414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENT –
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August 17, 2022

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: SUPPLEMENT FILING
TRANSMISSION COST RECOVERY RIDER
DOCKET NOS. E002/M-21-814 AND E002/M-20-680

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Supplement to our November 24, 2021 PETITION FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2021 AND 2022, TRACKER TRUE-UP AND REVISED ADJUSTMENT FACTORS. This Supplement is required by the Procedural Agreement between the Department of Commerce and Xcel Energy and as approved by the Commission in its June, 2022 Order in the above-referenced dockets.

Portions of our filing and Attachments A, B, and C contain protected data including Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b), and Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a), and are marked as "NOT PUBLIC." The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use and is subject to reasonable efforts by the Company to maintain its secrecy.

Attachments A, B, and C provided with the NOT PUBLIC version of this filing contain information classified as trade secret pursuant to Minn. Stat. § 13.37 for the above-noted reasons and are marked as "NOT PUBLIC" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

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Attachment A:

1. **Nature of the Material**: The AMI & FAN Cost Benefit Analysis Model developed by the Company.
2. **Authors**: Risk Analytics
3. **Importance**: The Company work product is proprietary to the Company.
4. **Date the Information was Prepared**: The CBA Model was created in the third quarter of 2019 and updated in third quarter 2021.

Attachment B:

1. **Nature of the Material**: The DI, AMI, & FAN Cost Benefit Analysis Model developed by the Company.
2. **Authors**: Risk Analytics
3. **Importance**: The Company work product is proprietary to the Company.
4. **Date the Information was Prepared**: The CBA Model was created in the third quarter of 2021 and updated in second quarter 2022.

Attachment C:

1. **Nature of the Material**: A description of our procurement process and bid pricing information for our selected AMI meter and alternatives considered.
2. **Authors**: Sourcing
3. **Importance**: The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use and is subject to reasonable efforts by the Company to maintain its secrecy.
4. **Date the Information was Prepared**: August 2022.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies on the parties on the attached service list. If you have any questions regarding this filing please contact Karin Haas at karin.b.haas@xcelenergy.com or me at bria.e.shea@xcelenergy.com.

Sincerely,

/s/

BRIA E. SHEA
REGIONAL VICE PRESIDENT, REGULATORY POLICY

Enclosures

c: Service Lists

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2021 AND 2022, TRACKER TRUE-UP, AND REVISED ADJUSTMENT FACTORS	Docket No. E002/M-21-814
IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2021 AND REVISED ADJUSTMENT FACTORS	DOCKET NO. E002/M-20-680 **SUPPLEMENTAL COMMENTS**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Supplement to our November 24, 2021 Petition, in accordance with the Joint Procedural Agreement (Procedural Agreement) with the Minnesota Department of Commerce that the Commission approved in its June 2, 2022 Order in the above-referenced dockets.

The Procedural Agreement requires the Company to provide additional information that comprehensively summarizes the Company's Advanced Metering Infrastructure (AMI) and Field Area Network (FAN) plans, and supplements and correlates the Company's filed information to the completeness review conducted by the Department's consultant, Synapse Energy Economics, Inc. (Synapse), that was attached to the Department's March 30, 2022 Comments in this proceeding.[1] In doing so, we continue to maintain that our previously filed materials fully comply with the Commission's requirements for information regarding advanced grid investments. However, in the spirit of collaboration and to aid the Department's review of our Petition, we are making a good faith attempt to provide additional information that meets the Department's new standards for its internal review of grid modernization investments, introduced into this proceeding and all Minnesota utility Integrated Distribution Plan proceedings in February 2022. This Supplement further shows that AMI and FAN are carefully planned projects that will produce significant benefits for our customers.

As contemplated in the Procedural Agreement, we have continued to work with the Department to more specifically understand the additional information it and Synapse are seeking and whether and how we can practicably provide it. In addition to discussions and written exchanges with the Department, the Company has also hosted two of the three technical workshops contemplated in the Procedural Agreement on July 19 and 25, 2022 – during which the Company's subject-matter experts provided significant information and answered stakeholder questions. We have scheduled the final technical workshop contemplated in the Procedural Agreement for September 7, 2022 from 1:00 p.m. to 2:30 p.m., when we will outline the financial details included in our Petition, our greatly expanded cost benefit analysis results, and the reporting to which we have committed.[2]

In an effort to ensure this Supplement is consistent with the Department's expectations as best as practicable, Xcel Energy subject matter experts also met with the Department and Synapse on July 20, 2022 to: (1) review and clarify the revised guidance the Department and Synapse provided on July 1, 2022, and (2) preview key aspects of this Supplement, including our expanded approach and preliminary results of our cost benefit analysis, (3) explain our alternatives analysis, and (4) present our approach to a more robust discussion of the qualitative benefits associated with AMI and FAN. In preparing this Supplement, we have drawn upon the points made, guidance expressed, and questions put forward by the Department and Synapse in an effort to productively address the issues they have raised, to the extent practicable. At the same time, we have also prepared this Supplement so as to summarize for the Commission the reasons why our AMI and FAN strategy, plan, and implementation

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[1] The Department and Synapse provided revised completeness guidance in an email dated July 1, 2022, which we also discussed and clarified in a July 20, 2022 meeting with the Department, Synapse, and Xcel Energy subject-matter-experts.

[2] See our August 4, 2022 Letter, which includes links to recordings of Workshops 1 and 2, and further information on Workshop 3.

are prudent, and recovery of the associated costs we seek in the Transmission Cost Recovery (TCR) is warranted.

As this Supplement explains, we must replace our current meters and ensure our new meters have the technology and capabilities to meet the demands of the next twenty years. The AMI and FAN we have selected will produce meaningful benefits for our customers now and well into the future. With this Supplement, we significantly expanded our cost-benefit analysis to include a robust sensitivity analysis that considers the costs and benefits of AMI and FAN, which indicates that, within a 95 percent confidence interval, AMI and FAN benefits exceed costs in all modeled scenarios. We have also given ourselves flexibility to adapt the AMI and FAN to meet future needs and desires of policymakers, regulators, stakeholders, and customers by selecting updateable technologies based on industry standards.

In this Supplement, we address the following topics:

- The procedural history and general background for the Supplement;
- The factors driving the Company's AMI and FAN projects and our AMI and FAN strategy and plans;
- An overview of the state of the industry and relevant trends;
- Our selection process for AMI and FAN, including discussions of alternatives that were considered;
- Our cost-benefit analysis for AMI and FAN, and also for AMI and FAN along with DI investments not included in the TCR Petition;
- A discussion of other issues raised by the Department;
- Customer bill impacts and class allocation, and,
- Our Conclusion.

I. BACKGROUND

In this section, we describe the procedural history and general legal background for this filing. Background information regarding market conditions and the Company's procurement process for AMI and FAN is addressed below in Sections IV and V.

In 2005, the legislature provided for the TCR rider by enacting Minn. Stat. 216B.16, subd. 7b, which authorized the Commission to approve a tariff mechanism for an automatic annual adjustment of charges for the costs of eligible utility investments in transmission facilities. Since then, the legislature has modified the TCR statute on multiple occasions, including amendments in 2015, which allow for the recovery of costs for investments that support the modernization of the distribution grid. As amended, Minn. Stat. § 216B.16, subd. 7b and 216B.2425, subd. 2(e) provide that such grid modernization projects must be certified by the Commission in order to be eligible for rider recover. Notably, the use of "two-way meters" was one of the types of grid modernization investments explicitly mentioned in the statute.[3]

Consistent with the statute, the Company sought and obtained certification for various distribution grid modernization investments. On November 1, 2019, the Company filed its 2019 Integrated Distribution Plan (IDP) in Docket No. E002/M-19-666, which included a request for certification of our AMI and FAN investments. The Company provided significant information regarding AMI and FAN, including descriptions of the planned investments, the deployment timelines of 2021 to 2024, information on projected costs, and cost-benefit analyses.

On July 23, 2020, after a hearing and with the benefit of comments from multiple parties, the Commission issued an Order accepting the IDP and certifying both AMI and FAN. In its Order, the Commission stated that AMI and FAN are "necessary for modernizing the distribution system and enhancing reliability, improving security, and increasing energy conservation opportunities."[4] At the certification hearing, the Commission spoke favorably of our AMI and FAN investments, with references to the necessity of AMI and FAN as foundational technologies for grid modernization.[5] The Commission also indicated that it wanted the Company to move forward with AMI and FAN.[6]

In its July 23, 2020 Order, the Commission also provided guidance with regard to the process and substantive requirements for recovery of the costs of AMI and FAN through the TCR rider. In order point 8, the Commission required the Company to provide a proposal for specific metrics and evaluation methods and a detailed plan for maximizing the benefits of investments in a future proposal for AMI and FAN cost recovery. The Company fulfilled this requirement in its November 24, 2021 TCR Rider Petition. In order point 9, the Commission ordered the Department to file a report informed by a stakeholder process with recommendations for specific metrics,

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[3] At the May 29, 2020 hearing at which the certification request was considered, the Commission indicated its understanding that AMI and FAN are the types of projects contemplated by the legislature. May 29, 2020 Hearing Transcr. at 101:11-16, 134:6-9, 162:6-10.
[4] Docket No. E002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS, July 23, 2020, at 14.
[5] May 29, 2020 Hearing Transcr. at 160:7-9, 174:15-22.
[6] Id. at 134:6-9.

detailed performance evaluation methods, and other conditions for the certified projects.[7] The Department fulfilled this requirement with its December 1, 2020 Report filed in Docket Nos. E002/M-19-666 and E002/M-20-680. In order point 10, the Company was required to include in any future cost recovery request a discussion of mechanisms used to control costs and a demonstration that it had thoroughly considered alternatives. The Company fulfilled this requirement in its November 24, 2021 TCR Rider Petition. Finally, in order point 13, the Company was ordered to file its preferred procedural path forward at least 60 days prior to filing a petition to seek rider recovery.

On August 28, 2020, in Docket Nos. E002/M-19-666 and E002/M-20-680, as ordered, the Company submitted a filing setting forth its preferred procedural pathway for consideration of cost recovery for the AMI and FAN projects. In the filing, the Company proposed the use of a standard miscellaneous filing process as set forth in Minn. R. 7829.1400, subp. 1, which would involve an initial filing by the Company and subsequent comments.

On December 1, 2020, after a stakeholder process, the Department filed its Report titled "Methods for Performance Evaluations, Metrics, and Consumer Protections for AMI and FAN" in Docket Nos. E002/M-19-666 and E999/DI-20-627. Included with the Report as Appendix E was a table summarizing reporting parties that participated in the stakeholder process recommended the Company provide.

Then, on November 24, 2021, the Company filed its Petition initiating this matter. Among other things, the Company's Petition seeks cost recovery for AMI and FAN. The filing was consistent with the procedural pathway the Company had proposed in August of 2020 and it addressed the Department's recommendations set forth in its December 1, 2020 Report. Notably, the Company specifically responded to each of the proposed metrics in Appendix E of the Report. We largely agreed with the AMI and FAN-related proposed reporting; however, we explained that some reporting items were not related to AMI and FAN deployment, some were more appropriately addressed in other dockets, and some would not be possible either because they related to comparisons to hypothetical futures or because they involve AMI functions that the Company does not intend to pursue in the near term.

On February 9, 2022, the Department filed a "Guidance Document" in multiple dockets involving the Company and other electric utilities, including in the Company's

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[7] The Order initially required the Report to be filed by November 1, 2020; however, that deadline was subsequently extended to December 1, 2020.

2021 TCR rider petition docket. The Department's filing was made several months after we had already filed our TCR petition and well after the filing of the Department's December 1, 2020 Report. Subsequently, the Department, the Company, and other parties have filed comments regarding our Petition and the process and criteria to use in evaluating the AMI and FAN projects, including discussion regarding the Guidance Document. While we accept that the Department may determine its own criteria and processes for internal analyses, in our comments the Company outlined our disagreements with the substance of the approach set forth in the Guidance Document and expressed procedural concerns with the Department's request that the Guidance Document be adopted and applied by the Commission months into this proceeding (and others) without the benefit of a robust review involving all appropriate stakeholders. The Company and the Department also directly communicated regarding the Guidance Document and how, in light of differing perspectives, to best move forward with regard to evaluation of the Company's AMI and FAN investments. On May 2, 2022, the Company and the Department both filed Reply Comments that set forth the proposed Procedural Agreement for the Commission's consideration. The Commission considered the Procedural Agreement at its June 1, 2022 hearing and then issued its Order approving it on June 2, 2022.

The key terms of the Procedural Agreement committed the Department and Company are summarized as follows:[8]

- The Company agreed to provide this supplement, which summarizes its plans for AMI and FAN;
- Both parties agreed to continue to work towards a mutual understanding of the Synapse Completeness Review, which was based on the Guidance Document;
- The Company agreed to make its best efforts to meet the spirit of the Synapse completeness review and provide the information it calls for, to the extent practicable;
- The parties recognized that the Company is not accepting the Guidance Document, as noted in prior comments;
- The Department agreed to withhold its determination regarding AMI and FAN pending review of this supplement;
- The Company agreed to hold additional technical workshops; and,

[8] The full terms are set forth in the May 2, 2022 Reply Comments filed by both the Department and the Company.

- The parties both agreed that in the event the Petition is not considered by the Commission before December 31, 2022, that they jointly request that the Commission affirmatively approve recovery of the 2020 and 2021 AMI and FAN revenue requirements by the end of December, subject to a later true-up.

The parties communicated regarding the information sought by the Department, as contemplated by the Procedural Agreement, and the Department indicated that it is particularly focused on a revised cost-benefit analysis. Accordingly, along with other information, the Company is presenting a robust CBA (Attachment A) that includes a Monte Carlo sensitivity analysis to consider the relative costs and benefits of AMI and FAN under a variety of scenarios. That analysis indicates at 95 percent confidence interval that expected benefits will exceed costs. We have also prepared a consolidated CBA that combines AMI-FAN with distributed intelligence (DI) costs and benefits, provided as Attachment B and discussed in Section V. Also in response to the Department and Synapse's stated priorities, we provide a description of our procurement process and bid pricing information for our selected AMI meter and alternatives considered (Attachment C).

To be clear, concurrent with the various regulatory filings and consistent with our understanding of the Commission's expectations, the Company has continued to move forward with the deployment of AMI and FAN in Minnesota. Meter installation began in April 2022, preceded locally by enabling FAN infrastructure. Although there have been some supply chain challenges affecting meter availability, the Company is continuing to progress toward full deployment of AMI and FAN by the end of 2024, which is consistent with the information provided to the Commission and stakeholders in the Company's 2019 IDP and certification request and its 2021 TCR Rider Petition.[9] The question at issue in this docket is whether the cost recovery we seek in the TCR rider is appropriate for the AMI and FAN projects the Commission certified in 2020, which requires consideration of the prudence of the Company's AMI and FAN procurement and implementation.

II. AMI AND FAN DRIVERS, STRATEGY, AND PLAN

The Company has provided substantial information regarding AMI and FAN in prior filings and discovery responses in this and other related dockets. In this Section of this Supplement, we provide a comprehensive overview, consolidating information and summarizing key aspects of our AMI and FAN strategy and plans.

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[9] The Company makes this point because some comments from the Department and Synapse suggest uncertainty as to whether or not AMI and FAN are being implemented.

A. Project Origin and Need

While much of the focus of the discussion of AMI and FAN by both the Company and other stakeholders has, understandably, been on the advanced capabilities of the AMI meters and the FAN, it is important to remember at the outset that utility meters serve a basic and critical function of measuring energy consumption for customer billing purposes. Historically, meters had to be manually read on a periodic basis. A Company employee or contractor would have to physically view each meter to obtain data on that customer's energy usage since the last meter reading. There were two significant disadvantages to such manual reading: (1) the cost of visiting homes and businesses and (2) the only energy consumption information obtained was for the gross energy usage between visits.

Automated Meter Reading (AMR) meters electronically transmit energy usage data, and were a significant step forward that allowed utilities and customers to realize significant efficiencies in meter reading costs. The Company deployed its current AMR meters in the mid-1990s, and has maximized its value for customers over a long period of time. This system collects meter readings remotely via a proprietary, fixed communications network by Landis+Gyr (Cellnet), which is our current meter reading services vendor. An AMR system has limited functionality and primarily is able to only transmit energy usage information from the meters for billing purposes.

After almost 30 years, our AMR service with Cellnet is approaching the end of its operational life. Cellnet has announced that it will no longer manufacture replacement parts for the meters after this year (2022). The system is proprietary and parts are not commercially available from vendors other than Cellnet. The result is that beginning next year (2023), we will not be able to purchase replacement parts for our aging meters, many of which are between 20 and 30 years old.[10] In addition, the Company's meter reading and support contract with Cellnet expires at the end of 2025.

With the approaching need to replace our current metering, we began the planning and procurement process for new meters and a method of communicating with meters in the early 2010s. In broad terms, we needed to decide on both a type of meter to purchase and what type of meter communication infrastructure and services would be appropriate. We considered but rejected pursuit of a new AMR solution.

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[10] We note that we have already procured sufficient replacement parts to maintain legacy meters remaining in the field as we complete AMI meter deployment.

AMR technology would not efficiently support current policy drivers and service expectations that favor advanced rates that better support customer load shifting and energy efficiency actions; two-way communications capabilities that enable Company efficiencies that translate to service improvements for customers; and the ability to provide more granular information to customers so that they can better understand and control energy usage within their homes and businesses. After exploring the marketplace, considering alternatives, analyzing how metering and field communications would fit with broader grid modernization efforts, and conducting competitive procurements, the Company decided to purchase the Itron Riva 4.2 AMI meters and design and deploy a Company-owned FAN that uses industry standard, non-proprietary communications protocols and that supports not only AMI meters, but also other grid sensing and remote automation capable devices on the Company's distribution grid.

B. AMI

The Riva 4.2 meter chosen by the Company is manufactured by Itron Inc. It is based on the earlier Riva 4.1 meter, which became Itron's standard AMI meter in 2015. The Riva 4.2 meter has four key components: (1) the core energy measurement capabilities, (2) an embedded two-way communication module, (3) embedded distributed intelligence capabilities, and (4) an internal service switch. AMI also includes infrastructure beyond the meters themselves, one component of which is the head-end application. The head-end application is a critical operating system that sends data to and from the meters, and sends commands to the meters from the Company's backend systems. Other AMI infrastructure include the systems for storing and managing meter data, known as the meter data lake, and the meter data management system.

1. Core Energy Measurement Capabilities

Like any meter, the Riva 4.2 collects energy usage data; it can also measure and transmit voltage, current, and power quality data. However, as an AMI meter it has more advanced capabilities than non-AMI meters. The Riva 4.2 can be remotely configured to, among other things, measure bi-directional and/or time of use information in kilowatt hours (kWh) and kilowatts (kW), as customers implement distributed energy resources (DER) or change rates; it also supports the broad implementation of Time of Use (TOU) rates. The broad capabilities of the Riva 4.2 avoids the need to maintain inventory of specific meters to be used for specific purposes – and the remote configuration capabilities avoids the need for a field technician to reprogram or replace meters at customer premises to affect a rate or other change.[11] The Riva 4.2 can also record energy consumption in intervals as short as five minutes, though most of our meters will be configured for 15-minute intervals.[12] This interval energy usage data will typically be transmitted to the Company every four hours; however, other readings can be provided in near real time, including on-demand readings, readings in response to events (such as power outages, power restorations, and power quality events), and readings to provide data to the Advanced Distribution Management System (ADMS). The Riva 4.2 also includes Distributed Intelligence capabilities, as discussed in sub-section 3 below, which allow customers to access near real-time usage information.

The Riva 4.2 Meter also has "last gasp" capabilities that allow it to send out a message to our system providing notice of an outage. In addition, the meter has built-in theft detection capabilities; while meter theft/bypasses are infrequent, when they do occur they create dangers to the public and property. This capability of the new meters allows the Company to systematically become aware of these circumstances, reducing costs.

2. Meter Communication Capabilities

The meter contains radios for both communication with Company systems, as part of the FAN, and communication with devices within the customer's home or business (with customer permission). For both radios, we chose protocols that align with accepted industry standards. Our choice to use non-proprietary, industry-standard protocols gave us greater certainty that they will function well and an increased likelihood that our meters will be interoperable with future devices and technologies over time.

The radio used for communication with other Company systems, as part of the FAN, is a two-way radio frequency (RF) mesh radio. These radios comply with the Wireless Smart Utility Network (Wi-SUN) industry standard. The use of mesh radio increases the resilience of communications with the meter. If one node within a mesh goes down, perhaps because of an outage, there are still multiple remaining pathways available and so communication to and from devices is more likely to remain intact.

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[11] See for example, the Company's October 30, 2006 Petition in Docket No. E002/M-06-1532, seeking authority to temporarily modify our time of day tariffs to accommodate a trial change in daylight savings time to avoid the need to manually reprogram 14,000 meters in Minnesota at an approximate cost of $350,000.
[12] The DI capabilities of the Riva 4.2 actually allow for analysis and communication regarding second and even sub-second data; however, we focus on those capabilities when discussing DI, not the core metering capabilities, as second and sub-second data capabilities require the use of on-meter computational processing.

Each meter also has a Wi-Fi radio, which will use the IEEE 2030.5 protocol for communication with the customer's own devices, if the customer chooses to use those abilities.[13] This radio, along with the DI capabilities discussed immediately below, will allow customers who opt to participate to receive detailed, near real-time information and insights about their energy usage, which can promote changes in behavior that create bill savings and environmental benefits. Wi-Fi radio was chosen for this capability because it is a radio technology widely used by our customers in their homes and businesses. With Wi-Fi, many customers will be able to communicate with the meter without the need to purchase a new device. Instead, they will be able to use existing devices such as smartphones and tablets. The IEEE 2030.5 communications protocol was selected because it is an industry standard specifically designed for communication with advanced grid devices.

The meter also has a Powerline Carrier (PLC) communications device. The PLC is not yet in use, but a firmware update planned for 2023 is expected to allow for its operation. This device will allow the meter to communicate through the power lines with other Company-owned devices. Specific uses that could be implemented to use the PLC include DI-enabled connectivity, which would help improve our planning and modeling of the distribution system by using the PLC to improve our information regarding the location of the meters, and a DI-enabled application that will improve the theft detection capabilities of the meter.

3. Embedded Distributed Intelligence Capabilities

The distributed intelligence (DI) capabilities of the meter refer to the meter's built-in computer components, which use a Linux-based operating system and include an ARM cortex microprocessor with 256 megabytes (MB) of RAM, 512 MB of flash memory, and two gigabytes of extended flash memory. This localized computing power at the "edge" of the distribution grid makes it possible to process and analyze very granular data collected by meters, including second and even sub-second data that would be impracticable and, to the extent even possible, very expensive to transmit to our back office systems to process and return meaningful information to our customers. These grid edge capabilities support customer-facing and grid-facing uses of such granular data that would not otherwise be feasible.[14] This on-meter analysis is key to expanded uses of the meter that go beyond base AMI capabilities to

[13] The Wi-Fi radio could also be used to communicate with a meter technician visiting the premises for repair activities; however, we anticipate that such visits will be relatively rare.
[14] To be clear, uses of the meters' DI capabilities will also involve other computing processes running on the Company's back-end system. The on-meter DI computer processing operates in conjunction with other Company computer systems.

empower and inform customers and enable the Company to better monitor and manage the distribution system. The Wi-Fi radio discussed above will also play a key role in DI as it will allow for direct communications with customers' own devices, if customers choose to use those capabilities.

Crucially, the DI capabilities of the meters allow the Company to implement new and expanded uses of the Riva 4.2 meter through installation of new DI software applications, which can be done remotely without having to upgrade or replace the hardware within the meter. The Company will have the ability to add new DI applications in response to evolving regulatory requirements, policy objectives, changed customer expectations, and/or changing operational needs without undertaking the difficulty and expense of physical modification or replacement. We expect this aspect of DI to allow for longer service lives than might otherwise be the case.

4. *Internal Service Switch*

Finally, the Riva 4.2 meter's internal service switch can be used to remotely connect or disconnect power to a residential or small commercial customer's electric service using a command transmitted from the AMI head-end application. We expect this capability, once fully implemented, will dramatically reduce the field work and truck rolls currently needed for such activities.[15]

C. Field Area Network

The Field Area Network is used to communicate with the AMI meters and other field devices equipped with communications capabilities. The Company has consistently presented AMI and FAN together for both certification and cost recovery because the two projects are inextricably intertwined. A communication method is foundational and fundamental to a modern grid, and in the case of AMI, avoids field visits by meter reading personnel and signals the Company in the case of a power outage, tampering, or other abnormal operating condition. An electric utility is required to bill customers based on their usage, and so we must have a method for getting energy consumption data from the meters located at customers' homes and businesses. Accordingly, AMI meters by themselves, without the FAN or some other communication pathway, would be underutilized and extremely inefficient. Conversely, while FAN can and will allow for communication with other field devices, not just AMI meters, its primary

[15] Full implementation will require a tariff change and waiver to Commission rules, which we have proposed in Docket No. E002/M-22-233.

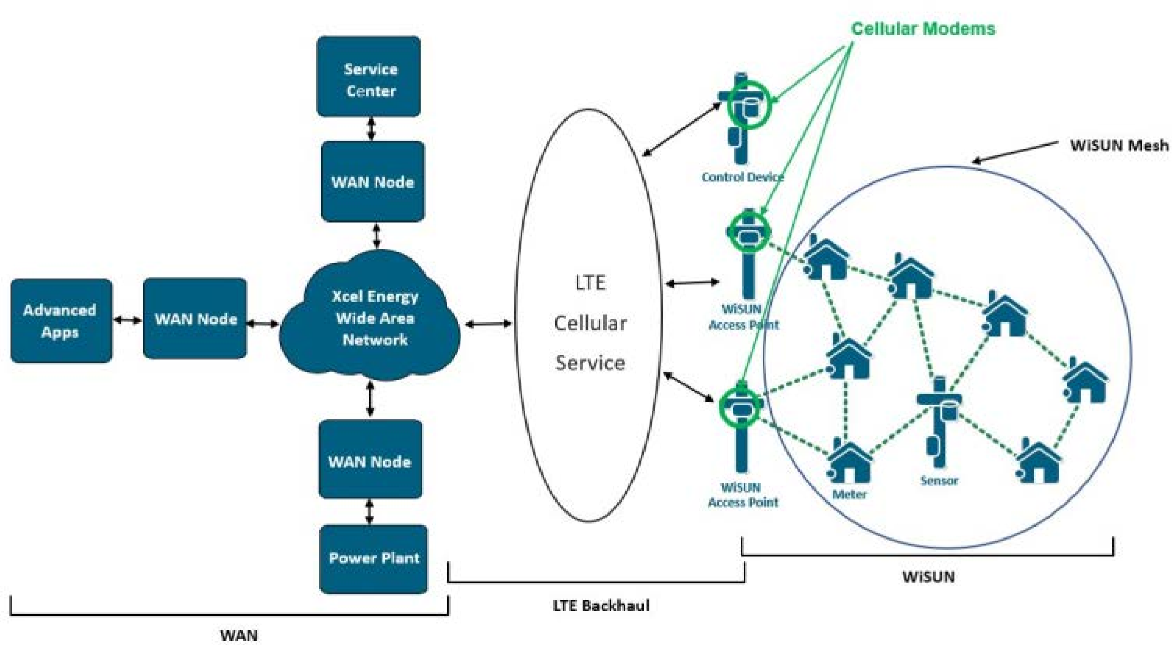
value arises from enabling AMI metering capabilities. Moreover, as noted above, the two-way Wi-SUN/mesh radios within each of the Riva 4.2 meters we selected are themselves a critical component of the FAN.

There are three components generally involved in the communication between field devices, including the AMI meters, and the Company's backend systems:

(1) A mesh Wi-SUN network between and among field access points and field devices (including the AMI meters), which uses radio frequency technologies;
(2) A backhaul network that delivers data between the mesh network and the Xcel Energy Wide Area Network (WAN); and,
(3) The Xcel Energy WAN, which is an existing high-speed network.

Figure 1 below depicts our current implementation of the FAN communications between field devices, including AMI meters, and the backend Xcel Energy systems.

Figure 1: Current FAN Strategy – Cellular for Backhaul



1. *Wi-SUN Mesh Network*

The Wi-SUN network is the mesh radio aspect of the FAN that operates in local areas to allow for communication between and among the AMI meters and other field devices.[16] In addition to the meters and other field devices, this portion of the FAN also includes access points and repeaters. The repeaters are primarily installed on distribution poles and are used to fill in coverage gaps. The access points are the connection between the mesh network and the backhaul and are mostly located on distribution poles or other similar structures. The access points connect wirelessly directly to the backhaul.

Wi-SUN is an industry standard that is similar to the IEEE standards used for Wi-Fi communication. The Wi-SUN mesh is an inherently resilient design and has been successfully implemented by other utilities. The mesh network allows multiple devices to connect with each other, which provides multiple potential communication routes, ensuring a robust communications network. The Wi-Sun radio located in a particular meter, access point, or repeater can communicate with a variety of neighboring devices within its range, each of which should also have a variety of devices to which it can connect. If a one node within the mesh goes down, for example, during a severe weather event, there are still multiple remaining pathways available and so communication to and from most of the devices remains intact.

As discussed below in Section III-A, other possible methods for connecting AMI meters include hard-wired connections and point-to-multipoint radio. We chose a mesh radio solution because it avoids the costs and complexities of hard-wired solutions, allows for better communication than use of a PLC,[17] and is more robust for communicating with multiple field devices, including AMI meters, than point-to-multipoint radio. Each of those potential alternatives can also be an appropriate communication method for other needs, and, in fact, Xcel Energy uses point-to-multipoint radio for backhaul – and our WAN primarily relies on a hard-wired connection (fiber optic cable), as discussed below.

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[16] The Fault Location Isolation and Service Restoration (FLISR) intelligent field devices are one example of field devices other than meters that will connect to the FAN. FLISR costs are not included in our TCR request; we have requested cost recovery for FLISR in our pending electric rate case in Docket No. E002/GR-21-630.

[17] The PLC will enable certain specific uses of the meters; however, it is not well suited to serve as the primary communication pathway for the meter.

2. *Backhaul*

The backhaul transmits information between the access points and the Xcel Energy WAN. The Company currently generally uses public long-term evolution (LTE) (cellular) service contracted from well-known providers such as Verizon, AT&T, etc.[18] However, in areas where public LTE is not available, the Company may also supplement public LTE with alternatives such as private LTE or fiber. Importantly, the RF mesh and the access point modems the Company purchased originally to use with private WiMAX as its backhaul solution can work with any LTE service (private or public).[19] In the future, we have the freedom and discretion to switch to different public LTE service providers or implement private LTE (an option the Company anticipates it may pursue in the future if doing so make sense operationally and financially) without the need to replace the modems. Once again, we selected industry standard, non-proprietary-based equipment that gives us flexibility to respond to future developments.

3. *Wide Area Network*

Finally, the WAN is the Company's network for high-speed, two-way communications among and between the Company's data centers, facilities (including generating plants and service centers), and the FAN. The WAN is an existing asset (it pre-dates the FAN) and is primarily composed of privately-owned fiber optic cable and a collection of routers, switches, and private microwave communication devices supplemented by leased circuits from a variety of carriers and satellite backup facilities. The Xcel Energy data centers connected to the WAN store data and contain the hardware on which various applications are run, including ADMS, the AMI head-end application, and other advanced grid and business applications, including the applications that use energy usage information to create customer bills.

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[18] LTE is a worldwide fourth-generation (4G) wireless standard.

[19] The Company initially planned on using a private WiMAX network for this communication pathway between the mesh networks and Xcel Energy's backend communication network; however, a Federal Communications Commission (FCC) ruling that was effective April 2020 made that solution infeasible. As described in past Company filings, the new FCC requirements would have required costly updates to WiMAX hardware, and vendors responded by abandoning support of WiMAX products. WiMAX became unavailable commercially and so, after considering various solutions, the Company selected public LTE. Importantly, the data in transit will be encrypted at all times.

D. Implementation

1. Deployment Approach and Schedule

The Company deploys FAN infrastructure geographically – preceding AMI deployment by approximately six months. It is necessary to have FAN access points and repeaters in place prior to AMI meter installation to ensure the system is operating properly in advance of the meters being deployed, so we are certain we can immediately begin to gather customer usage information from the new AMI meters for billing purposes upon installation. Installation of FAN network devices began in 2021. As we noted above, the Company began deploying AMI meters in April 2022 and plans to complete installations by the end of 2024.

a. FAN

The specific layout for the FAN devices is based on backhaul coverage, terrain, the locations of the meters, and distances over which meters and other devices can communicate. The network design for FAN contemplates that 497 Wi-SUN access points will be necessary in Minnesota, with each access point also having a cellular modem for the backhaul. In addition, we will be installing 2,218 Wi-SUN repeaters in Minnesota. Current per device costs for these equipment are as follows:

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

b. AMI

In contrast to the FAN, where the number of devices installed is impacted by a variety of factors, the quantity of AMI meters is based on Minnesota customer premise counts. Table 1 below sets forth our current planned meter deployment schedule. The meter deployment schedule outlined below is our latest projection, and what we used in the CBA that accompanies this Supplement. We additionally note that global supply chain issues have already slowed the progress of our planned 2022 installations and there is a significant risk that we will not achieve our 250,000 target for 2022. We expect there to will continue to be some uncertainty with regard to the deployment schedule at least through 2022. We are in regular discussions with our vendor and will update the Commission and stakeholders as appropriate.

Table 1: Latest Available Meter Deployment Schedule

Year	Meters Deployed
2022	250,000
2023	670,000
2024	496,893

Close to 20,000 Riva meters have been installed as of late July, with only approximately 0.6 percent of customers having chosen to opt-out of having an AMI meter installed. Post-installation customer survey results indicate that customers have been pleased with the Company's communications regarding the new meters.

2. Interoperability

Interoperability is crucial to the Company's plans for AMI and FAN and has been a subject of some inquiry from the Department and Synapse. With regard to interoperability between AMI and FAN, one focus of the Company's selection and design processes was ensuring that the meters would work with the FAN, as is reflected in the discussion below in Section IV. We have ensured interoperability, including with future devices and types of devices, by choosing to use industry standard, non-proprietary communication technologies and protocols such as LTE, mesh radio, the Wi-SUN standard, Wi-Fi, and the IEEE 2030.5 protocol.

The other key interoperability topic is the extent to which the meters can successfully connect to devices within a customer's home or business. In this respect, it is important to note that while earlier generations of AMI meters used other protocols and technologies that are not well-known, such as low-power Zigbee radio, the Riva

4.2 meter can connect with customer-owned devices using widely-accepted and used Wi-Fi radio and the IEEE 2030.5 communications protocol. Many of our customers have Wi-Fi at their homes and businesses and own Wi-Fi equipped devices, including smartphones, tablets, and "smart home" devices – and the IEEE 2030.5 protocol was designed to allow for communication between customers and smart grid devices. Even if customers do not have a home Wi-Fi network, they will still be able to directly connect to the meter via Wi-Fi if they have a Wi-Fi enabled smartphone or tablet. By using a form of radio communication widely used by our customers and a communications protocol explicitly designed to facilitate communication with customers, we were taking affirmative steps to ensure that customers will be able to directly interface with the meters located at their homes and businesses.[20] We are building upon those choices and further facilitating interoperability by providing software development kits for those seeking to design products and services that would interact with the meters (with customer consent) and by providing information to developers in workshops.

3. Measures to Limit Risks of Premature Obsolescence

We have been able to use our current AMR meters since the mid-1990s, leveraging their capabilities to maximize value for our customers and avoiding premature replacement costs. With AMI and FAN, we have taken affirmative steps to also get the maximum value from our selected AMI meters and FAN equipment. As a contractual matter, our agreement with the AMI vendor requires it to provide compatible components for a minimum of 20 years. In addition, the use of industry standard, non-proprietary protocols and technologies lessens the risk of premature obsolescence. Technologies and components with which we may wish to connect in the future are more likely to be interoperable with commonly deployed standards and technologies. The ability to use our modems to connect with other cellular networks, public or private, likewise gives us flexibility to adapt our FAN backhaul in response to future developments, and reduces the risk that equipment will need to be prematurely replaced or physically modified.

The AMI meters themselves can be reconfigured remotely. For example, as discussed above, we can enable time-varying rates or allow for bi-directional metering at customer premises with behind-the-meter solar generation without needing to

[20] This form of interoperability has an equity component. If the Company were to only allow for communication between home devices and meters using a more obscure communication method, the impact would be benefits only accessible to those customers who purchase specific devices for the purpose. However, the use of Wi-Fi broadens access to our many customers with Wi-Fi-capable smartphones and tablets.

physically install new meters. In addition, remote updates can similarly expand the capabilities of the meters by allowing for new rates, and also uses enabled by DI, without the need for physical replacement or modifications. These capabilities reduce the risk that customer expectations or regulatory requirements regarding meter capabilities will result in the Company needing to replace the AMI meters early. Some utilities that adopted early versions of AMI meters are already replacing those assets, and we have strived to avoid such an outcome by prioritizing the ability to flexibly adapt AMI and FAN in the future.

E. Security is Built-In Throughout

Cyber security was a key consideration at every stage in our planning, procurement, design, and implementation for AMI and FAN. Our cyber security controls leverage industry best practices, including the National Institute of Standards and Technology's (NIST) Cyber Security Framework (CSF). We are taking a defense-in-depth approach that will apply controls at many levels to identify and protect all components of the intelligent grid, including AMI and FAN. The multiple security mechanisms we have implemented include, but are not limited to, user access controls, encryption, firewalls, Intrusion Detection and Prevention Systems (IDS/IPS), vulnerability and patch management, system change and configuration management, monitoring, and incident response planning. We also have a rigorous vendor security risk assessment process to reduce supply chain risk.

F. Planned Uses of AMI and FAN

Like all meters and meter communication systems, the new AMI meters and the FAN are used for collecting and transmitting basic revenue metering information. We also have plans for using the advanced capabilities of the meters in new ways that will benefit our customers and society by facilitating energy efficiency, emission reductions, and improved operation of the distribution system. We comprehensively outlined our advanced grid customer strategy and plans in our 2019 certification request and in our 2021 IDP in Docket No. E002/M-21-694. We summarize these plans and benefits in this section. We also outline the benefits we have factored into our cost-benefit analysis and other qualitative benefits later in this Supplement.

We have categorized the benefits into two broad categories, each of which is discussed below: (1) customer-facing uses of AMI and FAN, which are the uses that will involve direct interaction with customers, and (2) grid-facing use cases, which involve uses of AMI and FAN to improve our operation of the distribution system.

We also note that while we have worked to identify the benefits that we expect will result from AMI and FAN, this is not an exhaustive list of all future possibilities – particularly with respect to the DI capabilities of the Riva 4.2 meters. Although consideration of customer preferences has been crucial to our plans, we also recognize that smart meters are a new type of device and customers themselves may not yet understand the ways in which they will want to interact with the technology. We expect that just as developers have conceived of new applications for smartphones, so too here they will conceive of new uses for AMI meters and that, when appropriate, we will be able to implement such new uses with relative ease by remotely upgrading the meters. Accordingly, we cannot provide a definitive list of all potential future cases for AMI and FAN. However, crucially, the capabilities resulting from initial use cases will provide foundational capabilities allowing for a variety of potential future uses. This "building block" approach is designed to give us flexibility to respond to developments in the marketplace and changing expectations.

1. *Customer-Facing AMI Uses*

In developing and planning customer-facing uses of DI, we took account of technological feasibility, customer preferences, industry trends and the experience of peers, and regulatory priorities and requirements. The resulting Company products and services roadmap is summarized in Table 2 below. In considering the roadmap, it should be noted that we have greater certainty regarding current and near-term offerings. Offerings contemplated for 2025 and beyond are more likely to change based on data from deploying earlier offerings, including feedback from customers, and the types of offerings that product developers bring to market.

Table 2: Product and Service Roadmap

Day One (2022)	Near-Term (through 2025)	Future (2025+)
• Energy Usage Dashboard • Enhanced Web and Mobile Apps • Energy Usage Alerts and Notifications • Green Button Connect My Data • Enhanced Communication Options with Behind the Meter Systems (HAN)	• Enhanced Outage Notifications • Emergency and Safety Notifications • Personalized Notifications • Power Quality Analysis • Whole Facility Monitoring • Rate Advisor • Time Varying Rates • Virtual Energy Audits • Demand management optimization • Enhanced access to battery storage and electric vehicles • Green notifications and controls • Enhanced DER detection and enablement	• Artificial Intelligence Enabled Notifications • Smart Premise Restoration • Enhanced Microgrid Integration • Smart Safety Disconnect • Enhanced Automated Demand Response

The customer-facing products and services enabled by AMI (and FAN, as it is necessary for communication), also fit into four broad and overlapping categories: (1) usage feedback, (2) time-varied pricing, (3) data disaggregation, and (4) behind-the-meter connectivity, each of which we discuss below.

a. Usage Feedback

The uses in this category include the initial energy usage dashboard, accessible on the web to customers, which will use AMI-enabled data to provide insights; enhanced mobile and web applications that will similarly provide more detailed energy usage information than was previously available to customers; and energy usage alerts and notifications, which involves notifications to customers to encourage load shifting behaviors that can save customers money while benefitting the environment and aligning with Minnesota public policies that encourage conservation. Customers will also be able to download their 15-minute interval energy usage data via the web portal and can opt to provide authorized third parties with automated access to the 15-minute interval energy usage data on a daily basis via Green Button Connect My Data, also included in the web portal.

As the Company develops its capabilities and better understands customer preferences and experiences with AMI, we plan to provide improved and more personalized energy usage notifications, which we call "green" notifications. With green notifications, customers who indicate they are particularly interested in helping to reduce carbon dioxide emissions could receive notifications focused on those outcomes. Such notifications would overlap to a significant extent with notifications focused on bill savings, with respect to timing and suggested courses of action. Customers vary in terms of their personal values and motivations, so these notification capabilities can be tailored to be meaningful to a significant portion of our customer base and produce environmentally meaningful load-shifting benefits.

The benefits of these uses are that customers will have access to much information regarding their energy usage, and notifications and alerts will provide guidance regarding behaviors that can save on their monthly bills while also reducing environmental impacts. In addition, customers can benefit from potential bill savings from lower usage and reduced carbon dioxide emissions. Attachment D provides further discussion of this and other qualitative benefits.

b. Time-Varied Pricing

AMI meters can measure energy usage in shorter intervals than predecessor generations of meters, which more easily allows for time-varied pricing. The Company's ongoing TOU residential pilot program, also known as the Flex Pricing Pilot, certified by the Commission in Docket Nos. E002/M-17-775 and E002/M-17-776, involves the use of AMI meters. As AMI meters become widely deployed across our service area and as appropriate Commission approvals are obtained, AMI and FAN will facilitate more widespread implementation of time-varying rates in the future. These rates can encourage customer load reductions and shifting that lowers environmental impacts and reduces the need for peak generation resources. In addition, TOU rates empower customers to make choices that can lower their monthly bills. Importantly, energy usage feedback, discussed above, can reinforce the impact of TOU rates by providing personalized information to customers about the specific changes they can make within the home or business that will have the largest impacts on bill amounts. As with usage feedback, the benefits are in the areas of customer bill savings and reduced carbon dioxide emissions. The Commission is currently examining TOU rate designs and implementation for commercial and industrial customers in Docket No. E002/M-20-86. We will file our final report on the Flex Pricing Pilot in early 2023.[21]

c. Data Disaggregation

Disaggregation involves analyzing the total energy information collected by the meter at a customer's premise to separate out the usage associated with specific end uses – providing customers with powerful information about how they are using energy and the impact specific end uses have on their overall usage profile and bill. With the use of the DI capabilities of the Riva 4.2 meters, disaggregation uses sub-second data and can identify multiple specific appliance types – such as toasters, computers, etc. – providing disaggregation information in near real-time. Without DI, AMI disaggregation relies on 15-minute interval data reported to back-end systems every four hours, and can identify general categories of base load and variable load, but not specific appliances and not in timeframes that are concurrent with the usage of those appliances. The accuracy of non-DI AMI disaggregation is also lower for some large types of peak load, like air conditioning. As a result, while both types of disaggregation have benefits, DI-enabled disaggregation can be used to provide more specific and timely information to customers.

DI-enabled disaggregation provides granular data that can be used for more personalized energy notifications and suggestion. Our research indicates customers have an interest in such information. Eventually, along with other DI-enabled capabilities, it could allow customers to put in place sophisticated energy-saving automation and control mechanisms. As is reflected in the CBA discussion in Section V below, we anticipate that DI deployment will enhance customer bill savings, and have included additional DI-specific benefits in our combined DI, AMI, and FAN analysis (Attachment B) on that basis.[22]

d. Behind-the-Meter Connectivity

Behind-the-meter connectivity involves leveraging the Wi-Fi radio to, with customer permission (secured through appropriate authentication and verification procedures), connect to devices within customers' homes or businesses. At the outset, this will involve connecting to a customer's smartphone or tablet, which could then be used to

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[21] The Commission set reporting deadlines and requirements in its August 7, 2018 Order in Docket Nos. E002/M-17-775 and E-002/M-17-776; see Order Point 4.

[22] Implementation of initial use cases for DI are not included in the TCR Petition or revenue requirement calculations; cost recovery for DI foundational capabilities and initial use cases is being sought in the Company's pending electric rate case in Docket No. E002/GR-21-630.

provide detailed energy insights and notifications based on detailed information provided via the meter. Later capabilities involve connection to DER on the premises and, eventually, connections to smart home systems or other smart devices in the home.

2. *Grid-Facing AMI Uses*

The Company's planned grid-facing uses of AMI and FAN are focused on improving the service quality for customers and the efficiency and reliability of our distribution system. As a general matter, AMI allows us to have greater insight into the operation of the grid at individual customer premises. The Company is planning to use AMI to improve outage detection, and the embedded DI capabilities to detect electric vehicles (EVs), locate power quality issues, improve our information regarding the geographic location of portions of our system, and discover high impedance issues. The grid-facing uses of the DI capabilities will initially be implemented as pilot programs and then, based on the lessons learned from those pilots, we plan on broader deployment.

a. Outage Notification

The Riva 4.2 Meter can use its "last gasp" capabilities to send out a message to our system providing notice of an outage. It also provides notice of power restorations and can be "pinged" to check on the status of service at a location. Taken together, these capabilities, which are integrated with our Outage Management System, provide the Company with quicker and more accurate information regarding outages. We can then use that information to more efficiently and quickly respond to outages, with the result that the Company will spend less responding to outages. If we know immediately exactly which homes and businesses lost power, it is much easier to promptly dispatch crews to the appropriate locations. The other key benefit is reduced outage durations, which improves reliability for our customers.

The meters can also provide information regarding voltage sags, which can be analyzed to identify momentary outages. The Company can then proactively address conditions which cause such momentary outages, which will enhance service quality for customers and remedy situations which might have otherwise eventually caused other problems.

b. Power Quality Improvements

The AMI meters can be used to provide information regarding power quality. High or low voltages can be detected, and the Company can then proactively address such issues. Without AMI, such issues are difficult to detect and rely on a customer to report a suspected problem that the Company then investigates.

c. High Impedance Detection

This DI-enabled capability will allow the meters to detect deteriorating or loose connections. Without those capabilities, such issues on the secondary system, which carries power from transformers to meters, might only be detected if a customer notices a problem, such as flickering lights, or when they cause outages. By proactively identifying high impedance situations, the Company can promptly dispatch crews to proactively address the issue. A significant benefit of this capability is the prevention of outages, which enhances service quality for our customers and reduces the Company's outage response costs.

d. EV Detection

This DI-enabled use of AMI will use disaggregation capabilities to determine when an EV is charging at a location. There are other, non-DI AMI EV detection solutions available; however, they are less accurate, and the DI solution requires less significant back-office support. Using information regarding the prevalence and location of EV charging, we can improve our distribution infrastructure planning and forecasting. In addition, this capability can allow the Company to promote EV-specific rates, which can result in both customer savings and load shifting that reduces peak demand and environmental impacts.

e. Connectivity

This DI-enabled capability will use the PLC communication device in the Riva 4.2 meters to securely communicate with other local meters and transformers, which will help the Company ensure that it has accurate information in our GIS system regarding the location of each meter and how it is connected to the rest of the distribution grid. Though the information in the GIS system is generally good, there are gaps, particularly with regard to the secondary system. Other methods of locating and correcting inaccurate information are more expensive and time-consuming. Improved information regarding the system will improve our analysis and planning, and, along with other efforts, can improve the accuracy with which we analyze potential DER connections.

III. INDUSTRY OVERVIEW AND TRENDS

In this section, we discuss the state of the industry with respect to field/operational communications and metering technologies and trends. This is important context for understanding our design and procurement decisions, including the possible alternatives.

A. Field Area Network

Field Area Networks involve a wireless communications network to provide two-way connectivity and communications between Internet of Things (IoT) devices and back-end systems. In addition to meters, FANs are used within the utility industry for communicating with other devices such as two-way switches, streetlights, and sensors that send important operational data to engineers and grid operators. Initially, FANs used proprietary communications protocols and design and were implemented to serve single purposes, and sometimes continue to be today. For example, some AMI meters use a proprietary communications network dedicated to just AMI meter data. It is therefore possible for a single company to have multiple FANs, with each providing communications for a specific type of field device. Increasingly, however, FANs are being designed and implemented so as to allow for communication with more than one type of device, as the Company is doing in Minnesota – and which is more efficient than deploying, operating, and maintaining multiple networks.

FANs are typically designed to have somewhat limited bandwidth, but low latency. This means that while they do not allow for the transmission of large volumes of data, such as from streaming video, they communicate that data from field devices relatively quickly. As we discuss in more detail below, the FAN communication between field devices and back-end systems has three broad components: (1) a two-communication network for sending and receiving data to and from field devices, (2) the backhaul method used for communication between that network and back-end systems, and (3) the communication system used by the back-end systems (the WAN).

1. Two-Way Communication with Field Devices

Two-way communication with field devices can be accomplished with different types of communication methods/systems. Broadly, these are: (1) point-to-multipoint, (2) wired connection, and (3) RF mesh. The method we chose for our FAN is RF mesh. We briefly discuss each method below.

Point-to-multipoint systems are one option. In broad terms, this is the type of system used for cellular phone service. Just as a cellular provider's antenna communicates to and from multiple phones in the vicinity, a point-to-multipoint FAN would have a similar design in which access points would communicate directly with multiple individual field devices, such as AMI meters. However, the field devices themselves would not communicate directly with each other.

The two-way communication with field devices can also involve wired connections such as use of digital subscriber line (DSL), fiber optic lines, power line communication (PLC), or telephone dial-up. A key issue with wired connections is that it needs to exist at every location in order to function, so it would require wired connections with nearly 1.5 million customer premises to support the Company's metering in Minnesota. DSL and fiber optic lines may or may not be present at individual customer premises, which means that these options can present significant costs and difficulties if they would need to be installed. PLC with meters can be useful in some specific instances, such as underground vaults; however, it has limited speed/bandwidth compared to other technologies, is sensitive to disturbance, and has limitations on application. For these reasons, utilities opting to use this method for field communication with AMI meters have tended to be smaller municipal utilities. Telephone dial-up requires the customer to maintain a hardline telephone at their expense and is subject to service interruptions.

The method we selected is RF mesh. In this approach, individual field devices communicate with each other as well as with the access points. Among our peer utilities, RF mesh topology is widely used for AMI-supporting networks. Where RF mesh has been used, the experience has been positive as a result of the inherent resiliency of a mesh solution, as discussed above.

2. *Backhaul*

As discussed above, the data from the field devices must be transmitted from the field access points to the Company's back-office systems. The next component of the FAN is the backhaul, which transmits data between the Company's WAN and the access points. The backhaul can be performed through a variety of options including public LTE, private LTE, and fiber optic lines. Public LTE, the option chosen by the Company, is a point-to-multipoint solution. An LTE antenna owned by a mobile telephone company such as Verizon (the "point" in point-to-multipoint) can simultaneously communicate with a number of individual devices (the "multi-points"), including cellular telephones and our access point LTE modems. WiMAX was also a possibility until FCC regulatory action made it commercially unavailable. Fiber optic cable works well, but installing it across a large service territory can be expensive and difficult. If at some point the Company decides to develop a private LTE network, all of the equipment we have implemented to use with public LTE will be fully compatible with private LTE. The Company standard for providing these connections, specifically the cellular modems used to connect to the public LTE, will also work with private LTE with the change of a SIM card. The hardware and firmware in the cellular modems would remain the same and useful for private LTE if that direction is chosen in the future by the Company.

3. Wide Area Network

As outlined above, the final component of the FAN is Xcel Energy's existing corporate WAN. The WAN is an existing asset (it pre-dates the FAN) and is primarily composed of privately-owned fiber optic cable and a collection of routers, switches, and private microwave communication devices supplemented by leased circuits from a variety of carriers and satellite backup facilities.

B. Advanced Metering Infrastructure

Advanced Metering Infrastructure is a general term for the combination of smart meters, communications networks, and IT systems. The specific capabilities of AMI systems differ, and have evolved over time as meter vendors have developed and improved their products. But key AMI capabilities include two-way communications, the ability to measure, collect and transmit energy usage information in short intervals, the related ability to support complex rates such as TOU rates, and the ability to provide near real-time notice to the utility of outages.

Figure 2 below summarizes AMI technology and compares it to other types of meters, including AMR meter with one-way communication systems, AMR meters with limited two-way communication systems, AMR meters with drive-by systems, and manual read meters. As the figure illustrates, AMI meters provide many more capabilities than the alternatives.

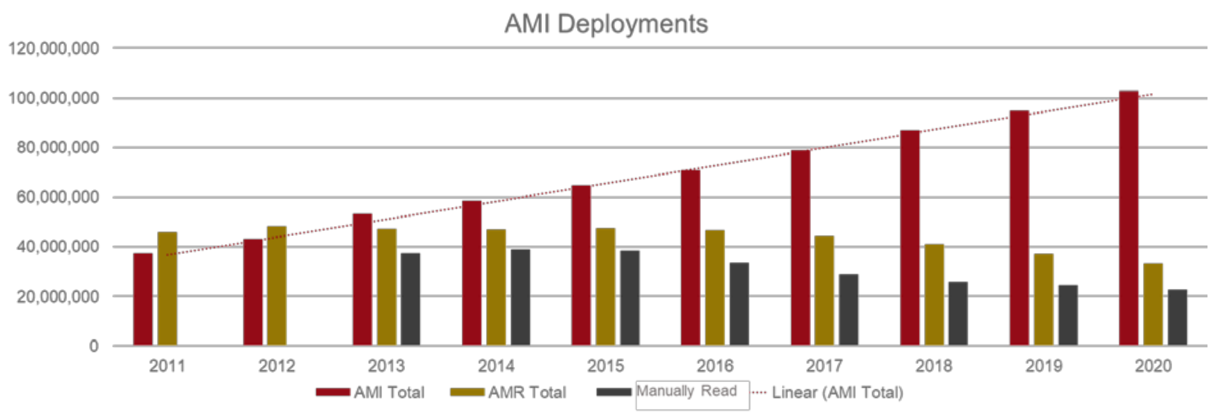
Figure 2: Meter Type Capabilities Summary

Feature/Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
Total cumulative consumption data	● Supports more complex rates	System supports 2 tier rates.	Support only two TOU rates and meters cannot be remotely programmed to capture TOU data.	Limited capability. Some meters could support one TOU bin in addition to other metering quantities.	○ Not supported
Interval Data	● Capable of measuring and recording more complex interval data sets; supports more interval data lengths	Can only be used for load research purposes and not for billing as data is not revenue grade quality; limited to traditional energy interval data	Data can be used for billing; limited to traditional energy data; limited to 5- or 15-minute interval lengths	○ Not Supported	○ Not Supported
Real time notification of power outages	● Real-time availability of outage information	Outage notification but not in real-time	Outage notification but not in real-time	○ Not supported	○ Not supported
Fast response to customer inquires	● Real-time access to customer metering data Access to real-time meter diagnostic information	Limited access to customers metering data Limited access to real-time meter diagnostic information	Lack of real-time view of customer's metering data No access to meter real time diagnostic information.	○ Not supported	○ Not supported
Support integrated systems that offer customers options for energy conservation and cost management programs	● Technology supports customer side technologies such as smart thermostats, load control devices, etc.	Limited and uncoordinated technology that can allow for such customer facing solutions. Highly customized options for various customer bases required to offer such programs.	○ Not supported	○ Not supported	○ Not supported
Ability to remotely upgrade metering devices e.g., firmware upgrade, meter configuration changes	● AMI offers the platform to remotely perform such functions.	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Availability of near real-time data e.g., voltage, current, power, etc. that are vital for distributed energy resource (DER) monitoring	● AMI offers the foundation that makes the availability of such data possible.	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Remote availability of meter diagnostic data e.g., missing phase, CRC errors, etc. useful for remote troubleshooting	● Data available with full AMI systems.	Feature supported to a limited extent.	Feature supported to a limited extent.	Feature supported to a limited extent.	○ Not supported
Detect unsafe field metering conditions	● Provides service condition information such as temperature and service quality that can be used to detect unsafe conditions such as hot sockets.	○ Not supported	○ Not supported	○ Not supported	○ Not supported

Full	Most	Partial	Minimal	None
●	◕	◑	◔	○

AMI deployments have been steadily increasing since 2011, as Figure 3 below illustrates. The figure is based on information collected from utilities by the U.S. Energy Information Administration. As it shows, AMI meters are now, by far, the most common type of meter installed by utilities in the United States.

Figure 3: U.S. AMI Deployment Trends



As of 2020, AMI meters already served approximately 65 percent of utility customers in the United States. Guidehouse Insights has predicted that this market penetration for AMI meters will approach 90 percent by 2028.[23] AMI meters are, thus, the industry standard. Customers and regulators increasingly expect the functionalities afforded by AMI to support policy priorities and customer service expectations, including the availability of granular energy usage information for customers (15-minutes or less), the ability to support broad time varying rates, capabilities to measure energy bi-directionally, and automated outage reporting.

IV. XCEL ENERGY SELECTION PROCESS

Xcel Energy began the initial stages of its planning and selection process for a new metering strategy back in the early 2010s, cognizant that the contract for the existing AMR meters would expire in 2025 and aware of the increasing pervasiveness of AMI meters. We discuss our selection process in detail below.

In summary, we determined that AMI would provide the greatest value for our customers over the long-term. Our procurement process initially started with an RFP

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[23] *See* Guidehouse Insights, "AI at the Grid Edge How Inside-the-Meter Analytics Drive Value at the Grid Edge," available at https://www.grid4c.com/hubfs/2021/AI-at-the-grid-edge.pdf.

seeking both AMI meters and a communications network for those meters. However, the two procurements were then separated, and we selected the RF mesh communications network vendor first. The AMI meter vendor selection then took place, and involved a consideration of whether to pursue DI-enabled meters. During meter procurement, our RFPs required interoperability with the already-selected network solution.

The following discussion is broken down into FAN and AMI sections. However, the two initiatives are intertwined. As stated above, the ultimate outcome was the selection of the Riva 4.2 meter and a FAN that uses RF mesh for communication among and between meters, access points, repeaters, and other field devices, with public LTE as the backhaul and the Company's existing WAN as the final leg between the field and the Company's back-office systems.

As a practical matter, it is not feasible to keep all options open through a complex procurement process such as was required for AMI and FAN. Instead, decisions are made along the way that impact what options are then subsequently available. For example, before an RFP is issued, decisions have to be made regarding the scope of the products or services for which proposals are solicited. These decisions points are discussed in narrative form below, and Attachment C provides additional detail on the decision points in the AMI procurement process. We also note that TRADE SECRET Attachment 4D and TRADE SECRET Attachment 4F of our initial TCR Petition include RFP evaluation scoring information for AMI and FAN, respectively.

A. Field Area Network

1. Process

We began the process of planning for a new communications network to connect with meters and other field devices in 2010. In 2013, the FAN was envisioned in our Network Strategy. We primarily used Requests for Proposals (RFP) to competitively solicit the capabilities and performance requirements established as part of our strategy and planning efforts. In 2016, Xcel Energy began its procurement process by issuing an RFP for both AMI meters and a communications network to communicate with those meters. Subsequently, in early 2017, we decided to separate the procurement process and select a communications network solution first before then choosing AMI meters that could work with that chosen network. We structured the selection process in this order so that we could include compatibility with the chosen communications network as one of the requirements for potential AMI meter vendors.

Three firms responded to the 2017 RFP, and Xcel Energy then evaluated those firms on a variety of criteria including price, technical and operational performance, security, long-term survivability, warranty and support, industry experience, and the vendor's ability to implement its proposed solution. Based on this evaluation, Silver Spring Networks was selected as the communications vendor. It offered good network performance and had the most resilient and secure network of the three potential vendors. Silver Spring's RF mesh communications solution, the Gen5 network, was also compatible with meters from all the major meter manufacturers. Silver Spring and Xcel Energy entered into a contract in December 2017 and we remain on the Gen5 network today.[24]

Of course, the FAN also involves the backhaul solution. As noted, the Company initially selected a private WiMAX solution, however in response to subsequent FCC action we later selected public LTE for most of the backhaul, with private LTE and fiber connections used in those locations where public LTE is not available. We chose the public LTE provider(s) based on the selection of public cellular as a backup to WiMax. Verizon was chosen as it was already the Company's standard vendor for connecting with remote devices (used in both gas SCADA and solar gardens). Pivoting to public cellular from WiMAX was a straightforward decision to use the pre-determined backup solution to ensure the Company met its commitments.

2. Alternatives Considered

As noted above, our consideration of alternatives took place in stages. The first stage of the FAN decisions relied on the Company's decision to pursue AMI metering. AMI meters require a two-way communication solution, whereas AMR meters generally only allow for one-way communications. This decision is described below in the AMI discussion.

Having selected AMI meters, we then needed to decide what type of two-way communications to use. Wired alternatives were considered, but rejected for reasons of practicality and expense. Simply put, our customers vary significantly with respect to what types of hard wired connections they have at their homes and businesses. Some customers have fiber optic or DSL connections, but many do not. As a result, a hard-wired approach to AMI would require either a patchwork of methods, with the associated complexities and costs, or the Company could, theoretically, itself install hard-wired connections across our service territory. That approach would be

[24] Silver Spring was subsequently acquired by Itron Inc.

prohibitively expensive and operationally and practicably complex. We determined that PLC was not a feasible option for the Company because of the limited bandwidth, sensitivity to disturbance, and limitations of application.[25]

In contrast with the cost and difficulties associated with hard-wired connections, a wireless solution would allow the Company to use a single communication method for its AMI meters, without the cost and expense of installing hard-wire connections to individual premises. Having decided upon a wireless connection, Xcel Energy then had to consider amongst the various wireless options. The key options in this area were a point-to-multipoint solution and RF mesh. We chose RF mesh because of the significant resiliency advantages it offered, which are discussed above. Then, after issuance of our 2017 RFP and review of the responses, we selected the Gen5 network from Silver Spring based upon its superior performance and the flexibility it offered, because it had and could be used with every major meter manufacturer.

The Department has inquired regarding the feasibility of a geographically limited phase-in of FAN deployment as a possible alternative to deploying FAN across our service territory. First, we clarify that the FAN is deployed in a phased approach – preceding AMI meter installation within an geographic area by approximately six months. So, in a sense, it is being deployed in a geographically-limited manner. That said, our FAN strategy and plan is comprehensive for our entire Minnesota service area. As we have discussed, we must completely replace our current meters and meter reading system, and while there may be some variation in how we achieve field area communications, particularly with regard to the backhaul, we need a comprehensive solution that will meet the needs of our entire Minnesota service area and allow necessary flexibility based on local geography or the availability of public LTE. The Company also implemented FAN in a manner that provides for flexibility for the future, including the ability to switch public LTE carriers or transition to private LTE, as appropriate. If FAN were not deployed in certain areas, we would have had to either not replace the meters in those areas, which is not a viable option given the currently obsolete equipment, or implement alternative methods of communication. Rather than have to use a patchwork of disparate communications, our comprehensive FAN approach with its inherent resilient and flexible design that can adapt to local conditions and that provides flexibility for the future is efficient, cost-effective, and overall a superior solution.

[25] As noted above in Section XX, use of the PLC device for the Riva 4.2 meter requires a firmware update, which is scheduled for 2023. However, the issue discussed in this Section is the general decision of what type of method to use for communication with AMI meters.

B. Advanced Metering Infrastructure

1. Process

In this Section, the Company will provide an general overview of our procurement process for AMI. A more detailed account, with trade secret information, including the pricing offered in proposals and some discussion of our evaluation of specific proposals is included in Attachment C.

As noted earlier, the Company decided to procure AMI meters to replace the aging AMR meters (and reading system) due to superior capabilities of AMI meters as compared to other types of meters, including newer vintages of AMR. We believe those capabilities are necessary to achieve the service expectations of our regulators and customers.

In March 2018, having already chosen a communications strategy and vendor, Xcel Energy issued an RFP for electric meters; four vendors responded. In August and September of 2018, Xcel Energy became aware that some manufacturers were developing DI-capable meters that would be coming to market. Having learned of the emergence of DI-capable meters onto the market, Xcel Energy carefully considered whether to pursue DI, including evaluating the potential benefits of various DI-facilitated use cases. Subsequently, we went back to the four bidders and asked them to submit RFP clarifications for meters with DI. Three vendors responded by proposing DI-capable AMI meters. Based on the responses received, Xcel Energy then made an initial selection of a meter vendor. However, in early 2019 it became clear that the selected vendor would not be able to meet the agreed-upon schedule. Following that, Xcel Energy issued RFP letters seeking updated proposals from both Itron and the previously selected vendor. After evaluating the responses, we selected Itron, based on schedule, pricing, and ease of integration with the Gen5 network.[26]

2. Alternatives Considered

As discussed above, the key driver for the AMI project was the approaching end of Cellnet's manufacture of AMR replacement parts and the 2025 expiration of the meter reading services contract. Given these factors, the Company determined that continued use of the existing, aging AMR meters and communication system was not a feasible long-term solution for our customers. The Cellnet contract could only be

[26] *See* our response to TRADE SECRET DOC IR No. 8 in Docket No. E999/DI-20-627.

extended through 2026 and such an extension would not have been appropriate or prudent because it would have required the Company to continue using aging equipment for which replacement parts and vendor support would no longer be available. Utility meters are a crucial aspect of utility operations and must operate accurately, timely, and reliably.

Needing to purchase new meters, we then needed to decide upon a type of meter. The potential alternatives were AMI meters, AMR meters, or manual read meters. The advantages and disadvantages of each type of meter are summarized in Figure 2 in Section III above. As the figure illustrates, AMI meters offer a much more robust set of features and capabilities than either manual read or AMR meters. Notably, some of the additional capabilities relate to interactions with customers, including the ability to integrate with energy conservation and cost-management programs, and others, such as near real-time outage information, support our reliable and cost-efficient operation of the distribution grid. We selected AMI meters over AMR and manual read meter alternatives based on the additional capabilities they offered. AMI meters allow us to reap the benefits of technology that supports a modern distribution grid and provides expanded capabilities that our customers and regulators expect.

We chose to purchase a DI-capable AMI meter for two key reasons: (1) the powerful, grid-edge incremental capabilities DI technology provides and (2) the ability to add or update the capabilities of the meters through the remote installation of new DI applications. The ability to enable new value from the meters and meter data through deployment of DI applications is particularly important when considering that the meters will serve our customers for the next twenty years. We are purchasing new meters at a time of great technological change and one risk is that changing customer and regulatory expectations could result in a premature obsolescence. DI reduces that risk substantially. The Riva 4.2 meter also met our needs with regard to schedule, pricing, and integration and has more advanced metrology functionality than the non-DI AMI meters we considered.

The prudence of our procurement decision are reflected in the favorable cost-benefit analysis set forth in the section below.

V. COST-BENEFIT ANALYSIS

The Company conducted a cost-benefit analysis (CBA) for AMI and FAN.[27] A CBA is a methodology that compares the quantifiable benefits and costs of a project or initiative to provide one perspective into the relative value of a project. The CBA provided is a comparison of the net present value (NPV) of the costs of the AMI with the NPV of the quantified benefits on a revenue requirements basis.

The CBA we provide in this Supplement is the third variation of CBA we have performed and submitted for our AMI and FAN investments. The first iteration was with our 2019 IDP and certification request (2019 Certification CBA).[28] At that time, we assigned a majority of FAN costs to AMI and the remaining FAN costs to the other advanced grid technologies we were proposing at that time. We provided our second iteration of CBA for AMI and FAN in our initial TCR Petition for cost recovery and because the Commission only certified AMI and FAN, the second iteration CBA (2021 TCR CBA) assigns all FAN costs to AMI. With this Supplement, we have refreshed the CBA (2022 Supplement CBA) to reflect the latest deployment schedule and updated general and labor rates; all other inputs and assumptions remain consistent with the 2021 TCR CBA. The 2022 Supplement CBA is included as Attachment A. The structure and approach of the 2022 Supplement CBA model is consistent with the Company's approach to the 2021 TCR CBA and 2019 Certification CBA.

However, in our 2022 Supplement CBA, we have expanded our analysis through use of a Monte Carlo simulation, which is a model that predicts the probability of different outcomes when the intervention of random variables is present; Monte Carlo simulations help to explain the impact of risk and uncertainty in prediction and forecasting models. Our 2022 Supplement CBA results in a benefit-cost ratio of 1.08 in the base scenario. Our sensitivity analysis similarly supports the AMI and FAN projects, showing benefit-cost ratios above 1.0 under 95 percent of scenarios examined in the Monte Carlo analysis.

The Department has requested clarification on the perspective used in the Company's CBA. The CBA is largely focused on the costs and benefits to our customers, which is why most costs and benefits were calculated in terms of the NPV of revenue requirements. However, there is also an element of a societal perspective resulting

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[27] The CBA is consolidated because of the manner in which the two projects are inextricably intertwined, with AMI requiring FAN and FAN consisting, in part, of the communication capabilities of the AMI meters.
[28] Docket No. E002/M-19-666.

from the inclusion of benefits arising from anticipated reductions in carbon dioxide emissions.[29]

There is no widely-accepted method to examine advanced grid investments. For certain investments, CBA is used. For others, least-cost best-fit is used. This differs from investments such as energy efficiency, where there is robust guidance and generally-accepted evaluation methods that include a participant cost test, utility cost test, a ratepayer impact measure, total resource cost test, and a societal cost test. These standardized measures of the costs and benefits of energy efficiency and demand response are rooted in guidance from the 1980s, and have been used to inform individual state program evaluation approaches and programs over many years. In the last several years, a national standards practices manual was published to aid evaluation of non-wires alternatives, which borrows and bases its concepts on these long-standing methods used for energy efficiency. While the approach we use in our 2022 Supplement CBA does not use one of these prescriptive approaches or specific cost-effectiveness tests developed for one of these other investment types, it uses similar principles. We took the perspective of our customers in identifying the benefits – either realized through cost reductions or Company efficiencies. We isolated and quantified the key, specific elements of the costs and benefits for analysis. We established a baseline against which we measured the costs and benefits that would be realized only with the AMI and FAN investment. Further, we used established financial analysis principles, such as calculation of the respective revenue requirements, converting all values to an NPV, and use of our established and approved weighted average cost of capital (WACC).

As with any CBA model, this one has some limitations, in that it only compares cost to the benefits that the Company has converted to dollars – whereas some benefits are difficult to quantify or attribute, and/or do not have a standard method for monetization. We consider such non-quantifiable benefits to be qualitative and discuss those further in Attachment D. Given its inherent limitations, the CBA provides one point of reference when considering the investments in AMI and FAN, and as such, the resulting benefit-cost ratio should be considered along with other information for a more holistic assessment of the project.

Finally, we note that in communications between the Company and the Department, Synapse provided a CBA prepared by National Grid for a conceptual AMI implementation as a model and example for the Company to emulate in its

[29] The monetary values assigned to reduced emissions of carbon dioxide were based on the values assigned by the Commission's January 3, 2018 Order in Docket No. E999/CI-14-643, adjusted for inflation.

Supplement. In summary, the Company's 2019 Certification CBA and 2021 TCR CBA were similar to the National Grid CBA in terms of approach, with the exception that National Grid performed sensitivities on only societal and customer behavior-based benefits. In our 2022 Supplement CBA we provide sensitivities not only for societal and customer behavior-based benefits through Monte Carlo simulation; we also include sensitivity analyses of costs, financial inputs, and numerous capital and O&M benefits. Attachment E compares the benefits included in the two AMI CBAs. Overall, the Company's quantification of benefits and CBA financial analysis are more robust and thorough than the example provided. The Company's CBA provides sensitivities around costs as well as benefits, develops justification and assumptions around the benefit outcome ranges, and incorporates additional monetized benefits such as efficiency gains, reliability, asset health and capacity, outage management efficiency, demand-side management, peak avoided generation (Critical Peak Pricing), and avoided carbon dioxide emissions due to load shifting that are not included in National Grid's CBA.[30] We detail our expanded analysis below.

A. Base Scenario AMI-FAN CBA

Key costs of our AMI and FAN initiative include the meters themselves, meter installation costs, related Technology Services costs (IT or Business Systems), network costs, and project management costs. This is consistent with the costs included in the previous CBA iterations. Figure 4 below provides the NPV of the total Capital and O&M costs broken down by category.

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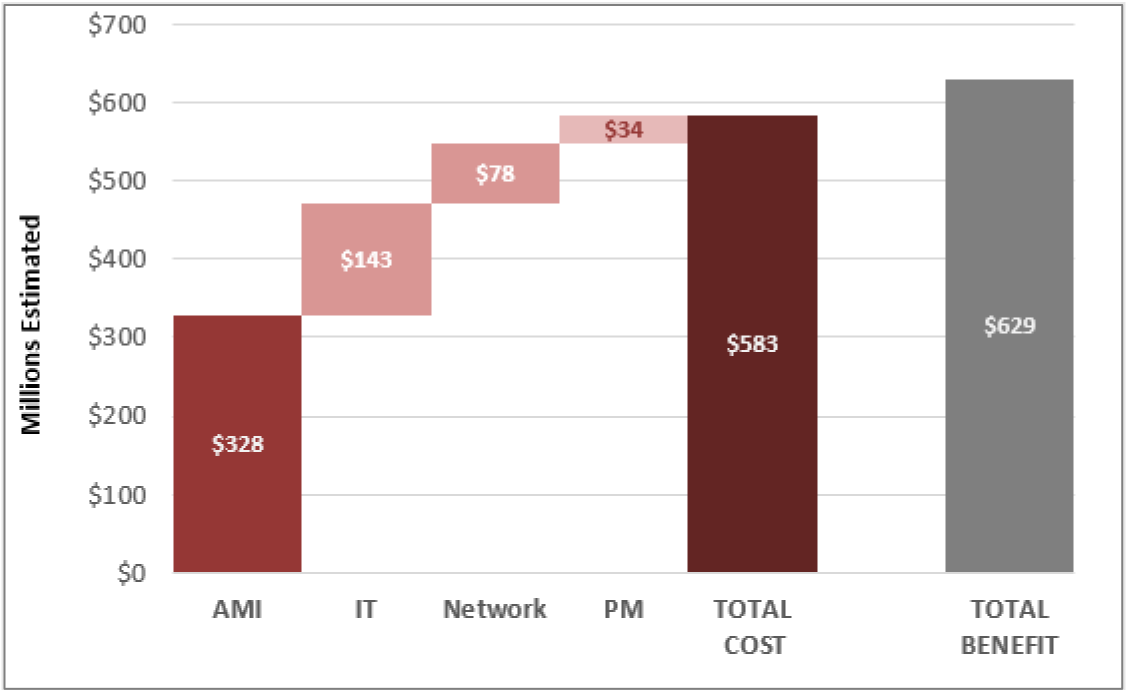
[30] National Grid's carbon dioxide emission benefit is calculated based only on reduced truck usage for drive-by meter readings.

Figure 4: AMI-FAN 2022 Capital and O&M – NPV



In determining the benefits to include in the 2022 Supplement CBA, we decided to keep them consistent with those quantified in our 2019 Certification CBA and our 2021 TCR CBA. We also decided to maintain the conservative timeframe for benefits we used in the 2021 TCR CBA and only include benefits for the 2024 through 2043 period. However, the 2022 Supplement CBA differs in that it reflects our latest meter deployment schedule and more accurately aligns the benefit timing by considering the year meters are installed. For instance, under the latest schedule, approximately 18 percent of meters will be installed in 2022, incurring costs and realizing benefits through 2041; approximately 48 percent of meters will be installed in 2023, incurring costs and realizing benefits through 2042; and, the remaining meters will be installed in 2024, incurring costs and realizing benefits through 2043.

The below series of three Tables summarize the quantifiable capital benefits, the avoided O&M benefits, and other benefits included in the 2022 Supplement CBA.

Table 3: Capital Benefits[31]

Benefit	Description
Distribution System Management Efficiency	More efficient use of capital dollars to maintain the distribution system. This benefit is based on an assumed one percent reduction in capital expenditures.
Outage Management Efficiency	Improved capital spend efficiency during outage events. This benefit assumes a 10 percent reduction in capital spending to respond to storm events.
Avoided Meter Purchases	AMI meters have a lower failure rate compared to AMR meters. By purchasing AMI meters, the Company avoids the need to replace failing AMR meters.
Avoided Investment of Alternative Meter Reading System	Avoided capital cost of an AMR meter reading system. Calculated based on the estimated cost of a drive-by system.

Table 4: Avoided O&M Benefits

Benefit	Description
Avoided O&M Meter Reading Cost	O&M component of the costs of an AMR meter reading system that will be avoided.
Reduction in Field and Meter Services	Reduction in O&M costs related to addressing meter and outage complaints and connections.
Improved Distribution System Spend Efficiency	Increased efficiency of distribution maintenance costs. This benefit is based on an assumed 0.1 percent reduction in distribution O&M expenditures.
Outage Management Efficiency	Improved O&M efficiency during outage events. This benefit is based on an assumed 0.1 percent reduction in O&M spending on storm response.

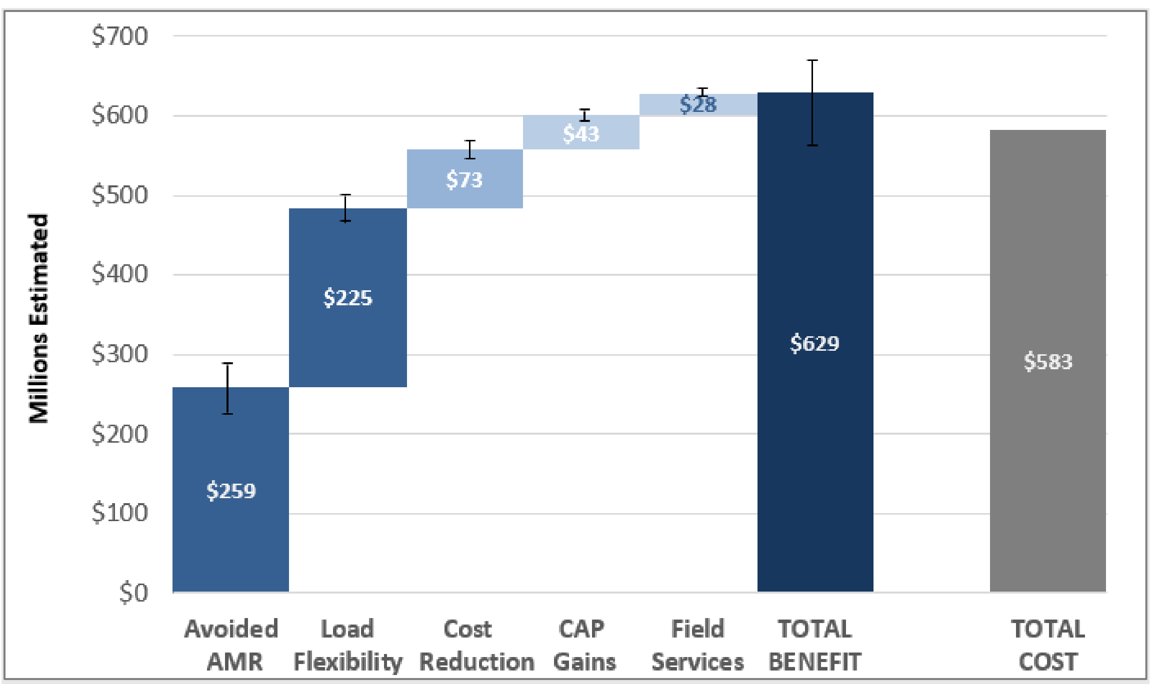
[31] The bases for the benefit amounts used are set forth in Attachment A. As that spreadsheet indicates, many of the benefits were calculated based on estimates from internal subject-matter experts. In certain instances, those estimates were compared to the estimated benefits calculated by Ameren Illinois when it sought approval for its AMI implementation. Ameren serves customers in a similar area of the country and so we would expect many AMI gains to be of a similar magnitude.

Table 5: Other Benefits

Benefit	Description
Reduction in Energy Theft	Decreased losses from easier identification of energy theft and an associated reduction in the amount of theft.
Reduced Consumption Inactive Persons	Decreased losses from the expedited ability to turn off power quickly when it is determined customer premises have been vacated.
Reduced Uncollectible/Bad Debt	Decreased losses due to uncollectable/bad debt.
Reduce Outage Duration	Direct benefit to customers in the form of a reduction in customer minutes out (CMO) associated with reduced outage duration. This benefit is calculated based on information from the Lawrence Berkeley National Laboratory's Interruption Cost Estimator (ICE) calculator.
Critical Peak Pricing	System demand savings in response to new rate structures, realized as a societal value in the CBA as greenhouse gas reductions.
TOU Customer Price Signals	Customer savings from new rate structures.
Reduced Carbon Dioxide Emissions	Differences in generation emissions resulting from load shifting.

Figure 5 below provides the NPV of benefits in comparison to costs for our base case CBA scenario.

Figure 5: AMI-FAN 2022 Benefit Base Scenario – NPV



After the updates discussed above, the CBA base case scenario indicates that the Benefit-to-Cost Ratio (BCR) of quantifiable benefits to costs is 1.08, which means that the quantified benefits are greater that the calculated cost of the project. The CBA base scenario is summarized in the below table.

Table 6: AMI-FAN Base Case Scenario Benefit-Cost Ratio Net Present Value (NPV) 2022 ($ millions)

	Total
Benefits	**629**
O&M Benefits	75
Other Benefits	321
CAP Benefits	234
Costs	**(583)**
O&M Expense	(163)
Change in Revenue Requirements	(419)
NPV – Net Customer Impact	**46**
Benefit/Cost Ratio	**1.08**

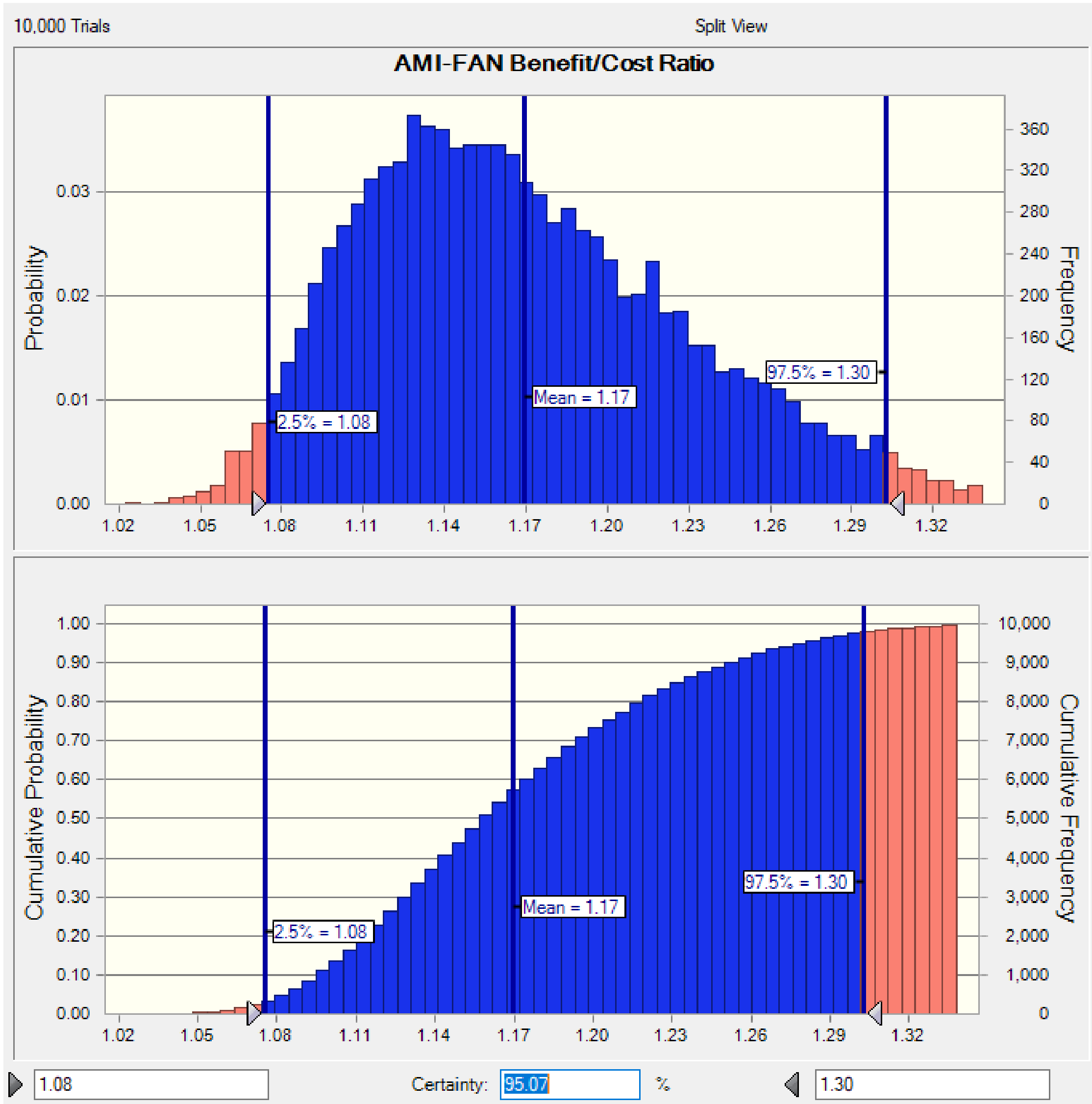
B. Sensitivity Analysis of AMI-FAN CBA

In addition to performing an updated base scenario CBA, the Company also conducted sensitivity analyses, through a Monte Carlo simulation, on some financial variables, contingencies, and most benefits. The Monte Carlo simulation is a statistical technique in which a quantity is calculated repeatedly, using randomly selected "what-if" scenarios for each calculation.

We used the Oracle-Crystal-Ball software to perform our Monte Carlo simulation. This software has been used by the Company for several years to simulate scenarios related to finance, engineering, project management, risk management, and our supply chain. A Monte Carlo simulation involves assigning multiple values to an uncertain variable to model many potential variations, and then averaging those results to obtain a mean estimate. To perform this analysis, the software requires a defined maximum number of trials that the system will run before it stops the simulation. The higher the desired confidence level, the more trials Crystal Ball will need to run. The Company conducted 10,000 random trials in order to reach the 95 percent level of confidence. The maximum and minimum values used in the analysis were based on historical information and/or estimates from subject-matter experts, and those values are each discussed below.

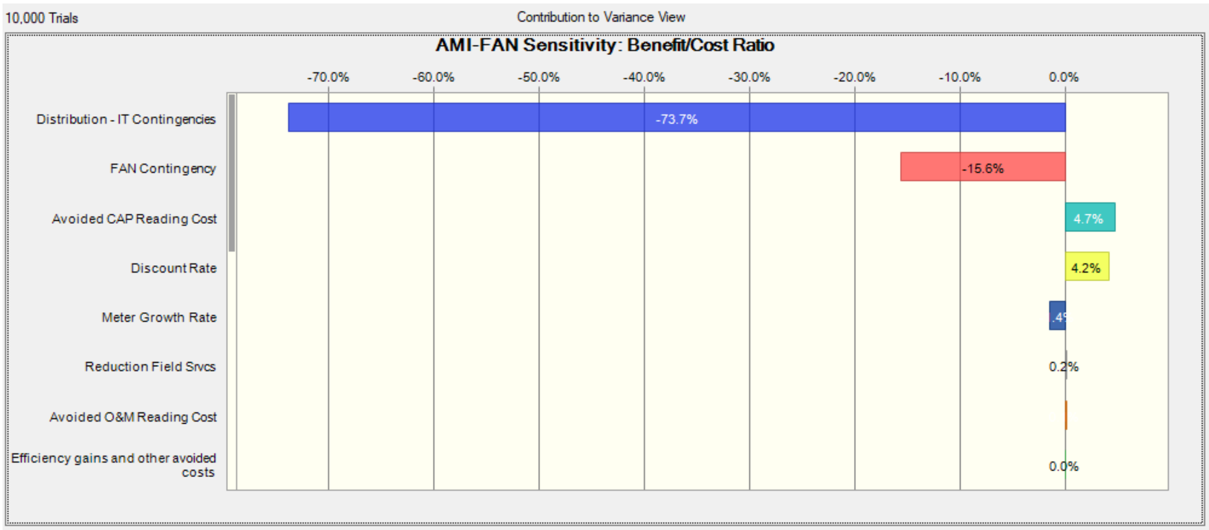
Our Monte Carlo simulation indicates that the benefits of the AMI and FAN project are expected to exceed the costs under a wide variety of scenarios. Even with various combinations of different cost amounts, benefit amounts, and financial conditions, the benefits of the project are expected to exceed the costs. More specifically, the results indicate that within a 95 percent confidence interval, the BCR range of our AMI and FAN initiative is between 1.08 and 1.30, with a mean of 1.17. Thus, within this confidence interval all outcomes of the BCR are greater than 1.0. Figure 6 below exhibits the probability distribution function and the cumulative distribution function for the BCR.

Figure 6: AMI-FAN Benefit Cost Ratio – Distribution of Probability Values at 10,000 Trials



Although many factors were varied as part of the Monte Carlo simulation, the extent to which we spend the Distribution and Technology Services Contingencies in the project budget is, by far, the single factor that contributed the most to the variations in the benefit to cost ratio. The FAN contingency is the factor with the next most impact. Figure 7 below exhibits the sensitivity percentage per variable.

Figure 7: AMI-FAN Percentage of Contribution of Variance per Variable



In the sub-sections below, we describe the CBA inputs that we varied in the Monte Carlo simulation. We start by explaining how financial factors in the CBA were varied, then discuss the cost variables and how they were modeled, and conclude by explaining the manner in which variations in estimated benefits were included.

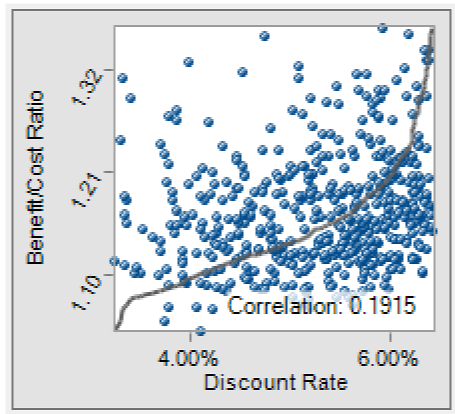
1. *Financial Sensitivity*

The Company considered the impacts of various financial scenarios on the benefit to cost ratio by including the variability of the financial factors discussed below within the Monte Carlo Simulation.

a. Discount Rate

The discount rate is used to convey future cash flows in a single present value for both costs and benefits. The discount rate used in the base scenario is 6.36 percent WACC after tax, which is an appropriate rate to use in evaluating the cost-effectiveness of proposed investments because the Company, not individual customers or society as a whole, is making these investments, and we use our capital to do so. For the Monte Carlo simulation, we used the highest WACC value approved by the Commission in the last 5 years, 6.44 percent, as the high bound and the Minnesota Conservation Improvement Program societal discount rate value, 3.02 percent, as the lower bound. The assumed probabilistic distribution selected for the variable was triangular skewed to the right. Figure 8 below is a scatter chart that represents BCR variations at different discount rates simulated along with other changing variables. For this particular simulation, the BCR increases as the discount rate increases; however, the impact on the BCR is relatively weak and the correlation is mostly random.

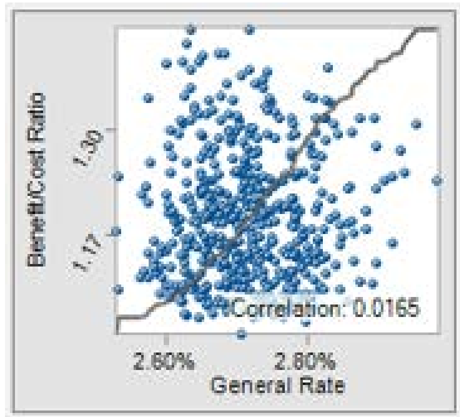
Figure 8: Monte Carlo Results – Discount Rate



b. General Rate

The general rate represents the rate of increase in prices, over a given period, for non-labor products. It is based on the Producer Price Index for finished goods from the U.S. Bureau of Labor Statistics. The assumed probabilistic distribution selected for this variable was a lognormal skewed to the right; therefore, the likeliest value used in the distribution was 2.71 percent. This value is based on estimates made by the S&P Global U.S. Macro Forecast, and it is utilized and distributed internally throughout the Company. The location and the standard deviation for the distribution of this rate were calculated based on the last five years of historical data. Figure 9 below is a scatter chart that represents BCR variances at different general rates simulated with other changing variables. The BCR increases as general rates increase; however, as with the discount rate, the correlation is mostly random.

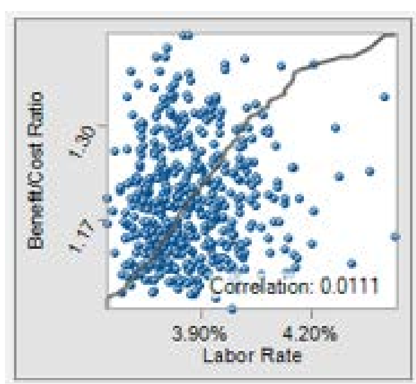
Figure 9: Monte Carlo Results – General Rate



c. Labor Rate

The labor rate is the rate of increase in cost of labor over a given period. The assumed probabilistic distribution selected for labor was a lognormal skewed to the right. The most likely value used was 3.87 percent based on estimates made by the S&P Global U.S. Macro Forecast. The location and the standard deviation of this distribution were calculated based on the last 5 years of historical data. Figure 10 below is a scatter chart that represents BCR variances at different labor rates simulated with other changing variables. The BCR increases as labor rate increases; however, once again, the correlation is mostly random.

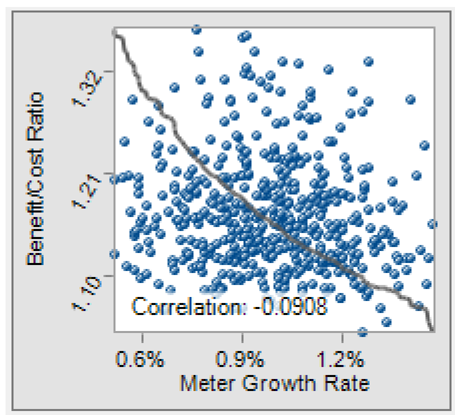
Figure 10: Monte Carlo Results – Labor Rate



d. Meter Growth Rate

The rate at which the number of meter installations grows based on new business/customers impacts capital *costs*; we clarify that we have not added corresponding additional *benefits* to our CBA based on the addition of these new meters. The base case scenario is a one percent growth rate, which is based on our historical experience. The probabilistic distribution behavior selected for this variable was triangular. The minimum value selected for the simulation was 0.5 percent and the maximum was 1.5 percent. Figure 11 below is a scatter chart that represents BCR variances with different meter growth rate values simultaneously changed with other variables. BCR values decrease as meter growth rates increase, which is to be expected because we did not add in corresponding benefits; however, again, the correlation is mostly random.

Figure 11: Monte Carlo Results – Meter Growth Rate



2. *Cost Sensitivity*

In addition to considering a variety of financial scenarios, we also used a range of cost contingency values and observed the influence of those to the final benefit to cost ratio as part of the Monte Carlo simulation.

a. Utilization of Distribution and IT Contingencies

The base scenario assumes 100 percent utilization of the Distribution and Technology Services contingencies. For the Monte Carlo simulation, this 100 percent value was considered as the high bound with zero percent set as the lower bound. The probabilistic distribution selected for the variable was triangular skewed to the left. Figure 12 below is a scatter chart that represents BCR variances with different contingency use percentages simultaneously changing along with other variables. As the figure shows, BCR values decrease as these contingencies increase.

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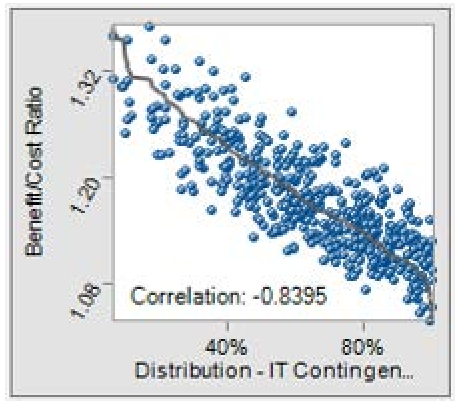
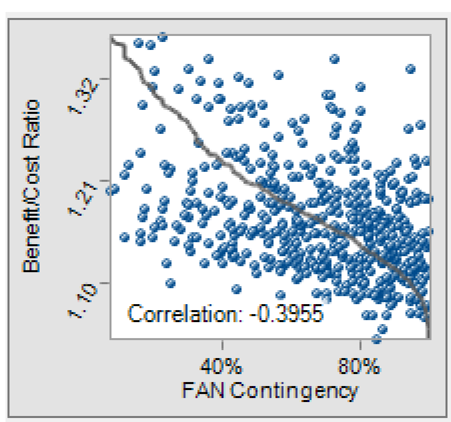
Figure 12: Monte Carlo Results – Distribution – Technology Services Contingencies



b. Utilization of FAN Contingency

In the base scenario, we also assumed 100 percent use of the FAN Contingency. For the simulation, this full use of the FAN contingency was considered as the maximum value while zero percent was set as the minimum value. The probabilistic distribution selected for the variable was triangular skewed to the left. Figure 13 below is a scatter chart that represents BCR variances associated with different FAN contingency use percentages varying simultaneously with other variables. BCR values decrease as FAN contingency increase; however, there is some degree of randomness in the correlation.

Figure 13: Monte Carlo Results – FAN Contingencies



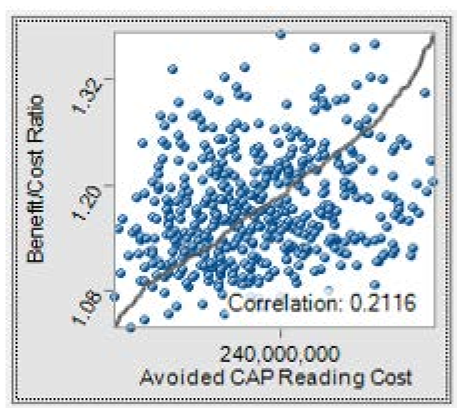
3. Sensitivity of Benefits

Along with financial factors and costs, the Company also used a range of benefit values in the Monte Carlo simulation. The benefits listed below were considered for the simulation.

a. Avoided Capital Meter Reading Cost

The estimate for the base scenario was determined by our subject matter experts in 2019. We maintained those initial calculations for the base scenario, and for the effects of the simulation, we added an additional 10 percent of the early estimates so as to arrive at the maximum value and subtracted five percent to create the minimum value. The assumed probabilistic distribution selected for this variable was a triangular one skewed to the right. Figure 14 below is a scatter chart that represents BCR variances associated with different avoided capital meter reading costs simultaneously changed along with other variables. BCR values increase as avoided capital reading costs increase; however, the correlation is mostly random.

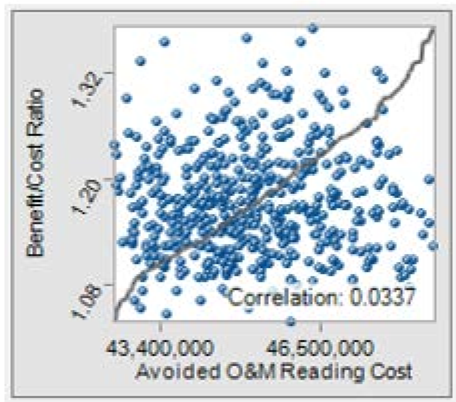
Figure 14: Monte Carlo Results – Avoided Capital Meter Reading Costs



b. Avoided O&M Meter Reading Cost

The same as the capital meter reading costs, the meter reading O&M estimates for the base scenario were determined by our subject matter experts in 2019. We maintained those initial calculations for the base scenario, and to accomplish the simulation, we set the maximum value by adding 10 percent to the estimates and deducted five percent to arrive at the minimum value. The assumed probabilistic distribution selected for this variable was a triangular one skewed to the right. Figure 15 below is a scatter chart that represents BCR variances with different avoided O&M meter reading costs simultaneously changed along with the other variables. BCR values increase as avoided O&M reading costs increase; however, the correlation is mostly random.

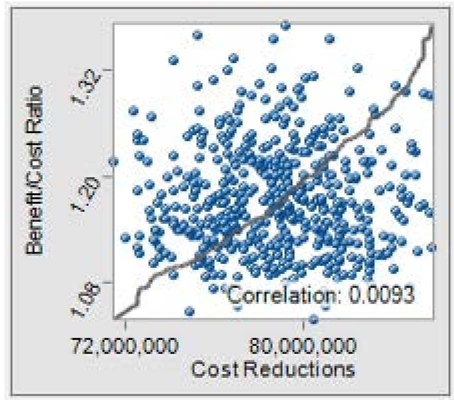
Figure 15: Monte Carlo Results – Avoided O&M Meter Reading Costs



c. Cost Reductions

As with other benefits, the AMI Cost Reduction benefits, which consist of Reduced Consumption On Inactive Meters, Uncollectible / Bad Debt Expense, Reduced Outage Duration, And Theft / Tamper Detection & Reduction were varied for purposes of the simulation. The assumed probabilistic distribution selected for this variable was a triangular with plus-minus 10 percent variance from the estimates used to set the maximum and minimum values. Figure 16 below is a scatter chart that represents BCR variances with different cost reductions simultaneously changed along with the other variables. BCR values increase as cost reduction increases; however, the correlation is mostly random.

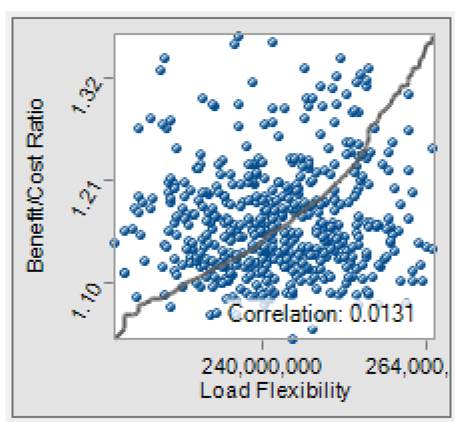
Figure 16: Monte Carlo Results: Cost Reductions



d. Load Flexibility

The Load Flexibility category of benefits includes benefits from Critical Peak Pricing, Time of Use rates, and Avoided Carbon Emissions benefits, and was also varied in the simulation. The assumed probabilistic distribution selected for this variable was a triangular with plus-minus 10 percent variance from the initial estimates use as the minimum and maximum values. Figure 17 below is a scatter chart that represents BCR variances with different load flexibility values, simultaneously changed along with the other variables. BCR values increase as Load Flexibility increases; however, the correlation is mostly random.

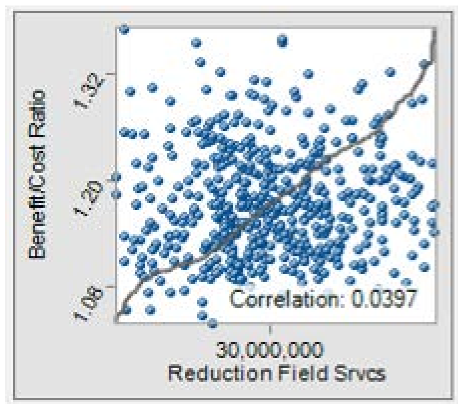
Figure 17: Monte Carlo Results – Load Flexibility



e. Reduction in Field Services

The Reduction in Field Services category of benefits includes cost savings from Remote Disconnect, Reduction In Trips Due To Customer Equipment Damage, Reduction In "OK on Arrival" Outages, And Reduction In Field Trips For Voltage Investigations benefits were also varied for purposes of the simulation. The assumed probabilistic distribution selected for this variable was a triangular with maximum and minimum values based on plus-minus of 10 percent from the estimates used in the base scenario. Figure 18 below is a scatter chart that represents BCR variances with reduction field services values, simultaneously changed with other variables. BCR values increase as Reduction Field Services increases; however, the correlation is mostly random.

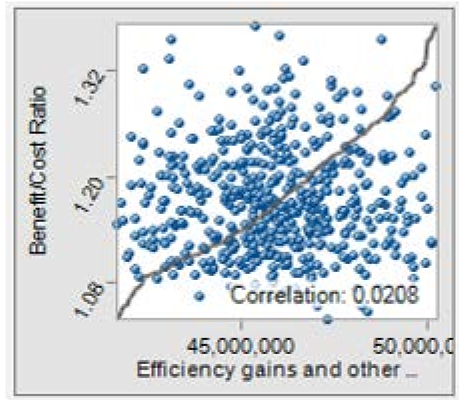
Figure 18: Monte Carlo Results – Reduction in Field Services



f. Efficiency Gains and Other Avoided Costs

The Efficiency Gains and Other Avoided Costs category includes Reliability-Asset Health-Capacity Projects, Outage Management Efficiency (Storm Spend), and Avoided Meter Purchases benefits, and was also varied in the simulation. The assumed probabilistic distribution selected for this variable was triangular with plus-minus 10 percent variance from the initial estimates used as the base scenario set as the maximum and minimum values. Figure 19 below is a scatter chart that represents BCR variances on Efficiency Gains and Other Avoided Costs values, simultaneously changed with other variables. BCR values increase as Efficiency Gains and Other Avoided Costs increases; however, the correlation is mostly random.

Figure 19: Monte Carlo Results – Efficiency Gains and Other Avoided Costs



C. Combined AMI-FAN and Distributed Intelligence CBA

While the Riva 4.2 meters have built-in DI capabilities, we have and continue to seek cost recovery of AMI and FAN separate from DI.[32] The CBA presented above and the two prior AMI-FAN CBAs provided to the Commission (the 2019 Certification CBA and the 2021 TCR CBA) do not include separable DI costs and benefits. However, in response to a request from the Department and Synapse, we have also prepared a consolidated CBA that combines AMI-FAN with DI, provided as Attachment B.

The combined AMI-FAN-DI CBA results in a benefit-cost ratio over one, indicating that the quantified benefits are greater that the calculated cost of the combined project. The combined CBA base scenario is summarized in the below Table 7.

[32] The Company is seeking cost recovery for AMI-FAN in the TCR proceeding and cost recovery of foundational DI and initial DI use cases in our pending multi-year rate case proceeding.

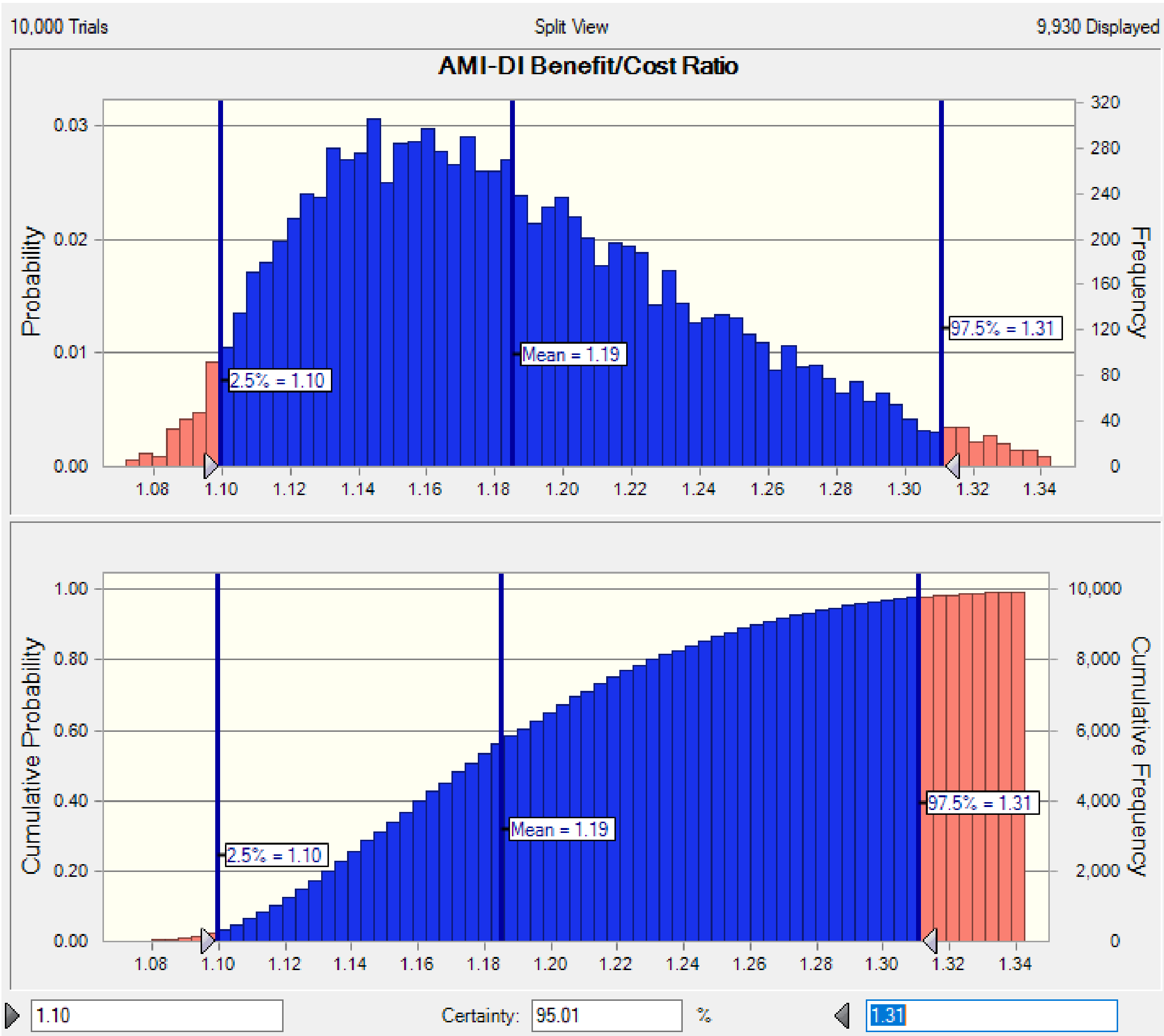
Table 7: AMI-FA-DI Base Case Scenario Benefit-Cost Ratio
Net Present Value 2022 ($ millions)

	Total
Benefits	**670**
O&M Benefits	75
Other Benefits	361
CAP Benefits	234
Costs	**(617)**
O&M Expense	(177)
Change in Revenue Requirements	(440)
NPV – Net Customer Impact	**52**
Benefit/Cost Ratio	**1.08**

D. Sensitivity Analysis of AMI-FAN and DI

The Company also conducted a Monte Carlo simulation sensitivity analysis for the combination of AMI-FAN and DI. The results of the combined simulation indicate that within a 95 percent confidence interval, the BCR range of our AMI-FAN-DI combined initiative is between 1.10 and 1.31, with a mean of 1.17. Consequently, within this confidence interval all outcomes of the BCR are over one. Figure 20 below exhibits the distribution curve of probabilities and the cumulative probability values obtained for the combined analysis.

Figure 20: AMI-FAN-DI BCR Distribution of Probability Values at 10,000 Trials



VI. REPORTING

As noted in the Background section above, the Department submitted its report regarding metrics for AMI and FAN in December 2020. In our TCR Petition, we responded to each proposed metric listed in Appendix E to the Department's Report. In our Petition, we largely agreed to provide the AMI- and FAN-related reporting proposed by various parties.[33] Although we plan to report on multiple items related to AMI and FAN and the benefits they provide, as we have explained in past related filings, establishing targets at this time would not be appropriate, nor would penalties

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[33] See TCR Petition, Attachment 4, Tables 11-19, pages 90-97.

or incentives for our performance. Discussions with the Department and its consultants led to a mutually agreeable approach in which we would tie our reporting back to the anticipated benefits outlined in our 2022 Supplement CBA (Attachment A), where applicable and to the extent practicable.[34] However, we note that while we can and do report items such as distribution O&M and capital spending in rate cases and IDPs, the reporting we would do for this as it relates to our AMI and FAN implementation will be estimates that use the same basis as our benefit assumptions used in the CBA. We do not have specific tracking mechanisms, and even if it were practicable to establish specific tracking, doing so would be administratively burdensome.

VII. OTHER – ADMS

In the Procedural Agreement, the Company committed to providing additional information regarding ADMS, including an update on ADMS implementation. The Department also requested additional information about Fault Location Isolation and Service Restoration (FLISR).

We clarify that we provide comprehensive updates regarding our implementation of ADMS each January 25th in the most recent TCR and IDP dockets. We submitted our most recent annual report on January 25, 2022 in Docket Nos. E002/M-21-694 and E002/M-21-814. We began deploying ADMS in 2016 and in 2021, the software went live in each of our three distribution control centers in Minnesota. ADMS went live in the first two control centers in April 2021 and the third in September 2021. Since the first control centers went live, the system has performed well and has been extremely stable. The Control Center has continued to provide positive feedback about ADMS performance. Features such as Fault Location Prediction have been utilized by engineers to assist with fault investigation, and in several instances, the ADMS has predicted the exact span of cable or conductor that experienced the fault, exceeding expectations.

The Company also agreed to provide information regarding synergies between ADMS and other investments, particularly AMI and FAN. As an initial matter, it is important to note that ADMS can and does operate without AMI and FAN. After all, ADMS came into operation well before the first AMI meters were installed. However, each installed AMI meter is capable of collecting and providing various information regarding the condition and operation of the distribution system at the customer meter; the FAN is used to provide that information to the Company's back office

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[34] Not all metrics on which we have agreed to report have a direct comparison point in the CBA.

systems where it can be accessed and used by ADMS. In that way, AMI and FAN can be used to provide additional granularity regarding the operation of the distribution system for ADMS. However, although benefits arising from detecting certain, specific types of problems are included in the CBA for AMI and FAN, such as the value of AMI-generated outage notifications, we consider ADMS to also be an enabler for both benefits that cannot be quantified and that are not solely attributable to AMI, FAN, and ADMS – such as the ability to effectively operate a distribution grid with high penetrations of DER and EVs – and also other types of benefits that can be quantified, such as reliability benefits from FLISR, which is described more below.

Another grid improvement that is in process and connected to ADMS (and the FAN) is FLISR, which is included in our pending multi-year rate case in Docket No. E002/GR-21-630. With FLISR, the Company will be able to locate (and even predict) faults on the system and close switches to isolate the faults, which will allow the continued operation of unaffected sections of the grid. Crews can then be quickly dispatched to the isolated sections of the grid where the faults are located. Overall, the benefit of FLISR is that it will enhance the reliability of the distribution grid.

FLISR deployment involves the installation of intelligent field devices that will be used to detect faults. The FLISR field devices will communicate with ADMS using the FAN and the Xcel Energy WAN, and are an example of the benefit of having a non-proprietary, device-agnostic FAN rather than one that is only designed to handle a single type of device. Information sent from the field devices will be transmitted using the RF mesh radio portion of FAN to the access points, at that point the data will go through the backhaul, and then it is communicated to ADMS through the Xcel Energy WAN. The ADMS FLISR application will analyze the data from the field devices to locate faults or potential faults. FLISR deployment began in 2021 and is expected to be complete by 2026.

The Department has also inquired regarding the possibility of implementing FLISR without ADMS. Because ADMS is already in operation, and FLISR operates as an ADMS application, it would not be cost-effective or efficient to develop or implement some other system to operate FLISR.

VIII. CUSTOMER BILL IMPACTS AND CLASS ALLOCATION

We provided an illustrative bill impact analysis in our 2019 certification request and repeated that in our 2021 TCR Petition. We also clarified in our 2021 TCR Petition that actual customer bill impacts from our AMI and FAN investments are part of the revenue requirements calculations and TCR Adjustment Factor calculations outlined in our TCR Petition. Those however include the cumulative impact of the projects subject to the Petition, which includes AMI and FAN and also transmission projects and other grid modernization investments. Table 8 below, which reproduces Table 2 from Section VII of the TCR Petition, compares the proposed TCR Adjustment Factors and overall revenue requirements as compared to the TCR Adjustment Factors currently in place with customers. The 2021-2022 Propose Adjustment Factors were calculated based on the assumption that it would be effective June 1, 2022, which did not occur. So, once the Commission takes action in the TCR proceeding, the Adjustment Factors will need to be recalculated to recover the approved revenue requirements, similar to treatment authorized by the Commission in past TCR rider Orders.

Table (TCR Petition Table 2) 8: Adjustment Factor Comparison

	2019-2020 Provisional	**2021-2022 Proposed**
Total Revenue Requirements	$81,883,541	$104,536,270
Residential Rate/kWh	$0.003607	$0.005783
Commercial Non-Demand kWh	$0.003185	$0.004545
Demand kW	$0.982	$1.081

Using these Adjustment Factors, an average residential customer using 675 kWh of electricity per month would see an increase on their bill of approximately $1.47 per month compared to the current TCR residential Adjustment Factor. We shared the residential result of this analysis in our Petition because it is representative of the overwhelming majority of our customer base, and is the common point of reference used to portray utility cost impacts.

We note that we are unable to conduct bill impact analysis specific to sub-categories of residential customers, with the possible exception of low-income customers, if those customers are defined as those having received LIHEAP in the last 12 months. In that case, the average customer receiving LIHEAP assistance uses 680 kWh of electricity per month, which would translate to an increase on their bill of approximately $1.48 per month compared to the current TCR residential Adjustment Factor. LIHEAP enrollment notwithstanding, we have no practicable method to determine which customers are low or moderate income or would be considered vulnerable or disadvantaged, as the Department and Synapse have requested, because we do not collect income or other sensitive information from our customers. We believe the "customer equity analysis" suggested in the Department's Guidance Document should be part of a stakeholder effort to define what type of customer cost impact information would be meaningful, and the information that utilities would be required to collect and maintain in order to provide that information. That, along with other aspects of the Guidance Document that would benefit from a stakeholder process, can then be considered by the Commission to determine what course of action would be in the public interest.

At the June 1, 2022 hearing where the Commission approved the Procedural Agreement, we agreed to include additional information about how TCR revenue requirements are allocated to customer classes. The first key principle in class allocation of costs is differentiating the types of costs. In the case of the TCR, these are:

- Transmission costs, and
- Distribution grid modernization costs.

We used allocators that were established in Xcel Energy's last approved electric rate case, Docket No. E002/GR-15-826, to allocate the transmission and distribution portions of the TCR costs between customer classes. The distribution allocator assigns a larger percentage of costs to residential customers than is the case for the transmission allocator. This is appropriate, as the need to have distribution equipment and infrastructure in place to serve the many individual customers is a significant driver of such costs, including AMI and FAN, which involve installation of large numbers of devices at individual customer premises. The details of the calculations for customer class apportionment are provided in Attachment 11 to the Petition.[35]

[35] Pages 56 to 58 of Attachment 4 to the Petition also provide an illustrative analysis of the impacts of just AMI and FAN, which was calculated with the Production, Transmission and Distribution (PTD) allocator used in the 2022 Class Cost of Service Study included with the Company's multi-year rate plan filed October 25, 2021 in Docket No. E002/GR-21-630.

CONCLUSION

We have provided additional information that comprehensively summarizes the Company's AMI and FAN plans and correlates the Company's filed information to the Synapse Completeness Review reflective of the recommended initial filing requirements from the Guidance Document attached to the Department's March 30, 2022 Comments in this proceeding. We have also provided information about the ADMS implementation, how the Company is using ADMS, the benefits or efficiencies being realized, and the synergies ADMS has with other current or planned grid modernization investments, particularly AMI and FAN. In addition, we have engaged in a cooperative dialogue with the Department and Synapse leading up to this Supplement, and expect that will continue through the comment period of this proceeding to resolve any additional questions or informational requests the Department or Synapse may have. The Company has complied with the Commission's requirements for cost recovery of its grid modernization investments, and we respectfully request that the Commission approve our proposed TCR revenue requirements and associated Adjustment Factors reflected in this proceeding.

Dated: August 17, 2022

Northern States Power Company

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

Attachments A, B, and C provided with the NOT PUBLIC version of this filing contain information classified as trade secret pursuant to Minn. Stat. § 13.37 for the above-noted reasons and are marked as "NOT PUBLIC" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment A:

1. **Nature of the Material**: The AMI & FAN Cost Benefit Analysis Model developed by the Company.
2. **Authors**: Risk Analytics
3. **Importance**: The Company work product is proprietary to the Company.
4. **Date the Information was Prepared**: The CBA Model was created in the third quarter of 2019 and updated in third quarter 2021.

Attachment B:

1. **Nature of the Material**: The DI, AMI, & FAN Cost Benefit Analysis Model developed by the Company.
2. **Authors**: Risk Analytics
3. **Importance**: The Company work product is proprietary to the Company.
4. **Date the Information was Prepared**: The CBA Model was created in the third quarter of 2021 and updated in second quarter 2022.

**PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED**

Attachments A, B, and C provided with the NOT PUBLIC version of this filing contain information classified as trade secret pursuant to Minn. Stat. § 13.37 for the above-noted reasons and are marked as "NOT PUBLIC" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment C:

1. **Nature of the Material**: A description of our procurement process and bid pricing information for our selected AMI meter and alternatives considered.
2. **Authors**: Sourcing
3. **Importance**: The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use and is subject to reasonable efforts by the Company to maintain its secrecy.
4. **Date the Information was Prepared**: August 2022.

QUALITATIVE BENEFITS OF AMI AND FAN

Although we quantify the costs and many benefits of AMI and FAN – as detailed in our cost-benefit analysis (CBA) – there are additional benefits that should be considered in order to conduct a holistic assessment of the projects.

In our TCR Petition, we discussed five specific qualitative benefits of AMI and FAN, as follows:

- Improved customer choice and experience, leading to customer empowerment and satisfaction,
- Enhanced integration of distributed energy resources (DER),
- Environmental benefits of enhanced energy efficiency,
- Improved safety to both customers and Company employees, and,
- Improvements in power quality.

We share the Department of Commerce and its consultants' desire to quantify all that can be quantified to evaluate our AMI and FAN investment. However, while we expect benefits from the above areas, they cannot necessarily be directly attributed to AMI/FAN deployment; the direct contribution of AMI/FAN to these benefits cannot be parsed out; or many assumptions would need to be made in the absence of established methodologies for quantification. In these cases, quantification is impracticable. In addition, direct costs associated with these qualitative areas are not included in the CBA, so even if they could be quantified or monetized, there would be asymmetry in the CBA. In the absence of quantifiable information, the Department and Synapse requested that we expand upon the explanations we have given for why a particular benefit cannot be practicably quantified or monetized. They also requested that we outline any existing reporting that we do for each qualitative area.

That said, in most cases we have existing mechanisms to broadly measure our performance in the areas of customer satisfaction. DER integration, energy efficiency, safety, and power quality. In the sections below, we reiterate how AMI and FAN contribute to each of the five qualitative benefit areas. We discuss the reasons quantifying each benefit in the context of AMI and FAN is not practicable. We also list AMI/FAN reporting items that may be directly or indirectly related to each benefit area. Lastly, we provide an overview of, and citations to, existing reporting related to each broad category.

I. CUSTOMER EMPOWERMENT AND SATISFACTION

A. How AMI and FAN Contribute to Customer Empowerment and Satisfaction

Giving customers choice and control over their energy usage by providing them with greater insight and greater input into the ways they use energy, and empowerment to make good choices about their impact on the environment are all important elements of both building customer satisfaction, increasing engagement, and managing electric demand.

In many cases, without AMI metering technology we have limited ability to identify outages without relying on the customer. Additional grid modernization initiatives that build on AMI and FAN will allow us to improve reliability by automating fault response and identifying more issues beyond the substation through technologies such as Fault Location Isolation and System Restoration (FLISR). Two-way communication and additional devices will allow us to enhance voltage optimization and better support DER. This further allows us to look to the future, and to emerging capabilities like Distributed Intelligence (DI), more customer application and interface technology, and additional energy sources through a modernized distribution grid. These benefits relate largely to customer satisfaction and future-proofing the distribution grid – benefits that are difficult or impossible to quantify.

Empowering customer choice is a key driver of our grid modernization strategy. Digital metering and technologies enable new programs and tools for customers that give them more information and thereby more power over their energy usage. Some of these options, such as the opportunities to receive regular updates about their electricity usage and to tailor their electric usage to reduce their electricity costs, are discussed above. But customer choice goes beyond time of use rates. With AMI, we have the option to implement customer-opted budgeting tools and high usage alerts that notify customers if they exceed or approach certain thresholds; to provide web and mobile applications that provide greater insight into energy consumption and peak demand; and to use those applications to also allow near real-time information access. AMI will also more readily support the two-way flow of energy via net metering, further supporting customers' abilities to invest in DER options such as rooftop solar and potential energy storage or battery options, if they should choose to do so.

References to AMI/FAN and Customer Empowerment and Satisfaction

Docket No. E002/M-21-814 – TCR Petition:

- Attachment 4, pages 68, 90-94 (Tables 11, 12, 13, 15, 16)
- DOC-41

B. Quantifying Customer Satisfaction and Empowerment Benefits Directly Attributable to AMI/FAN

Gauging customer satisfaction generally hinges on numerous key or fundamental tenets of utility service, such as billing accuracy, reliability, price, communications, and customer contact. Changes in broad customer satisfaction scores like J.D. Power cannot be directly attributable to AMI and FAN, even though AMI and FAN will have an impact on billing and reliability; these are affected by many variables, including weather, and it is not practicable to isolate the effects of AMI and FAN. Therefore, we consider customer empowerment and satisfaction to be a qualitative benefit. Likewise, we are not able to project any quantifiable expected improvement in J.D. Power scores that could occur after full deployment of AMI and FAN.

That said, we in Part C below, we outline a number of data points we are open to report that are directly or indirectly related to customer satisfaction and empowerment, should the Commission determine that is in the public interest.

C. Future Potential Reporting Related to AMI/FAN and Customer Empowerment and Satisfaction

Our TCR Petition outlined the following measures of customer satisfaction, empowerment, and/or engagement related to AMI and FAN. See Attachment 4, pages 68, 90-94 (Tables 11, 12, 13, 15, 16). Below, we list the relevant metrics from those tables.

- Survey results of customers on the adequacy and clarity of communications prior to installation of advanced meters.
- Survey of customer satisfaction with outage related communications.
- Number of complaints regarding AMI installation.
- Percentage of customers with an advanced meter that have made a complaint of inaccurate meter readings.
- Number of customers with an advanced meter with an active web portal (My Account) account.

- Percentage of customers with an advanced meter with Home Area Network (HAN) functionality.
- Number of customers with an advanced meter with HAN functionality.
- Percentage of customers with an advanced meter with Green Button Connect My Data (CMD) functionality.
- Number of customers with an advanced meter with Green Button CMD functionality.
- Percentage of customers with advanced meter at least 30 days that are targeted with energy savings messaging.
- Percentage of low-income customers with advanced meters at least 30 days that are targeted with energy savings messaging.
- Percentage of customers aware of AMI.
- Understanding of AMI technology and benefits.
- Percentage of low-income customers aware of AMI.
- Number of organizational events attended where information on AMI is presented, by region.
- Customer access to hourly or sub-hourly data.

We note that some of these items are more closely related to customer satisfaction than others. Further, we do not know whether or the degree to which these items would affect broader customer satisfaction scores. That said, customer empowerment satisfaction is still an important benefit of AMI and FAN.

D. Current Reporting Related to Customer Empowerment and Satisfaction

Our primary measure of customer satisfaction is the J.D. Power survey, the results of which we use as our corporate scorecard metric for customer satisfaction. We provide a description of the study and the survey results in our annual Service Quality report, most recently in Docket No. E002/M-22-162 as well as in our Performance Metrics Annual Report, Docket No. E002/CI-17-401.

As we described in our Service Quality annual report, J.D. Power independently measures relationship satisfaction and performs ongoing benchmarking studies that assess how utilities have performed in relation to one another. J.D. Power implements both a residential and business electric satisfaction study, measuring satisfaction with both customer segments across various categories or drivers of satisfaction. We subscribe to the J.D. Power survey because it provides a broad view of our customers and can combine it with other customer data, such as our transactional surveys, to develop action plans to improve satisfaction.

In addition, we use a variety of tracking surveys and studies to monitor customer satisfaction for specific customer interactions and experiences. These studies include:

- **Agent experience**: Gathers customer feedback on calls handled by call center agents. Metrics tracked include overall satisfaction with the call, whether the issue for the call was resolved with the first call, and agent knowledge to handle the issue. We include goals and actual performance at the Company-wide level in our Service Quality annual report in Docket No. E002/M-22-162.

- **Interactive Voice Response (IVR) experience**: Gathers customer feedback on calls to Xcel Energy involving the IVR system only, which typically involve bill payment and outage reporting. Metrics tracked include overall satisfaction with the IVR, ability to navigate the menu options, ability to resolve the customer's issue on the first attempt, and the ease of accomplishing their task. We include goals and actual performance at the Company-wide level in our Service Quality annual report in Docket No. E002/M-22-162.

- **Outage communications**: Gathers customer feedback on outage situations. Metrics tracked include the helpfulness of tips to use during the outage, whether a notification was received once power was restored, accuracy of any estimated restoration time (ERT) received, length of outage, and types of communication desired during outages. As noted in Attachment 4 of our TCR Petition, we propose to include these results in our AMI and FAN reporting.

- **Website satisfaction**: Gathers customer feedback from those accessing www.xcelenergy.com or My Account. Metrics tracked include ease of navigating the site, ability to complete the desired task, clarity of information, and overall satisfaction with the site.

Additional References

- Docket No. E002/M-22-162: Service Quality Annual Report
- Docket No. E002/CI-17-401: Performance Metrics and Incentives Annual Report
- Docket No. E002/M-19-666: 2019 Integrated Distribution Plan, Attachment M1

II. DER INTEGRATION

A. How AMI and FAN Contribute to DER Integration

AMI and FAN will contribute to DER integration by allowing, along with other investments and initiatives, for a more accurate modeling of the Company's distribution system, which will improve our ability to analyze and plan for DER integration. AMI will enable the creation of more accurate load profiles that are used by the Advanced Distribution Management System (ADMS) to create better system models for planning and operational purposes. Initially, ADMS will be using relatively few profiles to represent typical customer loads. Once AMI has been in place for a year, we will be able to create more refined profiles, which will significantly improve our models that are available not only to ADMS – but rather all of our systems and processes that rely on our Geospatial Information System (GIS). This data will then support planning and operational modeling, enabling us to more accurately identify problems (or the lack thereof) as more load or DER hosting is contemplated for the system.

The AMI meters will also be able to improve our information regarding the location of meters within the system using the powerline carrier communication (PLC) capabilities of the AMI meters to locate them in relation to transformers. As with the load profile improvements carried out using ADMS, the benefit of this use will be improved system modeling that will help us, among other things, better analyze the integration of DER on the system.

Additionally, the bi-directional capabilities of the AMI meters can allow for net metering without the need to install a replacement meter. This will lower costs and simplify the process of allowing for net metering of DER resources.

B. Quantifying DER Integration Benefits Directly Attributable to AMI/FAN

Taken together, the benefits discussed above will assist with the integration of DER. However, many other factors are also relevant to DER, including, among other things, available distribution system capacity, developer priorities, program frameworks, financial factors, and customer interest. Consequently, we cannot tie AMI and FAN directly to DER integration levels; instead, they will be among a variety of factors influencing DER integration.

C. Future Potential Reporting Related to AMI/FAN and DER Integration

As levels of DER integration are impacted by various factors and are not directly nor solely caused by AMI and FAN deployment, we are not proposing to provide additional reporting related to DER integration. In addition, the items we have proposed to report in Attachment 4 of the TCR Petition are not directly or indirectly related to DER integration. However, we report on DER integration in other venues, as discussed below.

References to AMI/FAN and DER Integration

- Docket No. E002/M-21-814 – TCR Petition: Attachment 4, page 69

D. Current Reporting Related to DER Integration

Currently, information about DER integration comes from our hosting capacity analysis (HCA), interconnection studies, Minnesota Distributed Interconnection Process (MN DIP) reports, and the Commission's annual DER reports that are submitted in Docket No. E999/PR-xx-10; these include information regarding DER MWhs of generation, by class, MWs installed as a percentage of load, by class, and DER adoption percentage, by class.[1]

Additional References

- Docket No. E999/PR-22-10: 2021 Distributed Energy Resource (DER) Interconnection Report
- Docket No. E002/M-21-767: 2021 Hosting Capacity
- Docket Nos. E,G002/M-12-383 and E999/CI-16-521: Quarterly Interconnection Reporting

III. ENVIRONMENTAL BENEFITS OF ENERGY EFFICIENCY

A. How AMI and FAN Contribute to Energy Efficiency

AMI/FAN is expected to enable greater energy efficiency by customers and the Company. AMI will provide customers more information on energy usage, and will enable the Company to offer programs and targeted messages that give the customer

[1] For additional information on the interconnection process and requirements, see Section 10 of the Company's electric rate tariff book: https://www.xcelenergy.com/staticfiles/xe-responsive/Working%20With%20Us/Renewable%20Developers/Me_Section_10.pdf.

more information and choices to control their energy usage and costs. To the extent these programs increase energy efficiency, and if those gains reduce the need for generation, they will contribute to lower energy emissions.

B. Quantifying Environmental Benefits of Energy Efficiency Directly Attributable to AMI/FAN

We note that in our CBA, we quantified avoided emissions and associated cost savings from increased load flexibility. Load flexibility, which *shifts* energy usage from peak times to off-peak times, should not be conflated with energy efficiency, which *reduces* energy usage. The technical potential of load flexibility programs was modeled by The Brattle Group and incorporated into our CBA.

We cannot tie environmental benefits of energy efficiency directly to AMI and FAN, because AMI and FAN alone do not enable energy efficiency programs. However, the energy usage information measured and communicated via AMI and FAN enable the Company to provide targeted messaging and tips to customers that could motivate them to reduce or shift when they use energy and/or enroll in existing and future energy efficiency programs offered through our Conservation Improvement Program (CIP). In addition, AMI and FAN enable the Company to make further investments in technologies like DI that will enable deeper engagement with customers and incremental savings through modifications to existing behavioral programs offered through CIP, as well as incremental participation in CIP programs. For these reasons, we consider environmental benefits of energy efficiency to be a qualitative, incidental benefit of AMI and FAN deployment.

C. Future Potential Reporting Related to AMI/FAN and Energy Efficiency

Although we cannot attribute any energy efficiency benefits directly to AMI and FAN, we have agreed to report on two measures related to the use of AMI and FAN to promote energy efficiency, as outlined in Attachment 4, page 94 (Table 16). Those two measures are:

1. Percentage of customers with advanced meters for at least 30 days that are targeted with energy savings messaging; and,
2. Percentage of low-income customers with advanced meters for at least 30 days that are targeted with energy savings messaging.

References to AMI/FAN and Energy Efficiency

- Docket No. E002/M-21-814 – TCR Petition: Attachment 4, page 69-70

D. Current Reporting Related to Energy Efficiency

We report energy efficiency results annually in our CIP Status Report, most recently in Docket No. E,G002/CIP-20-473, as outlined by Minn. R. 7690.0550.

Additional References

- Docket No. E,G002/CIP-20-473: CIP Status Report

IV. SAFETY

A. How AMI and FAN Contribute to Safety

As discussed on page 70 of Attachment 4, AMI minimizes safety risks for Company representatives and the customer by enabling remote meter reading, disconnection/ reconnection, and diagnostics. For example, AMI will allow us to assist emergency personnel more safely and quickly by remotely shutting off power to a burning building as opposed to dispatching a truck to perform the disconnection. In addition, while automated meter reading (AMR) meters can do some level of automated reading, they cannot minimize meter diagnostic and connect/disconnect visits to the same extent as AMI meters. These remote functions eliminate or minimize the need for the Company to visit the meter, which minimizes inherent risks associated with vehicle operation, as well as employee safety risks associated with customer pets and traversing unfamiliar properties.

References to AMI/FAN and Safety

- Docket No. E002/M-21-814 – TCR Petition:
    - Attachment 4, page 70
    - DOC-9
- Docket No. E002/M-19-666 – 2019 Integrated Distribution Plan: Attachment M2, Direct Testimony of Kelly A. Bloch
- Docket No. E999/M-15-439: Page 5 (general safety benefits of grid modernization)

B. Quantifying Safety Benefits Directly Attributable to AMI/FAN

This reduction in safety risk discussed above is a meaningful benefit, but we cannot tie improvements in employee safety directly to AMI and FAN, or any single grid modernization technology. Although we can approximate O&M savings from avoided field visits, we cannot directly tie any change in safety data to those truck rolls. For instance, to use the same example of remotely shutting off power to a burning building, we cannot know whether or when sending an employee to physically turn off power would in fact result in a near-miss or injury; therefore, we cannot quantify avoided near misses or injuries. As such, we consider safety to be an important, but qualitative benefit of AMI and FAN deployment.

C. Future Potential Reporting Related to AMI/FAN and Safety

Safety-related data points are not explicitly included in the future reporting we outlined in our Petition, but included in that reporting is annual avoided truck rolls/field visits pre- and post-AMI deployment. We note that, as stated in Table 15 in Attachment A of our Petition, further discussion may be necessary to determine avoided truck rolls attributable to AMI/FAN. As discussed above, avoided truck rolls and field visits can benefit employee safety, but are not safety metrics.

D. Current Reporting Related to Safety

Employee safety is an important priority for the Company, and safety culture is measured as part of our corporate scorecard. In 2020, we implemented a new approach to employee safety that encourages more open communication and information sharing. It is an approach to safety that moves away from traditional safety programs that focus on avoiding minor injuries in order to prevent more serious ones. Our new approach focuses on prioritizing and mitigating the risks that can cause serious and life-altering injuries through sharing, caring, and learning. While we still track and report injury data as required by the U.S. Occupational Safety and Health Administration (OSHA), we no longer include it as part of our corporate scorecard. Instead, we track leading indicators such as the number of near miss report submissions and the percentage of possible serious injury or fatality (PSIF) near miss reports.

Minn. R. 7826.0400 requires the Company to provide an Annual Safety Report on or before April 1 of each year on its safety performance during the last calendar year. We filed this information as part of our annual Service Quality Report in Docket No. E002/M-22-162. The report contains two pieces, as required by Minnesota Rules: (1) a summary of all reports filed with OSHA and the Occupational Safety and Health Division of the Minnesota Department of Labor and Industry during the calendar year; and (2) a description of all incidents during the calendar year in which an injury requiring medical attention or property damage resulting in compensation occurred as a result of downed wires or other electrical system failures and all remedial action taken as a result of any inquiries or property damage described.

We also track data related to our damage prevention program, which helps the public identify and avoid underground electric and natural gas infrastructure. We track the number of locate requests (i.e., through the Gopher State One Call) as well as any damage to Xcel Energy infrastructure. Our standard reporting data point is damages per 1,000 locates; we reported this figure most recently in our electric rate case. (See Direct Testimony of Kelly A. Bloch at page 132 in Docket No. E002/GR-21-630.)

Natural gas emergency response serves as our corporate-wide safety data point. Our targets are set based on benchmarking by the American Gas Association. We seek to respond to emergencies in 60 minutes or less, with response duration measured from the time an order has been created for an emergency to the time the responder arrives on scene. In 2021, our target was 96 percent. Our QSP tariff also includes a Gas Emergency Average Response Time measurement with a specific performance threshold of ≤60 minutes. As reported in our 2021 Annual Report in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383, we met the performance standard with a gas emergency average response time of 28.68 minutes.

Additional References

- Docket No. E002/GR-21-630: Direct Testimony of Kelly A. Bloch at page 132
- Docket No. E002/M-22-162: Annual Safety Report
- Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383: Service Quality Plan Annual Report

V. POWER QUALITY

A. How AMI and FAN Contribute to Power Quality Improvements

Currently, we can only monitor or verify voltage beyond the substation by sending workers into the field based on customer-reported issues.[2] Voltage deviations may manifest as customers experiencing problems with electrical equipment. For example, voltage issues can cause flickering lights, bright light bulbs – eventually shortening the life of the bulbs – or electric motor damage.

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[2] As noted at pages 26-27 in the Direct Testimony of Kelly A. Bloch, provided as Attachment M2 in Docket No. E002/M-19-666.

AMI will monitor and provide power measurement and voltage data at more points within the distribution system, which will be used in load flow calculations to enable improvements in power quality. This will help ensure voltage is within acceptable limits from the substation all the way to the customer's point of service. In other words, better monitoring of power quality reduces the potential for out-of-range voltages that may interfere with electronic devices in customers' homes or businesses and helps us identify and more efficiently respond to issues. With DI, the high-resolution meter data from the DI-capable meters can provide the Company with the ability to better identify and analyze power quality and reliability issues such as voltage sag/swell events and calculating the precise location of primary faults. Additionally, timely power outage and restoration will enable improved outage management and contribute to improved power quality to our customers overall.

Additionally, the AMI system will capture voltage and usage data that can be compared with nameplate or operational limits of our equipment. Using this data, we will be able to identify problems such as solar causing high secondary voltage, or transformer overload due to either a strong presence of EVs (load) or high reverse flows (such as solar generation). It is our intention to leverage AMI data for this purpose, which will allow us to better facilitate the interconnection of DER, while at the same time maintaining reliability and power quality for all our customers.

B. Quantifying Power Quality Benefits Directly Attributable to AMI/FAN

We cannot quantify power quality benefits directly attributable to AMI and FAN; AMI and FAN in isolation do not necessarily improve power quality. For these reasons, we consider power quality a qualitative benefit of AMI and FAN. However, as discussed above, better power quality data will allow us to respond to issues more efficiently and proactively, which could improve customer satisfaction and potentially reliability metrics, if we are able to proactively address an issue that could have eventually caused an outage.

C. Future Potential Reporting Related to AMI/FAN and Power Quality

Power quality-related data points are not explicitly included in the reporting we outlined in our Petition. That said, power quality is an aspect of customer satisfaction. We outline customer satisfaction reporting in Section II above.

References to AMI/FAN and Power Quality Improvements

- Docket No. E002/M-21-814 – TCR Petition: Attachment 4, pages 60; 69-70
- Docket No. E002/M-21-694 – 2021 Integrated Distribution Plan
  - Appendix B3; pages 3-5
  - DOC-84

D. Current Reporting Related to Power Quality

Our annual Service Quality report, most recently filed April 1, 2022 in Docket No. E002/M-22-162, reports a few measures related to power quality:

1. Voltage complaints.
2. Voltage fluctuations, as outlined by Minn. R. 7826.0500, which requires "data on all known instances in which nominal electric service voltages on the utility's side of the meter did not meet the standards of the American National Standards Institute for nominal system voltages greater or less than voltage range B."
3. Momentary Average Interruption Frequency Index (MAIFI). Currently, momentary outage information is available at the feeder level and above, by Feeder circuit, and only on Feeders that are located in substations with Supervisory Control and Data Acquisition (SCADA) capability. With current distribution infrastructure, there is SCADA capability at 67 percent of our substations and approximately 90 percent of customers are served from these substations.[3]

Regarding MAIFI, we note that, as discussed in our 2018 Service Quality Annual Report, filed April 1, 2019 in Docket No. E002/M-19-261, ultimately, we expect our grid modernization efforts will positively impact our service quality, but the nature of these metrics may create challenges in simply comparing our results for measures such as MAIFI before and after grid modernization. For example, with AMI and FAN, the Company will be notified more quickly of an outage, including momentary outages that may have otherwise gone unreported. This may make metrics like MAIFI appear to increase, when our actual performance has not changed – only the tracking has gotten more precise. We cannot quantify how AMI and FAN might affect MAIFI in the future.

[3] While these substations serve approximately 90 percent of our Minnesota customers, momentary outages could occur outside of these substations, which would not be captured in these statistics.

We also provide robust reliability reporting elsewhere, including in our Service Quality Tariff report filed annually on May 1 in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383, and in our annual Service Quality report, most recently filed April 1, 2022 in Docket No. E002/M-22-162. We also report on reliability in our annual Performance Metrics report in Docket No. E002/CI-17-401.

Lastly, the J.D. Power survey, discussed above, measures satisfaction with power quality & reliability. Those results are reported each year in the annual Service Quality report.

Additional References

- Docket No. E002/M-22-162: Service Quality Annual Report

MAPPING OF THE QUANTIFIED BENEFITS INCLUDED BY XCEL ENERGY AND NATIONAL GRID IN THEIR AMI-FAN ANALYSES

The Department of Commerce and its consultant, Synapse Energy Economics, provided a cost-benefit analysis (CBA) from National Grid as an example as a model and example for the Company to emulate. Upon review, we found that the quantification of benefits and CBA financial analysis in the Company's Supplement CBA are generally more robust and thorough than the example provided.

The table below shows the benefits quantified in National Grid's CBA and the corresponding benefits quantified in our 2022 Supplement CBA.

National Grid CBA – Benefits Quantified	Xcel Energy 2022 Supplement CBA – Benefits Quantified
AMR meter reading vehicles, personnel, and annual software and maintenance	AMR O&M New Drive-by avoided cost. Included vehicles, personnel, and others
Meter investigations	Reduction in field trips for voltage investigations
Meter visits required to connect and disconnect service	Costs savings from remote disconnect capability
Damage claims	Reduction in trips associated with customer equipment damage
Outages	Reduction in "OK on Arrival" trips associated with outages
Field Collection System ("FCS") for AMR meter reading	*Not applicable to Xcel Energy – no Field Collection System*
The MV-90 interval meter system	*Not applicable to Xcel Energy – no MV-90 interval meter system*
Not included	Efficiency gains in reliability, asset health and capacity projects – O&M
Not included	Outage management efficiency (storm spend – O&M)
Not included	Outage management efficiency (storm spend – capital)
Not included	Efficiency gains in distribution management of reliability, asset health, and capacity projects – O&M

National Grid CBA – Benefits Quantified	**Xcel Energy 2022 Supplement CBA – Benefits Quantified**
Not included	Efficiency gains in distribution management of reliability, asset health, and capacity projects – capital
Avoided cost of replacing aging AMR meters	Avoided AMR drive-by costs (capital)
Not included	Avoided meter purchases for failed meters
Reduced energy loads from volt-var optimization	*Not included – Integrated Volt-Var Optimization (IVVO) project not within AMI scope*
Customer response to energy insights/bill alerts	*Not included - distributed intelligence capability*
Avoided energy/demand cost associated with customers shifting EV charging	*Not included - distributed intelligence capability*
Shifting customer energy usage in response to TVR rate	Customer savings from TOU pricing
Reduced loss of customer load due to shorter duration outages	Reduced outage duration benefit
Not included	Critical Peak Pricing system demand savings
Not included	Reduced consumption on inactive meters
Improvement over electro-mechanical meter accuracy	*Not included – very few electro-mechanical meters in Minnesota; accuracy within acceptable limits*
Reduction in theft of service	Savings from reduction in theft
Reduction in bad debt write-offs	Reduction in bad debt write-offs
Reduction of CO2 due to decreased drive-by truck rolls	*Not applicable to Xcel Energy – no drive-by meter reading*
Not included	Generation avoided CO2 emissions due to load shift

Certificate of Service

I, Mustafa Adam, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket Nos. **E002/M-21-814**
E002/M-20-680

Dated this 17th day of August 2022

/s/
____
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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