This chart shows the total output from the solar as measured by the production meter and does not include the member's native load. The blue line is the average daily temperature during the month. The data in Figure 27 shows that energy output from the solar systems is quite variable. During the early June heat wave, the solar output was strong and consistent, but, later in the month, while the load levels continued to be generally high, there were a couple days with limited solar output.

Figure 27. Roof Top Solar Output June 2021

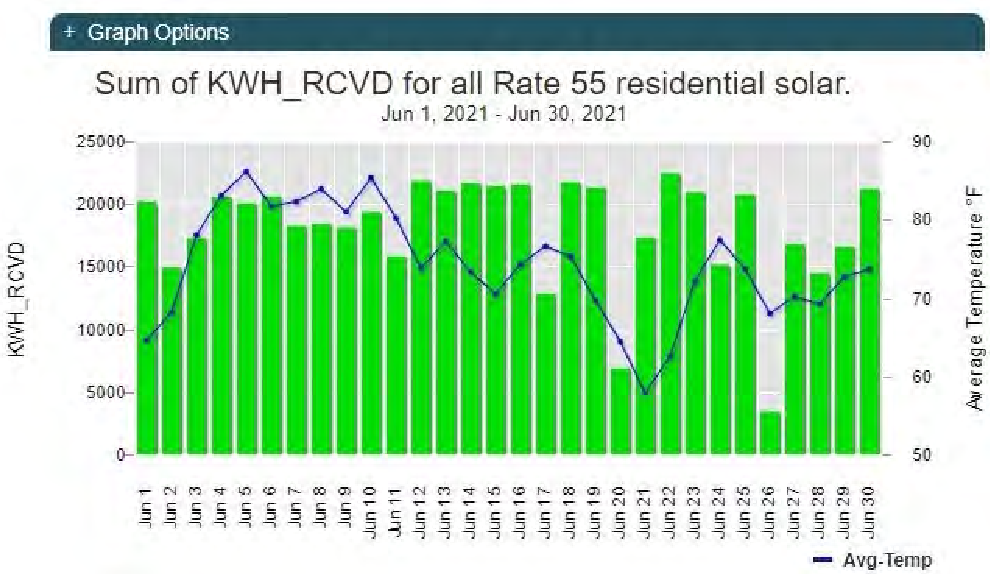


Figure 28. Roof Top Solar Output July 2021

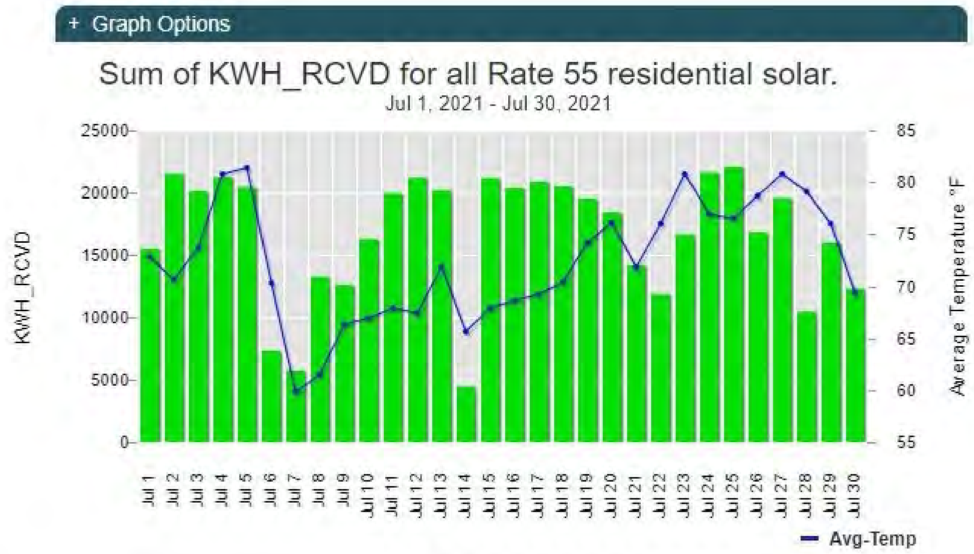
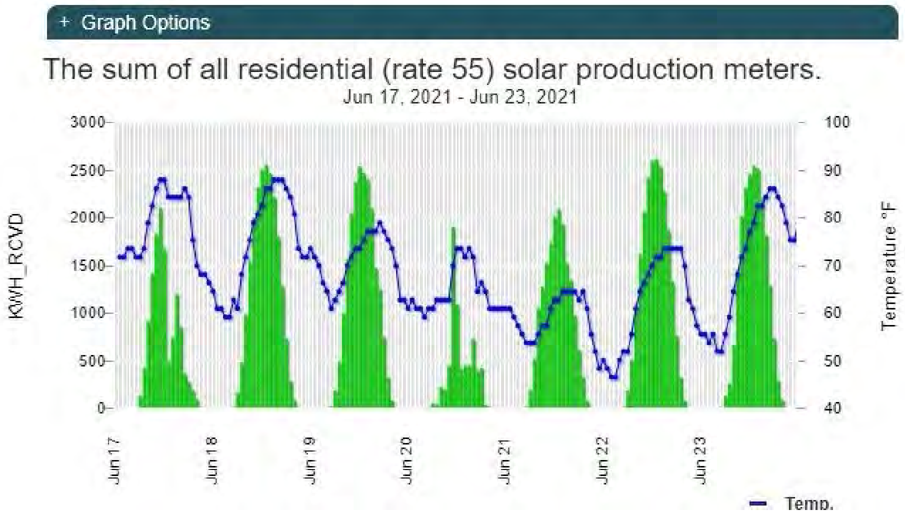


Figure 28 above, which represents total solar output for July, also shows a loss of solar output for a couple days during the month. During these periods, the local distribution system must still be built to supply electrical demand. Even during cloudy summer days, the humidity level coupled with latent heating in homes and businesses can result in high electrical demands. Loss of solar production due to increased cloud cover needs to be firmed up, or addressed, before the distribution system can reliably count upon solar as a "firmer" generation source.

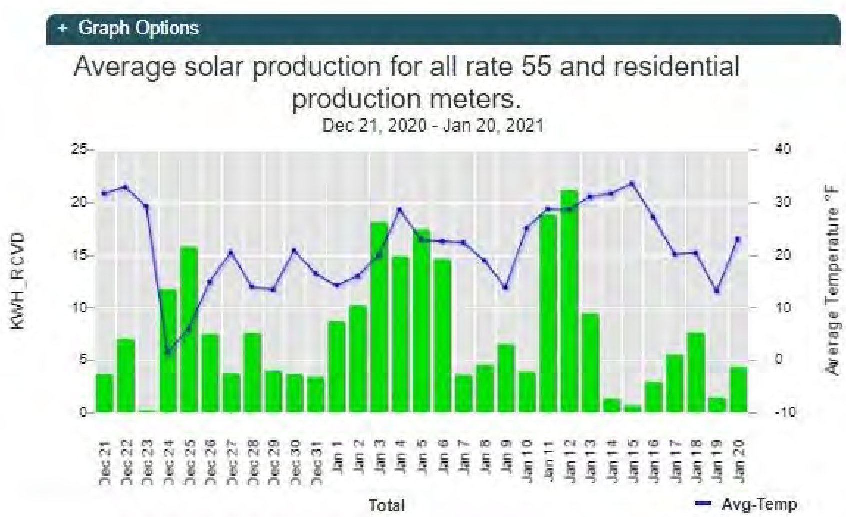
Looking at hourly interval data in Figure 29 below, for these same meters in June, Dakota Electric observed that some days experienced strong output while other days, like June 20, had limited output from the solar systems. On June 17, during the middle of the day, Dakota Electric notes a brief period of limited energy production. If the local distribution system is not built to provide energy during these brief periods of reduced production, our members will suffer an outage or low voltage and possible equipment damage.

Figure 29. Roof Top Solar output for a week in July 2021



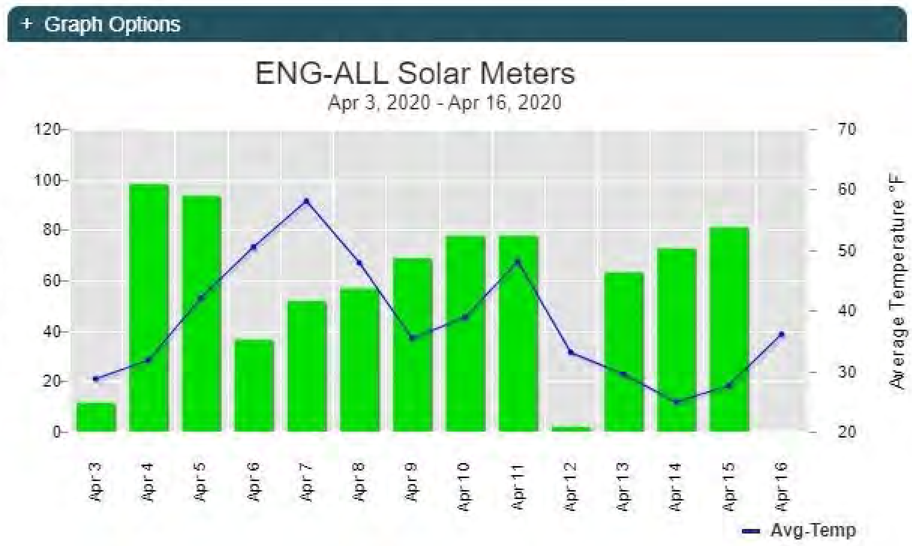
During the winter, typically due to snow cover, the periodic loss of solar output is significant. Figure 30 below shows solar output variability for December 2020 and January 2021. A common weather correlation in Minnesota is that winter snow coincides with the arrival of a cold front. With snow covering the solar panels, the output from the solar generation is limited. Based on Dakota Electric's data review, we observed that the reduction in solar generation coincides with the increase in energy demand associated with the passing cold front. December 23, 2020 is a good example of the loss of solar production with the arrival of a cold front. Through the data provided from its AGi metering, Dakota Electric observed that, during the winter months, there are days where there is a negative correlation between solar generation and higher electrical loads. Dakota Electric will continue to monitor this phenomenon in the future.

Figure 30. Roof Top Solar Output Dec-Jan 2020-2021



Another example of limited generation due to snow fall is shown Figure 31 below. Figure 31 shows solar generation during April 2020 on the Dakota Electric system.[17] The figure shows that with warmer weather, the snow melts off the solar panels much quicker, but the reduction in solar output is still significant.

Figure 31. Roof Top Solar Output April 2020



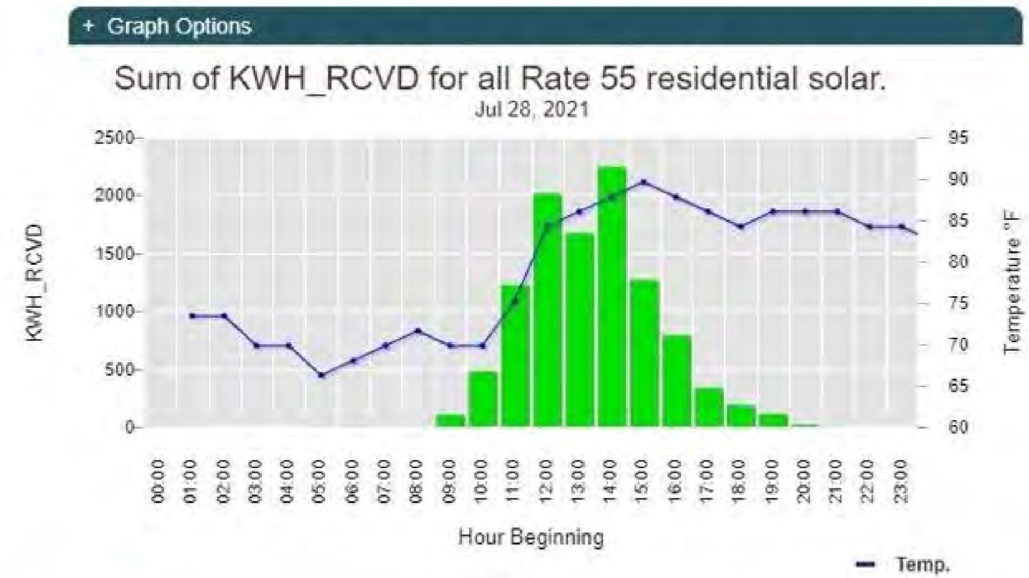
The key takeaway from this information about how solar generation is performing is, what do we need to do to firm up this generation resource? The information provided in this report is intended to identify areas which need to be understood and to provide information, so that ideas can be brought forth to mitigate the issues identified.

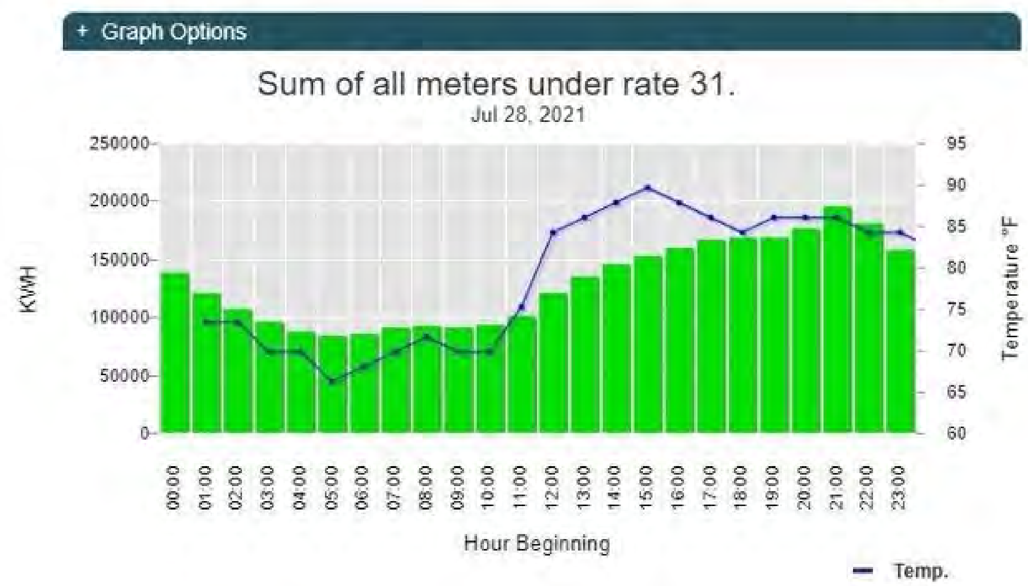
a. Solar Generation Alignment with Distribution System Peak Demands

Solar output is not aligned with peak electrical demands on the Dakota Electric system. Using its AGi metering, Dakota Electric looked at the output from the solar systems which are interconnected to its system. We confirmed that the output from the solar systems do not align with the peak electrical usage on a peak summer day. Looking at Figures 32 & 33 below, Dakota Electric experiences peak demand around 8 or 9 pm and, by that time, even during the summer months, solar output is at or near zero. The expectation was that during the summer, with the longer days, the output from the solar systems would have a reasonable coincidence with Dakota Electric summer peak demands. Unfortunately, there is little to no coincidence with residential usage at this time.

[17] Please note that these data were from 2020 and there are significantly less solar systems included in this virtual meter output than for the winter and summer 2021 figures. The April 2020 chart includes approximately 30 solar systems. All 30 systems were included in the 2021 graphs.

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





Figures 32 & 33 above, show solar output versus the residential electrical usage on July 28, 2021. The data in Figure 32 shows that solar generation began decreasing at 3 pm on this day and by 8 pm it had reached near zero output. On the other hand, electrical demand on the Dakota Electric system, Figure 33, continued growing and did not beginning falling until around 10 pm. The peak demand, shown as the Rate 31 load, was already reduced through the operation of Dakota Electric's load management system. Without this load control, the load values for hours 14:00-20:00 (2:00pm to 8:00pm) would have been even higher. The peak demand, occurring around 9 pm, is the result of the restoration of the loads being controlled by the load management system. As noted earlier in this report, this can be referred to as a rebound peak.

b. Impact of Electric Vehicles and TOU rates

Dakota Electric has been working with our members to support the use and charging of electrical vehicles for many years. It is clear that EVs impact the distribution system if they are all charging at the same time, and it is important to create programs and incentives to management and mitigate these impacts. Since the normal system peak demand for the Dakota Electric distribution system is between 5 pm and 8 pm, the charging of electric vehicles after returning from work will negatively impact the distribution peak and increase the cost of the distribution system required to supply electricity to our members. These additional costs will be borne by more than just members with electric vehicles. Given these concerns, Dakota Electric has created a TOU rate to encourage off-peak charging of EVs, which still allows the member to charge the EV at peak or other times, but the member is also aware that higher rates will occur and that this member will be paying a more appropriate price for electrical use during a peak period.

Since the 2019 IDP Report, Dakota Electric has expanded TOU rates for electric vehicle charging. In early 2021, Dakota Electric proposed TOU charging rates for non-residential members and multi-family residential members. These two offering were approved by the Commission in the Summer of 2021 and are now available to our members. The expansion of these offering will provide additional access to TOU for our members and all Dakota Electric to further promote EV charging in its service territory and manage the continued expansion of electric vehicles.

Below are two Figures (33 & 34) showing hourly energy consumption for EV charging. The figures are for two weeks in August 2021. The EV charging picks up just after 9 PM when the lowest priced off-peak period starts during the weekdays. It is interesting to see that the peak energy consumption occurs 2-3 hours after the start of the lower cost energy, around midnight each evening. It is also interesting that even with all the weekend hours included in the lowest cost energy periods, the EV owners still mostly utilize the weekend overnight period to recharge their EVs.

As more EVs are located within the Dakota Electric service territory, the off-peak windows may need to be reviewed to help soften the sharp rise in energy consumption between 9 pm – midnight. The issue of high consumption from 9-12 midnight is especially a concern on days with full load control as this EV charging would contribute to an overall rebound load control peak

Figure 33. Interval Energy Consumption for EV Charging Aug 15-21 2021

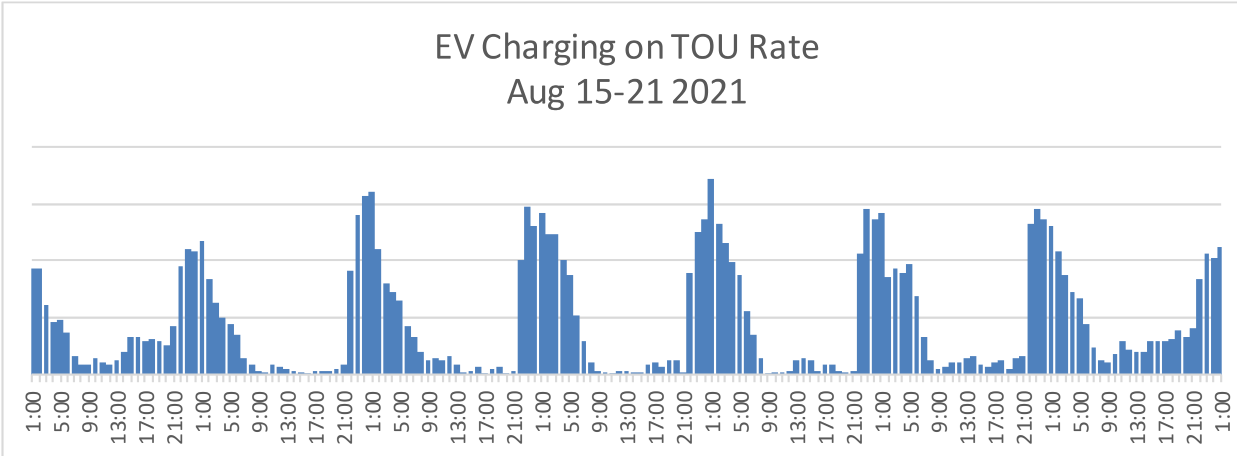
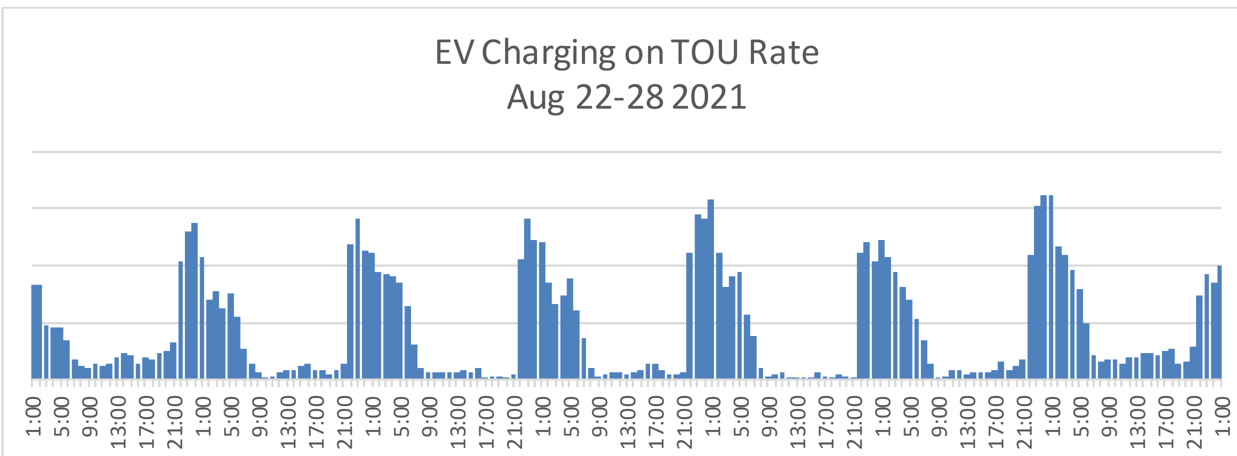


Figure 34. Interval Energy Consumption for EV Charging Aug 22-28 2021



8. Impacts from FERC Order 841 and FERC Order 2222

Section C.4. Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM- 18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators).

FERC order 841 is designed to remove barriers to participation of electric storage resources in the capacity, energy and ancillary service markets operated by the RTO's and ISO's. Dakota Electric as a distribution only utility has not been impacted by FERC order 841. The rules and procedures to support distribution interconnected energy storage to provide transmission grid services have not been developed. For an energy storage device to provide transmission services when interconnected to the distribution system, the energy storage system would need to purchase energy from the distribution system and then resell any energy generated to the distribution system. The energy sales and purchase rates to support grid services from the distribution system have not been established. The interaction between how Dakota Electric is billed for energy and demand from GRE and how a DER supplying grid services is billed for energy and demand while interconnected to the distribution system, would need to be reviewed as part of creating any new power sales or purchase rates.

Since the 2019 IRP report was approved by the Commission, FERC Order 2222 was been released and the implementation of this new order is being developed by working groups within MISO. Dakota Electric, due to its size, is exempt from FERC Order 2222 and, as such, is not expecting to be impacted by this latest FERC order. To the extent possible, Dakota Electric will monitor developments associated with this order so that our members are able to benefit if possible.

9. Limitations and issues with incorporating DER into future planning analysis

Dakota Electric has considered incorporating renewable energy systems into the distribution planning process. Using AGi metering Dakota Electric has learned that present renewable energy systems have limited output which is coincident with the maximum electrical demand. Dakota Electric does take load control into consideration when doing distribution planning. The load control has been shown to be able to reliability provide a reduction in the electrical demand coincident with the periods of peak demand. Dakota Electric has firm control over when the load is shed and when it is restored to being served by the distribution system. This ability to have firm control with a firm resource is critical to being able to reduce the amount of capacity required by the distribution system.

In looking at how DER can be incorporated into the distribution planning process to help reduce distribution spending, two concerns arise:

- Is the DER reliable and always available when needed?
- 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?

DER systems do need to be considered with distribution planning; in that they may result in additional distribution capacity requirements. Distribution planners need to ask the question, does the operation of a DER system hide loads which could be applied on the distribution system after an outage or upon failure of the DER system? If this additional load is not taken into consideration, it could cause, low voltage, overloading and possible damage to member owned and/or distribution equipment? Dakota Electric is utilizing production metering to help understand the amount of load, if any, which is hidden by the operation of the DER systems.

Traditional long-range distribution planning involves identification of electrical problems related to safety, power quality and reliability over a 20-40 year planning horizon. Solutions to the identified electric problems are also evaluated on their merits relating to safety, power quality and reliability, along with consideration of project viability, public opinion and project costs. Incorporating DER adoption into distribution planning should not lower the expected level of safety, power quality and reliability of electricity to Dakota Electric members. Dakota Electric cannot compromise on these core principles.

Distribution planning revolves around capacity needs of the end-user. Capacity is a measurement that occurs instantaneously but in engineering models, is normally incorporated in 15-minute intervals. Dakota Electric routinely models the distribution system at the seasonal peaks to analyze for distribution system problems.

In preparation for its 2021 IDP, Dakota Electric looked at possible scenarios for the DER analysis. The variables considered included the adoption of energy efficiency, load management, member-owned renewable generation and storage systems. Each DER type considered can be used in different ways to lower capacity needs for specific periods of time.

<u>Modeling Behind the Meter Loads – Cold Load Pickup</u>

Dakota Electric knows that as additional DER is added to the system, there will be more behind the meter loads which are not normally supplied by the distribution system. As noted, several times in this report, Dakota Electric already has a significant amount of load which is shed from the distribution system during monthly peak load periods. This load is shed using the load control receivers or SCADA control of member-owned generators. Dakota Electric’s existing planning process accounts for potential impacts on the distribution system if these loads are not controlled. Dakota Electric has multiple systems in place for controlling loads so that failure of one system will result in only a portion of the load being applied to the distribution system.

A significant issue with inverter based DER generation is the loss of energy production by the DER, immediately upon restoration of power after an extended outage. The IEEE Standard 1547-2018 for return to service (enter service) has a delay time where the DER is prohibited from interconnection with, and generating energy, into the distribution system after a prolonged outage. Even without the loss of the DER output, after a prolonged electrical outage, upon re-energization, the electrical demand is naturally greater than before the outage occurred. This is called “cold-load pickup.” There are two main drivers for this traditional increase in electrical demand. The first driver for cold-load pickup demand is from the energization of motors and transformers. The energy in-rush required to magnetize the cores of these devices causes a surge in electrical demand. This is only for a very short time frame, is well understood, and will not be increased by inverter-based generation.

The second driver for cold-load pickup is the loss of diversity of the electrical loads. This is because the electrical loads (*e.g.,* water heaters, electrical heaters, air conditioning units) all restart immediately upon restoration of power, to make up for the heating or cooling which was not possible during the electrical outage. This loss of diversity causes the electrical demand after an outage to be much greater that the electrical demand before the outage. The longer the outage lasts, the higher the level and longer the period of cold-load pickup is. The design of the electrical system must take this into account when sizing the capacity of the electrical equipment, especially the very fast-acting protective equipment like fuses and relays. The loss of DER output during the period immediately after an outage only causes this cold load level to be greater. Also, the addition of energy storage systems could negatively impact the system as these systems could start recharging immediately after an outage and contribute to an increased amount of cold-load pickup.

With the installation and interconnection of inverter based DER generation, the normal / pre-outage load experienced by the distribution system could be reduced by the DER generation. During electrical outages on the distribution systems, many consumers believe that the DER is capability of supplying the household electrical requirements. Most DER systems which are presently being installed shut down during distribution system outages and do not provide outage back-up protection for the consumer. Upon restoration of the distribution system, post outage, the inverter based DER was not and is not generating electricity to offset the electrical load of the member’s home or business. All the household or business electrical demand is placed on top of the traditional cold-load pickup demand and this greatly increases the demand during restoration of the distribution system. If the distribution system, especially the protective elements, was built to accommodate just the pre-outage peak electrical demands experienced during normal operation, and did not account for the electrical demands which can occur after an extended outage, subsequent outages resulting from overloading the distribution system during restoration will occur.

Incorporating energy storage systems of sufficient size and capacity, along with the installation of DER, could help reduce the level of increased demand being placed upon the distribution system as the result of short-to-medium duration electrical outages, if the energy storage is configured to not recharge immediately after power restoration. For short and medium duration power outages, the energy storage system, if properly configured, could keep the air conditioner operating or the refrigerator cooling during these short outages and help reduce the level of cold-load pickup. The problem would still exist for longer duration electrical outages where the capacity of the energy storage system to ride through the electrical outage would be exhausted.

Dakota Electric plans on utilizing production meters with DER generation to provide Dakota Electric with visibility about actual member peak electrical demand which could be placed on the distribution system after an electrical outage. Using information from the new AGi system and the 15-minute interval data from the main service meter, coupled with the production meter, Dakota Electric will be able to calculate the potential peak demand coincident with a feeder's peak demand. Dakota Electric will then also be able to understand the coincidence of behind the meter loads among the services on a feeder. This information can then be included in the engineering models and should help improve the estimates for potential post outage demand levels. With better information engineers would be able reduce the need to include additional safety margins and built in only the extra capacity required to support the system during post outage restoration and the resulting cold load pick up events.

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

1. 5-Year Action Plan

Section D.1. Dakota Electric shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures scenarios, hosting capacity/daytime minimum load data, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (topics and categories listed above). Dakota Electric should include specifics of the 5-year Action Plan investments.

AGi Project - Dakota Electric continues to work on completing the AGi project. In 2021 we are set to complete the exchange of the majority of existing meters. There are some meters which will take longer to exchange as we need to work with the member to resolve meter access issues. The following pictures are some meter exchange access issues we have seen.

Figure 35. Examples of meter access issues

Dakota Electric will work with the members to exchange these more difficult installations, and the goal is to exchange the remaining meters by the end of 2022. The replacement of load control receivers is also going well, and Dakota Electric will continue to replace these devices in 2022 and 2023.

Receiving the full benefits of the AGi project is a major objective for Dakota Electric. In 2022, we are scheduled to make a web-based portal available to our membership. This portal will allow access to the 15-minute interval data being supplied from the member's meter. Beyond this improvement, Dakota Electric will continue to develop ways to use the data provided by the meters and load control receivers to help our membership through improving the quality of their service.

The AGi project will support the following Commissions objectives:

- Improved safety and reliability through the ability of each of the meters to report events, such as high temp in the meter socket or LAST GASP outage notifications;
- Greater customer engagement and empowerment through providing the 15-minute interval usage data to the members and allow them to better understand how they are utilizing electrical energy;
- Support additional options for energy services, through better understanding of how different classes of members are using energy;
- Provides an accessible grid platform to help us develop new products (rates) and new services and adoption of new technologies; and
- Improved efficiencies, optimization, and utilization of the electric grid access and minimize total system costs thought the information provided from the meters and load control devices. The load control devices will alert Dakota Electric to non-functioning devices which are not able to control the loads as intended. The meters will alert us when they malfunction and need to be replaced.

Energy Storage - Dakota Electric is looking at the possibility of utilizing a utility scale energy storage system to support the interconnection of additional DER to one of our transmission limited substations. The project includes an analysis and review of the physical and economic possibility of installing an energy storage system at a substation where the transmission system protective relaying cannot support back feeding of the transmission. If nothing is done, Dakota Electric may need to tell our membership that they cannot add any more DER to specific substations. The physical fix, to allow back feeding of the transmission, requires the construction of a transmission switching substation, which would likely cost between $3-$4 million dollars. The alternative to these two solutions is for Dakota Electric to consider the installation of a utility operated energy storage system. The concept is the energy storage would charge the batteries when the DER is generating sufficient energy to potentially back feed the transmission system. The Battery Energy Storage System (BESS) would then discharge in the evening and at night when the DER is not generating excess energy.

Dakota Electric is in the initial stages of looking at this concept and has yet to develop an economic analysis detailing the cost/benefits of this potential solution. The initial information that we have received is that the cost of this solution is high and is not economic in all situations. Also, with the significant amount of utility scale energy storage projects occurring, the availability of vendors willing to bid on smaller projects such as what is required for Dakota

Electric, is limited. It is also important to note that this solution may result in unintended consequences for our wholesale power supplier GRE which may impact the overall economic viability of this project for Dakota Electric.

Research into energy storage utilization supports the Commissions objectives in the following ways;

- Supports additional options for energy services and empowers the membership to utilize a new technology;
- Helps optimize the utilization of the grid access though the management of distribution peak demands; and
- Enhances the reliability and security and resilience of the energy supply for our membership through back up power supply options.

Electric Vehicles – Dakota Electric is working to resolve issues which limit the ability for members who live in apartments or other places where there are physical limitations for taking advantage of Dakota Electric EV TOU and off-peak rate options. Dakota Electric recently implemented an EV TOU rate specifically for multi-family residential members and continues to work on various options and EV technologies that will provide benefits to all our membership.

The future support of Electric Vehicle adoption will support the Commission's objectives in the following ways;

- Increase options and accessibility for members to utilize EV rates and help provide cost effective options for charging Electric Vehicles;
- Provides increased support for new services and adoption of new technologies; and
- Transitioning additional members to EV TOU and/or off-peak rates will help optimize the utilization of electrical grid assets and resources through the management of peak demands.

Prairie Island Net Zero Project – Dakota Electric continues to work with the Prairie Island Community on their net zero project. There are many components to the plans which the Community has identified to support the reduction in their carbon footprint. Dakota Electric will work with them over the next couple of years to help implement those plans and to work through any issues which may occur. To the extent significant changes or developments occur regarding this project during the 2021 IDP proceeding, Dakota Electric will update the Commission.

Support for the Prairie Island Communities Net Zero Project will also meet the Commissions objectives in the following ways;

- Providing greater customer engagement for the Community through empowerment of member choice and support of options for energy service; and
- Ensure efficient optimized utilization of the electrical grid, through partnering with the Community to ensure the coordination of the design and installation of the renewable energy systems and the resulting reliable operation of the facilities.

Cyber Security – While this is not a physical component of distribution planning, or a field capital project, it is none the less a key focus for Dakota Electric and will be for the foreseeable future. Many of our internal systems must be replaced or upgraded to ensure proper cyber security. Updating just one system can be a large task and entail significant time to accomplish, but, due to the nature of cyber security, many systems require upgrading and, in some cases, full replacement. Dakota Electric's ERP and work order systems are currently in the replacement process phase, and, in a couple of years, the GIS, outage management system (OMS), and SCADA systems need replacement. There are other sub systems and supporting systems which will also need to be upgraded or replaced. These are significant expenditures for Dakota Electric, both in costs for the software and in labor, and it is necessary for us to direct resources to these projects so that our membership is fully protected from cyber-security threats and that our distribution system operates as expected.

Power Supply Transformation – GRE, Dakota Electric's power supplier, is working to transform their core energy supply. By 2025, GRE's power supply is expected to be 60% from renewable or hydro resources. GRE will also add 900 MWs of wind energy by the end of 2023 and remains on track to meet Minnesota 80% carbon dioxide reduction goal ahead of schedule. Although not directly tied to distribution planning, the make-up of our power supply is an important consideration for how we may plan certain distribution programs (*e.g.,* potential solar expansion) and the service expectations of our membership.

2. Overview of Investment Plan

Section D.1.i. Overview of investment plan: scope, timing, and cost recovery mechanism.

All of Dakota Electric initiatives are funded through existing rates except for the AGi project. Dakota Electric continues to implement the AGi project cost recovery tracker and is updated annually. No other special cost recover mechanisms are planned.

3. Grid Architecture Plan

Section D.1.ii. Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.

Dakota Electric continues to implement SCADA monitoring and control on key pieces of distribution equipment. Annually additional reclosers and regulators have SCADA added. The AGi project is replacing all the meters and load control receivers to provide 2-way data flow and is a foundation for supporting future operational needs of the distribution system.

Dakota Electric is beginning to evaluate Advanced Distribution Management Systems (ADMS) and will be working to identify how the existing systems need to be modified to support additional integration of DER to the distribution system. Dakota Electric believes that existing operational systems will be enough to support the operation of the distribution system for the next 5 years and expects that by then ADMS may be needed to provide to operate a more complex distribution system.

4. Alternative Analysis of Investment Proposal

Section D.1.iii. Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.

Based on current operations and performance of the distribution system, Dakota Electric did not complete an alternative analysis of investment proposals.

5. System Interoperability and Communication Strategy

Section D.1.iv. System interoperability and communications strategy.

Dakota Electric's AGi project is the foundation for gathering information about DER operations. Furthermore, the production meter allows us to better understand how the DER is operating and also provides a point of control for operations through use the meter's internal switch.

The use of the NOVA portal for DER applications has provided a method for DER applicants to easily apply for interconnection of DER and support increased communication between Dakota Electric and the DER applicant.

Dakota Electric continues to look at other systems which could be utilized to support additional DER integration. In 2022, Dakota Electric is gathering a team of employees to learn about ADMS systems. The team's focus in 2022 is developing a set of use cases for an ADMS system and a corresponding basic RFP document. As existing systems, such as the GIS and SCADA are replaced or upgraded, Dakota Electric is working to ensure that they will be able to integrate and support an ADMS system. Understanding eventual use cases for an ADMS will help drive the develop of the systems and integration required to support a future ADMS. The expectation is that this effort will also facilitate an efficient transition to a future ADMS.

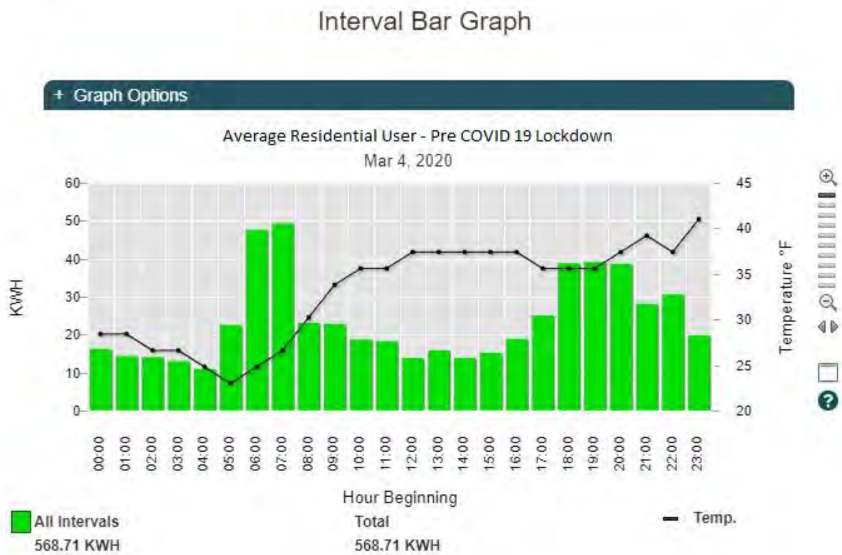
6. Cost and Plans Associated with Obtaining System Data

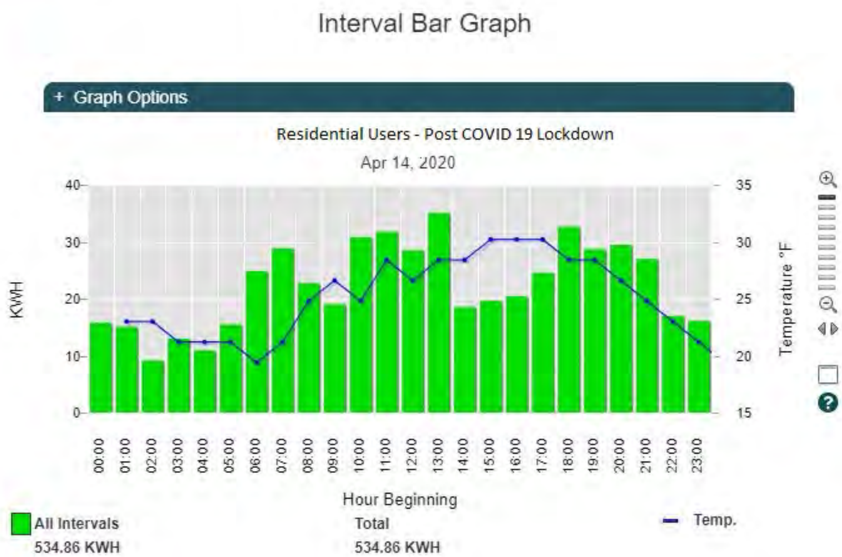
Section D.1.v. Costs and plans associated with obtaining system data (EE load shapes, photovoltaic output profiles with and without battery storage, capacity impacts of demand response combined with EE, EV charging profiles, etc.)

The AGi project includes interval usage data which is stored in a Meter Data Management (MDM) system. Within the MDM, Dakota Electric is able to aggregate energy usage across different types of users and classes of members. As part of AGi project, Dakota Electric is also installing production meters on DER installations. As noted throughout this report, these production meters support the gathering of operational information about energy consumption and generation by the DER systems. Throughout this IDP report, Dakota Electric provided examples of how it is already using the AGi system to obtain load shapes and learn about how DER systems operate and interact with the distribution system. By utilizing these production meters installed on DER generation systems, Dakota Electric is able to understand how best to utilize DER. Dakota Electric is also learning about limitations of DER generation and hopefully finding ways to reduce these limitations. Dakota Electric is optimistic that these data will improve distribution system planning in the future.

In 2020, at the start of the Covid pandemic, Dakota Electric was using the AGi system to see how load shapes for the average residential user was impacted. The first question Dakota Electric attempted to answer was whether the increased number of members working from home would cause an issue for the electrical system. Figure 36 below shows two graphs of daily load profile data. The top graph is for the month before the March 2020 stay-at-home order and the lower graph is for the following month.

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





The load profile data in Figure 36 above, which represents average residential member usage, shows that the stay-at-home order impacted daily loads for these members. Before the order, the average member experienced two peaks per day, one in the morning before work and then another, longer peak in the evening hours after regular work hours. After the stay-at-home order, consumption was generally steady throughout the day with higher overall consumption, especially in the morning hours. This case study illustrates the power of the AGi project, and the ability of Dakota Electric to quickly respond to, and test for, potential impacts to the distribution system.

7. Interplay of Investments with Other Utility Programs

Section D.1.vi. Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)

Dakota Electric's AGi project is a great example of the interplay between systems being implemented and these projects impact on utility programs. The two-way data, which is being reported from the load control receivers, coupled with the metering data, are showing us where there are failures in the system. This data represents a significant potential benefit to our members, and we are using the information to work with our members, when they contact us, to identify potential issues with their service and provide them with ideas about potential causes or even possible solutions.

Once the web-based member portal is available, our members will be able to review their interval usage and possibly identify ways to reduce their energy usage. When members contact member services with questions, Dakota Electric's member services personnel can review the interval usage data with the member and help them identify ideas to save energy. The information available in the member portal will be detailed enough for the member, and our member services personnel, to potentially recommend specific solutions to improve the member's electric service.

8. Customer Anticipated Benefit and Cost

Section D.1.vii. Customer anticipated benefit and cost.

The AGi project is expected to slightly increase the cost to the members over the next few years. The costs associated with the AGi are authorized for recovery through a separate monthly fixed charge rider based on actual costs incurred. This recovery method is appropriate because the costs of AGi meters and load control receivers are new plant investment and their associated costs are not in embedded costs. The Commission approved this recovery method in its Order in Docket No. E111/M-17-821. As part of this approval, the AGi rate is updated each year until the project is complete. Once the project is complete, the AGi rider will remain the same until Dakota Electric's next general rate case, when this rider is expected to end and the cost of the AGi will be rolled into base rates. As the AGi system becomes fully functional, the AGi system is expected to moderate future increases in the cost of delivering electrical services to the members. The savings will result from many process improvements, such as: the reduction in labor costs to read the meters, reduction in trips to resolve high bill issues, or power quality complains as all of these can generally be resolved using data in the office. Furthermore, Dakota Electric notes the following potential savings:

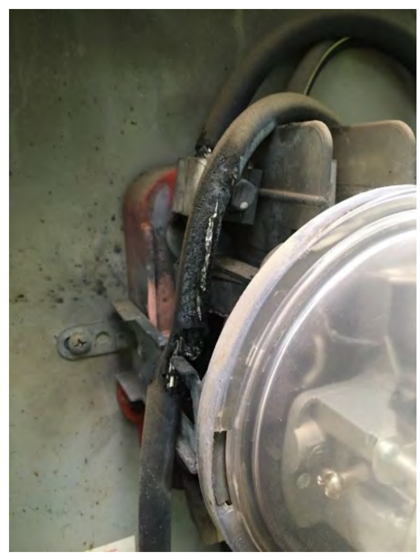
- overtime costs to fix issues that have historically occurred after hours may now be identified ahead of time and fixed during normal business hours;

- identifying non-functioning load control installations and repairing those to obtain the expected power cost savings;
- reductions in labor for billing issues, such as the need to estimate meter readings; and
- identifying metering issues so they do not continue for long periods of time.

Below are some examples including graphs of meter data and pictures of meters where an issue was discovered and fixed as a result of the AGi implementation.

Safety and Reliability - The pictures below are of two different of meters sockets where the wire was being pulled down by the ground sagging below the meter socket. These are an example of items found when replacing the meters. Note how the service wire is being cut and the burning around the wire. This was at least an outage that was saved and possibly a fire was avoided.

Figure 37. Electrical Issues Identified During AGi Meter Replacements



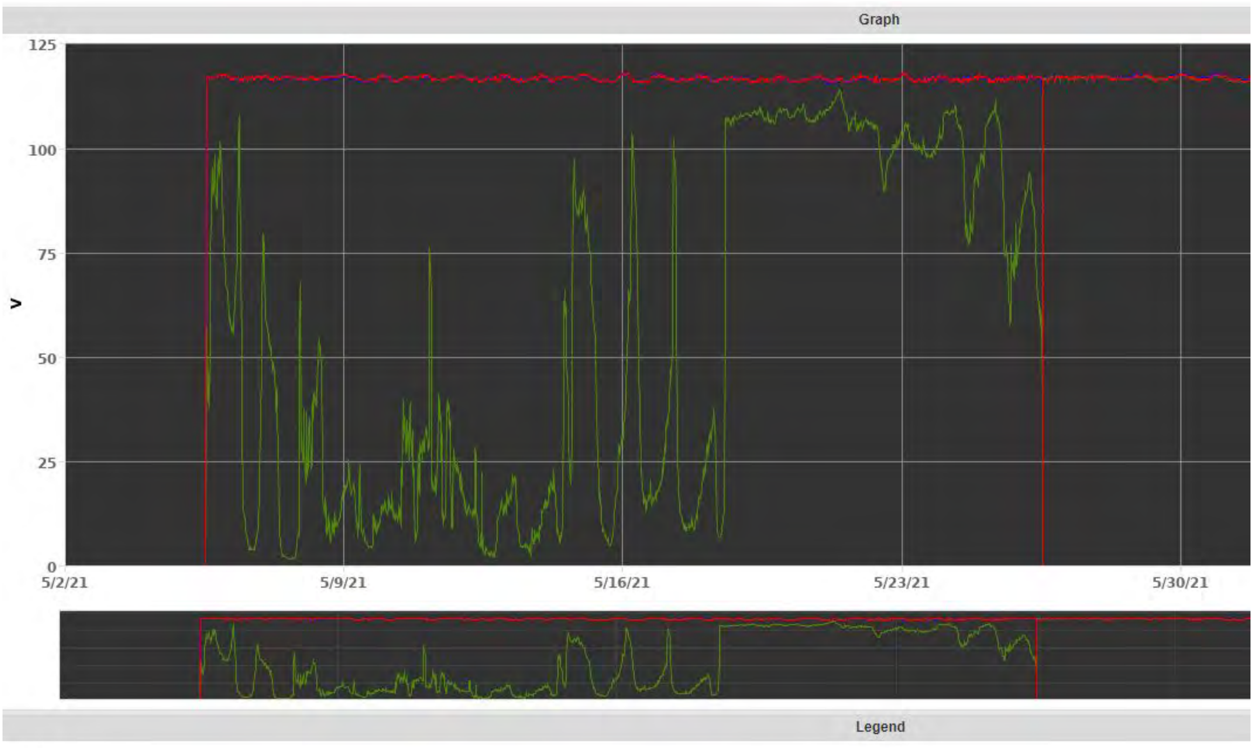
Outage Response - On a more humorous note, there was one meter which stopped communicating to the RF mesh. In response to this issue, Dakota Electric sent a meter tech out to investigate. The tech found the meter in the snow and quickly realized the cause of the metering issue. We are withholding the horse's name, but it looks like the horse is smiling in the picture.

Figure 38. Unique Metering Issue

On a serious note, these pictures help underscore the usefulness and cost savings potential of the AGi system. In the past, Dakota Electric would not have been aware of the outage until a meter reader went out to read the meter. In addition, without the prompt response to the outage notification, our techs may have reinstalled the meter and not realized it was caused by the horse and future issues may have occurred as a result of the horse.

Metering Accuracy Improvements - Below is a voltage graph from a three-phase meter. In this instance, the AGi meter was reporting low voltage on one phase. The issue was identified as a bad connection in the meter socket. Without AGi, this issue could have gone on indefinitely as the business was not seeing any voltage issues. The green line is the phase with intermittent voltage. The graph shows that around May 26, 2021, the metering issue was fixed as there was a short outage to the meter and then after that time all voltages returned to normal.

Figure 39. Graph of Meter Voltage with bad connection on one phase



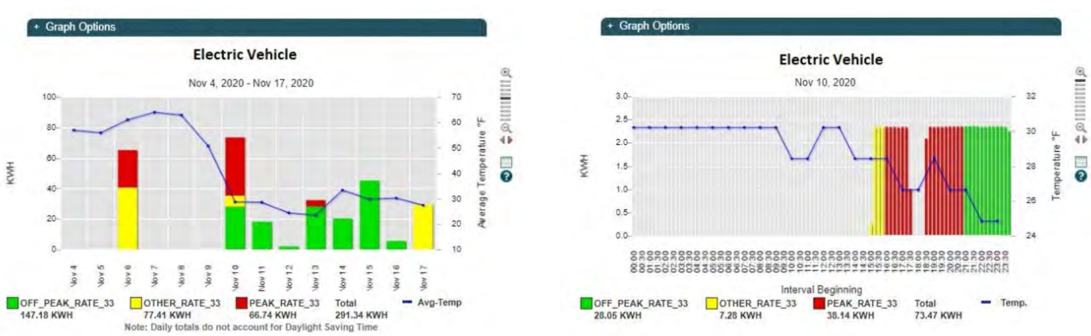
9. Customer Data and Grid Data Management

Section D.1.viii. Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties).

As discussed earlier in the IDP Report, the AGi project includes a member portal where the member may view and utilize information about their energy usage. As outlined in internal Dakota Electric operating guidelines, member energy use is considered private and Dakota Electric will not disclose this information to third parties without the member's permission. The member portal will support members being able to download information and allow the member to use this information or share information about their usage with third parties, if they wish. This ability for members to more readily obtain and share information may be useful to our members when considering DER installations or other electrical improvements. This is possible without the member portal, but it requires a member to contact Dakota Electric directly for the information and obtain a data release. With the member portal, members will be able to access their data directly through the portal.

Dakota Electric will continue to share information with the members about their usage during interactions with the membership. This has always been a regular part of Dakota Electric's relationship with members, but the AGi is significantly more powerful and provides members with more granular data. Figure 40 below is an example of an electric vehicle on the Dakota Electric TOU rate. The red bars show days where the member was charging their vehicle during the highest cost periods. After contacting Dakota Electric, the graph shows that the member was able to shift their charging to lower cost periods of the day. The second graph shows charging over a single day.

Figure 40. Electric Vehicle TOU Usage Example



Dakota Electric will internally use the member's usage to ensure the electrical system has enough capacity to supply the electrical needs of the member and to monitor the quality of the power delivered to the member's service. Dakota Electric will also use aggregated data from many services to aid in distribution planning and for associated reporting and data analysis.

These aggregated usage data may be shared with other entities for business (*e.g.,* GRE) and regulatory purposes. (*e.g.,* the Commission).

10. Plans to Manage Rate or Bill Impacts

Section D.1.ix. Plans to manage rate or bill impacts, if any.

Dakota Electric is a not-for-profit, member-owned utility, consequently any costs incurred by Dakota Electric are paid for by its members. Dakota Electric does not have the option or ability to shift certain costs to shareholders. Dakota Electric is mindful of this and possible rate impacts when looking to the future and potential upgrades associated with EVs and beneficial electrification. Dakota Electric will continue to work on controlling and identifying ways to reduce costs throughout the organization. Dakota Electric will continue to provide ways for the members to reduce their bills through energy efficiency and load management options. The implementation of the AGi project will only enhance the ability of the membership to make informed choices through the use of more information on their energy use. The AGi project also has the potential to manage rate and bill impacts by lower costs in other areas of Dakota Electric's operations.

11. Impacts to Net Present Value of System Costs

Section D.1.x. Impacts to net present value of system costs (in net present value revenue requirements/megawatt/hour or megawatt).

The AGi project is expected to help mitigate future costs for Dakota Electric. The lifetime costs of the AGi project are expected to be offset, in part, by the benefits received. Even if the AGi project was not initiated, Dakota Electric was expecting to spend similar dollars implementing and maintaining old technology. The old technology does not provide the functionality that the AGi project will provide and the old technology could not be leveraged to lower costs for Dakota Electric's membership. For a complete analysis of the economics behind the AGi decision, please reference Docket No. E-111/M-17-821.

12. Cost-Benefit Analysis

Section D.1.xi. For each grid modernization project in its 5-year Action Plan, Dakota Electric should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of the nonquantifiable benefits. Dakota Electric Association shall provide all information to support its analysis.

As discussed in other sections of this report, Dakota Electric is analyzing the possibility of adding a utility scale BESS at, or near, one or more of our substations. The system is being considered for use to support the interconnection of addition DER to a substation that is transmission limited. Dakota Electric is using the process to learn more about utility scale energy storage options and whether this project is feasible and cost effective. If this is the case, then Dakota Electric plans to continue learning about integration and control issues and operational uses and limitations of utility scale energy storage.

The concept is that the battery energy storage system would be charged from excess solar system produced energy that would likely back feed the transmission system. If properly calibrated, the BESS would then discharge during the evening and reduce Dakota Electric's daily demand level for this substation. The idea is the power cost savings, avoided transmission fees, and other potential savings could pay for the installation and operation of the BESS. The operation of the BESS would then allow additional DER to be interconnected with that substation.

No financial analysis of this installation has been completed. Dakota Electric is in the process of obtaining costs for such a system and working to identify potential issues with implementing such a system, before proceeding into a more detailed economic analysis. If this information becomes available during this IDP proceeding, Dakota Electric will provide update data in this record.

13. Status of Existing Pilots or New Opportunities for Grid Modernization

Section D.1.xii. Status of any existing pilots or potential for new opportunities for grid modernization pilots.

In addition to the energy storage system discussed in Section 12 above, Dakota Electric is also working with the Prairie Island Community on their Net-Zero project The Prairie Island Net-Zero project was authorized by the Legislature and will allow the Tribe to reach net zero carbon emissions. Dakota Electric has been working with the Tribe on various solutions and design specifications. Dakota Electric also continues to work closely with the tribe on how we can help facilitate Prairie Island's goals and objectives.

Section E. Non-Wires (Non-Traditional) Alternatives Analysis

1. Distribution System Projects of Significant Cost

Section E.1. Dakota Electric shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two (2) million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.

Dakota Electric has several projects planned for construction over the next 5 years which approach or exceed two million dollars. The following is a brief summary of each of those projects, followed by a more detailed analysis for each of the projects listed.

1) The first project identified for this IDP report is the siting and construction of a new substation near Elko-New Market, Minnesota. This project was reviewed in the 2019 IDP report and below is an updated review of the non-wires solutions versus the construction of a substation near Elko-New Market.

   The Dakota Electric service territory around Elko-New Market is currently supplied by a substation which is several miles north. The existing substation and the feeders connecting the Elko-New Market service area to the substation have a limited amount of spare capacity. The contingency substation, which would be required to supply the electrical needs of the area in the event of failure of the normal substation, is many miles to the east and also has limited capacity to provide energy in the event of a contingency. This area of service territory includes an Interstate 35 interchange which is prime location for economic growth because the surrounding area is open land with city water and sewer available. The service territory is envisioned to have a mix of small and large commercial along with residential development. As the load grows in this area, Dakota Electric will need to provide additional capacity, including feeders, to supply the new development expected for this area. The timing for this growth is unknown because commercial development in the area has been delayed due to the future rebuild of a bridge over I-35 and an interchange. This bridge rebuild has not been scheduled by the state/county and, as such, new commercial is hesitant to build in this area with a potential for some limited freeway access. The load growth could be mostly residential and would then be slowly developed over time or a new larger commercial development could occur at any time and there would be a step change in the load in this area. Dakota Electric's best estimates is a new substation is expected to be required within the next 5 years.

2) The second project being reviewed, is the development and construction of a new substation in southern Lakeville. Lakeville, Minnesota, is one of the fastest growing communities in Minnesota and significant load growth is occurring and expected to continue. This substation is required to provide the electrical energy needed by the new homes and businesses and to provide contingent support for the neighboring substations in case of a transmission line or substation equipment failure. A site which is adjacent to a 115kV transmission line became available at a reasonable cost in 2020 and Dakota Electric decided to move ahead with a substation because the development and resulting electrical growth is increasing faster than we anticipated. This substation was originally planned to be located further south and would have required additional transmission lines. The land which became available does not require additional transmission line construction. The land for the substation has been purchased and permitting for the site with the City of Lakeville has been completed.

   Within this section, we will look at the costs for options which would delay the purchase and installation of the electrical transformers and associated equipment at the site.

2. Basic Requirements for Non-wired Solutions

As we look at non-wired solutions, Dakota Electric must develop a set of requirements for which any solution will provide and support reliable electrical supply for our members. The cost of the solution is not the only variable which must be analyzed. For a non-wired solution to replace the upgrading of a distribution circuit or replace or delay the upgrade or installation a new substation, the non-wired solution would need to provide, at a minimum, the following.

1) <u>Firm energy output when requested.</u> Since most DER systems are intermittent generators of energy, the output from most types of DER may not be available when required. If a DER is to be considered as a non-wire solution, the DER will be required to provide firm energy when requested. Failure to provide firm energy when required will cause power outages to members in that area since the distribution system was not upgraded and is not available to provide that energy.

2) <u>Provide the firm energy for the duration of the need.</u> Each application of a DER on the distribution system will have a need for firm energy output for a duration of time. The duration of time will depend upon the needs of the loads in that area. The use of a DER in place of spending money to add circuits will put the DER system in a critical role of providing firm energy for the duration of the load's energy demand being above the level where the existing distribution system is able to supply.

3) Emergency repair / replacement of failed DER system components. If the DER is used in place of spending money to upgrade the distribution system, it is critical that the DER always be available to provide firm energy service. If a component of the DER fails, this must be repaired in an expeditious manner. Failure to repair, and return the DER to active service, puts all the electrical energy supply to members in that area in jeopardy. Any DER receiving energy credits will be required to agree to a restoration / repair time frame.

4) Enter into a contractual relationship to provide the service of the DER. Dakota Electric needs to provide 24/7 electricity to our membership. As a result, all the distribution system must be designed, and built, so that we have a way to supply electricity in the event of equipment failures. One place where DER systems could provide a benefit is during these contingencies. Upon failure of a portion of the distribution system, the DER would provide energy to an area while the failed equipment is replaced or maintained.

Once a decision is made to forego rebuilding a distribution circuit or adding a new substation, but instead rely upon the DER system(s) to provide electrical energy for a portion of the distribution system, this is a long-term commitment by the DER system(s). The future ability to site a new substation with the associated transmission lines may not be possible. Land availability for siting a substation, and landowner objections to transmission lines, may make it impossible to build in the future. Even adding or replacing circuits involves permitting / routing time considerations, so the DER will be required to make a long-term commitment to maintain the operation of the system.

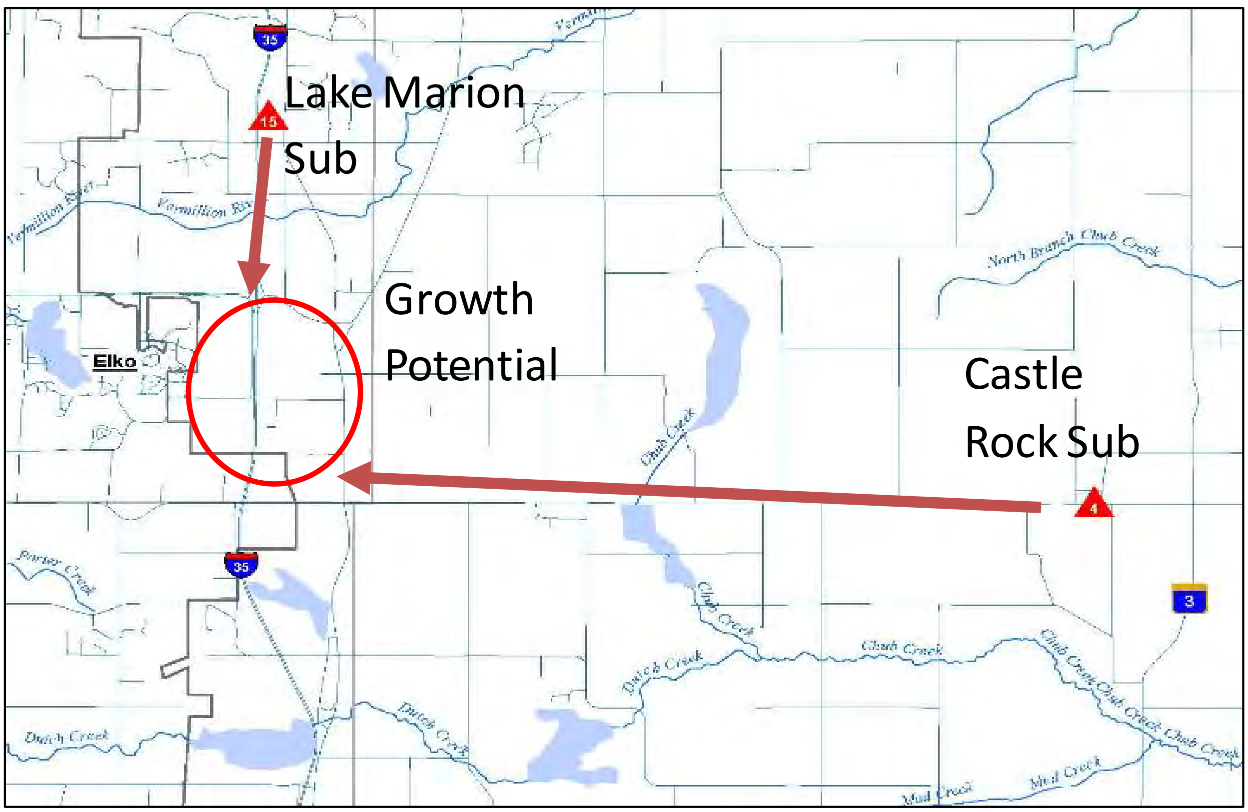
3. Project #1: Siting and Construction of New Substation Near Elko-New Market

This project was initially reviewed Dakota Electric's 2019 IDP report. The review below includes updated costs for non-wired solutions, land prices, and substation equipment costs.

As new residential and commercial buildings are constructed in and around Elko-New Market Minnesota, Dakota Electric will need to provide services to these buildings. The historical method of providing electrical service involves adding new feeders and distribution substation capacity to bring the electrical energy from the transmission system to the new services and growth area. The following analysis assumes that wires within local residential and commercial developments are required to be run to each of the new services and that larger wires, feeders, are required to supply the business and residential developments. This cost of local wires to each home, connected to main feeders, is assumed to be the same and required for all the solutions analyzed. As a result of this, the cost for these wires and distribution transformers are not included in any of the scenarios. The analysis looks at the unique costs associated with each option available to Dakota Electric for providing a reliable source of electrical energy to the circuits supplying the businesses and homes.

As shown in Figure 41 below, there is an area east of the city of Elko-New Market which has high growth potential. This area is presently supplied Dakota Electric's existing Lake Marion Substation (Lake Marion), located a few miles north of this area. Lake Marion currently has some capacity to supply new loads in this area, but, at some point, there will need to be more capacity added in the area to supply the growing load. The option of adding more feeders coming from Lake Marion, along with increasing the Lake Marion capacity, was considered. After reviewing this solution, Dakota Electric concluded that it is not feasible because it does not provide a method to supply this area if the Lake Marion substation is lost. If Lake Marion goes down, the remaining Castle Rock substation would be unable to supply the area.

Figure 41. Growth Potential of Lake Marion - Castle Rock Area



Since simply adding additional feeders from Lake Marion is not feasible, Dakota Electric must consider other solutions to serve load growth in the Elko-New Market areas.

<u>Load Growth Assumptions for the Comparison of the Options</u>

It is unknown how fast new load will be required to be serve this area. Large commercial growth is currently delayed because the local bridge over I-35 requires rebuilding / expansion. During the time this bridge is replaced, local freeway access will be limited, and the nearest freeway access is several miles away. With these pending construction and traffic flow disruptions, Dakota Electric is aware that immediate large commercial construction in this area is less likely; however, once the freeway access is improved, this area is well situation for residential and commercial growth.

If the freeway access question is not resolved, the load in this area is expected to grow slowly as new business and residential developments are built. However, once the freeway access is resolved, there is a real possibility that one or two larger, megawatt sized electrical loads could quickly develop. In light of the potential for significant new load, it is necessary that any solutions before this area are flexible to respond to and meet unknown future load growth.

For the following analysis, there were two load growth scenarios developed. One assumes slower load growth and the other represents a faster growth scenario. As noted above, Dakota Electric believes either scenario is possible. Table 20 below shows the peak load demand values that each load growth option would need to supply.

Table 20. Growth Scenarios for Lake Marion – Castle Rock Area

Analysis Year	Slow Growth	Faster Growth
Year 1	1 MW	2 MW
Year 3	1.5 MW	4 MW
Year 5	2 MW	8 MW
Year 10	5 MW	12 MW
Year 15	10 MW	15 MW
Year 20	15 MW	20 MW
Year 30	25 MW	30 MW
Year 40	30 MW	40 MW

The following potential wired and non-wired options were identified for a high-level review.

1A. <u>Traditional Solution</u> - Permitting and constructing a new 115kV substation capable of providing 25 MVA of capacity and be able to easily expand that capacity as required in the future.

1B. Energy Storage only - Permitting and developing a substation site, which is ready for future substation construction, but install an energy storage system (ESS) to defer the substation construction costs.

1C. Energy Storage plus Solar - Build a solar system to generate the energy and an associated energy storage system to provide 24/7 energy and deferring the substation construction for a longer period of time then Option B.

1D. Demand Side Management - Installation of demand-side management to defer the substation construction for a few years.

Summary of Assumption and Costs

Below is an estimate of the various cost considerations, regardless of option, that Dakota Electric included in its analysis. The analysis is a high-level (not detailed) study of benefits, costs, and risks to evaluate the relative benefits & costs of the different options

- Land costs in the area are very expensive
    - $400,000 per acre for 5 acres or less of land
    - $ 50,000 per acre for purchasing large amounts of land
- $400,000 to permit and develop a substation site (*e.g.,* grading, roads)
- $1,000,000 For a 115kV to 12.5kV substation transformer.
- $600,000 for a substation switchgear.
- $500,000 for construction of a substation (*e.g.,* grading, fence, high side, foundations, ground grid).
- $250,000 for construction to double end an existing substation.
- $500,000 for connection to the transmission line.
- 4% annual interest rate for Net Present Value Calculations.
- Energy Storage System Costs.[18]
    - $1000 Per kW for energy storage infrastructure.
    - $500 Per kWhr for energy storage capacity.
    - 10% round trip energy losses.
    - 10 years useful life for energy storage before refurbishing.
    - $10 / kW for ESS annual operating costs.

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[18] The costs for the energy storage were derived from the EIA August 2021 Energy Storage report. "Battery Storage in the United States: An Update on Market Trends." https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

  - Energy storage operation is 80% coincident with Dakota Electric monthly peak.
- Solar Installation Costs
  - $1,800 per kW for solar system installation.
  - 8 acres of land per MW.
  - 1,400 MWHR annual production per MW of solar installation.
  - All solar generation offsets the cost of higher cost on-peak energy.

Option 1A – Building a New 115 kV Substation

A new substation would require the purchase of a 3-4-acre site of land, permitting, development of the site, interconnection with the transmission system and the purchase and installation of the substation equipment. Building the substation would meet all the reliability criteria. The initial substation capacity would be at least 25 MW and the analysis includes doubling the capacity of the substation at 25 years to 50 MWs. The cost of land in the area is relatively expensive as this is an area with a high potential for development. Since this is using existing methods, Dakota Electric has spare equipment available to replace any failed equipment. All the Dakota Electric field technicians and line crews are fully trained to operate this standard equipment under both normal and abnormal conditions. The Dakota Electric crews can quickly repair or replace any equipment used for this option.

The following is the cost for both the slow growth and the fast growth scenarios as the same substation will satisfy both growth scenarios. Comparing these substation costs to the 2019 IDP report, you will see the cost of the substation transformer has doubled. This is due to limited production capacity and the current cost of metals, such as copper. Other substation costs also increased to reflect current costs.

Table 21. Option 1A - Building a New 115 kV Substation Cost Estimates

Project Year	Description	Cost 2021 Dollars	Present Value @ 4% Rate
Year 1	Acquire Land (3-4 acres)	$1,600,000	$1,600,000
	Permitting and Development of the Site	$400,000	$400,000
	Substation Transformer	$1,000,000	$1,000,000
	Switchgear	$600,000	$600,000
	Transmission Interconnection	$500,000	$500,000
	Substation Construction / Misc Equip.	$500,000	$500,000
Year 25	Increase the Substation Capacity		
	Substation Transformer	$1,000,000	$375,117
	Switchgear	$600,000	$225,070
	Substation Construction	$250,000	$93,779
	Total Cost	**$6,450,000**	**$5,293,966**

<u>Option 1B – Deferring Building a New Substation Using Energy Storage</u>

This option is to develop a substation site, to be ready for construction of the substation when required, but to defer the purchasing and installation of the substation transformer, switchgear, and transmission interconnection for a few years through the use of an energy storage system (ESS) to supply the daily peak loads. The assumption is the existing feeders, which are supplying the area from the adjacent substations, have enough spare capacity during every evening so the ESS can be recharged each night to be ready to supply the peak load the next day.

A key assumption of this option is the ESS can be charged from the grid each evening and then have sufficient capacity to augment the existing feeders from the neighboring substations. This assumption requires the new loads to have very low evening and overnight demand to allow the ESS to be recharged from neighboring substations. The ESS will also need to be able to cycle daily, which is known to be hard on the battery and reduces the life of the ESS. Dakota Electric also assumed that in the event a neighboring substation is lost, there is enough existing redundancy and capacity in the existing system to allow the energy storage device to be recharged during the evening and overnight hours.

The 10% loss of energy with the charging and discharging of the ESS is assumed. Suppliers of ESS have informed Dakota Electric that they will guarantee a maximum of 15% energy losses and over time that can grow to 20% energy losses due to the charging and discharging of the ESS. As such Dakota Electric notes that it used a less conservative value of 10% energy losses in this analysis.

Since the load to be supplied by this device has not been built, the required capacity (MWHr) of the energy storage is unknown. For this high-level analysis, Dakota Electric assumed that new load would be similar to a typical residential member. Using this assumption, the load would peak during the morning and evenings with decreased electrical demand during the day. The energy storage system would need to be sized to supply the peaks that are above the existing system capability. This electrical energy would need to be supplied for many hours on most days of the year. If a commercial load was the driving force for the new capacity, that may require an even greater energy capacity then was estimated for this high-level analysis.

Dakota Electric assumed that this option could defer substation equipment costs for 7 years. This option also assumes the energy storage continues to operate for the remaining life of the system, 10 years, and provides energy arbitrage and power supply demand reduction benefits during this time.

Dakota Electric also considered additional potential benefits in its review of the ESS. This analysis credits the ESS for reducing 80% of the peak demand charges over traditional power supply options. The analysis also gives credit to the ESS for charging the system using low cost, off-peak energy and then releasing the energy during on-peak hours. These benefits are partially offset by the round-trip energy losses of the ESS through charging and discharging. For the analysis, the ESS was assumed to last for 10 years. No addition costs for renewing the batteries were included within those 10 years. At the end of 10 years, the battery system was retired.

Table 22. Option 1B - Estimate Cost for Slow Growth of Load

Project Year	Description	Cost 2021 Dollars	Present Value @ 4% Rate
Year 1	Acquire Land (3-4 acres)	$1,600,000	$1,600,000
	Permitting and Development of the Site	$400,000	$400,000
	Energy Storage (2 MW - 18 MWHr)	$11,000,000	$11,000,000
Year 7	Substation Transformer	$1,000,000	$759,918
	Switchgear	$600,000	$455,951
	Substation Construction / Misc Equip	$500,000	$379,959
	Transmission Interconnection	$500,000	$379,959
Year 25	Increase the Substation Capacity		
	Substation Transformer	$1,000,000	$375,117
	Switchgear	$600,000	$225,070
	Substation Construction / Misc Equip	$500,000	$187,558
	Transmission Interconnection	$500,000	$187,558
	ESS Demand benefits minus Annual Operational Costs	-$3,967,880	-$3,218,306
	Total Cost	**$14,232,120**	**$12,732,784**

The fast-growth scenario assumes a second energy storage system would need to be added in Year 3 to double the capacity of the energy storage system. In addition, the fast growth scenario also assumes that the deferral of the substation equipment expenses would only be for five years. This also assumes the NPV for the capital costs of the second ESS is less than the first ESS.

Table 23. Option 1B - Estimate Cost for Fast Growth of the Load

Project Year	Description	Cost 2021 Dollars	Present Value @ 4% Rate
Year 1	Acquire Land (3-4 acres)	$1,600,000	$1,600,000
	Permitting and Development of the Site	$400,000	$400,000
	Energy Storage (2 MW - 18 MWHr)	$11,000,000	$11,000,000
Year 3	Add Energy Storage Capacity		
	additional (2MW - 18 MWHR)	$11,000,000	$9,778,960
Year 5	Build the substation		
	Substation Transformer	$1,000,000	$821,927
	Switchgear	$600,000	$493,156
	Substation Construction / Misc Equip	$500,000	$410,964
	Transmission Interconnection	$500,000	$410,964
Year 25	Increase the Substation Capacity		
	Substation Transformer	$1,000,000	$375,117
	Switchgear	$600,000	$225,070
	Substation Construction / Misc Equip	$500,000	$187,558
	Transmission Interconnection	$500,000	$187,558
First ESS	ESS Demand benefits minus operational costs	-$3,967,880	-$3,218,306
Second ESS	ESS Demand benefits minus operational costs	-$3,967,880	-$2,975,505
	Total Cost	**$21,264,240**	**$19,697,463**

Option 1B requires the energy storage system to have the capacity to carry the energy demand that is above the existing infrastructure capacity for most of the day, every day. For this option, under both growth scenarios, the amount of energy which could be unserved by the existing infrastructure could be large. Given this fact, the energy capacity requirements of the ESS are significant and increases the overall cost of this option. For the high-level estimates, detailed analysis of the load duration curves versus energy storage sizing was not considered. The NPV cost differences between the traditional solution (Option 1A) at $5.29 million and the lowest cost Option 1B scenario at $12.7 million are sufficiently large that additional detailed analysis of Option 1B was not warranted.

In addition to the much higher costs of Option 1B, this option also has significant reliability and resiliency risks over traditional substation construction. There are significant risks when relying on the ESS to supply a large amount of energy which could not be supplied by the existing infrastructure. The following are the two main risks associated with not being able to reliability supply load.

- Failure of the ESS – The repair time for replacing a failed component within the ESS is unknown. Are there spare components available within hours or will some of members in the area go without power for an extended period of time until replacement components are available?

- The ESS must have existing electrical infrastructure available every night to allow recharging of the ESS. Without the existing wires and adjacent substations, the ESS cannot recharge for future service. Since the existing infrastructure is not always available, due to storms and other failures, the risk of not being able to recharge the energy storage system is significant and tangible.

<u>Option 1C – Deferring a New Substation by Building a Solar System coupled with Energy Storage</u>

This option involves construction of a solar energy system to provide energy to meet the energy requirement of the new loads which are connected in the area in combination with an energy storage system to provide energy during times when the solar is unavailable. This option helps remove the risk of the adjacent substations and feeders not being available to recharge the energy storage system, but it adds significant costs. The original plan was to use the energy produced by the solar system and the ride-through capability of the ESS, to completely eliminate the construction of the substation. However, as the energy and demand amounts continued to increase, the overall costs of this option escalated, especially for the fast growth scenario. As such, the option to delay the construction of the substation to a future year was added to help cap the overall cost of this option.

As with Option 1B, the sizing of the ESS is difficult as the load profiles of potential new loads are unknown and will remain as such until they are constructed, or near completion. High-level assumptions were made for the energy and capacity requirements associated with these new loads. The energy storage will need to be sized to supply the energy requirements of the loads during evenings and periods when the solar panels are unable to produce energy, such as when they are covered with snow, or there is extended cloud cover. Given these disruptive events, the energy storage must be flexible and able to quickly add more capacity. In addition, both the solar and energy storage will need significant spare capacity available to serve new loads.

Assumptions

- The solar system will last for 30 years without refurbishment.
- Energy storage sizing:
    - Able to supply 50% of the peak load for 6 hours daily, also a portion of the local load for 10 hours each evening, since the solar production will not be possible during the nighttime hours.
    - ESS must be sized to supply 90% of the load for at least two consecutive days because of loss of solar production due to events such as snow or cloud cover.
- The production from the solar system is assumed to be produced on-peak and the costs are credited that full value.
- The Energy Storage reduces power supply demand charges by 90%.

The following are the costs to supply the slow growth scenario.

Table 24. Option 1C – Estimate Cost for Slow Growth Scenario

Project Year	Description	Cost 2021 Dollars	Present Value @ 4% Rate
Year 1	Acquire Land (80 acres – Solar Farm)		
	Enough for 30 years capacity	$4,000,000	$4,000,000
	Build 2 MW's of Solar	$3,600,000	$3,600,000
	Energy Storage (2 MW - 18 MWHr)	$11,000,000	$11,000,000
Year 10	Build 3 MW's of Solar	$5,400,000	$4,438,406
	Energy Storage (3 MW - 18 MWHr)	$13,000,000	$10,685,052
Year 15	Build Substation		
	Use land purchased for Substation	$0	$0
	Development of the Site	$400,000	$222,106
	Substation Transformer	$1,000,000	$555,265
	Switchgear	$600,000	$333,159
	Substation Construction / Misc Equip	$500,000	$277,632
	Transmission Interconnection	$500,000	$277,632
	Solar Energy Production Benefits	-$13,776,000	-$7,185,267
ESS #1	ESS Demand benefits - operational costs	-$4,666,848	-$3,649,893
ESS #2	ESS Demand benefits - operational costs	-$4,666,848	-$3,649,893
	Total Cost	**$18,445,920**	**$19,440,164**

For this scenario, the present value costs are higher than the total costs, which is much different than for the other scenarios. This is due to the benefits occurring annually during the life of the project. When adding up the total benefits, absent depreciation, the total amount of benefits is a much greater value. When present value of these benefits is calculated, they are significantly reduced.

The following are the costs for the fast growth scenario.

Table 25. Option 1C - Estimate Cost or Fast Growth Scenario

Project Year	Description	Cost 2021 Dollars	Present Value @ 4% Rate
Year 1	Acquire Land (120 acres)		
	Enough for 30 years capacity	$4,000,000	$4,000,000
	Build 2 MW's of Solar	$3,600,000	$3,600,000
	Energy Storage (2 MW - 18 MWHr)	$11,000,000	$11,000,000
Year 3	Build 2 MW's of Solar	$3,600,000	$3,200,387
	Add Energy Storage (2 MW - 18 MWHr)	$11,000,000	$9,778,960
Year 5	Build 4 MW's of Solar	$7,200,000	$5,917,875
	Energy Storage (4 MW - 20 MWHr)	$14,000,000	$11,506,979
Year 10	Build Substation		
	Use land purchased for Substation	$0	$0
	Development of the Site	$400,000	$222,106
	Substation Transformer	$1,000,000	$555,265
	Switchgear	$600,000	$333,159
	Substation Construction / Misc Equip	$500,000	$277,632
	Transmission Interconnection	$500,000	$277,632
	Solar Energy Production Benefits	-$24,640,000	-$13,444,984
ESS #1	ESS Demand benefits - operational costs	-$3,889,040	-$3,154,360
ESS #2	ESS Demand benefits - operational costs	-$3,889,040	-$2,916,383
	Total Cost	**$24,981,920**	**$31,154,269**

Overall, Option 1C is much like Option 1B because the energy capacity requirements are unknown for any new loads which will request electrical service from Dakota Electric. Therefore, a large amount of extra energy generation and storage capacity is required to allow enough reserve for supplying the electrical requirements of the loads. The energy storage system capacity amounts used for this option could easily be greater than what was used for the analysis. Dakota Electric is also concerned about what would happen if the solar system's output was limited for longer than a day or two. This is not an unlikely scenario because storms could damage panels requiring weeks or months to repair. If this scenario occurred, there are no options to supply energy to the homes and business in this area because there is no energy available for delivery to the area. The only solution would be for these members to procure their own backup generators or be disconnected for periods of time and experience rotating blackouts.

As noted above, the traditional solution (Option 1A) is $5.2 million dollars in present dollars compared to $19.4 million (slow growth) and $31 million (fast growth) for the non-wire solution. The traditional wires solution is also able to be repaired in a short time frame with standard equipment which is warehoused by Dakota Electric and others. For these reasons, the traditional solution was selected.

Option 1D – Deferring New Substation with Demand-side Management

This option would require Dakota Electric to work with new and existing loads to identify enough new load management to effectively reduce the system peak demands during times when the load in the area is greater than the existing infrastructure's capabilities. This would require developing new load management programs and, most importantly, the cooperation of many new and existing members to allow the control of the loads in their homes and businesses.

Assumptions

- The cost of incentives for members to accept load management is a high-level estimate. Based upon Dakota Electric's experience with load management, it is possible to get members to sign up for load management if communicating to all members across a large area. When the need is specific to a targeted area and specific to members during a short time period, such as 1 year, there must be additional incentives applied to motivate the members to sign up. This analysis assumes that it will cost $150 per kW to get members to sign up for a specific load management control program.
- There is enough load that can be identified for the load management programs to allow this option to occur.
- A combination of traditional load management using load control receivers and behind the meter energy storage is used to achieve the amount of controllable load.
- Cost per kW to install receiver-based load control is $250/kW.
- Cost to provide maintenance for the behind the meter ESS is $100/kW/year.
- Cost per kW to install behind the meter energy storage is $1,200/kW (assuming 4 kWhr per kW).

Over the past few years, due to very high demand, Tesla and others have continued to increase the cost of smaller behind the meter energy storage systems. For example, costs of over $4,000/kW have been reported.[19] These costs include actual installation costs in homes in Minnesota. Within this same report, Dakota Electric observed that the round-trip energy losses for the battery system were 30%, which is much greater than projected. The report also noted that the physical size of the batteries was much larger than anticipated by the consumers compared to the expectation of sleek, wall mounted units.

The cost of a Tesla Powerwall is listed as $8,500 without installation.[20] Dakota Electric reviewed installation costs and observed costs in the range of $12,000 to $16,500 for a 5kW 13.5kwhr system.[21] In its analysis, Dakota Electric assumes that the energy storage can output its capacity for 4 hours. Therefore, 13.5kWhr divided by 4 results in a 3.375 kW unit. As such, taking the lower $12,000 installation cost estimate results in $3,582 / kW for installed costs. Dakota Electric used a much lower cost of $2,000 / kW installed estimate for this analysis.

The following costs assume slow growth. 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. Since load control can only reduce loads for a maximum of 4-6 hours of each day, the high loads on the remaining hours could not be controlled making the solution not viable.

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[19] 2021 NRECA Battery Energy Storage Use Cases. https://www.cooperative.com/programs-services/bts/Documents/Reports/Battery-Energy-Storage-Use-Cases-January-2021.pdf.
[20] https://www.tesla.com/energy/design.
[21] https://www.energysage.com.

Table 26. Option 1D - Cost Estimate for Slow Growth Scenario

Project Year	Description	Cost 2021 Dollars	Present Value @ 4% Rate
Year 1	Cost of Incentives for Members	$300,000	$300,000
Year 1	Cost of Energy Storage Systems (500kW)	$1,000,000	$1,000,000
Year 2	Cost of Energy Storage Systems (500kW)	$1,000,000	$961,538
Year 3	Cost of Energy Storage Systems (500kW)	$1,000,000	$924,556
Year 1	Cost of receiver controls (500kW)	$200,000	$200,000
Year 5	Acquire Land (3-4 acres)	$1,600,000	$1,315,083
	Permitting and Development of the Site	$400,000	$328,771
	Substation Transformer	$1,000,000	$821,927
	Switchgear	$600,000	$493,156
	Substation Construction / Misc Equip	$500,000	$410,964
	Transmission Interconnection	$500,000	$410,964
Year 25	Increase the Substation Capacity		
	Substation Transformer	$1,000,000	$375,117
	Switchgear	$600,000	$225,070
	Substation Construction / Misc Equip	$500,000	$187,558
	Power Supply / Monthly Demand Reduction Benefit - Operating $	-$2,323,000	-$1,803,560
	Total Cost	**$7,877,000**	**$6,151,144**

One of the major differences between this Option (1D) and Options 1B and 1C is that the load management and energy storage systems are sized closer to the actual loads as they are added to the system. Since the load management is installed at the member's home or business, the overall cost of the energy storage is lower. However, a negative issue with this option, is that Dakota Electric cannot prebuild the energy storage to ensure that there is active energy storage installed before the load level on the existing infrastructure grows above the available capacity level. This option assumes many individuals will allow the installation of energy storage in their home. This also assumes that all loads which can be controlled are controlled with the installation of a load control receiver. Any installation of residential ESS or the application of a load control receiver must wait for the load to be built and then convince the member to install load management or energy storage. Given these facts, there is a risk of non-supply to members.

The following are some of the issues which would need to be resolved for the application of this option.

- With energy storage being installed behind-the-meter, there will be energy losses which will be recorded on the member's electrical usage. Actual energy losses have been reported to be as high as 30% with behind the meter energy storage.[22] Will the utility need to compensate members for these energy losses? The energy storage system would be designed to charge during off-peak hours and the ESS could be sub-metered to support the member being charged the off-peak rate for any energy used to charge the ESS. The energy stored in the ESS would then be released during the on-peak hours and hopefully the rate difference is greater than the energy losses. If this process was used there may be an additional net benefit for the member.

- The ESS could be used by the member for outage protection, which would be an additional benefit for the member, but there will need to be a control setting or system to ensure the ESS would not immediately recharge after a power outage and cause a demand on the system which is higher than the system can supply.

- If the ESS was discharged due to an evening or overnight outage, would the ESS be available to support the system the next day, during the daily peak demand?

- Other cost issues arise with BTM energy storage revolving around obtaining access into the member's home to maintain energy storage systems including access to member homes and businesses which typically requires scheduled afterhours visit.

- In time the battery system would need replacement. Costs for maintenance have been included, but no costs for replacement have been included in the analysis. The assumption is the system would work to defer the construction of the substation and not be replaced when it fails. The expected life is 10 years. What would the member think about Dakota Electric providing this system and then not maintaining it when it fails?

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[22] NRECA Business Technology Report – January 2021 "The Value of Battery Energy Storage for Electric Cooperatives" Page 9.

- If Dakota Electric provided ESS systems, with energy cost reduction and outage protection for members in a small geographical portion of the system, what would the other members served by the rest of the system respond to Dakota Electric spending money to install ESS and they do not have that same option?

Option 1D is interesting because the NPV cost of the traditional substation (Option 1A) is not much lower in cost, $5.29 million versus $6.15 million, than this option. However, this option involves a higher risk of non-supply versus a traditional substation. Since the ESS is dispersed among many homes and businesses, a single failure of an individual ESS would not eliminate the entire ESS system. A major risk associated with this option is from the inability to convince members to allow the installation of the ESS on their premise.

The fatal flaw in this option, as with option 1B, is the ESS would need to be able to recharge each night to be ready to reduce the next day's daily peak load. If a neighboring substation is out of service due to equipment failure, the existing circuits coming from the remaining neighboring substation would not have enough capacity to supply the loads and also recharge the ESS.

As this option is designed, each ESS has 4 hours of capacity stored, thus the ESS would not have enough capacity to supply the load in the area for a long enough duration to support the area during a contingency like the loss of a neighboring substation. Even with these fatal flaws, the benefits of energy storage, especially energy storage coupled with solar should continue to be analyzed. Dakota Electric, in concert with GRE, continues to look at ways to support the installation of behind the meter energy storage. Given the issues identified, this solution may not be able to target specific portions of the system. However, these storage options could make sense if applied across the entire Dakota Electric service territory to help reduce system peak demands. It may also be helpful for smoothing out transitions in the amount of overall power supply needs. As more solar is interconnected with the system, is there a way that ESS could be used to help smooth out operating issues, such as the duck curve, which occur with higher penetrations of solar interconnections.

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

As new residential and commercial buildings are constructed in Lakeville, Minnesota, Dakota Electric will need to provide electrical service to these buildings. The historical method of providing electrical service involves adding new feeders and distribution substation capacity to bring the electrical energy from the transmission system to services. The following analysis assumes that wires within local residential and commercial developments are required to be run to each of the new services and that larger wires, feeders would be required to supply the business and residential developments. Dakota Electric uses that same cost assumptions for Project #2 that it did for Project #1 discussed in in the previous section.

When one observes this substation versus Project #1, the possible options and costs are similar. The required load levels for this substation in southern Lakeville would be higher, which would make the options with Energy Storage even more expensive. However, this issue does not raise the cost for a traditional substation. All else being equal, one would expect the cost spread between the traditional substation option and the ESS options to increase.

In addition, the cost of land within the City of Lakeville is much higher than near Elko-New Market. Dakota Electric recently purchased a smaller 2-3-acre lot for a new substation at a reasonable cost and is a reasonable proxy for Project #2 land costs. However, the costs to purchase a piece of land to site a large solar project is cost prohibitive in the Lakeville area. Furthermore, it is unknown whether there will be permitting issues with siting a large solar farm within Lakeville city limits. As such, we expect the cost of ESS plus solar to be more expensive and prone to additional risks versus a traditional substation.

The ESS / load management option would require time to develop and with continued strong residential development in the Lakeville area, there is likely insufficient time to develop such a program to defer the initial substation installation. However, Dakota Electric is starting the process with its wholesale power supplier, GRE, to look at and develop programs to encourage and utilize behind the meter energy storage programs. Hopefully this combination of energy storage and solar systems will help reduce the overall peak demands on the system.

5. Project Types That Lend Themselves to Non-Traditional Solutions

Section E.2.i. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability).

Dakota Electric has found that demand side management or load management have the greatest potential to lend themselves to a non-wire solution. However, for these methods to achieve a non-wires solution, the area associated with these solutions needs to be geographically large and include a significant number of services. This area has to be sufficiently large because the ability to engage with a large enough amount of load to place under control requires a large amount of potential services. The take-rate for demand side management is far less than 100% and, in the long-term, there is appreciable attrition within the loads being controlled; in other words, not every member who signs up for demand side management will remain on the program.

It is unfortunate that a large amount of diverse solar installations does not provide a firm electrical supply and are not able to be used to help offset distribution facilities. The previous expectation was that if there were enough member owned solar systems, which were geographically diverse, those systems would provide a significant percentage of their capacity to allow their production to reduce the need for additional distribution capacity. Through the use of its AGi program and AMI meters, Dakota Electric has used around 400 DER production meters to monitor DER systems in its service territory. Based on a review of these production meters, Dakota Electric has not observed the expected diversity from a larger group of solar systems that is necessary to enable non-wires solutions. The loss of DER generation output from solar systems on the Dakota Electric system are concurrent with each other, which means there is not diversity in the loss of production. Section C of this report has more discussion on the data received from the DER production meters, which show the concurrent loss of solar production and how the output from the solar DER is not coincident with the distribution peak demands.

6. Timeline Required to Consider Non-Traditional Solution Alternatives

Section E.2.ii. A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation).

Dakota Electric is in the middle of an RFP for utility scale energy storage. The information Dakota Electric has received from vendors is that the availability of batteries for utility scale energy storage is well beyond a year from purchase. As such, the long lead times for some of the potential solutions, such as energy storage, make the application of these solutions more difficult to coordinate. Dakota Electric is optimistic that these current long lead times will improve over time. However, due to COVID related supply chain challenges, and high demand for utility scale energy storage systems, the demand has outstripped the supply and there is an imbalance in the market.

Dakota Electric requested responses from 4 vendors for a substation energy storage project and only received 1 response from our RFP. This shows how busy the vendors are with other projects and, because our project is relatively small compared to other very large planned utility scale energy storage projects, the vendors choose to focus their time on these larger projects.

The ability to respond to new loads and reconstruction of portion of the distribution system in a short time is a core requirement for Dakota Electric. This core requirement is the same for either traditional solutions or non-wires solutions. As noted in Section A, question #28 above, construction of new, or rebuilding of the existing distribution system, is triggered by committed new loads, road rebuilds, or equipment which are old and need to be replaced. For new loads and road rebuilds, the utilities receive limited prior notification. Many times, the notice to the utility is a few months or even weeks before the distribution addition or modification is required. Considering these issues and the especially long lead times currently for non-wired solutions, it makes these even more difficult to implement and use on the Dakota Electric system. In the case where aging equipment is being considered for replacement, there could be enough time to analyze alternative solutions to firm up an unreliable line and defer rebuilding the older facilities.

7. Cost Thresholds for Consideration of Non-Traditional Solutions

Section E.2.iii. Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed.

Through the 2019 RFI process Dakota Electric had for non-wired solutions, it became apparent that non-traditional solutions do not necessarily compete at a specific cost threshold. While economies of scale were important, the type and capacity size of problem played a larger role in determining a non-traditional projects cost viability compared to traditional distribution projects.

Dakota Electric uses demand side management at individual residential homes to reduce the electrical demand. Looking at a single residential home involves a very low cost of implementation. Using a cost threshold to identify whether non-wired solutions would help may not be the best gauge of when non-wired solutions can be applied.

8. Screening Process for Non-Traditional Solution Alternatives

Section E.2.iv. A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.

The main concept Dakota Electric learned from the 2019 RFI exercise was that NWS are not a global solution to every distribution system problem. However, there are specific scenarios in which NWS can be considered in lieu of traditional building of distribution circuits. The specific scenarios for NWS are not necessarily tied to the cost level of an infrastructure project. Often, the scenarios NWS would be considered for are related to infrequent, step-change needs in available capacity for an area that is underserved for short durations.

Non-wired solutions have the potential to delay capital-intensive traditional distribution projects. The delay in the capital investment may be short term, lasting 1 – 5 years; however, there may be a business case to analyze non-wired solutions further in these situations. One method to further increase the value of non-wired solutions is to design them so they could be moved and reused in a different location. Dakota Electric will continue to analyze these unique situations in future IDP reports and through the course of our regular business operations.

Appendix A – DER Summary Report

Dakota Electric Association - DER Summary Report **August 2021**

Feeder		Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)							
Feeder	LCR Units	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Standard		Curtailment		Solar		Wind	
		Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
21FB01	485	444	1,419	21	74	9	25	0	0	6	15	14	62	2	2,715	0	0	3	25	1	20
21FB02	1031	896	2,791	63	195	48	251	0	0	10	34	118	531	2	884	0	0	4	27	0	0
21FB03	393	344	1,042	26	101	11	57	0	0	7	28	16	72	0	0	0	0	4	39	0	0
21FB04	451	394	1,206	25	98	14	89	0	0	3	8	18	81	2	1,440	1	80	2	11	0	0
21FB05	125	105	341	8	30	9	54	0	0	1	1	5	23	1	936	0	0	0	0	0	0
21FB06	948	857	2,372	32	110	28	153	0	0	7	42	51	230	0	0	0	0	5	33	0	0
31FB01	420	391	995	9	30	14	70	0	0	3	10	8	35	0	0	0	0	1	36	0	0
31FB02	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2,230	1	1,048	0	0	0	0
31FB03	348	328	847	8	24	4	9	0	0	0	0	6	27	1	569	1	878	0	0	0	0
31FB04	24	24	167	0	0	0	0	0	0	0	0	0	0	1	311	0	0	0	0	0	0
05FB01	873	759	2,447	47	176	33	159	0	0	15	58	48	216	1	216	0	0	8	60	0	0
05FB03	651	608	1,999	22	87	19	110	0	0	8	33	44	194	0	0	0	0	5	34	0	0
05FB05	593	553	1,677	4	13	34	172	0	0	8	25	16	72	0	0	0	0	5	46	0	0
05FB07	77	62	196	2	11	6	38	0	0	3	14	3	14	3	372	0	0	0	0	0	0
05FB09	777	698	2,216	23	77	35	172	0	0	14	53	32	145	1	167	0	0	6	44	0	0
05FB11	1020	934	2,728	34	107	26	128	0	0	14	43	18	76	0	0	0	0	3	21	0	0
05FB02	946	863	2,476	16	53	24	122	0	0	4	19	47	210	3	1,728	0	0	6	35	0	0
05FB04	1013	973	2,597	13	48	23	91	0	0	2	6	4	17	1	559	0	0	0	0	0	0
05FB06	263	247	793	3	10	12	110	0	0	2	7	7	32	5	1,614	1	737	3	5	0	0
05FB08	583	550	1,556	9	28	16	57	0	0	4	16	62	279	2	407	1	737	2	10	0	0
05FB10	278	246	765	13	50	10	39	0	0	6	18	19	88	0	0	0	0	0	0	0	0
02FB01	42	12	33	9	27	10	113	12	795	2	25	23	103	0	0	0	0	0	0	0	0
02FB02	54	13	36	24	84	18	235	6	349	3	48	31	150	0	0	0	0	0	0	0	0
02FB03	45	31	100	3	12	8	117	1	47	1	1	14	63	0	0	1	426	0	0	0	0
02FB04	31	10	26	8	27	7	63	10	443	1	2	14	60	3	928	0	0	0	0	0	0

Dakota Electric Association - DER Summary Report **August 2021**

Feeder		Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)							
Feeder	LCR Units	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Standard		Curtailment		Solar		Wind	
		Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
04FB01	80	41	123	12	46	16	178	3	130	0	0	31	139	0	0	1	115	1	7	0	0
04FB02	62	26	77	15	52	17	207	3	100	3	22	28	128	0	0	0	0	4	42	0	0
04FB04	281	127	406	63	271	99	953	5	222	18	103	149	671	2	184	0	0	6	93	2	23
13FB01	394	365	1,071	9	28	3	9	0	0	2	10	6	27	2	552	0	0	1	6	0	0
13FB03	2	0	0	0	0	0	0	0	0	0	0	0	0	1	3,384	0	0	0	0	0	0
13FB04	346	311	1,020	15	50	5	17	0	0	4	26	42	189	1	256	0	0	2	11	0	0
13FB08	26	23	67	1	3	1	18	0	0	0	0	0	0	3	835	0	0	0	0	0	0
13FB09	421	387	1,105	8	27	8	46	0	0	2	6	67	296	3	1,110	0	0	0	0	0	0
13FB02	34	37	183	0	0	0	0	0	0	0	0	0	0	1	835	0	0	0	0	0	0
13FB05	92	88	211	0	0	5	43	0	0	0	0	65	333	0	0	0	0	0	0	0	0
13FB06	248	223	688	6	21	8	37	0	0	1	2	8	27	0	0	0	0	0	0	0	0
13FB07	23	24	201	0	0	0	0	0	0	0	0	3	14	3	940	0	0	0	0	0	0
13FB10	5	5	24	0	0	1	22	0	0	0	0	0	0	2	843	0	0	0	0	0	0
17FB01	686	606	1,843	33	108	36	286	0	0	8	25	25	113	0	0	0	0	5	36	0	0
17FB02	468	400	1,286	18	56	21	177	0	0	12	32	79	356	0	0	0	0	5	38	0	0
17FB03	422	366	1,157	18	65	27	239	0	0	3	11	44	198	0	0	0	0	2	23	0	0
17FB04	230	195	654	7	24	23	149	0	0	6	39	39	176	4	1,558	0	0	2	14	0	0
17FB05	538	474	1,426	20	62	24	162	0	0	3	16	31	141	0	0	0	0	1	7	0	0
17FB06	436	402	1,140	17	61	7	35	0	0	2	7	24	108	1	625	0	0	1	7	0	0
12FB01	472	417	1,329	25	108	21	90	0	0	8	46	43	194	2	3,288	0	0	3	31	0	0
12FB02	659	576	1,777	31	107	48	445	0	0	3	9	171	763	2	1,135	0	0	6	47	0	0
12FB03	698	678	1,837	7	21	15	73	0	0	6	19	4	15	2	672	0	0	1	9	0	0
12FB04	911	867	2,393	24	78	18	104	0	0	3	30	16	72	0	0	0	0	3	17	0	0
12FB05	1327	1242	3,442	26	86	18	94	0	0	4	23	243	1,096	1	415	0	0	8	45	0	0

Dakota Electric Association - DER Summary Report **August 2021**

Feeder		Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)							
Feeder	LCR Units	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Standard		Curtailment		Solar		Wind	
		Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
22FB01	928	842	2,343	31	91	24	119	0	0	6	10	36	162	0	0	0	0	3	30	0	0
22FB02	577	531	1,487	20	59	15	70	0	0	0	0	27	122	1	94	0	0	0	0	0	0
22FB03	558	504	1,470	11	35	14	94	0	0	6	19	73	329	0	0	0	0	7	53	0	0
22FB04	619	577	1,807	6	24	25	217	0	0	4	30	252	1,132	0	0	0	0	7	52	0	0
22FB05	665	561	1,729	62	217	32	145	0	0	7	14	194	873	1	250	0	0	7	53	0	0
22FB06	957	851	2,446	22	74	32	251	0	0	5	18	131	590	3	860	1	547	16	100	0	0
06FB01	308	263	859	27	97	13	81	0	0	0	0	11	50	1	806	0	0	7	45	0	0
06FB02	228	209	614	5	18	6	42	0	0	1	6	9	42	0	0	0	0	2	15	0	0
06FB03	163	146	464	6	19	4	25	0	0	2	8	24	108	0	0	0	0	1	8	0	0
06FB04	381	347	1,086	18	63	5	17	0	0	3	11	9	41	0	0	0	0	2	13	0	0
06FB05	322	282	911	26	87	10	47	0	0	2	6	10	45	0	0	0	0	6	53	0	0
06FB06	99	93	269	5	17	9	83	0	0	0	0	4	18	1	461	0	0	1	2	0	0
11FB01	126	109	338	2	9	0	0	0	0	3	8	5	23	3	710	0	0	0	0	0	0
11FB02	312	289	754	6	16	25	182	0	0	1	5	2	9	6	2,818	0	0	0	0	0	0
11FB07	155	148	462	0	0	0	0	0	0	0	0	0	0	4	621	0	0	0	0	0	0
11FB09	906	853	2,328	26	76	27	103	0	0	2	6	12	54	0	0	0	0	1	10	0	0
11FB10	192	179	473	1	3	5	17	0	0	0	0	2	9	0	0	1	1,142	3	16	0	0
11FB12	1093	1006	2,921	30	94	33	165	0	0	5	16	60	268	0	0	0	0	12	126	0	0
11FB03	308	293	895	8	61	3	42	0	0	0	0	7	30	1	691	0	0	1	7	0	0
11FB04	505	461	1,332	17	50	19	105	0	0	4	15	8	36	2	1,085	0	0	6	29	0	0
11FB05	274	243	723	16	56	12	69	0	0	2	10	14	63	0	0	0	0	1	10	0	0
11FB06	296	264	744	6	22	3	27	0	0	0	0	72	324	2	1,344	0	0	1	5	0	0
11FB08	730	675	1,930	23	73	17	85	0	0	0	0	12	54	0	0	0	0	4	22	0	0
11FB11	338	325	746	1	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Feeder		Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)							
Feeder	LCR Units	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Standard		Curtailment		Solar		Wind	
		Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
03FB01	817	733	1,901	25	73	21	147	1	65	6	30	91	414	0	0	0	0	1	8	0	0
03FB02	271	99	297	60	197	77	865	54	3,823	11	130	107	481	0	0	0	0	4	56	0	0
03FB03	148	57	162	30	111	23	330	33	2,336	3	10	49	222	0	0	0	0	1	5	0	0
03FB04	256	128	365	42	130	60	517	41	2,480	5	25	64	288	0	0	0	0	4	31	1	20
26FB01	121	113	284	4	11	3	40	0	0	1	2	2	9	0	0	0	0	0	0	0	0
26FB02	150	139	411	2	4	1	8	0	0	1	4	13	59	0	0	1	384	2	13	0	0
26FB03	30	20	147	6	29	10	75	0	0	3	32	9	41	1	800	0	0	0	0	0	0
26FB04	421	319	1,016	61	271	85	922	1	5	38	295	123	554	2	52	0	0	1	16	0	0
15FB01	232	171	591	27	114	51	574	0	0	11	129	80	361	0	0	0	0	6	70	0	0
15FB03	211	128	396	32	120	57	585	1	30	14	193	75	332	0	0	1	0	3	34	0	0
15FB04	248	143	451	44	154	63	794	0	0	11	119	108	487	0	0	0	0	4	36	3	19
25FB01	1211	1126	2,823	23	63	30	189	0	0	2	16	19	86	0	0	1	383	3	16	0	0
25FB02	638	575	1,693	29	97	20	129	0	0	6	23	118	531	0	0	1	0	5	38	0	0
25FB03	403	381	1,012	5	22	39	310	0	0	3	13	25	113	1	0	0	0	2	16	0	0
25FB04	1103	1052	2,587	18	55	6	39	0	0	5	18	234	1,053	0	0	0	0	4	29	0	0
25FB05	946	912	2,057	4	12	9	54	0	0	1	5	324	1,456	0	0	0	0	1	5	0	0
25FB06	484	453	1,219	3	9	8	81	0	0	0	0	16	72	1	778	0	0	8	59	0	0
16FB01	394	343	1,072	26	90	22	163	0	0	4	19	30	135	0	0	0	0	6	46	0	0
16FB02	678	528	1,771	65	262	120	1,116	0	0	25	228	179	804	0	0	1	200	7	57	1	38
16FB03	492	400	1,323	41	155	39	385	0	0	18	120	100	454	1	288	0	0	8	84	0	0
16FB04	450	388	1,246	34	116	18	85	0	0	10	80	31	140	1	675	0	0	7	51	0	0
16FB05	508	458	1,323	25	79	12	40	0	0	5	27	14	58	0	0	0	0	5	39	0	0
16FB06	352	270	942	41	191	46	454	1	102	21	89	97	441	0	0	0	0	6	70	0	0

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Feeder		Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)							
Feeder	**LCR Units**	**Air Cond**		**Heat Pump**		**Heat Device**		**Irrigation**		**Misc**		**Water Heat**		**Standard**		**Curtailment**		**Solar**		**Wind**	
		Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
14FB01	1	0	0	1	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14FB02	13	10	46	0	0	0	0	0	0	0	0	1	5	2	690	0	0	0	0	0	0
14FB03	571	491	1,369	12	39	15	63	0	0	2	13	76	341	0	0	0	0	3	16	0	0
14FB04	198	197	543	1	3	3	20	0	0	0	0	8	36	1	520	0	0	1	6	0	0
14FB05	154	108	370	0	0	0	0	0	0	0	0	55	248	2	781	0	0	1	133	0	0
14FB06	260	247	867	6	19	1	7	0	0	2	8	42	188	1	1,100	0	0	0	0	0	0
18FB01	297	188	533	55	183	48	517	16	1,218	16	61	88	395	0	0	0	0	6	1,066	1	12
18FB02	213	153	447	22	82	30	300	3	312	9	104	49	222	0	0	0	0	3	36	0	0
18FB03	40	14	43	10	42	6	78	9	663	4	34	14	63	0	0	0	0	1	13	0	0
18FB04	121	66	196	18	62	21	159	20	1,408	6	102	33	147	0	0	1	202	1	10	0	0
07FB01	97	49	138	12	67	21	316	13	1,024	7	21	27	116	0	0	0	0	3	61	0	0
07FB02	158	90	259	18	58	26	251	5	442	9	58	46	209	0	0	0	0	2	15	0	0
07FB03	76	32	113	19	70	28	316	1	111	3	14	44	194	0	0	0	0	2	25	1	20
07FB04	123	39	130	34	141	52	1,051	18	1,218	14	79	55	262	0	0	0	0	4	42	0	0
07FB05	174	82	256	36	199	44	561	13	923	7	59	76	343	0	0	0	0	2	51	0	0
29FB01	175	153	374	7	20	19	133	1	88	1	5	59	262	0	0	0	0	2	11	0	0
29FB03	184	164	448	9	27	20	202	2	52	8	32	23	104	0	0	0	0	1	10	0	0
29FB04	82	45	126	8	32	22	288	14	1,107	1	40	35	165	0	0	0	0	0	0	1	39
08FB01	520	431	1,337	36	143	56	577	0	0	14	91	86	387	0	0	0	0	7	46	0	0
08FB02	648	554	1,605	17	56	21	177	0	0	4	17	78	350	1	98	0	0	1	5	0	0
08FB03	618	561	1,664	20	72	25	158	0	0	4	14	31	139	1	49	0	0	5	41	0	0
08FB04	575	500	1,511	21	81	40	350	0	0	12	42	72	319	0	0	0	0	2	9	0	0
08FB05	78	67	194	4	13	5	62	0	0	1	1	4	18	1	645	0	0	0	0	0	0
08FB06	387	309	1,045	30	120	58	559	0	0	13	143	112	509	0	0	0	0	2	10	0	0

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Feeder		Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)							
Feeder	LCR Units	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Standard		Curtailment		Solar		Wind	
		Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
19FB01	284	263	790	16	56	10	82	0	0	2	10	8	36	0	0	0	0	1	0	0	0
19FB02	331	285	902	22	77	29	196	0	0	4	17	27	122	0	0	0	0	0	0	0	0
19FB03	231	180	552	17	106	9	60	0	0	5	61	33	150	0	0	0	0	0	0	0	0
19FB04	934	826	2,583	52	192	106	910	0	0	11	127	148	664	0	0	0	0	5	35	0	0
19FB05	597	553	1,776	15	57	22	126	0	0	4	13	15	68	0	0	0	0	3	15	0	0
32FB01	59	21	64	11	34	30	508	7	408	3	16	27	122	0	0	0	0	0	0	0	0
32FB02	47	18	88	15	53	22	321	6	315	1	20	34	153	0	0	0	0	2	13	1	10
32FB03	6	1	3	1	3	2	43	1	47	0	0	2	10	0	0	1	276	0	0	0	0
32FB04	277	104	287	59	210	73	794	48	2,473	9	71	124	555	0	0	0	0	7	83	0	0
30FB01	12	0	0	0	0	0	0	0	0	0	0	0	0	1	4,900	0	0	0	0	0	0
30FB03	71	44	129	8	42	24	241	0	0	5	23	30	135	0	0	0	0	1	10	0	0
30FB04	77	54	155	14	38	9	133	3	74	1	14	12	54	0	0	0	0	1	8	0	0
27FB02	83	47	215	3	10	2	106	0	0	1	12	8	36	3	1,380	0	0	3	45	0	0
27FB03	234	214	748	13	51	28	225	0	0	9	22	41	183	1	965	0	0	4	33	0	0
27FB04	829	742	2,365	28	94	50	432	0	0	7	44	240	1,080	1	706	0	0	7	49	0	0
27FB05	149	134	419	7	28	10	86	0	0	6	33	39	178	1	770	0	0	0	0	0	0
09FB01	552	523	1,189	5	14	5	22	0	0	3	8	26	117	1	338	0	0	2	11	0	0
09FB05	686	650	1,877	14	40	12	42	0	0	5	14	12	51	0	0	0	0	1	6	0	0
09FB06	376	357	990	4	13	6	26	0	0	0	0	3	14	0	0	0	0	0	0	0	0
09FB07	262	248	735	5	16	3	12	0	0	0	0	5	23	0	0	0	0	0	0	0	0
09FB02	932	774	2,159	27	88	16	92	0	0	4	15	120	535	0	0	0	0	2	11	0	0
09FB03	450	410	1,222	11	36	20	120	0	0	6	20	31	140	0	0	0	0	4	28	0	0
09FB04	451	416	1,329	22	92	15	180	0	0	6	27	24	105	0	0	0	0	3	23	0	0
09FB08	40	45	148	0	0	0	0	0	0	0	0	1	5	0	0	0	0	0	0	0	0
09FB10	539	355	903	5	19	7	35	0	0	1	19	173	778	0	0	0	0	0	0	0	0

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Feeder		Load Control Receiver Loads (kW assumes zero diversity)														DER Systems (kW is DER AC rating)							
Feeder	LCR Units	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Standard		Curtailment		Solar		Wind	
		Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
24FB01	741	672	1,905	23	71	31	263	0	0	3	8	64	287	1	92	1	264	9	69	0	0
24FB02	242	111	336	31	123	65	838	14	712	7	46	84	381	2	447	0	0	6	80	0	0
24FB03	124	66	191	26	111	23	413	2	80	2	19	53	239	0	0	0	0	0	0	0	0
24FB04	50	19	67	6	33	14	190	9	429	0	0	18	78	1	180	0	0	1	15	0	0
24FB05	11	6	19	1	3	4	34	0	0	0	0	4	18	0	0	1	893	0	0	0	0
24FB06	980	899	2,416	13	42	17	107	0	0	5	16	69	308	0	0	0	0	8	63	0	0
20FB01	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20FB03	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20FB05	7	0	0	0	0	0	0	0	0	0	0	0	0	1	10,500	0	0	0	0	0	0
20FB02	0	0	0	0	0	0	0	0	0	0	0	0	0	3	5,800	0	0	0	0	0	0
20FB04	324	260	881	30	138	44	391	0	0	15	93	65	297	0	0	0	0	2	16	0	0
20FB06	321	276	993	23	86	23	172	0	0	2	5	24	108	0	0	0	0	2	15	0	0
20FB07	0	0	0	0	0	0	0	0	0	0	0	0	0	1	3,050	0	0	0	0	0	0
10FB01	24	21	98	1	46	0	0	0	0	0	0	0	0	1	1,116	0	0	0	0	0	0
10FB03	496	448	1,353	27	97	27	139	0	0	2	7	38	171	1	230	0	0	3	20	0	0
10FB05	69	79	280	0	0	0	0	0	0	0	0	1	5	1	1,202	0	0	1	30	0	0
10FB07	162	151	450	4	14	3	23	0	0	1	208	6	26	1	575	0	0	2	14	0	0
10FB02	0	0	0	0	0	0	0	0	0	0	0	0	0	1	3,900	0	0	0	0	0	0
10FB04	12	12	59	0	0	0	0	0	0	1	73	1	5	2	735	0	0	1	45	0	0
10FB06	183	141	476	11	49	17	233	0	0	1	10	30	135	1	0	2	1,037	5	38	0	0
10FB08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10FB10	5	5	17	0	0	0	0	0	0	0	0	0	0	1	366	0	0	0	0	0	0

Feeder	LCR	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Standard		Curtailment		Solar		Wind	
		Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
Grand Total																					
167	**59,968**	**52,189**	**153,276**	**2,765**	**10,091**	**3,331**	**29,443**	**377**	**24,030**	**738**	**4,724**	**7,372**	**33,175**	**127**	**85,176**	**20**	**9,349**	**419**	**4,665**	**12**	**204**

Appendix B – Substation and Feeder Minimum Loading Levels

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
Byllesby (2)	Substation	3,531	3,502	535	230	647	299
	1			73	63	77	64
	2			34	29	44	71
	3			133	88	146	122
	4			109	28	124	68
Hastings (3)	Substation	11,257	9,961	1,707	1,706	2,211	2,173
	1			1,077	603	1,466	1,431
	2			59	91	59	136
	3			232	178	232	218
	4			181	131	221	225
Castle Rock (4)*	Substation	3,445	3,029	549	577	749	743
	1			56	28	76	38
	2			68	70	68	75
	4			256	195	289	208
Burnsville North (5)	Substation	32,736	25,487	5,950	6,152	7,859	7,377
	1 (N)			526	1,063	526	1,226
	3 (N)			950	857	1,270	1,067
	5 (N)			139	649	139	770
	7 (N)			1,558	421	1,901	421
	9 (N)			253	837	319	1,085
	11 (N)			786	365	1,108	575
Burnsville South (5)	Substation	22,893	21,372	5,565	5,473	7,564	6,743
	2 (S)			449	1,498	449	1,883
	4 (S)			1,141	1,123	1,572	1,253
	6 (S)			1,608	1,534	2,034	2,033
	8 (S)			419	391	554	547
	10 (S)			275	276	375	346
Eagan (6)	Substation	10,103	9,051	1,731	2,138	2,418	2,833
	1			264	489	264	704
	2			210	141	250	144
	3			10	210	106	276
	4			353	353	448	406
	5			364	300	477	331
	6			113	162	217	235
Miesville (7)	Substation	6,919	6,643	1,240	1,034	1,431	1,510
	1			38	123	41	201
	2			296	136	382	136
	3			106	114	106	176
	4			169	105	169	140
	5			38	193	41	193
Orchard Lake (8)	Substation	20,017	19,119	4,322	3,922	5,949	5,104
	1			608	617	749	685
	2			791	189	973	189
	3			965	221	1,100	473
	4			71	190	71	247
	5			8	13	12	22

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
River Hills East (9)	Substation	12,966	12,486	2,817	2,844	4,049	4,021
	2			824	852	1,148	1,183
	3			110	315	395	351
	4			1,003	202	1,359	1,433
	8			320	300	459	446
	10			261	266	385	369
River Hills West (9)	Substation	11,849	11,470	2,644	1,804	3,471	2,678
	1			298	582	756	749
	5			653	182	653	182
	6			756	731	1,051	1,069
	7			12	20	117	20
Yankee Doodle North (10)	Substation	12,141	14,095	3,632	4,053	4,100	4,511
	1			849	1,006	879	1,591
	3			625	298	828	830
	5			940	491	940	1,033
	7			324	175	541	230
Yankee Doodle South (10)	Substation	12,417	14,476	4,312	2,727	4,341	2,834
	2			3	3	3	3
	4			141	138	141	138
	6			339	505	453	505
	8			1,449	258	2,126	258
	10			111	94	112	126
Fischer West (11)	Substation	19,738	24,086	4,175	4,708	6,482	6,628
	1			419	285	610	548
	2			1,573	1,566	1,876	1,907
	7			648	650	850	851
	9			683	684	958	896
	10			156	161	182	214
Fischer East (11)	Substation	21,260	33,134	5,278	5,207	6,952	7,488
	3			1,251	1,291	1,540	1,630
	4			1,176	947	1,602	947
	5			253	258	330	284
	6			805	903	1,125	1,242
	8			1,118	660	1,868	701
Deerwood (12)	Substation	24,338	23,179	6,102	6,607	7,826	8,633
	1			678	808	768	992
	2			1,246	1,257	1,574	1,636
	3			867	922	1,274	1,247
	4			1,012	974	1,273	974
	5			1,215	1,365	1,874	1,845

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
LeMay Lake (14)	Substation	20,553	23,030	10,782	8,878	11,794	10,360
	1			1,890	1,266	2,593	1,266
	2			550	219	668	219
	3			780	778	849	1,032
	4			1,602	1,580	2,151	2,180
	5			1,007	429	1,361	429
	6			78	80	82	89
Lake Marion (15)	Substation	8,900	5,330	1,148	1,356	1,214	1,356
	1			140	404	218	404
	3			287	228	349	315
	4			543	473	592	604
Lebanon Hills (16)	Substation	19,635	17,196	4,011	3,482	4,247	4,425
	1			523	489	661	621
	2			1,001	361	1,010	361
	3			784	519	994	876
	4			182	495	316	602
	5			311	281	311	385
	6			500	63	529	195
Dakota Heights (17)	Substation	14,516	22,548	4,267	3,664	4,780	4,155
	1			685	716	719	905
	2			730	599	893	735
	3			321	351	321	351
	4			525	194	853	196
	5			244	69	244	69
	6			447	456	609	610
Marshan (18)	Substation	6,762	5,862	413	314	413	314
	1			-477	< 0	-477	< 0
	2			276	83	332	222
	3			31	30	31	30
	4			166	158	219	158
Pilot Knob (19)	Substation	11,762	12,773	2,311	2,408	3,323	3,183
	1			264	257	402	356
	2			240	233	249	275
	3			200	218	210	268
	4			886	306	1,114	318
	5			647	697	895	894

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
Wescott Park East (20)	Substation	6,953	7,563	0	0	0	0
	1			0	0	0	0
	3			0	0	0	0
	5			0	0	0	0
Wescott Park West (20)	Substation	10,145	10,808	1,619	867	2,023	867
	2			0	0	0	0
	4			496	325	600	325
	6			364	361	477	399
	7			0	0	0	0
	8			981	99	1,335	293
Apple Valley (21)	Substation	22,423	21,587	5,468	5,577	6,012	6,379
	1			616	877	930	1,002
	2			1,150	1,141	1,334	1,168
	3			361	368	436	411
	4			642	309	801	335
	5			176	240	435	302
	6			937	503	1,068	503
Dodd Park (22)	Substation	30,139	24,678	5,673	4,608	6,680	4,608
	1			865	1,040	1,072	1,061
	2			629	351	906	379
	3			658	367	819	367
	4			985	684	1,164	787
	5			156	111	252	111
	6			1,303	85	1,559	88
Empire (23)	Substation	3,920	3,938	452	512	646	600
	1			371	172	498	224
	2			138	136	152	158
	3			0	0	0	0
	4			105	102	125	120
Vermillion River (24)	Substation	15,345	11,296	318	1,868	318	2,809
	1			700	458	923	940
	2			137	146	260	239
	3			-2,628	236	-2,628	300
	4			238	190	274	246
	5			159	166	165	169
	6			869	843	1,122	976
Lakeville (25)	Substation	28,113	23,981	5,862	4,800	8,368	7,229
	1			1,325	1,139	1,542	1,482
	2			767	222	1,066	222
	3			839	464	1,396	623
	4			854	832	1,143	1,140
	5			696	492	1,005	492
	6			945	316	1,514	758

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
Kenrick (26)	Substation	9,832	7,294	1,582	2,149	2,129	2,820
	1			121	53	164	53
	2			759	601	922	690
	3			384	306	475	396
	4			961	986	1,103	1,132
Ritter Park (27)	Substation	17,155	16,837	3,735	3,077	4,781	3,907
	2			1,084	189	1,375	189
	3			568	570	788	570
	4			1,454	372	2,249	538
	5			369	257	419	388
Nininger (29)	Substation	3,910	3,315	634	616	926	847
	1			195	117	299	216
	3			251	226	356	268
	4			142	120	179	180
Ravenna (30)	Substation	6,810	7,680	619	652	1,027	721
	1			0	0	0	0
	3			163	293	163	342
	4			163	152	185	167
Burnscott (31)	Substation	10,730	11,656	1,653	1,556	2,246	2,520
	1			428	367	428	367
	2			148	455	150	588
	3			421	404	432	513
	4			303	N/A	397	N/A
Randolph (32)	Substation	4,254	3,308	-1,117	< 0	-1,108	< 0
	1			113	133	153	161
	2			102	87	108	87
	3			2	< 0	2	< 0
	4			61	14	141	20

Appendix C – Wellspring Renewable Energy Residential Program

ENERGY WISE

FOR YOUR HOME

While the electricity delivered to your home includes increasing amounts of renewable energy, our Wellspring Renewable Energy® program gives you the option to help us do even more for the environment. By participating in Wellspring, you not only help support wind and solar development in Minnesota, but you also help reduce our dependency on non-renewable energy sources, like fossil fuels.

DAKOTA ELECTRIC ASSOCIATION
Your Touchstone Energy® Cooperative

WELLSPRING RENEWABLE ENERGY®

Support Wind and Solar Power!

What does participating in Wellspring mean?

Wellspring Renewable Energy is a voluntary program offered to our members. While the electricity delivered to all homes and businesses includes renewable energy in the mix, participating in Wellspring is a way for members to provide additional support for renewable energy technologies.

How does the program work?

Those who participate in the Wellspring program are purchasing renewable energy credits (RECs). For every 1,000 kilowatt-hours (kWhs) of clean, renewable electricity generation, a REC is created. A REC embodies all of the environmental attributes of the generation and can be tracked separately from the underlying electricity. Dakota Electric provides Wellspring energy to you through Great River Energy, our wholesale power supplier. This means you can support renewable energy and its future without having to build or buy anything.

How much will it cost?

Wellspring is sold in 100 kWh blocks, and members can purchase a fixed number of blocks each month or enough to power their monthly electricity use. You have two options:

- **Option 1:** Choose a fixed number of 100 kWh blocks to purchase each month. You can purchase just wind energy, just solar energy, or a combination of both. You cannot purchase more than your minimum monthly use over the past 12 months.
- **Option 2:** Let the number of blocks you purchase each month fluctuate based on the amount of energy you use. You must choose **either** wind energy or solar energy with this variable option.

Each 100 kWh block of wind energy costs an extra $0.20* per month.

Each 100 kWh block of solar energy costs an extra $2* per month.

The average home uses 800 to 1,000 kWhs of electricity per month, or eight to 10 blocks.

How long do I have to stay on the program?

You must remain on the program for at least 12 months. After 12 months, you may discontinue at any time.

- continued on back

WELLSPRING® | SOLAR ENERGY   WELLSPRING® | WIND ENERGY

Renewable Energy – Harnessing the power of the wind and sun

Where is Wellspring Renewable Energy produced?

Wind energy is produced from giant wind turbines mainly in southern Minnesota, while the solar energy is produced by Great River Energy solar resources throughout Minnesota. Wind resources currently account for 663 megawatts (MW) of total generation capacity, of which 13 MW are dedicated to the Wellspring program, and 250 kW in solar resources are dedicated to Wellspring.

Is the wind or solar power supplied directly to my home?

No. The electricity generated by the wind turbines and solar panels is fed into the state's electric system, called the grid. It is like pouring a pitcher of water into a pond. You can't get the exact water molecules from the pitcher back out of the pond. The same holds true for recapturing renewable electricity from the grid. It is available to use, but to deliver the exact electron generated by wind or solar to a specific location is not possible. The wind and solar power you purchase replaces electricity that would have been generated by conventional fuels.

Will I still receive power from conventional sources?

You will receive a mix of power sources. You won't be able to distinguish whether the electrons flowing into your home are generated by wind, solar or another resource. But, you can be assured your commitment to purchase Wellspring Wind and Solar Energy helps lessen our reliance on fossil fuels.

What if the wind isn't blowing or the sun isn't shining? Will I still have power?

Your power will continue as usual because additional generation is built to ensure power is supplied when the wind is not blowing or the sun is not shining.

Can we generate all our electricity from wind and solar?

No. Wind and solar are great ways to meet some of our electricity needs and are an important part of the overall mix of generation options. However, wind and solar could never generate all of our electricity needs because the wind doesn't blow and the sun doesn't shine all the time.

Who can participate?

To qualify for the program you must live in Dakota Electric Association's service territory.

How can I get started?

Contact Dakota Electric to learn more about how to sign up for the Wellspring program.

DAKOTA® ELECTRIC ASSOCIATION
Your Touchstone Energy® Cooperative

CONTACT THE ENERGY EXPERTS®
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
651-463-6243 • 800-874-3409
www.dakotaelectric.com

ENERGY WISE MN

Price and program subject to change without notice.

01/21

Appendix D – 2021 Capital Construction Projects > $100,000

2021 Capital Construction Projects (greater then $100,000)					
Project Description	DEA Project Reason	PUC IDP Category	Project Identified in 2021 Budget	Project Started	Expected Completion
Dodd Park Substation expansion	Substation Equipment	System Expansion for Capacity and Reliabilty	Y	2021	2022
Cedar Substation Land Purchase	Capacity Upgrade	System Expansion for Capacity and Reliabilty	N	2021	2021
AGi Meter Exchange	AGi Project	Grid Modernization and Pilot Projects	Y	2019	2022
AGi LCR Exchange	AGi Project	Grid Modernization and Pilot Projects	Y	2020	2023
Barnes Grove Substation Build	Capacity Upgrade	System Expansion for Capacity and Reliabilty	Y	2021	2021
Diffley Road Reconstruction	Road Construction	Project Related to Government Requirement	Y	2021	2021
C/R Mickelson 2nd	Cable Replacement	Age Related Replacement & Asset Renewal	Y	2021	2021
CP 91-25 GRE Underbuild - Miesville	Reliabilty	Project Related to Government Requirement	Y	2021	2021
CSAH 78-12 Reconstruction	Road Construction	Project Related to Government Requirement	Y	2021	2021
Barnes Grove Substation Feeder	Capacity Upgrade	System Expansion for Capacity and Reliabilty	Y	2021	2021
CSAH 70 Reconstruction	Road Construction	Project Related to Government Requirement	Y	2021	2021
AV Cimarron OH to UG - 2021 ph	OH Line Replacement - Age	System Expansion or Upgrades for Reliability	Y	2021	2021
Summers Creek 2nd	Development	Age Related Replacement & Asset Renewal	N	2021	2021
Knob Hill 2nd	Development	Age Related Replacement & Asset Renewal	N	2021	2021
Lake Marion Line Rebuild	Capacity Upgrade	System Expansion for Capacity and Reliabilty	Y	2021	2021
GARRETT SBF APARTMENTS	Development	New Service	N	2021	2021
Pinnacle Reserve 4th	Development	New Service	N	2021	2021
CR - Chateaulin 4th/5th	Cable Replacement	Age Related Replacement & Asset Renewal	Y	2021	2021
CR - Apple Valley East 4th	Cable Replacement	Age Related Replacement & Asset Renewal	Y	2021	2021
Cedar Hills	Development	New Service	N	2021	2021
PINE BEND RNG PROJECT	Member Request	New Service	N	2021	2021
Northfield Ave Line Rebuild	Reliabilty	System Expansion for Capacity and Reliabilty	Y	2020	2021
Glacier Creek 2nd	Development	Age Related Replacement & Asset Renewal	N	2021	2021
Aging Pole Rpl - 225th Hamburg	OH Line Replacement - Age	Grid Modernization and Pilot Projects	Y	2021	2021
SUMMERS RIDGE OF APPLE VALLEY	Development	New Service	N	2021	2021
Autumn Path Road Extension	Road Construction	Project Related to Government Requirement	Y	2021	2021
Avonlea 5th	Development	New Service	N	2021	2021
Miesville Double Circuit Line Rebuild	OH Line Replacement - Age	System Expansion for Capacity and Reliabilty	Y	2021	2022
CSAH 86 Rebuild	Road Construction	Project Related to Government Requirement	Y	Delayed to 2022	2022
Glacier Creek 2nd	Development	Age Related Replacement & Asset Renewal	N	2021	2021

Appendix E – 2022 Proposed Capital Construction Projects > $100,000

2022 Capital Construction Projects (greater then $100,000)					
Project Description	DEA Project Reason	PUC IDP Category	Project Identified in 2021 Budget	Project Started	Expected Completion
AGi Meter Exchange	AGi Project	Grid Modernization and Pilot Projects	Y	2019	2022
AGi LCR Exchange	AGi Project	Grid Modernization and Pilot Projects	Y	2020	2023
CP 86-34	Road Construction	Project Related to Government Requirement	Y	2022	2022
CSAH 32 Cliff Reconstruction	Road Construction	Project Related to Government Requirement	Y	2022	2022
179th Street Alignment	Road Construction	Project Related to Government Requirement	Y	2022	2022
Dodd Park Feeder Reconfiguration	Capacity Upgrade	System Expansion for Capacity and Reliabilty	Y	2022	2022
County 91 & Vernon	Capacity Upgrade	System Expansion for Capacity and Reliabilty	Y	2022	2022
Glacier Creek 4th	Development	New Service	Y	2022	2022
Pheasant Run	Development	New Service	Y	2022	2022
Cedar Substation Site Prep	Capacity Upgrade	System Expansion for Capacity and Reliabilty	Y	2022	2023
Dodd Park Substation expansion	Substation Equipment	System Expansion for Capacity and Reliabilty	Y	2021	2022
Capacitor Control Upgrades	Communication	Grid Modernization and Pilot Projects	Y	2021	2022
Miesville Substation Tower	Communication	Grid Modernization and Pilot Projects	Y	2022	2022
Ches Mar East 1st ADDN	Cable Replacement	Age Related Replacement & Asset Renewal	Y	2022	2022
Burnsville Parkway/35W NW	Cable Replacement	Age Related Replacement & Asset Renewal	Y	2022	2022
Rich Valley Estates	Cable Replacement	Age Related Replacement & Asset Renewal	Y	2022	2022
150th Street Pole Replacement	OH Line Replacement - Age	Age Related Replacement & Asset Renewal	Y	2022	2022
255th/Chippendale	OH Line Replacement - Age	Age Related Replacement & Asset Renewal	Y	2022	2022

Note: On the date this Report was filed, the capital budget for 2022 and the projects listed above, have not been approved by the Dakota Electric Board.

Appendix F – Table Showing Where Commission's Objectives are Discussed in IDP.

In the introduction, pages 19 and 20 provide a brief summary of how each of the main sections of the Report address the Commission's objectives. Below is a summary of the pages which contain information in support of the Commission's planning objectives.

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;

Objective #1 Components	Page #s where information is available
Safety	29, 93-94,101
Security	29-31,89-92,108-109,118,121
Reliability	6-7,21-22,89-94,102,108-109,118,121,126
Resilience	6,29,31,108-109,121,126
Maintaining Costs	7-10,22-23,31,37,40,45,49,50-53,61,103,107-130

Planning Objective #2: Enable greater customer engagement, empowerment, and options for energy services;

Objective #2 Components	Page #s where information is available
Customer engagement	*15-17,46,49,93-94,125-126*
Customer empowerment	*5,30,49, 93-94*
Options for Energy Services	*7-10,14,87-88,93-94*

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;

Objective #3 Components	Page #s where information is available
Efficient, cost-effective grid	*29-31,93-94*
Accessible grid platforms to support new products and services	*93-94, 97-99*
Opportunities for adoption of new distributed technologies	*77,81-86, 89-92, 94-95*

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

Objective #4 Components	Page #s where information is available
Optimized utilization of grid assets	*7-10,29-31,93-94,98-104*
Minimize total costs	*31,37,45,50-53,61,93-94,107-130*

Planning Objective #5: Provide the Commission with the information necessary to understand Dakota Electric's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of rate payer cost and value.

Objective #5 Components	Page #s where information is available
Short-term and Long-term plans	*30-34,58-61,78-80,97*
Costs and benefits of investments	*61,97,100-130*
Analysis of rate payer cost and value	*37,45,100-105*