MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	April 19, 2018	Agenda Item **5
Company	Dakota Electric Association	
Docket No.	**E-111/M-17-821**	
	In the Matter of a Dakota Electric Association Petition to Implement Tracker Recovery for Advanced Grid Infrastructure Investments	
Issues	Should the Commission approve Dakota Electric Association's request to implement a tracker for recovery of advanced grid infrastructure investments?	

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✓ **Relevant Documents**	**Date**
Dakota Electric Association – Initial Petition	November 20, 2017
Minnesota Office of the Attorney General Residential Utilities and Antitrust Division - Comments	January 19, 2018
Minnesota Department of Commerce, Division of Energy Resources – Comments (Non-Public, Attachment 4)	January 26, 2018
Dakota Electric Association – Reply Comments	February 5, 2018
Minnesota Department of Commerce, Division of Energy Resources – Response Comments	February 13, 2018

I. Statement of the Issues

Should the Commission approve Dakota Electric Association's request to implement a tracker for recovery of advanced grid infrastructure investments?

II. Background

On November 20, 2017, Dakota Electric Association (Dakota Electric or the Company) submitted a *Petition* requesting Minnesota Public Utilities Commission (Commission) 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 general rate cases.

On January 19, 2018, the Minnesota Office of Attorney General Residential Utilities and Antitrust Division (OAG) filed *Comments* questioning the statutory authority for Dakota Electric's *Petition*.

On January 26, 2018, the Minnesota Department of Commerce, Division of Energy Resources (Department) filed *Comments* requesting further information from Dakota Electric.

On February 5, 2018, Dakota Electric responded to both the OAG's and Department's *Comments* and provided additional information regarding its *Petition*.

On February 13, 2018, the Department provided *Response Comments* recommending approval of the *Petition* with certain modifications.

III. Relevant Statutes

Minn. Stat. § 216B.02, Subd. 4 – Definition of Public Utility

The definition of public utility excludes cooperative electric associations.

Minn. Stat. § 216B.026 - Cooperative Electric Association; Election on Regulation

A cooperative electric association that elects to become subject to rate regulation by the Commission, does so pursuant to sections 216B.03 to 216B.23 but is specifically exempted from 216B.48 to 216B.51.

Minn. Stat. § 216B.1636 – Recovery of Electric Utility Infrastructure Costs

The Electric Utility Infrastructure Costs (EUIC) statute authorizes but does not require the Commission to 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.

IV. Acronym and Term Glossary

Grid modernization introduces a number of new and potentially unfamiliar acronyms. Staff provides the following list for reference while reading these briefing papers.

AGi	Advanced Grid Infrastructure
AMI	Advanced Metering Infrastructure
CIS	Customer Information System
FAN	Field Area Network
GIS	Geographic Information System
LCR	Load Control Receiver
LM	Load Management
MDM/MDMS	Meter Data Management (System)
OMS	Outage Management System
SCADA	Supervisory Control And Data Acquisition
WAN	Wide Area Network

V. Introduction

Dakota Electric's *Petition* requests recovery for an Advanced Metering Infrastructure (AMI), a Meter Data Management (MDM) system, and an upgraded Load Management (LM) system. As discussed in the *Petition*, Dakota Electric proposes to recover the AMI and MDM capital costs through a new recovery mechanism (AGi Rider) and the LM costs through the pre-existing energy conservation and load management adjustment component within the Resource and Tax Adjustment (RTA) which is consistent with the historic recovery of load management system costs. Dakota Electric discusses the three components in its *Petition* as follows:

Advanced Metering Infrastructure is the foundational component of the Advanced Grid functions. AMI encompasses both meters and a communications system that transmits data from devices throughout the distribution system. The communications network and associated devices provide a greater level of insight into a utility's system, and can allow a number of advanced applications beyond meter reading.

Dakota Electric's AMI will use a mesh network as its communications system. In a mesh network, data from meters can take multiple paths to collection points, which are then transmitted back to a centralized data repository. Meters themselves function as communication devices in a mesh network. A mesh system provides resiliency – if one meter goes out, the data from other meters can reroute itself to reach the data collection point. The communications network that meters use to transmit data to collection points is oftentimes referred to as a ***Field Area Network***, or ***FAN***. From these collection points, a more robust backhaul communications system transmits data to a head end system, and then back to the utility. These communications systems are sometimes referred to as a ***Wide Area Network*** or ***WAN***. Dakota Electric will use Dakota County's existing fiber communications infrastructure to transmit data back to its centralized systems.

Data from AMI meters is compiled in a ***Meter Data Management System (MDM)***. The MDM stores information from meters and other devices, which can then be accessed by other utility systems, like ***Customer Information Systems (CIS)*** and ***Outage Management Systems (OMS)***. The MDM can handle the increased volume, frequency, resolution, and type of data that comes from upgraded meter technology. In legacy systems, data oftentimes went directly from the meter to the CIS. However, AMI can provide additional data that is beneficial to the utility in its operational capacity, but not necessary for billing. The MDM allows each utility function to access just the information it needs.

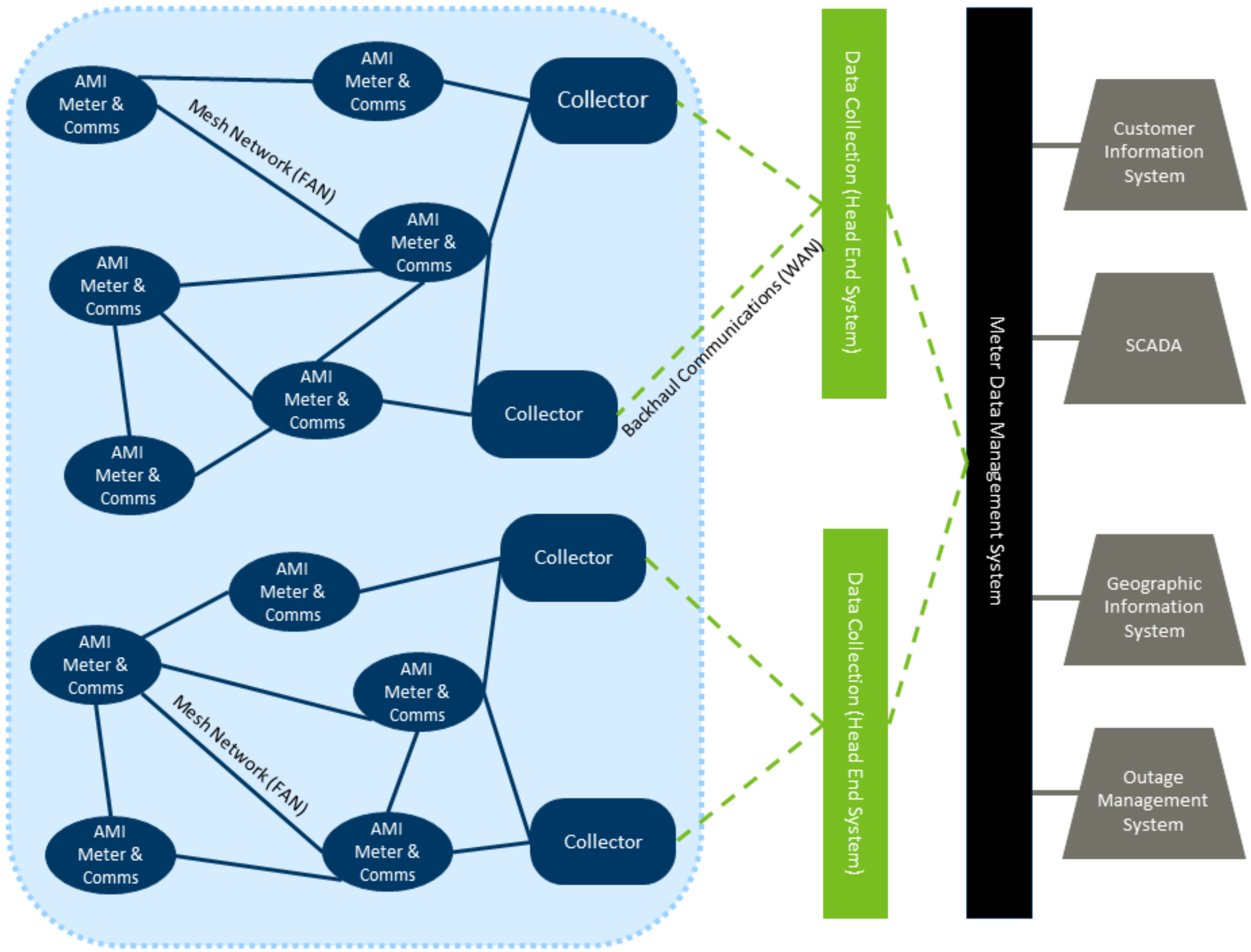
In its business case analysis[1], Dakota Electric identifies the following key uses for the MDM:

- Data Storage – for example, increased information from higher interval readings.
- Data Integrity – validation through automatic processes in the case of missing information.
- Billing – calculate more complex rates and deliver final information to CIS for bills.
- Virtual Meters –aggregation of data for customers with multiple meters for systems engineers to check transformer loading.
- Special Rates – better support for TOU rates for customers who elect them.
- Analytics – makes it easier to perform advanced analysis, for example, Loss Analysis, Energy Diversion, Rate Analysis, Accounting, and Member Service.
- Member Interaction – increased access to data through a web portal.

Staff provides Figure 1 below that shows the different components of the AMI and MDM system for reference. "Comms' refers to mesh network communications infrastructure.

[1] Department *Comments*, Attachment 1 pp. 30-32.

Figure 1: AMI and MDM Graphic

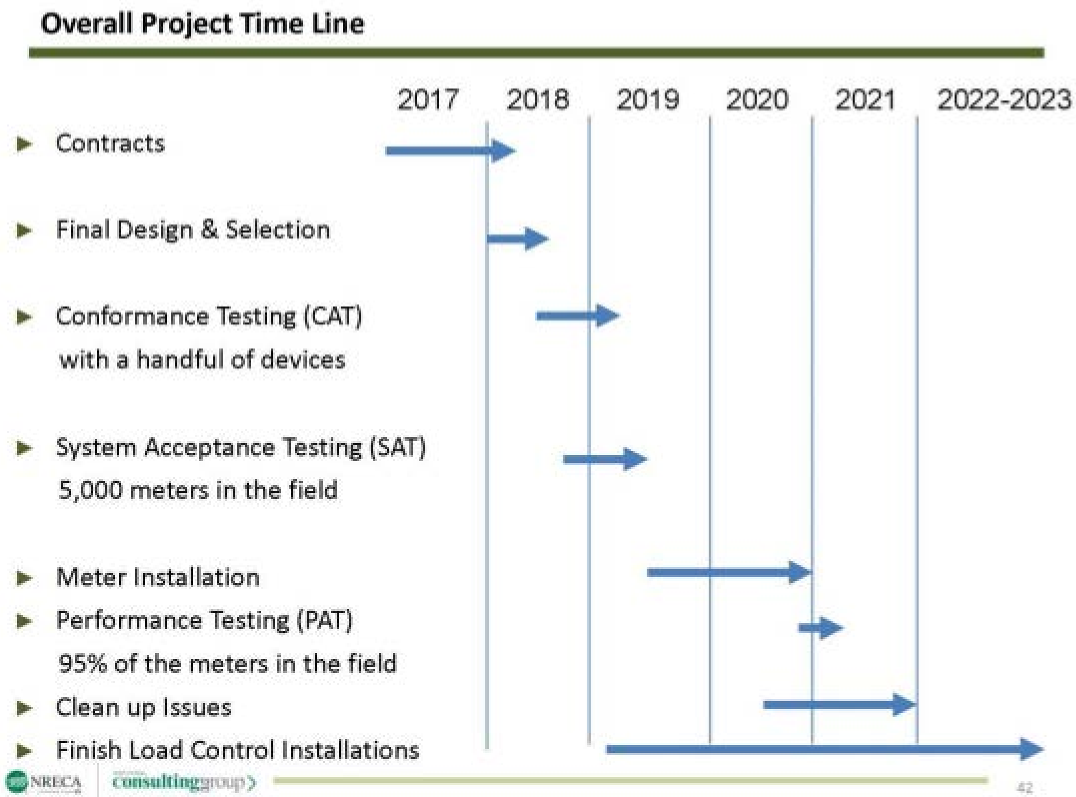


Dakota Electric also has an extensive ***Load Management (LM)*** system that allows it to control over 100 MW of load during peak system times. Key components of this system are ***Load Control Receivers (LCRs)***, which control around 40% of the Company's load management program. Participating members have a LCR mounted to their building, and during a control event a signal sent through the LCR remotely turns off devices enrolled in the program, such as water heaters, AC units, or electric heat, and turns the devices back on when the event is over.

Dakota Electric's current LCRs were installed in the mid 1990's and are reaching the end of usable life. In a 2013 inspection of almost 500 LCR devices, the Company found that almost 20% were not functioning. Current LCR devices only have one-way communications, meaning Dakota Electric has no way of knowing if an LCR has received the signal during a load control event. Additionally, because of the one-way communications, the only way to tell if a device is broken is to perform an in-person or on-site inspection. New LCR devices, like their AMI counterparts, have two way communications, allow Dakota Electric to know if a load is responding to an event without needing to perform a physical inspection.

Dakota Electric plans to implement the majority its AGi investments over the next five years, starting with AMI deployment and finishing with the replacement of its LCRs.

Figure 2: AGi Implementation Schedule



In its AGi proposal, Dakota Electric performed a cost benefit analysis of what it considered "direct financial benefits." However, aside from these benefits, it also identified other *potential* direct financial benefits and "soft" benefits that were not included in the analysis, but still would provide positive outcomes to its members and to the cooperative. These included:

- Member benefits
    - Improved outage detection, management, and notification
    - Improved billing accuracy
    - Decreased need to access member property
    - Ability to offer new billing and rate options
    - More efficient resolution of member issues and questions
- Dakota Electric benefits
    - Eliminate multiple internal technologies
    - Detailed load and usage data – ability to accurately size transformers, support rate analysis

  - Automated outage reporting – quickly ID problems, support outage updates to customers
  - Voltage and power quality information – ID transformer problems, troubleshoot problems remotely, ID issues in real time before they become major concerns
- Dakota Electric and Member benefits
  - Safety – fewer people in harm's way (dogs, accidents, etc.)
  - Environment – fewer miles driven, support renewable integration, support load control and demand response

In preparation for its AGi initiative, Dakota Electric conducted extensive member outreach and communications. Some of these communications were attached in their proposal, along with copies of the presentations from 2015 and 2017 planning meetings at the Commission. These materials include the results of the Company's member survey.

Dakota Electric requested Commission review no later than April 23, 2018, to maintain the current pricing options. A delay in the Company's ability to proceed could result in repricing that could negatively affect the overall business case for the overall AGI investments put forward by Dakota Electric.

VI. Parties' Comments

Cost Benefit Analysis

1. Dakota Electric

Dakota Electric centered its cost-benefit analysis on either upgrading to the proposed AGi technology or taking no action, which the Company refers to as "maintaining the status quo." Dakota Electric reasoned that maintaining the status quo should be considered an active decision because aging equipment and infrastructure will require replacement in the near future, even if AGi is not implemented. Dakota Electric provided a breakdown of the anticipated costs for maintaining the status quo (Table 1) and upgrading to AGi (Table 2).

Table 1: Costs of Maintaining the Status Quo[2]

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**

Table 2: Costs of Implementing AGi[3]

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**

Dakota Electric also noted that operational savings can be achieved by implementing AGi. Cost reductions from fewer meter reading expenses and reduced load control costs provides an offset to the increased cost of AGi. Dakota Electric provided a table (Table 3) detailing its known and measurable operational savings.

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[2] Dakota Electric *Petition*, p. 18
[3] *Id.*

Table 3: Anticipated Benefits of Implementing AGi[4]

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, Dakota Electric discussed that this analysis does not reflect some of the hard benefits recognized by other utilities, as well as direct member benefits. Improvements in energy conservation efforts, communications with members, and reductions in response time to outages are some of the non-financial benefits provided by AGi.

2. Department

The Department summarized Dakota Electric's cost-benefit analysis but argued that the Company made three choices that limit the usefulness in providing information on the net benefit or cost of AGI. [5]

> *…First, the cost-benefit analysis is not directly based on cash flows and thus does not accurately reflect how funds are expected to flow in and out of Dakota Electric. Second, it does not discount cost or benefits and therefore does not account for uncertainty or the time-value of money. Third, as indicated earlier in these comments, it does not include several streams of readily quantifiable benefits, which the Department concludes are reasonable to include. As noted earlier in these comments, these omitted but readily quantifiable benefits are the avoided costs of replacing load control receivers, the avoided costs of replacing Dakota Electric's automated meter reading system, and avoided feeder monitoring costs.*

The Department performed its own cost-benefit analysis,[6] starting with Dakota Electric's forecasted net cash flows and adjusting the net cash flows upwards by its estimate of the

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[4] *Id.*
[5] Department *Comments*, p. 14.
[6] Department *Comments*, Attachment 4, labeled **TRADE SECRET** contains the Department's full analysis.

annual cost reductions resulting from the three benefit streams the Department felt Dakota Electric missed in the Company's initial analysis.[7]

> *The first benefit stream, the avoided costs of LCR replacements, assumed that Dakota Electric replaced 80% of its LCRs over the 15-year base case, which is a proxy for the amount needed to maintain the current working rate of LCRs and current level of power cost savings. To estimate the annual amounts, the Department used the $12,558,000 total cost of replacing all load control receivers from page 26 of Dakota Electric's full business case as an input. It is appropriate to include this benefit stream in the cost-benefit analysis because Dakota Electric states on the same page that "the load management system has reached its end of life and needs to be replaced." Therefore, installing new LCRs allows Dakota Electric to avoid replacing its existing LCRs with non-AMI technology.*
>
> *The second benefit stream, avoided costs related to automated meter reading (AMR) for members in more rural areas, used the costs cited on page 47 of Dakota Electric's business case. It is appropriate to include this benefit stream because the same page of the business case states: "the existing AMR system … is no longer supported or manufactured. At some point Dakota Electric will need to replace this system. [The costs cited are] the expected cost of operation of the existing system and the cost of replacement. With the installation of AGi technology, these costs would be avoided."*
>
> *The third benefit stream, avoided feeder monitoring costs, uses the cost estimates on page 48 of Dakota Electric's business case. It is appropriate to include this benefit stream because Dakota Electric states that it would avoid feeder monitoring costs due to having AGi. According to Dakota Electric, the AMI meters and communication system allow Dakota Electric to monitor the voltage of each feeder, which Dakota Electric indicates is not currently possible and will be needed to ensure that the distribution system functions properly as the penetration of distributed solar increases. Therefore, according to Dakota Electric, without AMI the Cooperative will need to install other equipment to properly monitor feeders as more members install distributed solar.*

The Department added the three cash flows and used an average of the 10- and 20- year treasury yields to determine the discount rate. The Department added risk premiums to the costs and avoided costs, and ultimately concluded that AGi will save Dakota Electric's ratepayers $2.8 million in today's dollars over the 15-year business case. The Department noted that slight variations in the discount rate can significantly alter the anticipated savings but considers $2.8 million to be the average of those variations. The Department also argued that even if the project costs ratepayers a little money, it might be worth pursuing, to a point,

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[7] Department *Comments*, p. 15.

for the non-financial benefits that members would receive, such as the ability to access more data, availability of new rate structures, and quicker response time to outages.

The Department concluded by stating that the Dakota Electric Member's board has voted that the project is beneficial to ratepayers, even if the ratepayers are not saving money.

3. Staff Analysis

Staff reviewed the analysis completed by Dakota Electric and by the Department. The Company took a more conservative approach in estimating avoided costs and operational savings. The analysis concluded that AGi would cost members an additional $4.6 million over maintaining the status quo. The Department argued that additional avoided costs are reasonable to include, thus eliminating the financial shortfall. The Department believes AGi will ultimately save members $2.8 million (based on the average discount rate). Both Dakota Electric and the Department agreed that even if AGi financially costs more than maintaining the status quo, it is worth pursuing due to the non-financial benefits received by members. Staff appreciated the analysis completed and agrees with Dakota Electric and the Department.

Rate Design

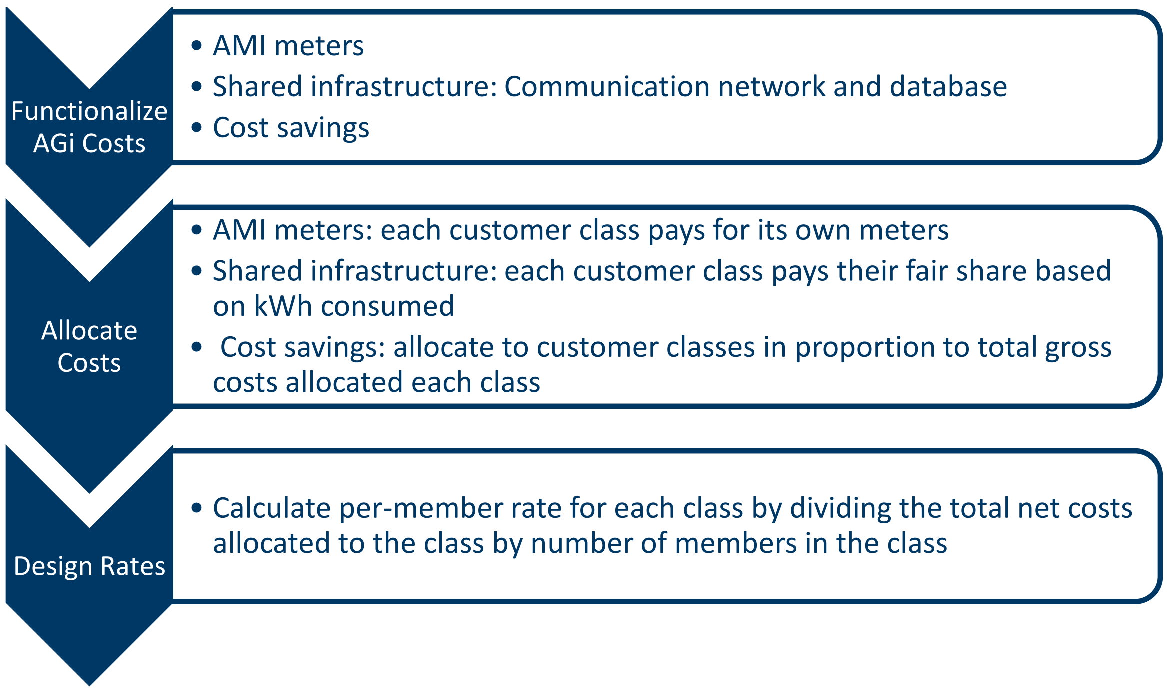
1. Department

The Department recommended that AMI and MDM costs be recovered via a fixed charge rather than Dakota Electric's proposal to recover capital costs through a per-kWh charge. To estimate the fixed charge, the Department proposed using the following steps:

- First, group the AMI/MDM capital costs into three categories: AMI meters, shared infrastructure (communications network and any capital costs of the data system);
- Second, require each member class to pay for the costs of its own meters, under the principle that each member should pay for their own meter; and allocate the shared infrastructure costs among customer classes on a per-kWh basis, under the principle that members benefit from the communication and data system in accordance with how much energy they consume. After this gross sum is calculated for each class, allocate the reduction in base revenue requirements due to AMI/MDM (capital-cost savings associated with existing meters and operational-cost savings) proportionately to arrive at a net amount to recover from each member class. The total net amount to recover from each member class is thus the sum of their cost responsibility for the AMI and MDM costs, minus their share of the resulting cost savings, allocated on the same basis.
- Third, set the fixed charge for each member class by dividing the net costs allocated to the class by the number of members in the class.

The Department included the following figure to illustrate these steps.

Figure 3: Department's Proposed Rate Design[8]



Implementing this methodology would require performing these basic steps each year, which the Department expected to be a relatively simple exercise given the limited amount of costs considered. Like Dakota Electric's proposed method, this method would require a true-up to account for any over- or under-recovery from the prior year, but the true-up would likely be lower under the Department's proposed method, as recovering fixed costs based on kilowatt- hours consumed will likely result less accurate cost recovery versus recovering fixed costs based on the number of members (because consumption of kilowatt-hours is more volatile than the number of members).

2. Dakota Electric

In response, Dakota Electric agreed that the Department's proposed rate design resulted in fairer charges to its members. The Department's rate design approach spreads relative meter costs based on the cost of meters to each rate class and other common costs based on energy usage with total costs then collected through a monthly per meter charge.

In *Reply Comments*, Dakota Electric did recommend that capitalized project management cost be allocated in proposition to the allocation of shared-infrastructure costs, and provided rate design calculations assuming this modification.[9]

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[8] Department *Comments*, p. 13

[9] In its *Response Comments* the Department agreed to Dakota Electric's recommendation.

Table 4: Department's Proposed Rate Design[10]

Member Class	Monthly Fixed Charge per Member
Residential	$1.22
Irrigation	$3.30
Lighting	$1.54
Small General	$1.22
General	$4.39
C&I Interruptible	$14.97

Statutory Authority

1. Dakota Electric

Dakota Electric stated in its *Petition* that in the early 1980s, Dakota Electric's members voted to become subject to rate regulation by the 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.

Dakota Electric recommended Commission approval of its recovery of infrastructure investments through Minn. Stat. § 216B.1636 (EUI Statute) which deals with the recovery of electric utility infrastructure costs. In addition, Dakota Electric notes that Minn. Stat. § 216B.03 provides the Commission with "broad overall authority to approve rates," which it argues reflects the legislative intent to allow for rate recovery of investments in distribution facilities to modernize the utility's grid. Therefore, pursuant to both Minn. Stat. §§ 216B.1636 and 216B.03, the Commission can approve an AGi tracker mechanism for Dakota Electric.

2. OAG

The OAG disagreed with Dakota Electric's analysis and stated that Minn. Stat. § 216B.16, subd. 7b (TCR Statute) is the only statute "that explicitly allows for rider recovery of investments made to modernize a utility's distribution system." In addition, even though the EUI Statute is within the Dakota Electric rate regulation sections discussed above, it has two important provisions related to Dakota Electric's *Petition*. First, the statute applies only to "electric utilities." The statute defines an "electric utility" as "a public utility as defined in section 216B.02 subdivision 4, that furnishes electric service to retail customers." Second, the EUI Statute allows rider recovery of "electric utility infrastructure projects," which are defined as projects owned by a utility that do one of the following:

[10] Department *Response Comments*, p. 6

- [R]eplace 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
- Conserve energy or use energy more efficiently by using waste heat recovery converted into electricity as defined in section 216B.241, subdivision 1, paragraph (o).

Thus, in order for the Commission to approve Dakota Electric's Petition, it would need to determine that Dakota Electric is an "electric utility" as defined by the EUI Statute, and that its AGi projects are "electric utility infrastructure projects." Since both use definitions outside of the rate regulation sections that apply to Dakota Electric, discussed above, the OAG contends that the EUI statute cannot apply.

3. The Department

The Department agreed with Dakota Electric that it can request rider recovery pursuant to Minn. Stat. §216B.1636. The Department acknowledged that one objection to this conclusion is that section 216B.1636, subdivision 1, defines eligible utilities using the definition of "public utility" in section 216B.02, and this definition excludes cooperatives organized under chapter 308A, such as Dakota Electric. However, since section 216B.026 clearly states that Dakota Electric is subject to regulation under section 216B.1636 and other statutes within the specified range of sections 216B.03 to 216B.23, the Department concluded that section 216B.026 overrides the definition of "electric utility" in section 216B.02.

The Department continued by noting that while Dakota Electric's *Petition* agrees that Minn. Stat. § 216B.026 overrides the definition of "public utility" in § 216B.02, in the past Dakota Electric has held a different view from that set forth in its petition. In the Cooperative's January 12, 2015 letter to the Commission, which the Department included as Attachment 2 to its *Comments*, it argued that section 216B.1614—another statute within the range of sections 216B.03 to 216B.23—does not apply to the Cooperative due to the 216B.02 definition. [11] As noted above, the Department concluded that Dakota Electric's current interpretation of its regulatory obligations is correct.

4. Staff Analysis

No one argues against the value of the Company's proposal or that the proposed infrastructure improvements are not in the public interest. However, the Commission needs to decide under which statute Dakota Electric can recover costs for the AGi investments. Staff notes that pursuant to the definition of public utility in Minn. Stat. § 216B.02, none of Chapter 216B applies to cooperatives "except as specifically provided"[12] by the chapter:

> Because . . . . cooperative electric associations are presently effectively regulated and controlled by the membership under the provisions of chapter 308A, it is

[11] The letter was filed in Docket No. E111/M-12-874, *In the Matter of Dakota Electric's Petition to Implement an Electric Vehicle Rate.*

[12] Minn. Stat. § 216B.01.

> deemed unnecessary to subject such utilities to regulation under this chapter <u>except as specifically provided herein</u>. (emphasis added)

In addition, Subdivision 1 of Section 216B.026 specifically provides that Sections 216B.03 to 216B.23 apply to an electric cooperative that, like Dakota Electric, has elected to be rate regulated by the Commission pursuant to those sections. Based on this clear statutory scheme, all statutory provisions of Sections 216B.03 to 216B.23 apply to Dakota Electric, including Section 216B.1636.

VII. Decision Options

1. Approve Dakota Electric's *Petition* for recovery of AGi investments, modified to recover costs on a per-meter basis with the total costs recovered modified to incorporate revenue gains from reductions in meter losses; (DEA, Department]

   and,

2. Affirm that Dakota Electric is authorized to use the conservation component of the RTA to recover the load control receiver capital costs, with the conditions that the costs must satisfy the requirements of Minnesota Statute § 216B.16, subd. 6b, paragraphs (c) and (d), and be approved by the Deputy Commissioner of the Department of Commerce. (DEA, Department)

   or,

3. Deny Dakota Electric's Petition.