November 20, 2017

Daniel P. Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

Re: Dakota Electric Association Petition to Implement Tracker Recovery for Advanced Grid Infrastructure Investments Docket No. E-111/M-17-___

Dear Mr. Wolf:

Dakota Electric Association (Dakota Electric or Cooperative) submits the attached Petition requesting Minnesota Public Utilities Commission (Commission or MPUC) approval to implement tracker recovery for Advanced Grid Infrastructure (AGi) investments. The proposed tracker would provide recovery for distribution grid modernization and load management investments that occur between Cooperative general rate cases.

If you or your staff have any questions regarding this petition, please contact me at (651) 463-6258.

Sincerely,

/s/ Douglas R. Larson

Douglas R. Larson
Vice President of Regulatory Services
Dakota Electric Association
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Farmington, MN 55024
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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF A DAKOTA ELECTRIC ASSOCIATION PETITION TO IMPLEMENT TRACKER RECOVERY FOR ADVANCED GRID INFRASTRUCTURE INVESTMENTS

DOCKET NO. E-111/M-17-____

SUMMARY

On November 20, 2017, Dakota Electric Association (Dakota Electric or Cooperative) submitted a Petition requesting Minnesota Public Utilities Commission (Commission or MPUC) approval to implement tracker recovery for Advanced Grid Infrastructure (AGi) investments. The proposed tracker would provide recovery for distribution grid modernization and load management investments that occur between Cooperative general rate cases.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

IN THE MATTER OF A DAKOTA ELECTRIC ASSOCIATION PETITION TO IMPLEMENT TRACKER RECOVERY FOR ADVANCED GRID INFRASTRUCTURE INVESTMENTS	DOCKET NO. E-111/M-17-____ NOVEMBER 20, 2017

PETITION OF DAKOTA ELECTRIC ASSOCIATION

I. Introduction

Dakota Electric Association (Dakota Electric or Cooperative) submits this Petition requesting Minnesota Public Utilities Commission (Commission or MPUC) approval to implement tracker recovery for Advanced Grid Infrastructure (AGi) investments. The proposed tracker would provide recovery for distribution grid modernization and load management investments that occur between Cooperative general rate cases.

II. Filing Requirements

Pursuant to Minn. Stat. § 216B.16, subd. 1 and Minn. Rule 7829.1300, Dakota Electric provides the following required general filing information.

1. Summary of Filing (Minn. Rule 7829.1300, subp.1)
A one paragraph summary accompanies this Petition.

2. Service on Other Parties (Minn. Rule 7829.1300, subp. 2)
Pursuant to Minn. Rules 7829.1300, subp. 2, Dakota Electric eFiles this Petition on the Minnesota Department of Commerce – Division of Energy Resources and the Office of Attorney General – Residential Utilities and Antitrust Division.

3. Name, Address and Telephone Number of Utility (Minn. Rule 7829.1300, subp. 4(A))

Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
(651) 463-6212

4. Name, Address and Telephone Number of Utility Attorney (Minn. Rule 7829.1300, subp. 4(B))

Eric F. Swanson
Winthrop & Weinstine, P.A.
225 South Sixth Street, Suite 3500
Minneapolis, Minnesota 55402-4629
(612) 604-6511

5. Date of Filing and Date Proposed Rate Takes Effect (Minn. Rule 7829.1300, subp. 4(C))

This Petition is being filed on November 20, 2017. Minn. Rule 7825.3200 requires that utilities serve notice to the Commission at least 90 days prior to the proposed effective date of modified rates. With Commission approval, the proposed tracker recovery will take effect when investments are made in the proposed Advanced Grid Infrastructure, but no sooner than February 19, 2018.

6. Statute Controlling Schedule for Processing the Filing (Minn. Rule 7829.1300, subp.4(D))

This Petition is made pursuant to Minn. Stat. § 216B.16. Dakota Electric's proposed tracker recovery for Advanced Grid Infrastructure investments falls within the definition of a "Miscellaneous Tariff Filing" under Minn. Rules 7829.0100, subp. 11. Minn. Rules 7829.1400, subp. 1 and 4 specify that comments in response to a miscellaneous filing be filed within 30 days, and reply comments be filed no later than 10 days from the expiration of the original comment period.

Dakota Electric recognizes that there may be interested parties who wish to review and comment on this petition, which could result in a longer regulatory review. However, we request that the regulatory review schedule result in a Commission decision no later than April 23, 2018. Dakota Electric requests a Commission decision by this date to maintain the pricing offered in proposals to the Cooperative. A delay in Dakota Electric's ability to proceed could result in repricing that could negatively affect the overall business case.

7. Utility Employee Responsible for Filing (Minn. Rule 7829.1300, subp. 4(E))

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8. Impact on Rates and Services (Minn. Rule 7829.1300, subp. 4(F))

The proposed tracker would provide recovery for distribution grid modernization and load management investments that occur between Cooperative general rate cases. The impact on rates and services is described throughout the remainder of this filing.

The additional information required under Minn. Rule 7829.1300, subp. 4(F) is included throughout this Petition.

III. Petition

Introduction

Dakota Electric's petition for approval of a proposed tracker mechanism to recover distribution grid modernization and load management investments that occur between Cooperative general rate cases includes the following information:

- Overview of Advanced Grid Infrastructure,
- Background on Regulatory Processes and Reports,
- Statutory Authority,
- DEA's Evaluation Process,
- Business Case Results,
- Implementation Schedule, and
- Proposed Tracker Recovery Mechanisms.

This petition also includes support material in the following exhibits:

Exhibit A – September 29, 2015, PUC Planning Meeting Presentation

Exhibit B – May 23, 2017, PUC Planning Meeting Presentation

Exhibit C – *Circuits* articles

Exhibit D – Advanced Grid Infrastructure (AGi) - Business Case Executive Summary

Exhibit E – Advanced Grid Infrastructure Rider

Exhibit F – AGi Adjustment Example Calculation

Overview of Advanced Grid Infrastructure

Advanced Grid Infrastructure (AGi) is the term Dakota Electric is using to refer to new technologies that would enhance the communication and operation of our distribution system that delivers electricity to our members. These technologies will help Dakota Electric monitor our distribution system for better efficiency and operation and allow us to have two-way communication to field equipment, providing numerous benefits to our members and Dakota Electric. The main AGi components include Advanced Metering Infrastructure (AMI), Meter Data Management (MDM), and the Load Management (LM) system.

Advanced Metering Infrastructure is the foundational component of the Advanced Grid functions. AMI is a system wide communication network for meters and other devices. AMI provides a communication path which can be used to read meters, control loads within the Load Management system, and interface with the SCADA (Supervisory Control And Data Acquisition) system for distribution operations and monitoring.

Meter Data Management provides an organized place to store, retrieve, report and analyze the data collected by the AMI and many other systems. The MDM is a data warehouse and hub, with integration to many of the other Advanced Grid technologies including SCADA, Customer Information System (CIS), Outage Management System (OMS), and Geographic Information System (GIS).

Load Management provides control of consumer loads when required through Load Control Receivers (LCR) mounted to each member building participating in a load management rate. The LCR device is the “switch” at members’ homes and businesses to directly control the load when required. Air conditioners, water heaters, electric heat etc., are remotely turned off by a signal sent to the load control receiver. The load management system provides this capability/functionality to residential, commercial and agricultural loads.

Background on Regulatory Processes and Reports

Over the past decade, the Commission has initiated several dockets that directly and indirectly touch on increased automation of electric utility systems including:

- Standards Related to Smart Grid Investments and Information (Docket No. E-999/CI-08-948)
- Grid Modernization Stakeholder Meetings (Docket No. E-999/CI-15-556)
- Distribution System Planning Efforts and Considerations (Docket No. E-999/CI-15-556)
- Generic Standards for the Interconnection and Operation of Distributed Generation Facilities (Docket No. E-999/CI-16-521)

The Commission initiated the docket on Standards Related to Smart Grid Investments and Information in response to the federal Energy Independence and Security Act of 2007. After receiving comments from interested parties, the Commission issued an Order on June 5, 2009, requiring utilities to implement the following measures:

> "First, the Commission will adapt and modify the federal smart grid standards considered for appropriate use in Minnesota. The Commission will authorize and encourage utilities to move forward to implement new smart grid technologies, in order for the utilities and the Commission to gain a greater understanding and experience with these technologies. The Commission will also require utilities to file with the Commission reports on past, current, and planned smart grid projects, so as to educate itself on the results of such efforts. Finally, the Commission will host annual or other appropriate periodic public meetings for utilities to report on their smart grid projects as part of a continuing dialogue for information gathering purposes.
>
> Second, the *Commission will encourage utilities to file appropriate cost recovery petitions for recovery of reasonable and prudent costs for the deployment of qualified smart grid system projects as allowed by law*, when made in an appropriate fact-specific filing to the Commission.
>
> Third, the Commission will encourage utilities utilizing smart grid technology to petition to recover the remaining book-value costs of any equipment rendered obsolete by the utility's deployment of smart grid technology, if reasonable, allowed by law, and made in an appropriate fact-specific filing to the Commission.
>
> Fourth, the *Commission puts utilities on notice that it may require utilities to provide electricity purchasers with information relating to: time-based pricing in the wholesale and retail markets, specific customer usage information*, updates of information on prices and usage where available, and, on an annual basis, information on the source of the power provided by the utility to the consumer.

> Finally, while the *Commission's decision in this docket applies only to rate-regulated utilities*, as specified under the federal standards, the Commission requests that non-rate-regulated utilities also provide reports to the Commission and participate in any meetings in the manner that the Commission has ordered for rate-regulated utilities." (*emphasis added*)

On May 12, 2015, the Minnesota Public Utilities Commission initiated an inquiry into Electric Utility Grid Modernization with a focus on Distribution Planning. The first phase of this initiative included a series of three meetings to facilitate a dialogue on Minnesota's electric distribution systems. The first meeting focused on Minnesota's electric utility distribution systems, with a discussion of the design, operations, performance, capability, and planning processes for existing distribution systems. The second meeting examined national distribution grid modernization work and emerging best practices. The third meeting considered stakeholder perspectives, giving interested parties an opportunity to provide feedback on current distribution planning processes and to suggest next steps the Commission could take to improve distribution planning in the future. These workshop and stakeholder comments supported a PUC *Staff Report on Grid Modernization* that was issued in March 2016. In this report, Staff proposed the following definition to guide grid modernization in Minnesota:

> "A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. *An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network*." (*emphasis added*)

The March 2016 *Staff Report on Grid Modernization* also summarized the May 12, 2015 planning meeting presentation and Commission discussion of key points as follows:

- The electric distribution grid is at a strategic inflection point, a time of significant change;
- Changing customer demands, new technologies, and evolving public policy will drive increased deployment of new grid technologies and expanded deployment of a variety of distributed energy resources;
- Tomorrow's integrated electric grid will be more distributed and flexible; will be operated in concert with customer owned resources to optimize value; will operate resiliently against natural disaster and attacks. Development of tomorrow's grid is

already underway, and investments are being made today that will influence the capabilities of the future grid;

- Updates to distribution planning process will be needed to support a reliable, efficient, robust grid in a changing (and uncertain) future; new planning efforts should be coordinated with resource and transmission planning.

After the Grid Modernization stakeholder meetings and issuance of the *Staff Report on Grid Modernization*, Docket No. E-999/CI-15-556 focused on Distribution System Planning Efforts and Considerations. This phase of the docket is still in progress.

Finally, on June 21, 2016, the Commission opened a docket for Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities. As has been noted above in previous dockets, increasing implementation of distributed resources will require enhanced monitoring and control capabilities to ensure continued reliability and safety of distribution systems.

Statutory Authority

In the early 1980s, Dakota Electric's members voted to become subject to rate regulation by the Minnesota Public Utilities Commission under the provisions of Minnesota Statutes 216B.026. Minnesota Statute 216B.026 specifically states that such rate regulation is pursuant to sections 216B.03 to 216B.23.

Minnesota statutes regulating utilities have been drafted with a focus on investor-owned utilities. The regulation of electric cooperatives is an option within statutes – not a focus. As a regulated electric distribution cooperative, Dakota Electric must often navigate through statutes designed for vertically integrated investor-owned utilities.

Minnesota Statute 216B.16 (Rate Change; Procedure; Hearing) describes various requirements for changing rates by regulated utilities. Subdivision 7b of this statute applies to transmission cost adjustments, with Part b stating, "Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that:" As a member of Great River Energy, Dakota Electric provides transmission service to our retail members through GRE. Beyond transmission, Part b(5) of this statute "allows the utility to recover costs associated with investments in distribution facilities to modernize the utility's grid that have been certified by the commission under section 216B.2425." While this statutory intent is clear regarding recovery of investments in distribution facilities to modernize the utility's grid, the certification referenced under Minnesota Statute 216B.2425 does not fall within the range of statutes that apply to a rate-regulated electric cooperative.

Minnesota Statute 216B.1636 deals with recovery of electric utility infrastructure costs (EUIC) and falls within the range of statutes that apply to a rate-regulated electric cooperative. This statute indicates that "The commission may approve an electric utility's petition for a rate schedule to recover EUIC under this section. An electric utility may petition the commission to recover a rate of return, income taxes on the rate of return, incremental property taxes, if any, plus incremental depreciation expense associated with EUIC." EUIC is defined as "costs for electric utility infrastructure projects that were not included in the electric utility's rate base in its most recent general rate case", with utility infrastructure projects defined in part as "projects owned by an electric utility that … replace or modify existing electric utility infrastructure, including utility-owned buildings, if the replacement or modification is shown to conserve energy or use energy more efficiently, consistent with section 216B.241, subdivision 1c." Subdivision 2 of M.S. 216B.1636 details the filing requirements for seeking EUIC recovery. While this statutory intent is clear regarding recovery of EUIC, this specific section of the statute defines "electric utility" as a public utility as defined In M.S. 216B.02, subdivision 4. This language arguably does not extend the reach of this particular section of the statutes to electric cooperatives that have chosen to become rate regulated, even though it falls within Sections 216B.03 to 216B.23. Dakota Electric respectfully submits that this is an overly narrow reading of the statute and that its election "to become subject to rate regulation by the Commission pursuant to sections 216B.03 to 216B.23" provides Dakota Electric the ability to file this petition under Section 216B.1636.

Even if the Commission determines that Section 216B.1636 does not specifically apply to Dakota Electric, with clear legislative intent to allow for rate recovery of investments in distribution facilities to modernize the utility's grid in Minnesota Statute 216B.16 and equally clear legislative intent to allow for recovery of electric utility infrastructure costs in Minnesota Statute 216B.1636, the AGi tracker mechanism should be approved. Minnesota Statute Section 216B.03 provides the Commission broad overall authority to approve rates and specifically requires that: "To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05." Therefore, pursuant to both Minnesota Statute 216B.1636 and 216B.03, the Minnesota Public Utilities Commission can approve an AGi tracker mechanism for the Cooperative.

<u>DEA's Evaluation Process</u>

Dakota Electric has been monitoring and evaluating components of AGi for many years. During the past four years these efforts have intensified as the underlying AGi systems have matured. Dakota Electric's monitoring and evaluation over the past four years has included:

- Over 50 internal team meetings related to functions and requirements, use case development, and business case development.
- AGi Team Members have:
  - Visited 9 different utilities outside Minnesota
    - Discussed lessons learned including what went right, what went wrong, and what they would do differently
  - Participated in over 40 vendor presentations on AMI, LM and MDM
  - Attended 5 vendor conferences
  - Conducted an extensive multi-layered request for proposal evaluation process
- Provided 10 update sessions for the Dakota Electric Board of Directors that included project overviews, member survey results, and discussed AMI issues with two Minnesota cooperatives that are in various stages of AMI implementation.
- Dakota Electric has been in contact with state agencies regarding our AGi efforts including:
  - 2 PUC Planning Meeting presentations (attached as Exhibit A and Exhibit B)
  - Informal meetings with Department of Commerce and Office of the Attorney General staff
- Dakota Electric conducted a member survey based on Commission comments during a planning meeting.

- Dakota Electric conducted a risk assessment (facilitated by GRE's Risk Manager) with team members, senior staff, and several board directors.

Some overall information obtained specifically from the utility visits, member survey, and risk assessment include:

- Takeaways from discussions with other utilities that have implemented AMI/MDM include:
    - AMI technology is solid and works
    - AMI is a foundational system which affects all departments
    - AMI is a communication system which happens to collect meter readings
    - AGi system benefits were greater than expected
    - MDM is needed to help extract the benefits
- Key responses/member perceptions from the Member Survey on AGi included:
    - Members identified the following AGi features as being most important for consumers:
        - Dakota Electric could be automatically informed when power is out at your home, allowing them to address the problem more quickly.
        - Member could receive information to help them conserve energy. They could also see the results of their energy efficiency measures.
        - Member could use flexible pricing, which could reduce bills if more electricity is used during off-peak hours or raise bills if electricity is used when demand from others is the highest.
    - Members identified the following AGi features as being most important for Dakota Electric:
        - Dakota Electric could better manage how to restore power after storms, reducing the time customers are without power.
        - Dakota Electric could use data on electricity use to target maintenance dollars to places with more outages than normal or with inefficient equipment.
        - Dakota Electric needs to regularly replace its meters —by installing AMI meters, Dakota Electric will be using the most advanced meters

available for a smart grid.

    - Dakota Electric could receive information allowing power plants to operate more efficiently.
    - Dakota Electric could evaluate energy use throughout its system and take steps that reduce the pressure to increase rates.

- Risk Assessment:

The risk assessment process involved a thorough evaluation of more than a hundred separate considerations that have been identified as critical to the organization, across strategic, stakeholder, financial, project implementation, and utility operations. The evaluation results in a comprehensive identification of potential beneficial and adverse impacts (benefits and risks), and drives project plan preparations and contingency plans to ensure the realization of project benefits, and the mitigation or elimination of risks. In addition, the project team's engagement in the process ensures a consistent understanding by the team of those issues most critical to project success.

The risk analysis was conducted with the following assumptions:

Project Management – qualified project management resources are hired and they have the appropriate technical experience and tools.

Resource Availability – Committed staff where management does not schedule additional work to dilute internal staff resources

AGi Works as Advertised – Use clearly defined use-cases and include delivery of these functions in the contract

Strategic Options – the AGi project is the best strategic option

Stable CIS Platform – AGi is dependent upon a stable and robust CIS platform and should not be implemented until the new CIS is completed and stabilized.

PUC – Filing for recovery of costs between general rate cases must be submitted and accepted by the Commission.

The risk assessment identified the following top 5 risks and benefits:

- Risks:
    - Project complexity/uniqueness and potential impact on success

        - Integration with and changes to existing operations, systems, personnel, projects
        - Use of well-tested, effective, repeatable project management process
        - Potential for a large financial exposure/liability
        - Vendor default, contract non-compliance, misdeeds; impact on DEA's reputation
    - Benefits:
        - Alignment with DEA strategic business goals, objectives and strategic imperatives
        - Shape our future
        - Operation represents an opportunity to increase value of existing DEA assets/resources
        - Positions the portfolio to increase member/partner/consumer satisfaction
        - Most opportune/optimal use of resources

With the benefits and risks identified, the risk analysis provides the following recommendations:

Project Management - Hire qualified project management resources, which have experience with implementing AMI / MDM systems

Project Communication – AGi project team will be established and communicate with management

Member Communication – Our Membership must be kept informed and provided clear communication about the project

Project Scope – The project scope must be clearly defined and a definition of “what is success” developed and tracked

Contract Documents – Contract documents must be used to protect Dakota Electric and support the extraction of benefits contained within the business case.

Finally, Dakota Electric has communicated our initial efforts regarding AGi through a number of articles in our monthly newsletter *Circuits* (attached in Exhibit C). This is the single best vehicle we have to communicate important information to Dakota Electric members. Dakota Electric will continue to inform members about AGi progress in *Circuits*.

AGi Business Case

Dakota Electric's AGi evaluation process supported the preparation of an "Advanced Grid Infrastructure Project (AGi) - 2017 Business Case Report". The results of this report were provided to the Dakota Electric Board of Directors, who authorized Dakota Electric staff to submit a filing to the PUC seeking rate recovery through appropriate mechanisms and take other steps necessary to pursue AGi implementation. The Business Case Executive Summary is attached as Exhibit D.

Dakota Electric is facing several major transitions; one is with technology; another with the makeup of and wants of our members; and the third is within the core business due to the interconnection of renewables. Coupled with these transitional elements impacting the Cooperative, some of the existing systems have reached the end of their useful life and require significant investment just to maintain the status quo. Dakota Electric's evaluation looks at the cost of continuing to provide electricity using existing systems with existing technology vs. the cost of moving forward with implementing new Advanced Grid technology. Also explored are the risks associated with not moving forward vs. the risks associated with implementation of Advanced Grid Infrastructure (AGi) technology. Not making a decision to move forward with AGi technology has risks just as implementing any new technology has risks.

The AGi evaluation identified benefits of AGi that were placed into three categories including:

1. *Direct financial benefits* are savings included in the financial analysis that lower costs. These savings include things such as reduced kWh losses, lower demand costs, reduced meter reading expenses, and reduced overtime expenses.
2. *Potential direct financial benefits* are savings that are likely to occur but are not included in the financial analysis. These potential direct benefits include things such as savings for Solar/PV metering.

3. Finally, there are *other "soft" benefits* related to improved distribution system operations, customer service, and societal benefits. Like the potential direct benefits, these soft benefits are <u>not</u> included in the financial analysis.

The evaluation process identified the following soft member benefits:

- Improved service
    - Identify outages even when the member is not home or does not call
    - Improve efficiency of outage management
    - Improve accuracy and timeliness of meter readings
    - Improve DEA's ability to proactively identify and resolve power quality issues - before the member calls
- Member privacy
    - Reduce the need for DEA employees to access member property
- Flexibility
    - Ability to offer new billing and rate options
- Efficiency
    - Enables more efficient resolution of member issues and/or questions

The evaluation process identified the following soft benefits related to Dakota Electric's operations:

- Eliminate multiple internal systems including:
    - Turtle AMR meters (end of life)
    - PLC based load control (end of life)
    - Pager based load control (near end of life)
    - Drive-by ERT meters
    - MV-90 based meters
- Provide detailed member usage, e.g., hourly or sub-hourly, readings
    - Having the detailed usage data allows Dakota Electric and the member to evaluate load and usage information
    - Sizing transformers (reduce outages, reduce capital costs, reduce system losses)
    - Supports rate analysis
    - Identify non-working load control devices

- Automatic Reporting of outages
    - Provide a member benefit of reducing the need to report outages (especially while away from home, or special non-home services)
    - Enhance DEA's ability to respond to outages – identifies nested outages (blown fuse downstream)
    - Reduce busy signal on telephone calls (allows the important calls to get through)
    - Support the Outage Management System (OMS) for items such as informing members about the status of an outage
- Member voltage and power quality
    - Know about member blinks and possibly power sags
    - Quickly identify transformer problems - reduce insurance claims
    - Helps us help the member trouble shoot problems remotely (saves crew trips)
    - Provide real-time data about system problems before they get serious

Finally, the evaluation process identified the following soft benefits for members and Dakota Electric:

- Employee/Member Safety
    - Fewer people in harm's way (dogs, accidents, physical collections)
    - Reduced risk for vehicle accidents
    - Less incentive to tamper
- Environmental
    - Supports the efficient use and integration of renewable resources
    - Supports load control and demand response initiatives
    - Fewer miles driven by DEA employees

At a very basic level, Dakota Electric's evaluation identifies what it could cost to keep operating "Status Quo" vs. implementing new AGi technology. It also goes into detail about the existing systems and the risks involved with continuing to operate those systems which have reached the end of their useful life. It compares the status quo to the cost and benefits provided with implementing the Advanced Grid Infrastructure (AGi) technology. The evaluation documents that overall costs of continuing with the status quo vs. the cost to implement AGi technology are very similar. The base case analysis is continuing as is, or "status quo," and resolving each issue as it develops. With the base case option, little if any additional new capabilities will be added and some of the existing functionality and capabilities will be lost over time. We will continue to spend dollars on old technologies and, in most cases, we will not be able to implement systems with new technology that could provide increased flexibility and benefits. If Dakota Electric does not implement AMI and MDM (components of the AGi system), the following estimated costs are expected to be incurred throughout the 15-year evaluation timeframe:

Estimated COSTS for Continuing to Operate Status Quo (2018-2033)	
Reason	Cost
Costs to Read Meters	$17,900,000
Replacing Rural AMR meters (Turtles)	$1,100,000
Replacing Aging Meters	$6,300,000
Special Meters for DER (Solar)	$800,000
Replacing Load Management System	$15,400,000
Unrealized Customer Service Savings	$6,400,000
Necessary Feeder Voltage Monitoring	$1,200,000
Less accurate metering and resolving metering issues	$9,900,000
Unrealized Operational Savings	$7,500,000
Total Status Quo Costs	**$66,500,000**

The evaluation of AGi looked at both the costs and benefits of proceeding with the new technology systems. The AGi systems costs are summarized as follows:

Summary of Total Expected COST of AGi Technology (2018-2033)	
Reason	Cost
AMI & MDM system (Meters and Database)	$37,000,000
LM System (New LCRs)	$13,400,000
Communication Infrastructure	$2,100,000
Project Delivery	$3,900,000
New Positions Created	$9,000,000
Project Interest Expense	$11,800,000
Total AGi Costs	**$77,200,000**

While the overall estimated costs for the AGi project are higher than estimated Status Quo costs, the estimated financial benefits of proceeding with AGi are significant. The benefits included in the AGi analysis are summarized as follows:

Expected BENEFITS With AGi Implementation (2018-2033)	
Reason	**Benefits with AGi**
Reduction in Meter Reading Costs	$17,400,000
Member Service Savings	$6,400,000
Reduction in Meter Losses	$9,900,000
Meter Revenue Finance Cost Savings	$300,000
Operational Cost Savings	$7,500,000
Meter Capital Costs Savings	$6,700,000
Load Control Power Cost Savings	$24,400,000
Total AGi Business Case Benefits	**$72,600,000**

While the projected 15 year AGi costs are somewhat higher than the 15 year benefits included in the analysis, this does not reflect some hard benefits recognized by other utilities, as well as direct member benefits and soft benefits which are described in this filing.

Based on the Cooperative's evaluation, Dakota Electric believes that we must begin preparing for a future state that integrates many technologies not present today, which requires advanced capabilities for monitoring, communication and control. The Cooperative's evaluation supports a deployment throughout the Dakota Electric service territory of Advanced Metering Infrastructure (AMI) coupled with installation of a Meter Data Management system (MDM) and the replacement of the existing Load Management (LM) system. The system wide communication network provided by the installation of AGi will support future operational monitoring. This will be required to support the operation of the distribution system with the installation of renewables, such as solar.

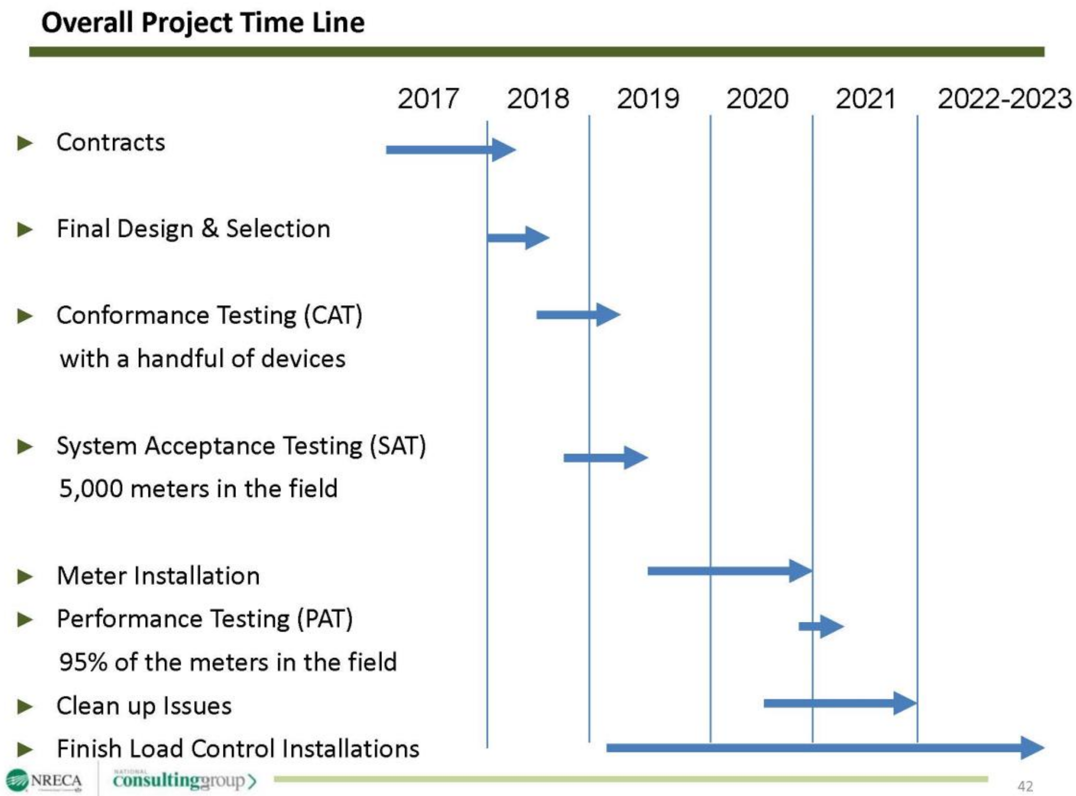
Together these systems will provide options for Dakota Electric to provide increased service levels and meet the future expectations of our Members. The Advanced Grid Infrastructure technology will also provide the foundation and flexibility for Dakota Electric to respond to the future issues as they arise.

This conclusion is consistent with Dakota Electric's strategic vision adopted by the Cooperative's Board of Directors. The values articulated in the strategic vision include safety, integrity and honesty, member service, reliability, innovation, environmental commitment, and community. AGi supports these values as follows:

- Safety
  - Less driving / walking / slipping for reading meters
  - Safer meter based switches for remote operation vs. pulling meters
- Reliability
  - Reduce need for members to call to report problems with their electrical service through AMI monitoring
  - Faster knowledge of outages
- Member Service
  - Provide more web-based information and services
  - Provide quicker review and help with members billing issues
  - Mining of usage data to help members save money
- Power Supply
  - Help GRE manage demand / generation through improving our Load Management capability
  - Help reduce our member's power supply costs through improved LM functionality
- Environmental
  - Improved information to help members conserve energy
  - Less miles driven by DEA vehicles
- Innovation
  - Implementing advanced proven technologies to benefit our members

Implementation Schedule

The projected schedule for implementing AGi is as follows:



This high-level schedule assumes that PUC approval for rate recovery is obtained in the spring of 2018. It shows that initial high-volume meter installations will not begin until around mid-year 2019, with full installation of all metering equipment anticipated around 2020 to 2021. Dakota Electric will be taking a slower approach to replacing the load management equipment and will first be replacing the very oldest units and the units which are identified through the AMI metering as not functioning. Then over the next few years the rest of the load management units will be replaced as necessary. At the present time, Dakota Electric expects that this timing for AGi equipment installation will happen between two general rate cases. Based on our most recent forecast of financial metrics, it appears that our next general rate case could be filed around mid-year 2019 using our traditional historic test year approach with adjustments for known and measurable changes. In recent years our general rate cases tend to be filed every five years, which means the following rate case would happen near the end of AGi equipment installation. The proposed tracker mechanisms will provide the needed bridge to recover AGi costs between these future rate cases.

Proposed Tracker Recovery Mechanisms

As described above, the projected 15 year AGi costs are somewhat higher than the 15 year AGi benefits. More importantly, the timing of costs to proceed with AGi do not align with the timing of benefits. That is, the AGi technology capital costs are front loaded and thus Dakota Electric needs to recover those capital costs that are expected to occur between general rate cases.

Dakota Electric proposes to use two separate tracker mechanisms to record and recover net investments in AGi infrastructure – one new and the other existing. Implementation of the first recovery mechanism would establish a new line item on Dakota Electric bills for the net costs associated with installing advanced metering infrastructure and meter data management equipment and related systems between general rate cases. It is anticipated that the costs recovered through this mechanism would be rolled into overall rates in a subsequent general rate case and the separate billing line item would be discontinued.

Load management costs, primarily load control receivers, would be recovered through the Cooperative's existing energy conservation and load management adjustment component within the Resource and Tax Adjustment (RTA). This treatment is consistent with the historic recovery of load management system costs in the Cooperative's RTA. From the mid 1990s until 2005, Dakota Electric included the depreciation for the load management "master station" in the conservation component of the RTA. The master station is an integral component for the load management system to function. Dakota Electric also expenses load control receivers, which are included each year in the conservation component of the RTA.

AGi Infrastructure Recovery Mechanism

Dakota Electric proposes to establish a mechanism for recovery of net AGi infrastructure investments between general rate cases consistent with the provisions of Minnesota Statute 216B.1636, which provides for recovery of electric utility infrastructure costs. M.S. 216B.1636 defines electric utility infrastructure costs and electric utility infrastructure projects as follows:

> “(b) "Electric utility infrastructure costs" or "EUIC" means costs for electric utility infrastructure projects that were not included in the electric utility's rate base in its most recent general rate case.
>
> (c) "Electric utility infrastructure projects" means projects owned by an electric utility that:
>
> > (1) replace or modify existing electric utility infrastructure, including utility-owned buildings, if the replacement or modification is shown to conserve energy or use energy more efficiently, consistent with section 216B.241, subdivision 1c; or …”

The proposed recovery mechanism is specifically intended to recover AGi infrastructure investments between general rate cases. As noted previously, the anticipated schedule for AGi implementation will likely occur between two future general rate cases and the costs for AGi are front loaded compared to the timing of anticipated benefits. The equipment (meters) that will be installed for the AGi project will be owned by the Cooperative and the data collected and administered through the meter data management system will allow Dakota Electric to operate the distribution system more efficiently and size equipment properly, all of which will conserve energy and use energy more efficiently.

Dakota Electric proposes to recover rate of return, incremental property taxes, and incremental depreciation expense associated with AGi equipment that will become part of the Cooperative’s rate base. This recovery is consistent with Subdivision 2 of M.S. 216B.1636 which states in part:

> “(a) The commission may approve an electric utility's petition for a rate schedule to recover EUIC under this section. An electric utility may petition the commission to recover a rate of return, income taxes on the rate of return, incremental property taxes, if any, plus incremental depreciation expense associated with EUIC.”
>
> (b) The filing is subject to the following:
>
> > (1) an electric utility may submit a filing under this section no more than once per year; and …”

M.S. 216B.1636 indicates that “an electric utility must file sufficient information to satisfy the commission regarding the proposed EUIC or be subject to denial by the commission. …" The statute goes on to identify specific information that must be included in a filing seeking recovery of EUIC. Following are the filing requirements contained in M.S. 216B.1636 with an indication of where the information is located in this instant filing:

(i) the location, description, and costs associated with the project;

- The AGi facilities will be located throughout our service territory, with meters at every location and load control receivers at member sites participating in a load management program. The description of the project and costs are contained in this filing and in the AGi Business Case Executive Summary (attached as Exhibit D).

(ii) evidence that the electric utility infrastructure project will conserve energy or use energy more efficiently than similar utility facilities currently used by the electric utility;

- The benefits of AGi are described in the AGi Business Case Executive Summary. AGi will allow for more advanced operation and control of the distribution system and facilitate the interconnection of renewable generation at consumer sites.

(iii) the proposed schedule for implementation;

- The proposed schedule for AGi is provided in the "Implementation Schedule" section of this filing.

(iv) a description of the costs, and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;

- The description of the status quo costs of continuing to operate existing infrastructure are described in this filing.

(v) the proposed rate design and an explanation of why the proposed rate design is in the public interest;

- Dakota Electric proposes to use two separate tracker mechanisms to record and recover net investments in AGi infrastructure – one new and the other existing. Implementation of the first recovery mechanism would establish a new line item on Dakota Electric bills for the net costs associated with installing advanced metering infrastructure and meter data management equipment and related systems between general rate cases. Load management costs, primarily load control receivers, would be recovered through the Cooperative's existing energy conservation and load management adjustment component within the Resource and Tax Adjustment (RTA).

- Dakota Electric proposes to implement an Advanced Grid Infrastructure Rider (AGi Rider) that is attached in Exhibit E. The AGi Rider would apply a per kWh charge to metered retail rate schedules. This charge will appear as a separate line item on bills identified as "AGi Adjustment". This application is appropriate since the AMI and MDM systems relate to metered service. The per kWh charge recognizes the general regulatory inclination that most riders are consumption based – as compared to a flat monthly amount. (If a flat monthly amount per consumer were applied, we estimate that amount at about $1.35 per month.) The AGi Adjustment would also be capped at a monthly maximum amount of $25.00. This cap provides some uniformity in the average estimated bill impacts of implementing AGi until such costs are allocated in a future general rate case process.
- The calculation of the AGi Adjustment will be filed with the Commission at the beginning of the calendar year just like we have done for decades with the Resource and Tax Adjustment (RTA). The AGi Adjustment will be implemented with bills mailed after January 1, subject to any correction or modification after regulatory review and Commission approval. This is the same annual process we use for the RTA.

(vi) the magnitude and timing of any known future electric utility projects that the utility may seek to recover under this section;

- The scope of the AGi project is detailed in this filing.
- An example calculation of the AGi Adjustment is provided in Exhibit F based on estimated project costs and billing units.

(vii) the magnitude of EUIC in relation to the electric utility's base revenue as approved by the commission in the electric utility's most recent general rate case, exclusive of fuel cost adjustments;

- Dakota Electric's base annual revenue approved in our last general rate case (Docket No. E-111/GR-14-482) was $203,574,418. When meter and communication equipment is fully installed, the total annual AGi tracker revenue is estimated at about $1,700,000. When LCR equipment is fully installed, the total annual revenue collected in the CIP component of the RTA is estimated at about $1,600,000.

(viii) the magnitude of EUIC in relation to the electric utility's capital expenditures since its most recent general rate case;

- The Rate Base approved in the Cooperative's last general rate case was $171,181,006. Dakota Electric's annual net capitalized additions since the rate case test year range from about $10,000,000 to about $14,000,000. Since our last general rate case test year (historical 2013) we have made total net capitalized additions of almost $50,000,000. The AGi project will result in estimated total capitalized additions of about $32,000,000.

(ix) the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case;

- Dakota Electric's last general rate case was filed on July 2, 2014. The high-level AGi schedule shows that initial equipment installations will not begin until around mid-year 2019, with full installation of all equipment anticipated around 2022 to 2023. At the present time, Dakota Electric expects that this timing for AGi equipment installation will all happen between two general rate cases. Based on our most recent forecast of financial metrics, it appears that our next general rate case could be filed around mid-year 2019 using our traditional historic test year approach with adjustments for known and measurable changes. In recent years our general rate cases tend to be filed every five years, which would happen near the end of AGi equipment installation. The proposed tracker mechanisms will provide the needed bridge to recover AGi costs between these future rate cases.

(x) documentation supporting the calculation of the EUIC; and

- The documentation and calculation of the proposed tracker recovery for the AGi Adjustment are shown in Exhibit F.

(xi) a cost and benefit analysis showing that the electric utility infrastructure project is in the public interest.

- The cost and benefit analysis of AGi is described in the AGi Business Case Executive Summary and in this filing.

Load Management Recovery Mechanism

Dakota Electric proposes to recover load management AGi infrastructure investments (load control receivers) under the provisions of the Cooperative's existing Resource and Tax Adjustment. This treatment is consistent with the historic recovery of load management system costs in the Cooperative's RTA. From the mid 1990s to 2005 Dakota Electric included the depreciation for the load management "master station" in the conservation component of the RTA. The master station is an integral component for the load management system to function. Dakota Electric also expenses load control receivers, which are included each year in the conservation component of the RTA. An example calculation of the LCR related costs that would be included in the CIP component of the RTA is provided in Exhibit F based on estimated project costs identified in the Business Case.

IV. Conclusion

Based on the information provided in this filing, Dakota Electric requests that the Commission:

1. Approve the proposed Advanced Grid Infrastructure Rider that allows Dakota Electric to recover rate of return, incremental property taxes, and incremental depreciation expense associated with AGi equipment that will become part of the Cooperative's rate base.
2. Affirm that Dakota Electric is authorized to recover rate of return, incremental property taxes, and incremental depreciation expense associated with load management AGi infrastructure investments (load control receivers) under the provisions of the Cooperative's existing energy conservation component in Resource and Tax Adjustment.
3. Issue a decision in this matter by April 23, 2018 to maintain the pricing offered in proposals to the Cooperative.

If you or your staff have any questions regarding this petition, please contact me at (651) 463-6258.

Dated: November 20, 2017

Respectfully Submitted,

/s/ Douglas R. Larson

Douglas R. Larson
Vice President of Regulatory Services
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024
651-463-6258

Certificate of Service

I, Cherry Jordan, 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/M-17-___

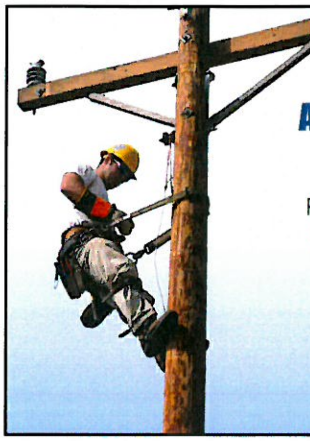
Dated this 20th day of November, 2017

/s/ Cherry Jordan

____

Cherry Jordan

Exhibit A: September 29, 2015, PUC Planning Meeting Presentation



AMI / MDM / LM Update

PUC Planning Meeting
September 29, 2015

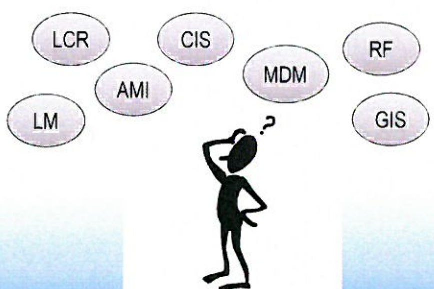
Craig Turner, Engineering Services Manager
Doug Larson, VP of Regulatory Services

DAKOTA ELECTRIC ASSOCIATION

Agenda

- Introductions
- Background
- Project History
- Existing Issues / Pending Issues
- State of the Industry (AMI / MDM / LM)
- Benefits (why do this)
- Considerations

Terminology



Tie to DEA Strategic Vision

- Safety
  - Less driving / walking / slipping for reading meters
  - Safer meter based switches for remote operation vs pulling meter
- Reliability
  - Improve power quality through AMI monitoring
  - Faster knowledge of outages
- Member Service
  - Provide more web-based information and services
  - Provide quicker review and help with member billing issues
  - Mining of usage data to help members save $$
- Power Supply
  - Help GRE manage demand / generation through improving our Load Management capability
  - Help reduce our member's power supply costs through improved LM functionality
- Environmental
  - Improved information to help members conserve energy
- Innovation
  - Implementing advanced proven technologies to benefit our member

Smart Grid - What has been done

- SCADA (Remote Control and Monitoring)
  - All Substations / All Feeders have SCADA
  - All feeders have digital relays
    - Provide distance to fault from substation
    - Have multiple relaying elements available
- All Capacitors are remotely controlled
  - Saving energy due to reduced system losses
- Drive-by / walk-by meter reading
  - Hard to read / access meters
  - Fewer estimated bills
- Auto-transfer Switches for Large Commercial Loads
  - Transfer loads in less then 2 seconds
- GIS (Geographic Information System)
  - OMS (Outage Management System)
  - Asset Management
  - Work Management System (City Works)

Smart Grid – In process

- Adding more Remote Operated Switches
- Adding SCADA to Voltage Regulators located in the field (50% are completed)
- AMI Business Case Development
  - What are the benefits for our members?
  - What are the costs and impacts if we don't do this?
- Looking at Replacing Load Management System
  - What features do our members want?
  - What does MISO require?
- High Speed Fiber Communication System
  - Working with Dakota County and GRE
  - Need to support AMI

2005 Study History

- 2005 Study
  - Looked at just AMI systems
  - AMI technology was still developing
  - AMI companies were not stable
  - MDM systems were fairly new and emerging
  - No clear cost benefit
  - Decided to wait

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2013 Study History

- Findings
  - AMI systems matured and are working well
  - MDM stable but still undergoing improvements
  - Update CIS before AMI is started
  - Communication system needs long term solution
  - Identified several internal systems - end of life / needing upgrade
  - Business case included only AMI & MDM
    - Load Management was not included
  - Team identified web presentment a significant need
- Created basic technology roadmap for cooperative
  - It takes years to implement an AMI system

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2015 Study Progress

- Have identified existing system issues
  - Systems needing upgrading due to end of life
- Developing recommended strategy
- Developing business plan
- Working with the Senior Management
- In 2016 - Considering a detailed review of vendor offerings and other utility experiences.

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Existing System Issues

- The sky is not falling!

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Existing Issues – Meter Reading

- Meter reading is working well
  - Overall costs are low to read our billing meters
  - Limited to monthly read per meter / Limited information
- Rural AMR (Turtle system)
  - System is no longer manufactured and is not supported
  - 5,000 meters – can only do single daily reading
  - Not integrated with other systems
  - Expect up to 5 years, remaining life

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Existing Issues – Load Management

- Existing LM system
  - Responsible for millions of dollars in savings from power costs annually
  - Two parts to the system
    - SCADA controls all the member owned generation
    - Load Control Receivers (LCRs) control the rest of the loads

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Load Control System - Issues

- LM system uses Power Line Carrier (PLC) and Pager signal to communicate with LCRs
- PLC system is over 20 years old – not supported by manufacturer
- Pager communication has limited support and functionality
- Existing system (LCRs & equipment) is old and reached end of life. It has worked well for the past 20 years!

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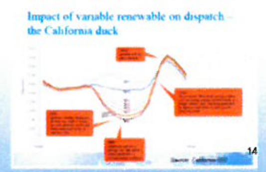
Pending Issues

- Increased solar penetration results in:
  - Significant changes to the DEA load curve:
    - Increased volatility
    - Increases the potential for sharp peaks
- Increasing need for:
  - Dynamic Rates, e.g., TOU, Critical Peak Pricing (CPP)
  - Residential demand rates
  - Load Control
  - Demand Response
  - Customer Engagement



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Pending Issues - Solar

- Solar Power affects safety and reliability of the distribution system which could be identified by AMI information
  - Reverse power flow
  - System voltage issues
  - High Voltage results in equipment damage and member damage
- AMI / MDM systems provide system measurements needed to operate a dynamic distribution system

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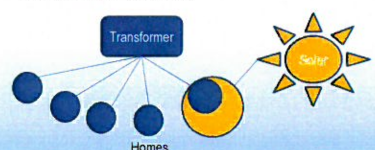
Pending Issues - Solar

- Distribution System overload due to solar
  - Transformer loading example
    - Solar covers up member's actual usage
    - Need AMI to see actual peak demands
    - Currently we only know monthly energy (kWh)
    - We estimate peak from monthly numbers based on a "typical user"
      - Solar install creates "non-typical" user



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AMI / MDM / LM Systems

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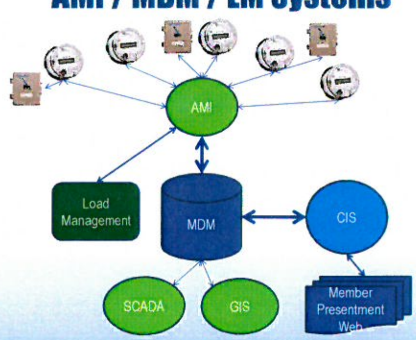
AMI / MDM / LM Systems



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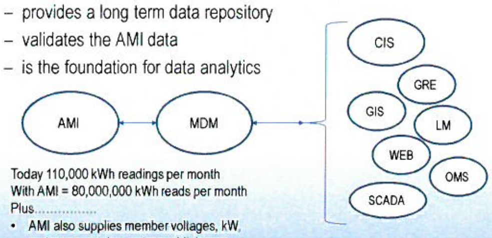
Meter Data Management (MDM)

- MDM
  - serves as an integration hub
  - provides a long term data repository
  - validates the AMI data
  - is the foundation for data analytics



Today 110,000 kWh readings per month
With AMI = 80,000,000 kWh reads per month
Plus...............

- AMI also supplies member voltages, kW, meter error codes, outages, blinks etc.
- so LOTS of DATA!

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MDM Offerings

- MDM software is ready to be used and extracts significant value from AMI
- MDM's functionality continues to improve and stabilize, shown by developments since 2013 study
- MDM provides analytics and data presentment, e.g.,
  - Combining load data from multiple meters into a single "virtual" meter, e.g., total load on a transformer, load for all the McDonald's, etc.
  - Outage followed by reverse power flow on meter could be theft
  - Web portal data for members

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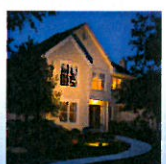
AMI Status

- AMI has been proven by many utilities to be much more than a basic meter reading system
- AMI is a key component of "Smart Grid"
- AMI provides a system-wide communications infrastructure for a direct link to members and to utility assets, performing:
  - Metering
  - Load Management
  - Street light management
  - Voltage controls
  - Distribution automation



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AMI Systems

- Most use Radio Frequency (RF) technology
  - Capacity of the AMI communications is very important
- AMI systems are mature
  - Utilities and vendors continue to add functionality to extract higher value returns
- Existing utility users reporting a high degree of satisfaction with their AMI system

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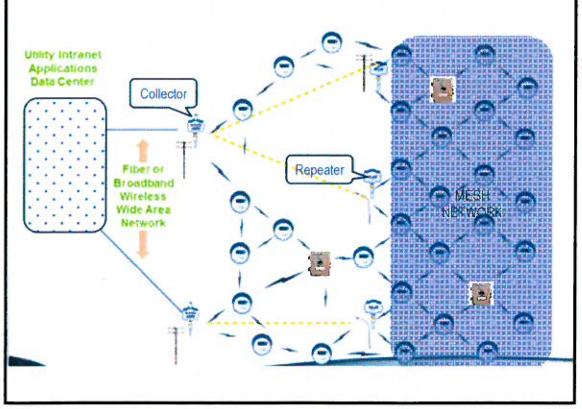

Load Management Offerings

- New two-way LCRs utilize AMI network for communication
- AMI data is needed to validate LCR performance
  - Validation is needed for Selling into MISO
- LCR functionality varies between different vendors
  - 2-way LCRs verify the operation of the LCR relay but don't catch if the unit is bypassed.

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Benefits

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Member Benefits

- Some benefits seen by the member include:
  - Automatic reporting of outages
    - Great when on vacation or away from home. Also confirms that DEA knows of the outage
  - More information about member usage (web portal)
    - Energy saving analysis
    - Puts member in control of their energy usage (member set alarms to alert the member)
  - Pre-pay and payment options
    - Members save deposit and reconnect fees
    - Provides flexible payment options for members
  - Special rates (Time-of-Use)
    - Provides more choice for the members
  - High bill complaint resolution
    - Quick resolution of high bill issues
  - High / low voltage issues
    - Automatically reports on voltage and power quality issues
  - Outage response
    - Could help speed up restoration during larger storms

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DEA Benefits

- Many internal process benefits
  - Transfers – reduce read-in/out costs
  - Remote reconnect – less OT and truck rolls
  - Remote voltage / outages – less OT and truck rolls
  - Transformer right-sizing (less outages and lower losses)
  - Supports improved billing process (MDM)
  - Streamlines LM information to GRE
  - Pre-pay metering & payment options
  - Revenue protection analysis for metering issues, theft, etc.

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Future AMI / MDM Benefits

- Provides opportunity for targeted solutions
- Increased accuracy and volume of data for planning
  - Conservation analysis
  - Rate analysis

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Additional Options – Remote Disconnect Device

- Needed for Pre-Pay
- Remote Disconnect Operation
  - MN Rules require sending a person to the site to allow for payment before disconnection is allowed
  - Use remote disconnect after visit for safer disconnecting
- Remote Reconnect Operation
  - May be allowed to remotely reconnect
  - Saves overtime and drive costs for crews driving to site to reconnect
  - Faster response to member requests
  - Lower charges for the member

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High level takeaways

- A solution is needed to respond to end of life for existing LM and rural metering systems (AMR)
- AMI and Load Management are mature systems and will use the same communication network
- MDM will be required as a hub, data repository and analytics platform
- The 2014 Communication Study identified a need for down-line communications network; AMI can provide this functionality
- Any solution must be agile to meet the needs of Members, power supply, regulatory, environmental, and other stakeholders

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What about cost?

- Cost of AMI/MDM may be about the same as upgrading/patching existing systems
- However, AMI/MDM provides the potential for many new or enhanced services
- Study will fine tune the numbers

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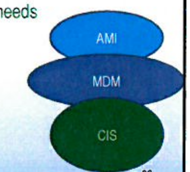
Other Items to Consider

- How much integration is required?
  - AMI to MDM to GIS & CIS & OMS to ???
- What does the CIS project cover?
- Different positions required to manage the new AMI / MDM systems?
  - What new skill sets?
- Ensure future LM system meets GRE & MISO needs
- Project Management
  - What is needed to manage a project of this size?
- Oversight Costs
  - Internal
  - Regulatory



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Issues to be Addressed

- Utilization of features
  - Prepay (Will this be allowed?)
  - Remote disconnect
- Privacy concerns/complaints
- Health concerns/complaints
- Cost recovery
  - What if 50¢ or $1 more per month?
- "Refusal" fixed charge
- Data ownership
- Regulatory review
- Rate recovery
- Rate case timing

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Discussion

Thank you

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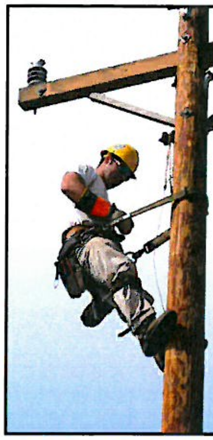
Exhibit B: May 23, 2017, PUC Planning Meeting Presentation



Advanced Grid Infrastructure (AGi) Update

PUC Planning Meeting
May 23, 2017

Doug Larson, VP of Regulatory Services
Craig Turner, Director of Engineering Services

DAKOTA ELECTRIC ASSOCIATION

Agenda

- Introductions
- Overview
- Member Survey
- Utility Learning Sessions
- Implementation Features / Questions
- Next Steps / Regulatory Process(es)

Tie to DEA Strategic Vision

- Safety
  - Less driving / walking / slipping for reading meters
  - Safer meter based switches for remote operation vs pulling meter
- Reliability
  - Improve power quality through AMI monitoring
  - Faster knowledge of outages
- Member Service
  - Provide more web-based information and services
  - Provide quicker review and help with member billing issues
- Power Supply
  - Help GRE manage demand / generation through improving our Load Management capability
  - Help reduce our member's power supply costs through improved LM functionality
- Environmental
  - Improved information to help members conserve energy
- Innovation
  - Implementing advanced technologies to benefit our member

Smart Grid – DEA to Date

- SCADA (Supervisory Control and Data Acquisition) - Remote Control and Monitoring
  - All Substations / All Feeders have SCADA
  - Feeders have digital relays
    - Provide distance to fault from substation
    - Multiple relaying elements available
- All Capacitors are remotely controlled
  - Saving energy due to reduced system losses
- Auto-transfer Switches for Large Commercial Loads
  - Transfer loads in less then 2 seconds
- GIS (Geographic Information System)
  - OMS (Outage Management System)
  - Asset Management
  - Work Management System (City Works)

Smart Grid – DEA In Process

- Adding more Remote Operated Switches
- Adding SCADA to Voltage Regulators located in the field (50% are completed)
- High Speed Fiber Communication System
  - Working with Dakota County and GRE
  - Needed to support AMI
- Looking at Replacing Load Management System
  - What features do our members want?
  - What does MISO require?
- AGi Business Case Development
  - What are the benefits for our members?
  - What are the costs and impacts if we don't do this?
  - Issued RFP and evaluating bids

Existing Issues

- Meter reading is working well
  - Overall costs are low to read our billing meters
  - Limited to monthly read per meter / Limited information
  - Rural AMR (Turtle system)
    - System is no longer manufactured and is not supported
    - Expect up to 5 years remaining life
- Existing LM system
  - LM system uses Power Line Carrier (PLC) and Pager signal to communicate with LCRs
  - PLC system is over 20 years old – not supported by manufacturer
  - Pager communication has limited support and functionality
  - Existing system (LCRs & equipment) is old and reaching end of life

Pending Issues

- Increasing solar penetration results in:
  - Changes to the DEA load curve:
    - Increased volatility
    - Increases the potential for sharp peaks
- Increasing need for:
  - New rate options
  - Load Control
  - Demand Response
  - Member Engagement

7

Impact of Regulatory Proceedings

- Several dockets have been opened in the past couple of years that have implications for gathering more detailed information and providing enhanced system capabilities including:
  - Grid Modernization
  - Standby Service
  - DG Interconnection and Process
  - Distribution System Planning
  - Customer Energy Usage Data
  - Hosting Capacity Analysis

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Categories of Benefits Delivered by AGi

- **Direct Financial Benefits**
- **Potential Financial Benefits**
- **"Soft" Benefits**
  - **Improved Operations –** Helping system operations for improved performance
  - **Member Service –** Faster response to billing issues, improved electric service, consumption information, etc.)
  - **Societal –** Typically environmental improvements due to lower system demand, conservation, etc.

Member Benefits

- **Improved service**
  - Identify outages even when the member is not home or does not call
  - Improves efficiency of outage management
  - Improved accuracy and timeliness of meter readings
  - Improves DEA's ability to proactively identify and resolve power quality issues - before the member calls!
- **Member privacy**
  - Reduce need for DEA employees to access member property
- **Flexibility**
  - Ability to offer Members more billing and rate options
- **Efficiency**
  - Enables more efficient resolution of member issues and/or questions
  - Reduces DEA operational costs which may result in lower rates

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DEA Benefits

- **Eliminate multiple internal systems**
  - Turtle AMR meters (end of life)
  - PLC based load control (end of life)
  - Pager based load control (near end of life)
  - Drive-by ERT meters
  - MV-90 based meters
- **Detailed member usage, e.g., hourly or sub-hourly readings**
  - Having the detailed usage data allows us to evaluate load and usage information
  - Sizing transformers (reduce outages, reduce capital costs, reduce system losses)
  - Supports rate analysis
  - Identify non-working load control devices

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DEA Benefits cont'd

- **Automatic reporting of outages**
  - Provides a member benefit of not needing to report outages
  - Enhance DEA's ability to respond to outages – identifies nested outages
  - Reduce busy signal on telephone calls (allows the important calls to get through)
  - Supports the OMS system for items such as texting members on the outage application
- **Member voltage and power quality**
  - Know about member blinks and possibly power sags
  - Transformer problems
  - Helps us help the member trouble shoot problems remotely (saves crew trips)
  - Provides real-time data about system problems before they get serious

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Benefits for DEA and its Members

- Employee/Member Safety
  - Fewer people in harm's way (dogs, accidents, physical collections)
  - Reduced risk for vehicle accidents
  - Less incentive to tamper

- Environmental
  - Supports the efficient use and integration of renewable resources
  - Supports load control and demand response initiatives
  - Fewer miles driven by DEA employees
- Supports Pre-Paid Metering
  - Potential to reduce member disconnect and bad-debt costs
  - Reduce DEA disconnect letter costs
  - Potential conservation savings based on industry experience

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AMI is a foundation for the future

Solar/Renewables	The penetration rate of solar implementation is uncertain but even a small amount of installations can have an impact on metering costs, operations, planning, etc.
Distribution Automation (DA)	DA provides additional opportunities to lower operating costs while improving the quality of electric service.
Load Control/Dispatch	Load Control and other activities related to Demand Response.
Transformer (and other asset) monitoring	Support for asset management also requires the use of Meter Data Management (MDM) to fully deliver the desired functionality.
VVO	Volt VAR Optimization applications are moving past the trial stage at some smaller utilities and into volume production at larger utilities.

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High level takeaways

- A solution is needed to respond to end of life for existing LM and rural metering systems (AMR)
- AMI and Load Management are mature systems and will use the same communication network
- MDM will be required as a hub, data repository and analytics platform
- The 2014 Communication Study identified a need for down-line communications network; AMI can provide this functionality
- Any solution must be agile to meet the needs of Members, power supply, regulatory, environmental, and other stakeholders

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Member Survey

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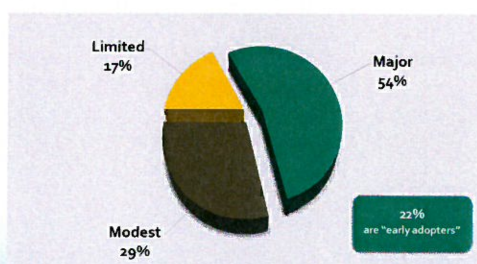
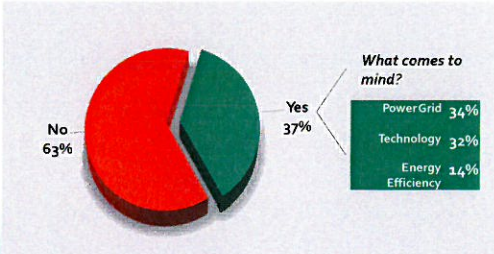
Methodology

- DEA contracted with Himle Rapp & Company, Inc.
- 400 sample of adult members of Dakota Electric
- Sample reflects Dakota Electric member demographics
- June 9-16, 2016
- Average interview time of 20 minutes
- Margin of error ± 5.0%

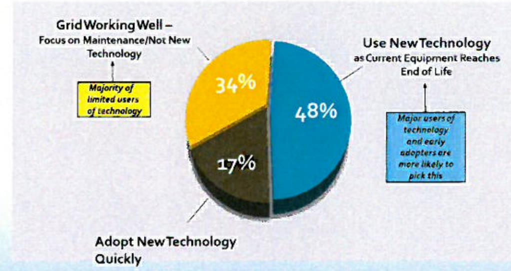
Technology Use



Awareness of Smart Grids



Views on Investments in New Technologies



Importance of AMI Meters: Consumer Uses

	Importance	Rating
Dakota Electric would be automatically informed when power is out at your home, allowing them to address the problem more quickly.	86%	+116
You could receive more information about **how conservation is helping you reduce electricity use**.	77%	+76
You **could use flexible pricing,** which would reduce your bill if you use more electricity during off-peak hours or raise your bill if you use electricity when demand from others is the highest.	75%	+71
You could ask to **receive a text on your phone to tell you when your power is out**.	72%	+65

Importance of AMI Meters: Dakota Electric Uses

	Importance	Rating
Dakota Electric could better manage how to restore power after storms, reducing the time members are without power.	85%	+105
Dakota Electric could use data on electricity use to **target its maintenance dollars** to places with more outages than normal or with inefficient equipment.	82%	+95
Dakota Electric regularly needs to replace its meters — by installing AMI meters, Dakota Electric will be **using the most advanced meters available** for a smart grid.	83%	+93
Dakota Electric could **receive information allowing power plants to operate more efficiently**.	81%	+90
Dakota Electric could evaluate energy use throughout its system and **take steps that reduce the pressure to increase rates**.	79%	+89

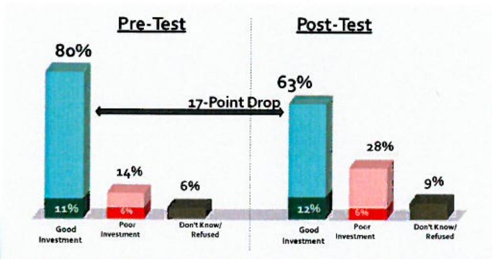
Concerns About AMI Meters

	Concern	Rating
Replacing all of the old meters with new AMI meters **will cost members millions of dollars**.	71%	+66
AMI meters are **only as good as the software** used to read and transmit the data — if the software doesn't work, Dakota Electric will be getting bad data.	68%	+54
Transmitting data is not very secure — information about my **energy use or billing information might be stolen by hackers**.	67%	+54

Concerns About AMI Meters

	Concern	Rating
If we automate more of the electric grid, there **will be a greater risk of cyber-attacks**.	64%	+40
Electromagnetic waves, such as those transmitted by AMI meters and cell phones, **can be harmful to humans at high level of exposure**.	64%	+39
Dakota Electric will be obtaining more information than ever, and **will know too much about my daily electricity use**.	62%	+28

Views on AMI Meters



Utility Learning Sessions

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Local Utilities

- DEA staff is in communication with other cooperatives in our area
- Presentations by two local cooperatives during DEA Board Meeting
  - Overview of process and implementation
  - Lessons learned
  - Opportunity for DEA Board to ask questions

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Site Visits

- DEA reached out to several utilities around the country and met with their staff responsible for evaluating and implementing AMI/MDM
  - List of specific questions and topics to cover with each utility
  - Learn from their experience
    - What went right?
    - What went wrong?
    - What would you do differently?

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Takeaways from Utility Visits

- AMI technology is solid and works
- AMI is a foundational system which affects all departments
- AMI is a communication system which happens to collect meter readings
- AGi system benefits are greater than expected
- MDM is needed to help extract the benefits

- Best Quote from the trips:
  "The system identifies problems before they become problems"

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Review of AMR/AMI in the US – Market Penetration

Available US Meter/Utility Market

Total Market	Companies	Meters
IOU	200	104M
Cooperatives	900	18.5M
Municipals	2,000	21M
Total	3,100	144M

Estimated Market Penetration – AMR/AMI

AMR (PLC/RF)	Companies	Meters
IOU	~50 (25%)	25M (24%)
Cooperatives	~550 (61%)	11.7 M (63%)
Municipals	Unknown	Unknown
Total	~600 (20%) +	36.7M (25%) +
AMI (RF)	**Companies**	**Meters**
IOU	~150 (75%)	79M (76%)
Cooperatives	~250 (28%)	6.1M (33%)
Municipals	~200 (10%)	10.3M (50%)
Total	~600 (20%)	95.4M (66%)

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Issues to be Addressed
&
Regulatory Process(es)

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Issues to be Addressed

- Utilization of features
  - Flex pay/Prepay (Will this be allowed?)
  - Remote disconnect and reconnect
- Privacy concerns/complaints
- Health concerns/complaints
- Cost recovery
- "Opt-Out" fixed charge
- Regulatory review
- Rate recovery
- Rate case timing

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Next Steps / Regulatory Process(es)

- Complete project evaluation
- Dakota Electric BOD decision
- LM costs recovered in existing conservation tracker
- PUC:
  - "Between rate case" tracker for other investments
  - Authorization of features

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Discussion

Thank you

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Exhibit C: *Circuits* articles

What's ahead for your electric co-op in 2017

Greg Miller
President & CEO

"We are adding our own 1-MW solar array that will offset wholesale power purchases and directly connect to Dakota Electric's distribution system for the sole benefit of our members."

Dakota Electric Associations' board of directors recently reviewed and approved the 2017 budget and construction work plan. These documents outline how we intend to invest in our cooperative for the benefit of our member-owners.

New services

Indications are that Dakota Electric will add approximately 1,000 new services throughout the year. Most of this growth will be new homes and apartments. Despite the growth in new services, our kWh sales remain nearly flat, which reflects overall improvements in energy-efficiency standards, participation in utility conservation programs and other factors.

Solar

Our members have indicated they would like Dakota Electric to have more renewables in our generation mix, so we are adding our own 1-MW solar array near Hastings that will consist of more than 3,500 solar panels. The solar array will offset wholesale power purchases and directly connect to Dakota Electric's distribution system for the sole benefit of our members. This should be online in early summer.

Technology

Dakota Electric is in the process of updating and enhancing our website with greater functionality and features. Our new website is expected to launch in the first quarter of 2017. This will complement our new outage application that we launched just a few weeks ago to report and track outages from your wireless device. I encourage you to download this app for convenient outage reporting.

Our customer information system software is the hub of our member service and billing departments and it is now 20 years old. Our employees have been busy preparing to change to a new system which is expected by the middle of 2017. This software will be a foundation on which to provide even better services in the future.

We are currently halfway through a project to connect all of our 34 electrical substations in the field to fiber optics for enhanced communication and control of our system. This communication network will also be a foundation for future functions and services. Plans are to complete this project by the middle of 2018, with most of our substations connected by the end of this year.

New meter equipment

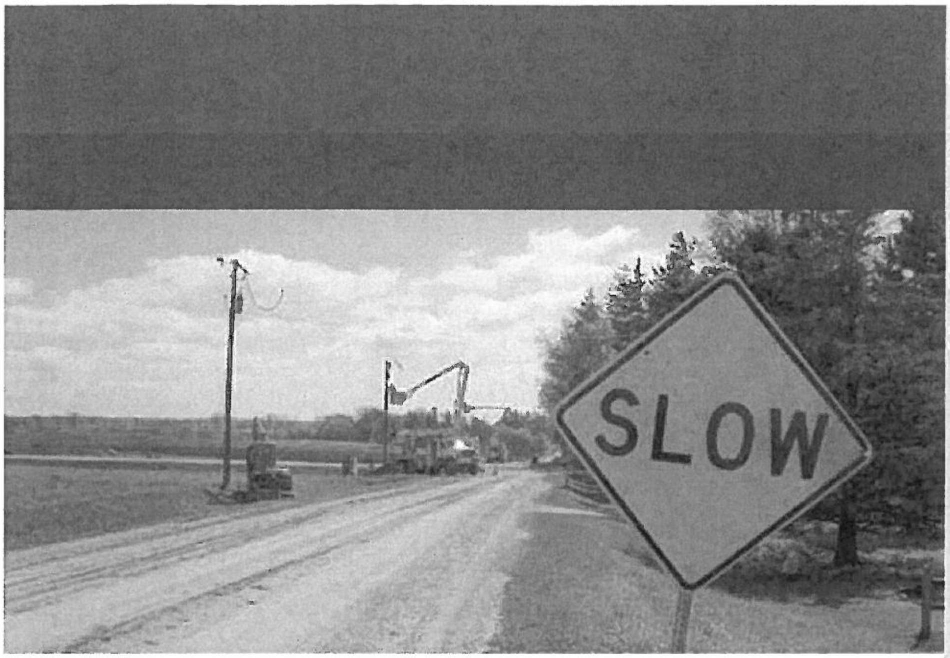
Another foundational project we are researching involves the replacement and updating of our aging electric meters and load management devices. Many of these devices are more than 20 years old and nearing end of life. Dakota Electric has over 116,000 electric meters and about 50,000 load control devices in use today, and we are looking at the best technology to replace this infrastructure.

Employee teams and consultants have been researching the options available over the past five years, and we are looking carefully at the technology that has been successfully used at other utilities around the country. New metering technology can communicate the meter readings and outage information directly to Dakota Electric's office and help us prevent outages by seeing overloaded situations or blinks which can turn into extended power outages.

When an outage occurs, this system will rapidly collect information from the individual meters and identify the outage so power can be restored even if the member is away from home.

If all goes as planned, we will conclude our research this year and send out requests for proposals. Upon approval, we will install a limited number of meters in 2018 to verify the operation and performance of the interconnected systems. If all goes well, we will begin replacing the rest of the meters beginning in 2019, over approximately a 24-month period. Dakota Electric will provide our members with regular updates as we proceed, with more frequent updates as we get closer to the installation. We will also have a special section on our website to update our members on our progress and answer frequently asked questions.

We are excited to utilize all of these technology systems to serve you even better in the future. It will surely be an exciting year at Dakota Electric, and we encourage you to visit our website or like us on Facebook/Twitter for updates about your electric cooperative. Thank you for the privilege to serve you.



2016: Continued achievement in service and reliability

As a member-owned cooperative, we strive to provide quality service to our members. Below is a brief overview of our 2016 achievements:

- Reliability indices, as reported to the Public Utilities Commission, continue to be among the best in the nation:
    - Outage frequency per member averaged less than one outage every three years (normalized for major events).
- Continued the installation of remote monitoring and distribution equipment controls to allow improved restoration times.
- Began installing fiber optic communications to our substations and have about one-third of substations connected to the fiber system.
- Helped members conserve more than 23.2 million kilowatt-hours (kWhs) of electricity, which is enough energy to power more than 2,300 homes for an entire year.
- Reduced our wholesale power bill by approximately $17 million through member participation in Energy Wise® off-peak programs.
- Member service representatives received 151,641 calls in 2016 and answered 89.2 percent of calls in 20 seconds or less.
- Meter readers completed approximately 1.4 million meter readings, estimating less than three percent of all readings.
- Awarded $200,000 in scholarships and educational donations using unclaimed capital credits.
- Launched a new program that provides turnkey solutions for small business lighting retrofits.
- Launched smartphone app that allows members to quickly report outages and more.

2017 Goals

RELIABILITY

- Continue the installation of fiber optic communication to more substations in 2017 and 2018.
- Address the poorest performing feeders to improve reliability in outage-prone areas.
- Complete construction on a new substation north of Randolph to improve capacity and service to the southern part of our service territory.
- Review advanced grid proposals and determine if grid enhancements meet project goals for improved service and reliability.

EFFICIENCY

- Encourage residential members to conserve 4.8 million kWhs of electricity through energy-efficiency rebates and programs.
- Offer rebates and grants to help business members conserve at least 11.5 million kWhs.

AFFORDABILITY

- Work with our wholesale power supplier, Great River Energy, to minimize power cost increases.
- Work with legislators on the impact potential legislation may have on Dakota Electric members.

COMMUNITY

- Send five high school students to Washington, D.C. to learn about our nation's government.
- Educate area students and adults about electrical safety.
- Actively support the communities we serve through various outreach programs and volunteer efforts.

ENVIRONMENT

- Install 1-MW solar array (3,500 panels) near Hastings.
- Distribute more than 6,000 tree seedlings to communities and schools.

MEMBERSHIP

- Pay out more than $2.5 million in capital credits.
- Host annual Member Appreciation Event at the Minnesota Zoo

CIRCUITS

NEWS FOR DAKOTA ELECTRIC MEMBERS

Dakota Electric is researching ways to better manage outages and improve operations through Advanced Grid Infrastructure (AGi)

As Dakota Electric continues to make investments to improve our electric grid, we are researching the replacement of aging electric meters with advanced meters, similar to what other cooperatives and utilities around the country have already done.

For the last several years, Dakota Electric has researched new technology to serve you even better.

Advanced Grid Infrastructure (AGi) refers to important new technologies that would enhance the communication and operation of the distribution system that delivers electricity to our members. Anyone who purchases electricity from Dakota Electric is a member-owner of the cooperative.

These technologies will help Dakota Electric monitor our system for better efficiency and operation. It will allow two-way communication to field equipment, providing numerous benefits to our members and Dakota Electric.

When we use the term AGi, we are referring to what has been called "smart meters," but it is also referring to more than that. AGi captures the wider scope of this project, from the meter to load management to meter data management software and analytics.

Why are we researching this new technology?

Dakota Electric's existing meters and load management devices are nearing the end of life. The average age of these devices is more than 20 years old. We have more than 116,000 electric meters and about 50,000 load control devices in use today. We are looking at the best technology to replace this critical infrastructure.

What are the benefits of AGi?

New metering technology can communicate meter readings and outage information directly to Dakota Electric's office. This would help avoid outages by identifying failing equipment or overloaded situations before they turn into extended power outages. When an out-

- continued on page 3

In This Issue

May 2017

Upcoming events

C&I Member Meeting ..... May 4, 8-10 a.m.
GreenTouch .... May 6, 9 a.m. - Noon
Energy Trends Expo .... May 9, 6-8 p.m.
Twins Youth Baseball Clinic .... May 13
Board Meeting .... May 25, 8:30 a.m.
Memorial Day - Office closed....... May 29

DAKOTA ELECTRIC ASSOCIATION

Your Touchstone Energy® Cooperative

AGi (cont.)

age does occur, the system will rapidly collect information from individual meters and automatically report the outage so power can be promptly restored, even if the member is away from home.

AGi is also needed to support the increased integration of member-owned renewable energy on the distribution system.

What is the timeline for AGi implementation at Dakota Electric?

Dakota Electric's AGi project is a long-term initiative. Over the last few years, we have studied AGi technology and the business case. This past year, Dakota Electric staff visited several electric utilities to learn from their experience with similar infrastructure implementation.

Requests for proposals (RFPs) have been sent to potential vendors and a team of employees will review and evaluate proposals in the next couple of months. If a proposal meets our objectives and budget, we will present the project to your board of directors for a decision by the end of this year.

If approved, a limited number of meters and equipment will be installed next year to verify operation and performance of the interconnected systems. If all is in order, installation of the new meters will begin in 2019, with meter installation taking approximately 24 months.

What will AGi cost?

The entire project is estimated to cost less than $1 per member per month, though exact costs will not be known until proposals are received.

Dakota Electric is still early in this process. As we complete the evaluation process and select a vendor, we will know more about the equipment and how it functions. We will continue to update you regularly with information as it becomes available. For questions, call 651-463-6243, email customerservice@dakotaelectric.com or visit dakotaelectric.com/agi.

Advanced Grid Infrastructure (AGi)

Summary of Benefits

MEMBERS

- Automated power outage reporting, improved restoration and member communications.
- Enhanced reliability and power quality improvements.
- Improved energy usage information and options for our members.
- Support increased integration of member-owned renewable energy.

OPERATIONS

- Improved employee safety.
- Replaces aging infrastructure with current technology.
- Better planning, utilization and operation of our distribution system.
- More efficient internal business processes regarding billing and metering.
- Improved and more effective load management system.
- Reduced costs for power delivery to our members.
- Operational savings.

Technology and 80 years of service discussed at Dakota

Celebrating 80 years of service and using technology to serve members even better were a couple of the topics discussed at Dakota Electric Association's annual meeting on April 27.

President and CEO Greg Miller discussed how good planning and technology has helped Dakota Electric keep its reliability among the best in the nation. He also highlighted the recently launched outage app that allows members to easily report a power outage and receive updates on outages without having to call the dispatch center.

"With just a couple of clicks you can now use your mobile device to report a power outage and receive updates on the progress of the restoration," Miller said.

Miller reported on another new technology project the cooperative is investigating.

"Dakota Electric's meters and load management receivers are nearing the end of their useful life," he told the audience. "This project combines the replacement of electric meters and load management receivers and adds a software system to capture the data and run analytics to improve our services."

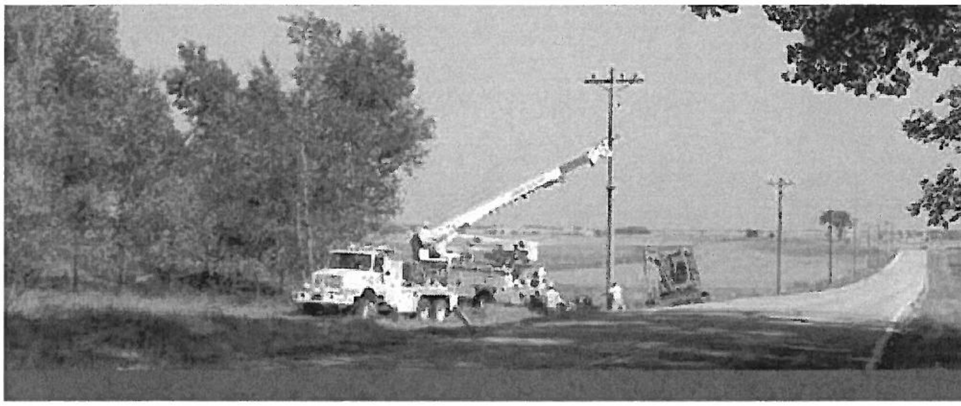
> "The advanced grid project will provide many benefits: increased system efficiencies, improved outage notification and restoration, and more energy information for our members."
>
> Greg Miller, president and CEO

Board Vice Chair Jerry Pittman discussed the board's strategic planning work in 2016. He also reviewed the cooperative's roots and how local residents worked together to start the cooperative.

Board Treasurer David Jones gave an overview of the 2016 financials, which received a clean audit report from Dakota Electric's auditor.

Will Kaul, vice president and chief transmission officer for Great River Energy, brought an update from Dakota Electric's wholesale power supplier. He talked about the transformation of the utility industry affecting how electricity is generated, new technologies being developed and how technology is enabling customer choices.

"These changes are being driven by a convergence of digital technologies which enable customer choices," Kaul said. "Devices such as smart thermostats, energy management systems, more efficient appliances and lighting, and affordable renewable energy resources give consumers options they've never had before, and that's not a bad thing. But we do need to anticipate our customer's wants and needs and adapt along with the market."



Circuits Quick Clips

AGi project update

Dakota Electric's AGi project is progressing as planned. Proposals have been reviewed and the team has narrowed the list of potential vendors. The group is currently working with those vendors on proposal details in order to select the one with which they will begin negotiations.

AGi stands for advanced grid infrastructure. It refers to what has been called "smart meters," but it is also referring to more than that. AGi captures the wider scope of this project, from the meter to load management to meter data management software and analytics.

Dakota Electric's existing meters and load management devices are nearing the end of life, so we are looking at the best technology to replace this critical infrastructure and provide even better service to our members.

With the AGi project, Dakota Electric looks to increase system efficiencies, improve outage notification and restoration, and provide more energy information for members.

Dakota Electric building 1-MW solar array near Hastings

Dakota Electric, in conjunction with SoCore Energy, is currently constructing a 1-megawatt (MW) solar array on five acres along Hwy. 316 near Hastings.

The array will have more than 3,500 panels and will generate enough energy to power about 150 homes. The solar energy generated will be used within Dakota Electric's distribution system and will benefit all of its members. The 25-year solar array is expected to provide a hedge on future wholesale power costs, providing savings for all members.

The project is expected to be completed this month. A 2-MW solar project is in the planning stages and is expected to be operational in the spring of 2018.

More than 3,500 solar panels will be constructed on five acres of land along Hwy. 316 near Hastings.

Register to attend our annual wind farm tour

Dakota Electric's popular wind tours offer an up-close look at an operating wind farm. Space is limited, so sign up early! Tours fill quickly on a first-come,first-served basis.

Tour dates

Tours will take place on Sept. 7 and 8. Each tour leaves Dakota Electric's headquarters in Farmington at 8 a.m. and returns at approximately 3:30 p.m.

Tour stops

McNeilus Wind Farm, located in Dodge Center, Minn., includes 41 turbines. Members will have the opportunity to go inside the base of a turbine and talk to an engineer.

Pleasant Valley Station, near Sargeant, Minn., is a natural gas peaking plant that generates electricity during times of high electricity demand.

If you have questions, contact Brenda at 651-463-6234. Registration deadline is Friday, Sept. 1. The cost is $10 per person and includes transportation and lunch.

Due to limited space, we request that members who have previously attended a tour please let others attend. Children must be at least 12 years old and accompanied by an adult.

REGISTER ONLINE

https://2017deawindtour.eventbrite.com

Select the tour date you plan to attend and click register.

Exhibit D – Advanced Grid Infrastructure (AGi) -

Business Case Executive Summary

Advanced Grid Infrastructure Project (AGi) 2017 Business Case Report Executive Summary

<u>Business Case for:</u>
Advanced Meter Infrastructure (AMI)
Meter Data Management (MDM)
Load Management (LM)

November 6th, 2017

Executive Summary

Should Dakota Electric move forward with Advanced Grid Infrastructure projects? Advanced Grid Infrastructure (AGi) is the term Dakota Electric is using to refer to new technologies that would enhance the communication and operation of our distribution system that delivers electricity to our members. These technologies will help Dakota Electric monitor our distribution system for better efficiency and operation and allow us to have two-way communication to field equipment, providing numerous benefits to our members and Dakota Electric. The main AGi components include Advanced Metering Infrastructure (AMI), Meter Data Management (MDM), and the Load Management (LM) system. Dakota Electric has assembled a cross functional team to review the AGi technologies. The decision to implement AGi technologies at Dakota Electric represents a critical decision for the future of the Cooperative. There are many factors to consider including traditional economic and financial factors, but also important member, public, and community issues.

To put the AGi decision in perspective, it is important to consider what happens if Dakota Electric does nothing regarding implementing AGi technologies. A decision to do nothing does not mean that nothing happens. Doing nothing means accepting the status quo which in and of itself, is a decision. It is equally important to understand that the decision to do nothing carries significant risk and cost.

This is a summary of the full 2017 AGI Business Case Report which details what it would cost to keep operating status quo vs. implementing new AGI technology. The full business case report also goes into detail about the existing systems and the risks involved with continuing to operate those systems which have reached the end of their useful life. It compares the status quo to the cost and benefits provided with implementing the Advanced Grid Infrastructure systems. This summary provides an overview of the information included in the full business case report and includes a recommendation from the AGI team.

BACKGROUND

Dakota Electric is facing several major transitions; one is with technology; another with the makeup of and wants of the membership; and the third is within the core business due to the interconnection of renewables. Coupled with these transitional elements impacting the Cooperative, several of the existing systems have reached the end of their useful life and require significant investment just to maintain the status quo.

Changes in technology have opened up new and innovative options for providing services to our members. These technology changes are also affecting the expectations which the members have for the services provided by Dakota Electric. The members now expect to be able to use mobile apps to interact with the utility and that information about how they are using energy will be readily available to them.

Dakota Electric is faced with a mix of members that have different wants and needs. The transition with more technologically savvy members increasingly using the internet to pay their bills and answer their questions is creating pressure to provide new services. Members are also looking for information 24/7, especially about how they are using energy. Many want the ability to make choices and customize their relationship with the Cooperative, such as changing when and how they pay for electrical usage. They are no longer ok with just getting a single kwh meter value each month. Instead, members want access to more information about how they are using energy and help on identifying ways to save.

Dakota Electric has been a leader in helping our members save energy and money. Dakota Electric's off-peak programs and demand reduction systems have been saving our members millions of dollars annually since before the 1990s. The Turtle system used to remotely read rural and difficult to access meters has saved thousands in meter reading costs. Unfortunately, the infrastructure used to support these programs has reached end of life. For example, many of the load control receivers have been out in the field working for 20 years and the amount of these devices which are not working is growing. Also, the Turtle AMR remote meter reading system is no longer manufactured or supported.

While new technology has changed what services the membership is looking for, this same new technology can enable many new capabilities to reduce labor costs and improve responses. Dakota Electric is at a crossroads. The Cooperative could continue to provide electrical services as it has done for many years or embark on the installation of new foundational technology. The tradeoff between the two options is costs and risks.

A Dakota Electric employee team, including staff from across the company has worked together with an NRECA Technology Business Associate. Over the past three years members of the AGi team have viewed over 40 vendor presentations, attended several conferences, met as a team more than 30 times and visited 9 different utilities outside of the State of Minnesota who have already implemented AGi technologies. The AGi Team heard from the other utilities about the benefits they have achieved and how implementation of AGi has transformed their utilities, from improved member communications and support to overall improved efficiency of their organizations. The Team also heard how AGi technology has improved service to their members by identifying issues before they became serious problems.

The additional services supported by the Advanced Grid Infrastructure and the operational flexibility available with the AGi systems were the deciding factors between the two decisions. The business case supports a deployment throughout the Dakota Electric service territory of Advanced Metering Infrastructure (AMI) coupled with installation of a Meter Data Management system (MDM) and the replacement of the existing Load Management (LM) system.

STATUS QUO COSTS

For this report, we wanted to look at what the estimated costs are if we did not install the AGi technology. The base case analysis is continuing as is, or "status quo," and resolving each issue as it develops. With the base case option, little if any additional new capabilities will be added, and some of the existing functionality and capabilities will be lost over time. We will continue to spend dollars on old technologies and, in most cases, we will not be able to implement systems with new technology that could provide increased flexibility and benefits.

The existing load management system has reached its end of life and must be replaced. Additional special metering and monitoring will be required to support the integration of distributed energy systems, including solar systems. The Turtle meter reading system must also be replaced and the existing aging metering infrastructure must also be addressed. These costs are significant and many are new capital expenses Dakota Electric is facing over the next several years.

If the decision is made to not implement AMI and MDM (components of the AGi system) the following costs are expected to be spent during the 15-year term of the business case. If Dakota Electric did not implement the new technology with the AGi project these expenses would be spread out over the 15-year period.

The following costs are an estimate and do not include the interest expense associated with replacing these systems. The costs estimated in this table would be incurred throughout the 15 years of the business case.

Estimated COSTS for Continuing to Operate Status Quo (2018-2033)	
Reason	Cost (Millions)
Costs to Read Meters	$17.9
Replacing Rural AMR meters (Turtles)	$1.1
Replacing Aging Meters	$6.3
Special Meters for DER (Solar)	$0.8
Replacing Load Management System	$15.4
Unrealized Customer Service Savings	$6.4
Necessary Feeder Voltage Monitoring	$1.2
Less accurate metering and resolving metering issues	$9.9
Unrealized Operational Savings	$7.5
Total Status Quo Costs	**$66.5 Million**

AGI IMPLEMENTATION

Below are the estimated costs to implement and operate the AGI technology over a 15-year period.

Summary of Total Expected COST of AGi Technology (2018-2033)	
Reason	**Costs (Millions)**
AMI & MDM system (Meters and Database)	$37.0
LM System (New LCRs)	$13.4
Communication Infrastructure	$2.1
Project Delivery	$3.9
New Positions Created	$9.0
Project Interest Expense	$11.8
Total AGi Costs	**$77.2**

BENEFITS

Listed below are the estimated 15 year benefits from a full AGI implementation. This list does not include all of the benefits which other Cooperatives reported to us during our visits. The Dakota Electric team instead took a conservative approach with the benefits in the business case. Benefits such as a reduction in bad debt, eliminating the cost for replacing the existing rural meter reading system or the potential costs resulting from the integration of DER including solar generation metering and monitoring, are not included in the benefits.

Expected BENEFITS With AGi Implementation (2018-2033)	
Reason	**Benefits with AGi (Millions)**
Reduction in Meter Reading Costs	$17.4
Member Service Savings	$6.4
Reduction in Meter Losses	$9.9
Meter Revenue Finance Cost Savings	$0.3
Operational Cost Savings	$7.5
Meter Capital Costs Savings	$6.7
Load Control Power Cost Savings	$24.4
Total AGi Business Case Benefits	**$72.6**

Implementing the recommended Advanced Grid Infrastructure AMI system will eliminate the need to send employees out in inclement weather to read the meters and the safety concerns which result. Members will benefit from improved proactive outage management detection and improved services related to having tools available to monitor daily usage. AMI will improve efficiency and turnaround time needed for disconnects re-reads and outage restoration. The AMI system, coupled with the MDM system, will provide the foundation to offer members new improved rate options, allow members to choose their billing due dates and provide increased energy management options.

The key benefits which will be achieved with the implementation of AGI systems include:

- Reduction in meter reading labor and expense costs,
- Reduction in travel required to read the meters each month; meter readings for service transfers; avoided fault outage calls and efficiencies in service restoration following storms,
- More efficient internal business processes, due to reduction in estimated or incorrect billing and the disputes associated with estimated or miss-read billings,
- Enhanced reliability and the knowledge to know that, while away from their home, power outages will be automatically reported,
- Less people walking through members' property,
- Increased energy use information available to the member,
- Elimination of the need to install special interval metering for DER and Time-of-Use installations,
- Replacing older meters with newer, more accurate digital meters,
- Providing voltage and usage interval data to engineering and operations to support more efficient sizing of equipment and system designs,
- Providing power quality alarms and information to allow Dakota Electric to identify and resolve issues during normal business hours before they become a problem for our members and also reduce overtime costs,
- Provide a foundation for future member rate options,
- Reduce the need to install sensors along the feeder to support the installation of DER systems,
- Be able to maintain the load management program by identifying and replacing existing failed load control receivers,
- Increased demand savings with new two-way communicating LCRs, and
- Be able to expand the load management system by enabling new load control options with the members.

AGI TEAM RECOMMENDATION

The AGi team recommends the implementation of AMI and MDM and the replacement of the existing Load Management system at Dakota Electric, as an essential building block and platform to support the future needs of Dakota Electric. The team is recommending that implementation of the AGi system would best benefit the members of Dakota Electric and be in their long-term interest vs. a decision to maintain the status quo.

There are similar risks associated with going in either direction and delaying the decision is not an option as we need to replace the existing load management system. The team has found that two of our key systems, Load Management and the Turtle AMR system have reached the end of their useful life and must be replaced. The team believes that due to the condition of the existing systems and the time it will take to install the AGI technology, Dakota Electric must move forward with the AGI project. At this point, a decision to not decide, will be a decision for the status quo and the associated costs.

The AGi team believes that Dakota Electric must begin preparing the business for a future state that integrates many technologies not present today. These future technologies will require a more advanced state of monitoring, communication and control. The system wide communication network provided by the installation of AMI will support future operational monitoring. This will be required to support the operation of the distribution system with the installation of renewables, such as solar. Together the AGi systems will provide options for Dakota Electric to provide increased service levels and meet the future needs and wants of our members. The Advanced Grid Infrastructure technology will also provide the foundation and flexibility for Dakota Electric to respond to future issues as they arise.

This business case is reasonable and the team believes that benefits greater than those outlined can be realized. The AGi team recommends proceeding with the project and the implementation of this new technology to help our members. The project includes 1) the installation of a communication network which will be utilized by both AMI and LM, 2) all new AMI meters and new load management receivers which both include two way communication capabilities and 15-minute interval data, 3) a Meter Data Management system which is a data repository, with an analytics engine and reporting tools, and 4) the development and installation of a web portal for our members to have access to their data to allow them to make decisions about their electrical usage.

Exhibit E: Advanced Grid Infrastructure Rider

ADVANCED GRID INFRASTRUCTURE RIDER

Application
Applicable to bills for electric service provided under the Association's metered retail rate schedules.

Rider
There shall be included on each member's monthly bill an Advanced Grid Infrastructure (AGi) Rider adjustment. The AGi Adjustment shall be multiplied by the consumer's monthly billing kWh for electric service. The AGi Adjustment shall be calculated before city surcharge and sales tax.

Determination of AGi Adjustment
The AGi Adjustment shall be the quotient obtained by dividing the forecasted balance of the AGi Tracker Account by the forecasted applicable retail energy sales for the calendar year. All factors shall be rounded to the nearest $0.0001 per kWh. The AGi Adjustment may be changed annually upon a filing with the Minnesota Public Utilities Commission (Commission). The AGi Adjustment shall apply to bills rendered on and after January 1st of the year.

The AGi Adjustment for each metered retail rate schedule is:

> $0.0000 per kWh
> The maximum monthly charge for the AGi Adjustment shall not exceed $25.00 per account.

Recoverable AGi Costs shall be the annual revenue requirements associated with AGi capital costs (a) not recovered through base rates, (b) recorded in the AGi Tracker Account for the designated period, and (c) determined by the Commission to be eligible for recovery under this Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the AGi Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the AGi Adjustment shall be credited to the AGi Tracker Account.

Forecasted retail sales shall be the estimated retail electric sales for the designated recovery period.

True-Up
For each 12-month period ending December 31, a true-up adjustment to the AGi Tracker Account will be calculated reflecting the difference between the AGi Adjustment recoveries and the revenue requirements for such period. The true-up adjustment shall be calculated and included in the AGi recovery filing submitted to the Commission for the following calendar year. No carrying cost shall be applied to the AGi Tracker.

Exhibit F: AGi Adjustment Example Calculation

Rate Recovery for AGi - Meters & Communication

		Statute	Notes
Capitalized Costs - Added to Rate Base		$ 20,092,475	***Initial Capitalized Outlay***
Rate of Return Recovery	6.47%	1,299,983	***Rate from 2014 Rate Case***
Income Taxes	N/A	-	
Incremental Property Taxes		179,000	***See Property Tax***
Incremental Depreciation		1,526,602	
Subtotal Before Savings		3,005,585	
Operational Savings		(1,310,899)	***From Model***
Net to Recover		1,694,686	
Number of Members		**105,000**	
kWh		**1,810,000,000**	
Monthly Average kWh - Residential		**772**	
Recovery per kWh		$ 0.00094	
Monthly Recovery per Avg. Residential member		$ 0.73	
Fixed Monthly Recovery - per member		*$ 1.35*	

Sample Recovery Calculation
2016 Data

	Residential	41(+51/52)	Subtotal		46	49	54	70	71	Commercial	Irrigation	Metered Total	Amount To Recover
kWh	898,633,000	44,000,000	942,633,000		447,912,000	177,000	926,000	389,395,000	22,682,000	861,092,000	7,002,000	1,810,727,000	1,810,727,000
# Meters - EOY	*97,493*	*4,349*	*101,842*		*2,627*	*3*	*6*	*227*	*24*	*2,887*	*392*		
# Meters - BOY	*96,516*	*4,299*	*100,815*		*2,580*	*3*	*6*	*221*	*23*	*2,833*	*391*		
Avg Meters	*97,005*	*4,324*	*101,329*		*2,604*	*3*	*6*	*224*	*24*	*2,861*	*392*		
Average kWh	9,264	10,176	9,303		172,009	59,000	154,333	1,738,371	945,083	298,265	17,862		
Mo Avg kWh	772	848	775		14,334	4,917	12,861	144,864	78,757	24,855	1,489		
Straight kWh Charge	***0.00094***												
Monthly $	$ 0.70	$ 0.80	$ 0.70		$ 13.50	$ 4.60	$ 12.10	$ 136.20	$ 74.00		$ 1.40		
Annual $	$ 8.40	$ 9.60	$ 8.40		$ 162.00	$ 55.20	$ 145.20	$ 1,634.40	$ 888.00		$ 16.80		
Total $	$ 814,842	$ 41,510	$ 856,352		$ 421,848	$ 166	$ 871	$ 366,106	$ 21,312	$ 810,303	$ 6,586	**$ 1,673,241**	**$ 1,700,000**
Maximum Commercial (if all at max)													
$ 25.00			$ 697,341		$ 781,200	$ 900	$ 1,800	$ 67,200	$ 7,200	$ 858,300	$ 117,600		
per mo	$ 0.57	$ 0.63	*0.00074*										
Amount Recovered (Lesser of kWh or Max amount)													
$ 25.00				*$ 1,598,841*	$ -	$ -	$ -	$ 67,200	$ 7,200		$ -		
per kWh	$ 1,024,466	$ 50,161	$ 1,074,627	*0.00114*	$ 510,616	$ 202	$ 1,056			$ 586,274	$ 7,985	$ 1,668,886	
	$ 0.88	*$ 0.97*											

Methods of Rate Recovery for AGi - Load Control

		Year 1	Year 2	Year 3	Year 4	Year 5	Notes
Capitalized Costs - Added to Rate Base		$ 1,970,719	$ 4,236,691	$ 6,549,351	$ 8,910,158	$ 11,320,620	*Cumulative*
Rate of Return Recovery	6.47%	127,506	274,114	423,743	576,487	732,444	*Rate from 2014 Rate Case*
Income Taxes	N/A	-					
Incremental Property Taxes		27,000	58,000	90,000	122,000	155,000	*See Property Tax (LC)*
Incremental Depreciation		131,381	282,446	436,623	594,010	754,707	*15 year life*
		285,887	614,560	950,366	1,292,497	1,642,151	
Total to Add to CIP		$ 285,887	$ 614,560	$ 950,366	$ 1,292,497	$ 1,642,151	
Total kWh Sales		1,810,000,000	1,810,000,000	1,810,000,000	1,810,000,000	1,810,000,000	
Cost per kWh - Tracker		$ 0.00016	$ 0.00034	$ 0.00053	$ 0.00071	$ 0.00091	
Avg Residential kWh		772	772	772	772	772	
Per month avg residential cost		0.12	0.26	0.41	0.55	0.70	

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Corey	Hintz	chintz@dakotaelectric.com	Dakota Electric Association	4300 220th Street Farmington, MN 550249583	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List