Xcel Energy®

414 Nicollet Mall
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September 25, 2023

—Via Electronic Filing—

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

RE: COMPLIANCE FILING
TRANSMISSION COST RECOVERY RIDER
DOCKET NO. E002/M-21-814

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this filing in the above-referenced docket in compliance with the Commission's June 28, 2023 ORDER APPROVING RIDER RECOVERY, CAPPING COSTS, AND SETTING FILING REQUIREMENTS. Order Points 14 and 15 require the Company to make a compliance filing within 60 days of the date of the Order. This timeframe was extended to September 25, 2023 by the Commission's Notice of Extended Compliance Deadline dated August 16, 2023.

We have electronically filed this document with the Minnesota Public Utilities Commission and copies have been served on the parties on the attached service list. Please contact Nathan Kostiuk at nathan.c.kostiuk@xcelenergy.com or 612-215-4629 or me at amber.r.hedlund@xcelenergy.com or 612-337-2268 if you have any questions regarding this filing.

SINCERELY,

/s/

AMBER HEDLUND
MANAGER, REGULATORY PROJECT MANAGEMENT

Enclosures
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY'S PETITION FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2021-2022, AND THE RESULTING ADJUSTMENT FACTORS BY CUSTOMER CLASS

DOCKET NO. E002/M-21-814

COMPLIANCE FILING

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Compliance Filing in compliance with Order Points 14 and 15 of the Minnesota Public Utilities Commission's Order dated June 28, 2023 in the above-referenced docket.

Order Points 14 and 15 state:

> 14. Xcel shall, within 60 days of the date of this order, file an .xls spreadsheet containing data for at least the three previous years pertaining to all metrics in Attachment 1, Table 1 of Staff Briefing Papers–Volume 2 filed on April 26, 2023, to the extent possible, and where the data cannot be provided, explain why. The Commission delegates authority to the Executive Secretary to set baselines after a 30-day negative check off process.
>
> 15. In a compliance filing to be submitted no later than 60 days of the date of this order, Xcel shall:
>   a. Provide interim performance targets for each of the performance metrics that are "undefined" in Attachment 1, Table 1 of Staff Briefing Papers– Volume 2 filed on April 26, 2023. Such interim performance targets must be based upon projected benefits used in the Company's benefit-cost analysis of the AMI and FAN Projects, and any other pertinent information.
>   b. Propose evaluation methods for each of the metrics.

As an initial matter, the Company continues to believe that it is premature to set baselines and targets for AMI and FAN performance metrics, and the process as required by the Commission's TCR Order is inconsistent with the approved performance-based ratemaking (PBR) process and principles the Commission has established in Docket No. E002/CI-17-401 (the PBR docket). In the PBR docket, a recent comment period sought to determine a methodology by which to set baselines and targets for the metrics on which we have been reporting for three years. To comply with the Commission's Order in this docket, we are leapfrogging that process. More importantly, however, we do not yet have the necessary information from AMI meters that will enable the Company to evaluate how various teams could adjust processes to achieve and maximize not only the benefits referenced in the Commission's Order, but also potential additional benefits of our AMI investments. It will take time for the Company to fully, operationally leverage the many capabilities of AMI and the data that it will provide.

That said, in this filing, we provide:

1. An introduction to how we approached development of evaluation methods – including alternative performance metrics for certain benefits – as well as baselines and targets,
2. Discussion of each benefit outlined in Table 1 and the associated evaluation method(s), baseline, and interim targets,
3. The estimated cost of ongoing performance measurement, tracking, and reporting, for awareness, and
4. An update on AMI deployment.

Attachment A to this filing, provided in live, Microsoft Excel format, complies with Order Point 14. In Attachment A, where possible, we provide data for at least the three previous years pertaining to all metrics in Table 1 above; where we cannot provide data, or where we provide alternate data, we explain why below. For benefits where historical data informed the CBA model, we provide that data, which is typically 2014 through 2018; we also provide data from 2019 through 2022 in response to the Commission's Order. Data for 2022, where provided, is offered for illustrative purposes but, as we will discuss further, we generally did not consider 2022 data in developing pre-AMI baselines because AMI deployment began in 2022.

I. DEVELOPMENT OF EVALUATION METHODS, BASELINES, AND TARGETS

In this section, we begin by discussing the challenges in evaluating AMI benefits and how we have crafted evaluation methods for each benefit. In some cases, these evaluation methods appropriately rely on alternative and/or additional metrics separate from those in Table 1 below. Then, we introduce our approach to baseline development, noting the differences between the PBR process and this AMI-specific approach. Finally, we discuss how we have determined interim targets and how targets could be updated in the future.

For reference, we provide a slightly modified version of Attachment 1, Table 1 of Staff Briefing Papers – Volume 2 filed on April 26, 2023.

Table 1: AMI and FAN Performance Evaluation Metrics and Targets
(Modified from Attachment 1, Table 1 of Staff Briefing Papers – Volume 2 filed April 26, 2023)

Benefit	Metric	Target
Distribution Management Efficiency	Capital and O&M $ spent on Asset Health and Reliability projects and Capacity projects	1% reduction
Outage Management Efficiency	Capital and O&M $ spent on storm recovery*	10% Capital reduction 0.1% O&M reduction
Avoided Meter Purchases	$ spent on meter replacement due to failure	Undefined
Reduced Field and Meter O&M Expenses	Field trips due to customer equipment damage*	50% reduction
	"Ok on arrival" outage field visits*	50% reduction
	Percent of disconnects and reconnects done remotely	70% of disconnects 90% of reconnects
Reduced Consumption on Inactive Meters	Usage on unassigned accounts	20% reduction
Reduced Bad Debt Expense	$ of bad-debt write-offs	8% reduction
Reduced Theft/Meter Tampering	Increase in retail revenue	Undefined
Load Flexibility Benefits	Customer energy price savings due to time-of-use (TOU) rates	Undefined
	Avoided tons of CO_2 emissions due to TOU rates	4,500 tons annual reduction
	Customer savings due to critical peak pricing (CPP)	Undefined

O&M = operations & maintenance
* For purposes of ongoing performance tracking and reporting, we propose combining these performance metrics, as we discuss in Section II.B.

A. Evaluation Methods

Order Point 15.b of the Commission's June 28, 2023 Order requires the Company to propose evaluation methods for each of the metrics.

First, it is important to remember that most of the benefits assumed in our CBA, on which these metrics are based, will not necessarily lead to net budget reductions or direct and traceable cost savings in the near term. Each benefit can be categorized as follows:

1. An *efficiency* is expected to lead to a lower cost of service over the long term, compared to what would have been the case without our AMI implementation. For example, with outage management efficiency, we expect that we will be able to manage outages more efficiently through meter pinging and other meter capabilities, and finish outage-related work more quickly, enabling our crews to focus on other projects. An efficiency does not directly correlate to a net budget reduction or easily discernible cost savings. For example, by leveraging efficiencies in storm response, we are able to direct resources to other important work, but we do not intend to reduce headcount.
2. An *avoided cost* may or may not result in budget reductions or cost savings over time. For example, by using the remote disconnection capability of AMI meters, we can disconnect service at a premise without an active account faster, *avoiding* the further usage and the associated cost. We can use assumptions and generalizations to create an illustrative calculation to assign a monetary value to this avoided cost; however, it is not possible to know precisely how much energy usage *would have* occurred absent our leverage of AMI's remote disconnect capabilities. Conversely, avoiding some meter purchases needed to replace failing meters reduces our spending on replacement meters; however, as we will discuss below, we do not track or budget specifically for meter replacements due to failure.
3. A *cost savings* would be reflected in business area budgets over time. Reducing truck rolls for disconnections, for example, reduces costs and will reduce the overall cost of service for all customers over time.

Furthermore, many metrics associated with these benefits are affected by various factors unrelated to AMI and/or outside the Company's control altogether, or otherwise do not conform to the Commission's approved Metric Design Principles established in the Performance Based Ratemaking docket (listed below for reference), creating the potential for confusion and disputes.[1]

Commission Metric Design Principles

- *Tied to a policy goal.* A metric should clearly reflect whether or not the underlying policy goal is being met. That is, it should seek and evaluate data that is specifically tied to the particular policy goal underlying the metric.
- *Clearly defined.* The method of calculating a metric should be precise and unambiguous to enable meaningful comparisons and to reduce potential disputes.
- *Able to be quantified using reasonably available data.* Using already reported data or data that is readily available will reduce administrative burden and the costs associated with implementing the metric.
- *Sufficiently objective and free from external influences.* Metrics should seek to measure behaviors that are within a utility's control and free from exogenous influences, such as weather or market forces.
- *Easily interpreted.* Metrics should exclude the effects of factors outside a utility's control so they provide a better understanding of utility performance and should use measurement units that facilitate comparisons across time and utilities (i.e., "per kWh" or "per customer").
- *Easily verified.* Straight-forward data collection and analysis techniques should be used, and independent third-party evaluators can further ensure accurate verification with respect to performance metrics.
- *Should complement and inform evaluation of utility performance.* Performance metric systems should be designed to complement – not replace – other parts of a utility's regulatory system such as multi-year rate plans and cost trackers.

Where applicable, in Section II below, we discuss how the certain performance metric or metrics do or do not align with the Commission's approved Metric Design Principles.

The fact that the benefits modeled in our CBA will not necessarily create near-term, direct cost savings or net budget reductions – combined with the reality that the benefits and metrics are affected by outside factors – create challenges in ongoing evaluation of the benefits in the context of AMI. Therefore, attempting to measure the benefits directly attributable to AMI requires creative thinking, a deep understanding of the business functions, and multi-faceted evaluation methods. To

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[1] Docket No. E002/CI-17-401, ORDER ESTABLISHING PERFORMANCE-INCENTIVE MECHANISM PROCESS (January 8, 2019), Order Point 2.C.

holistically evaluate our AMI performance against baselines and targets, we must consider not only real year-over-year results of a specific metric (which may be affected by many variables); for some benefits, we must also consider – and have developed – a proxy or illustrative evaluation method that places a dollar value on the individual benefits that are directly attributable to AMI.

For these reasons and others, we further explain why we propose an alternative performance metric for some benefits – and therefore alternative baselines and targets that differ from metrics shown in Table 1. We propose these alternative performance metrics because they are more appropriately within the Company's control and more consistent with the Commission's Metric Design Principles. As we will demonstrate, the alternative performance metrics we set forth below will serve to hold the Company accountable for our performance with respect to AMI. They may also serve as a basis for future performance incentive mechanisms (PIMs), which – as required by the Commission's Order – we will propose in our forthcoming TCR petition.[2]

In Section II, we discuss the specific evaluation method or methods for each individual benefit.

B. Baselines

As discussed in our July 31, 2023 Comments in the PBR docket, when developing baseline values for metrics, consideration must be given to how each baseline will stand the test of time, including customer growth and policy changes. Baseline values will differ between metrics and the standard they can be compared to may require a different baseline methodology for some.

In our July 31, 2023 PBR Comments, we stated (*emphasis added*):

> Generally, utilizing a *rolling three years* of filed data for each metric provides the necessary historical data to inform baseline setting and target development setting as we move into steps five and six of the PIM process.

However, to set baselines in compliance with the Commission's TCR Order, we are using historical information from years with AMR meters to facilitate a comparison of metrics before and after AMI deployment. Our legacy AMR system is in the process of being replaced with AMI and will be completely replaced with AMI before 2026. So, three years of rolling pre-AMI data will no longer be available. The pre-AMI data is utilizing different meters – AMR – providing incomparable baselines for ongoing

[2] And which will include penalty options for underperformance, as well as incentives for exceeding performance.

AMI performance. It would therefore be appropriate to revisit baselines after three full years with AMI, after 2028.

To come to a single baseline value for the above-mentioned metrics, we considered:

1. Historical reference period data that informed the CBA, if applicable. Typically, this reference period data spanned 2014 through 2018.
2. Additional reference period data, if applicable and where possible, for 2019 through 2021, the last full year of data with the legacy AMR system.
3. Contextual information that may be underlying the data; e.g., the global pandemic's effect on disconnections, truck rolls, etc.
4. Other relevant information, where needed, as described below.

We note that Attachment A also provides 2022 data, where available, in relation to the above-described baselines, for illustrative purposes.[3] Below, we discuss target development for each individual metric.

C. Targets

In this filing, we present interim performance targets that are grounded in benefit values assumed in our CBA model but are also based upon "other pertinent information," consistent with Order Point 15.b of the Commission's June 28, 2023 Order. Interim performance targets are necessary because in the CBA model, the benefits span the full 20-year life of the AMI meters and include cost escalation assumptions – yet we are in the early stages of our AMI deployment in Minnesota. These are long-term investments that will serve our customers for decades to come, and annual variations in data and performance are to be expected. Further, the benefit assumptions are based on full AMI deployment, which will not be complete until mid-2025, as we discuss in Section IV below. Interim targets provide the opportunity for the Company and parties to meaningfully review our performance as AMI deployment is underway and as we expand our operational and reporting capabilities to take full advantage of AMI. Only after deployment is complete and we have three full years of post-deployment data will there be sufficient data to inform long-term performance targets or PIMs.

The interim performance targets set forth below are for 2023, 2024, and 2025 – which is the period when AMI deployment is underway – plus 2026, 2027, and 2028 – the

[3] As outlined above, we did not consider 2022 data in determining baselines, because data from 2022 reflects a system partially with the legacy AMR system and partially with AMI. Therefore, 2022 data does not reflect pre-AMI performance.

first three full years after AMI deployment is complete. In some cases, the targets are the same for some or all of the six years; in others, the targets shift as meter deployment continues and operational capabilities evolve. This target-setting approach will provide the Commission the ability to meaningfully measure and monitor our performance during and immediately after deployment, and at the same time, build new reference period data to inform future performance evaluation, and thus expected ongoing performance.

As stated in our July 31, 2023 Comments in the PBR docket, it is appropriate to revisit targets periodically. In the PBR process, the Commission requires Xcel Energy to provide three years of baseline data before setting targets. Therefore, it is appropriate, and consistent with Commission Order, to revisit the targets after gathering three full years of updated data after AMI deployment is complete. We will have three full years of updated data by the end of 2028. Therefore, if the Commission and parties wish to continue setting performance targets for these discrete investments, we would re-evaluate the targets in 2029.

II. BENEFITS AND PERFORMANCE METRICS

In this section, we provide background information on each benefit in Table 1 above. We include a summary table at the beginning of each subsection showing the respective metric(s) from Table 1; CBA model assumption; our alternative proposed performance metric, where applicable; the baseline value; and interim target(s). We then provide background information on each benefit; discuss the evaluation method(s); and explain the baseline and interim targets in detail.

A. Avoided Meter Purchases

Metric (Table 1)	**$ spent on meter replacement due to failure**
Alternative Proposed Performance Metric	*Meter failure rate*
Baseline	1.84% AMR meter failure rate
CBA Model Assumption	0.5% AMI meter failure rate
Interim Target (2023-2028)	0.5% AMI meter failure rate

1. Background

The CBA modeled benefit of Avoided Meter Purchases assumes that 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. This benefit is an <u>avoided cost</u> that will be reflected in the cost of service over time; it is not a direct cost savings or net budget reduction. As discussed further below, the Company does not track or budget a single line item for meter replacement due to failure, so we propose an alternative performance metric that is more appropriately representative and better aligned with the Commission's Metric Design Principles.

Attachment A depicts historical AMR meter failure rates by year 2014 through 2022.

2. *Evaluation Method*

As noted above, the Company does not track or budget a single line item for meter replacement due to failure, so simply comparing actual year-over-year spend is not possible. Therefore, the primary evaluation method for this benefit relies on the actual observed failure rate for AMI meters, and setting a target tied to this evaluation method is appropriate. The failure rate is calculated as follows:

$$Failure\ rate = \#\ of\ failed\ AMI\ meters\ \div total\ \#\ of\ AMI\ meters\ purchased$$

The assumed AMI meter failure rate in the CBA model was 0.5 percent, consistent with the information provided by the meter manufacturer, Itron.

3. *Baseline and Interim Target Development*

The CBA model assumption was based on the average of actual AMR meter failure rates from 2014 through 2018 – 1.92 percent – compared to Itron's estimated AMI meter failure rate of 0.5 percent, which is calculated using the equation above. As we have explained, the Company does not track or budget a single line item for meter replacement due to failure.

To develop a single baseline value for this metric, we incorporated the AMR meter failure rate data from 2019 through 2021, which as shown in Attachment A was 1.70 percent on average. Taken together, the average failure rate of AMR meters from 2014 through 2021 was 1.84 percent. That is a reasonable baseline value that encompasses eight years of actual data and which we expect would reasonably account for normal fluctuations in failure rates of the aging meters.

A "target" based on a 0.5 percent AMI meter failure rate – the failure rate estimated by Itron and used in our CBA model – is appropriate. Unlike some other metrics that rely heavily on full deployment of AMI meters, AMI failure rate is anticipated to remain constant over the deployment period and beyond because the calculation accounts for the actual AMI meter population. That said, we do not have control over meter failure rate.

The alternative meter failure rate metric we propose better fits within the Commission-approved Metric Design Principles:

- **Clearly defined**. AMI meter failure rate is clearly defined as the number of failed AMI meters divided by the number of AMI meters purchased.
- **Able to be quantified using reasonably available data**. Meter replacements are tracked; however, the cost associated with meter failure is not specifically or directly tracked or reported.
- **Sufficiently objective and free from external influences**. The definition of meter failure is sufficiently objective; however, we note that failure of meters is not directly within the Company's control, as we discuss below.
- **Easily interpreted**. Any avoided cost is difficult to prove objectively. Further, assigning a dollar value to avoided meter purchases is more complex than it may seem on the surface because different types of meters have different costs, and the total cost of meter replacement includes many variables. Meter failure rate is easy to interpret and based on actual data.

We emphasize that while meter failure rate is a clearly defined, quantifiable, objective, and easily interpreted metric, meter failure is outside the Company's control. A lower meter failure rate is indicative that our meter selection was sound, but any suggestion that we could realize a lower meter failure rate with another meter is a counterfactual explanation that is inappropriate for setting targets or PIMs. For that reason, a penalty or incentive for this performance metric would not be appropriate.

B. Outage Management Efficiency *and* Reduced Field and Meter O&M Expenses: Avoided Truck Rolls

Metrics (Table 1)	**Field trips due to customer equipment damage**	**"Ok on arrival" outage field visits**	**Capital $ spent on storm recovery**	**O&M $ spent on storm recovery**
CBA Model Assumption	50% reduction in trips		10% efficiency	0.1% efficiency
Alternative Proposed Performance Metric	*# of canceled outage orders due to AMI, all days*			
Baseline	0 canceled outage orders due to AMI, all days			
Interim Targets	n/a			

These metrics measure the efficiency of the Company's outage response, both overall, and with respect to outages that occur as the result of severe weather/storms. As we evaluated measurement methods for purposes of this filing, we determined it is impracticable, and there would be no benefit from attempting to disaggregate two types of avoided truck rolls that essentially have the same result – the Company's equipment is found to be performing as expected. We also determined that the AMI tie to more efficient storm recovery similarly relies on the avoidance of truck rolls. Thus, as we discuss below, we propose to combine the reporting for these benefits into a single report of canceled outage orders due to data provided by AMI, but not set targets at this time.

1. Background

Efficiencies in the Company's outage management efficiency, including the benefits of 'reduced truck rolls due to customer equipment damage' or 'ok on arrival' outage visits are realized through capabilities the Company developed to integrate data from the AMI meters into its Network (Outage) Management System (NMS), and includes these key components: (1) automated outage notifications and restoration confirmations (power-on information), and (2) the ability to ping individual or groups of meters to check for line side power.[4]

These AMI capabilities will help eliminate unnecessary field trips to customer premises that result in field personnel finding no electric service issue upon arrival – both during storm response and on blue-sky days. Our control center operators will use both the automated notifications from the AMI meters and the AMI pinging capabilities to cancel outage orders – with a newly developed cancellation code – and thus avoid rolling trucks to locations where power has been restored or no problem with the Company's service exists.[5]

Automated outage notifications. AMI meters send a "last gasp" message to the Company as the meter loses line side power. That information helps the NMS predict which system components and thus customers are affected. Outage notifications from the AMI meters will provide the Company with a timelier and more accurate scope of an outage, which will then assist the Company in restoring power more quickly by allowing the Company to deploy crews more efficiently to outage areas, especially during storm events. The other aspect of this capability is verification of power

[4] Group pinging capabilities through the Company's NMS have been developed but are not yet integrated into the Company's operations.

[5] The new cancellation code that facilitates tracking the information for these metrics is "Canceled due to AMI" and is in the process of being implemented in Q4 2023.

restoration after an outage. Restoration verification occurs when a meter "reports in" to the NMS after being reenergized. This notification can serve to shorten the outage event and avoid unnecessary truck rolls. These notifications, however, require control center operators to review and confirm – through meter pinging (see below) – that power has indeed been restored, and that the outage can be closed.

Meter pinging. The Company developed a tool that allows authorized personnel to send a remote command to an AMI meter to check for line side voltage. The ability to ping a meter like this allows control center operators to use this functionality during and at the tail-end of outage events, to ping single meters to determine outage status and whether outage orders can be canceled. While not related to the benefits we discuss in this section, call center representatives also have access to this tool to perform initial verification of a reported outage before an outage order is even created.

The outage-related benefits assumed in our CBA model are efficiencies and will be reflected in our cost of service over time, but do not necessarily result in an immediate, direct net budget reduction. To the extent the Company's outage-related costs do decrease as a result of AMI (or for any other reason), those lower costs would be reflected in our cost of service in future rate cases.

For reference and in compliance with Order Point 14, Attachment A provides annual storm spend, capital and O&M, for the years 2014 through 2022. Our CBA model assumption was informed by actual, annual Minnesota storm spend from 2014 through 2018. Attachment A also provides the actual number of truck rolls that resulted in a finding of "ok on arrival" or "customer equipment damage" in 2014-2018, which informed the CBA model, and 2019-2022.

2. Evaluation Method

This benefit is an efficiency, not a direct cost savings or net budget reduction. Specifically, we propose to track and report the numbers of outage orders we cancel due to AMI data, which achieves the measurement of the [ok on arrival and customer equipment problem] avoided truck rolls benefit contained in our CBA. The number of canceled outage orders due to AMI during a storm also measures the direct contribution of AMI to the efficiency of our storm response, as represented in the Outage Management Efficiency benefit in the CBA model; while this benefit was portrayed in the CBA model as a capital and O&M efficiency, the efficiency itself stems from our ability to reduce outage orders and thus conclude our storm response more quickly, which will make our storm costs lower than they otherwise would have been.

Measuring this through canceled outage orders is appropriate, because storm-related capital and O&M naturally varies from year to year based on the number and strength of storms, and prevailing costs of labor and equipment. To be clear, we do not necessarily expect our actual storm spending to be lower with AMI compared to pre-AMI. Weather is increasingly volatile and severe; rather, we expect our storm restoration costs to be lower than they *otherwise would have* been in the absence of AMI. Therefore, the proper evaluation method for the Outage Management Efficiency benefit must seek to isolate the effects of AMI on our outage management.

Through our recent implementation of a new cancellation code, we will be able to track the number of outage orders canceled due to our use of the AMI data and capabilities described above. Using this method to measure the contribution that AMI has on our outage management efficiency is appropriate, whether that efficiency occurs during a storm or on a blue-sky/non-storm day.

Separating our tracking into storm-related outage orders and non-storm-related outage orders that have been canceled due to AMI is impracticable, because our information systems have been developed to manage our storm response and track our restoration performance in terms of reliability indices. Storm determinations, or Major Event Days (MED) under an IEEE definition are determined after the fact. Attempting to go back and tie specific outage orders canceled or created to MEDs would require significant manual intervention and judgement to be applied – thus would not be systematic, clearly defined, quantified using reasonably available data, nor easily interpreted. Further, MEDs do not fully represent storm/escalated operations windows or restoration efforts or costs; some storm restoration may continue past a single MED or our return to normal operations, making it impracticable to discern whether an individual canceled outage order happened as part of our storm restoration.

For the outage-related Field Efficiency and Outage Management Efficiency, using the number of outage orders canceled due to AMI data as measurement method is appropriate because it is better aligned with Commission-approved Metric Design Principles:

- **Clearly defined**, **Able to be quantified using reasonably available data**, and **Easily interpreted.** The number of outage orders canceled due to AMI data is specific and unambiguous. Through our NMS, we can track the number of outage orders canceled as a result of data we receive from AMI meters.
- **Should complement and inform evaluation of utility performance**. Number of outage orders canceled during storms due to AMI data is a new

performance measure, whereas actual storm spend is reported in the Integrated Distribution Plan, and also in rate cases where we are responsible for demonstrating prudency.

- **Sufficiently objective and free from external influences.** While storm strength and intensity vary year-to-year, measuring the number of outage orders we cancel due to data from AMI objectively measures the efficiency of the Company's response to all outages, whether they occur as a result of severe weather or for other reasons. Conversely, storm-related capital and O&M is subject to significant external forces, primarily the number and strength of weather events in the reporting period, and the likely increasing costs of materials and labor over time.

While we propose to report the total numbers of canceled outage orders due to AMI data for these metrics, we intend to include additional information in our reports about storms/escalated events. For example, we will note any MEDs that occur in the reporting timeframe. We will also report the capital and O&M associated with any declared escalated operations during the reporting period.

3. Baseline and Interim Target Development

Zero is an appropriate baseline for this performance metric, because the capability to use data from the AMI meters is new and did not exist prior to AMI deployment.

Setting interim targets for this metric at this stage is not appropriate for two primary reasons. First, the unpredictable nature of severe weather makes setting of targets impracticable, as there is no such thing as a typical year for severe weather; similarly, due to the large standard deviation, an average over a period of time does not reasonably remove the effects of the numbers and severity of severe weather events that occur year-to-year. As such, setting interim targets would require the Company to predict the weather or somehow neutralize the uncertainties of the weather, which is not possible or practicable. Second, we are still deploying AMI meters and the new software capabilities described above, and adjusting our operational practices to maximize the benefits of the AMI data integration into the NMS.[6] We are committed to fully leveraging these AMI capabilities to benefit our outage management and our customers, and the tracking and reporting of our use of the AMI capabilities with respect to our outage response will serve to hold us accountable without setting targets at this time.

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[6] In addition to a phased approach to implementing the AMI-NMS data integration capabilities that will mature and expand over time, the AMI deployment and release of the AMI-NMS capabilities to control center personnel are geographically-based on AMI meter penetration levels.

As we report canceled outage orders due to AMI over the coming years, we may be able to find ways to refine our reporting and tracking capabilities such that setting targets after 2028 – i.e., after we have three years of full data with AMI – may be possible.

C. Reduced Field and Meter O&M Expenses: Remote Disconnect / Reconnect

Metrics (Table 1)	**Percent of disconnects done remotely**	**Percent of reconnects done remotely**
CBA Model Assumption	70% of disconnects done remotely	95% of reconnects done remotely[7]
Baseline	0% of disconnects done remotely	0% of reconnects done remotely
Interim Target – 2023	50% of disconnects done remotely	70% of reconnects done remotely
Interim Target – 2024	60% of disconnects done remotely	80% of reconnects done remotely
Interim Target – 2025	65% of disconnects done remotely	90% of reconnects done remotely
Interim Target – 2026-2028	70% of disconnects done remotely	95% of reconnects done remotely

1. *Background*

AMI enables remote connection and disconnection of service without the need to dispatch crews. The CBA model assumed some credit disconnections and reconnections would continue to require field visits. We explained in the remote connection/disconnection docket (Docket No. E002/M-22-233) that we will still conduct a field visit and door knock if our "last call" attempt to reach the customer by phone or leave a voicemail is unsuccessful.[8] The assumptions in the CBA model factored-in: (1) that we will not be able to reach some customers, so a field visit will still be required for some disconnections, (2) that a field visit will still be required for customers who choose to opt out of AMI, and (3) the potential for technical difficulties that could interfere with our ability to remotely disconnect or reconnect. These factors are largely outside of our control, yet will affect our reported performance. It is therefore important to note that to the extent the underlying

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[7] The target for reconnects shown in Table 1 is 90 percent; however, we believe this to be a typo as our CBA model assumption was 95 percent.

[8] In Docket No. E002/M-22-233, the Commission granted a temporary variance to Minn. R. 7820.2500, which requires a personal visit to a customer premise prior to disconnection. *See* March 22, 2023 Order at Order Point 1.

assumptions are incorrect in either direction – e.g., if fewer "last call" phone calls are successful, or if fewer customers opt out – that is not indicative of our performance with respect to AMI remote disconnection and reconnection.

2. *Evaluation Method*

We can evaluate our performance for remote connection and disconnection by calculating a simple percentage for each, as shown below. We note that the numbers used in these calculations will include disconnections for residential and small commercial premises and will reflect disconnections and reconnections for credit reasons only.

$$Percentage = Number\ of\ remote\ connections \div Total\ number\ of\ connections$$

$$Percentage = Number\ of\ remote\ disconnections \div Total\ number\ of\ disconnections$$

We are able to approximate the avoided cost associated with remote connect/disconnect capability by multiplying the number of remote operations by the average cost of a truck roll. This avoided cost value is illustrative, because the Company could not conduct the same volume of disconnections manually, which is the only option with our current AMR meters. In addition, the estimated avoided cost will increase as the number of credit disconnections (and reconnections) increase. Disconnection is a last resort, and we always strive to work with our customers to connect them to resources that can help with their bills and set up payment arrangements to avoid disconnection. Therefore, seeking to maximize an estimated avoided cost value would require maximizing the number of disconnections, which would be counter to the Company's, Commission's, and stakeholders' goals of reducing credit disconnections. Therefore, at this time, we have not included estimated avoided costs associated with remote connections/disconnections as a proposed evaluation method. This request is consistent with our position in the recent Performance Based Ratemaking, Notice of Comment Period in Docket No. E002/CI-17-401. It was also supported by the Office of the Attorney General in their Comments and the Citizens Utility Board in their Reply Comments.

In addition, the Commission's March 22, 2023 Order in Docket No. E002/M-22-233 requires the Company to file a report in our service quality reports for 2023, 2024, and

2025 and include a re-analysis of actual costs for disconnection/reconnection requiring in-person visits and those performed remotely. This analysis of actual costs – as opposed to illustrative, avoided costs – can serve as another point of reference when evaluating our performance.

3. *Baseline and Interim Target Development*

For reference, Attachment A provides the number of credit disconnections by year 2014 through 2021. However, none of these disconnections were conducted remotely without a field visit; without AMI, we are unable to conduct disconnections or reconnections remotely. Therefore, when considering future performance with respect to remote disconnections and reconnections compared to AMR, zero is an appropriate baseline.

The CBA model assumptions were based on full deployment of AMI meters. Therefore, our interim targets during the deployment period, set forth above, consider the volume of AMI meters installed in a given year. The ratio of remote to in-person disconnections and reconnections will improve as more AMI meters are installed. We expect to reach our CBA model assumption of 70 percent and 95 percent for remote disconnections and reconnections (respectively) by 2026, when AMI meter deployment is complete.

D. Reduced Consumption on Inactive Meters

Metric (Table 1)	Usage on unassigned accounts
CBA Model Assumption	20% reduction
Baseline	89,031,000 kWh
Interim Target – 2023	87,250,000 kWh
Interim Target – 2024	83,760,000 kWh
Interim Target – 2025	77,059,000 kWh
Interim Target – 2026-2028	71,224,000 kWh

1. *Background*

This benefit is realized through the use of remote disconnection capabilities of AMI meters. When our system detects usage on an unassigned account (also known as "unknown user" or "UU"), we can more quickly disconnect the meter, preventing additional usage. Our CBA model assumption was informed by the actual unassigned usage for residential premises from 2014 through 2018.

As shown in Attachment A, from 2014 through 2018, the average annual usage on unassigned residential accounts was approximately $6.5 million. In 2019 through 2021, the average annual usage on unassigned residential accounts was approximately $10.6 million. This increase can be attributed to three major factors:

1. *Pandemic disconnection moratorium and the pandemic's effects on disconnection operations.* We halted all disconnections from March 15 to August 1, 2020 due to the global pandemic, and our overall disconnection volume was lower in 2020 and 2021.
2. *Headcount reduction*. In anticipation of AMI, we leveraged natural attrition to reduce the number of field employees who were responsible for, among other things, conducting field disconnections of meters unassigned to a customer account. Therefore, disconnections of UU meters took longer, resulting in higher unassigned usage.
3. *Change to Cold Weather Rule (CWR) period.* In 2021, Minnesota's Cold Weather Rule (Minn. Stat. § 216B.096) was extended by one month, reducing the total number of UU disconnections.[9]

As we began the rollout of AMI meters in Minnesota in 2022, we began utilizing the remote disconnect capability to prevent unassigned usage.[10]

We prioritize remote disconnections for UU using two factors:

1. A kWh usage threshold, and
2. Days of vacancy

We have begun UU remote disconnections using a ramp-up approach. We began in July 2022 and started with a kWh usage threshold of 1,250 kWh and 182 days vacant. We have increased the UU disconnection volume over time as our systems became more automated over the past year. Currently our thresholds are set at 500 kWh and 60 days vacant. We have learned more about the operational impacts to the volume of disconnections over time as well. For instance, our contact center may receive phone calls after these types of disconnections if a customer had not previously contacted us to start service. Therefore, to ensure a positive contact center experience for all customers, we are limiting the volume of remote UU disconnections, which is reflected in our interim targets, discussed below.

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[9] Vacant premises do not have a residential customer associated with the account; therefore, Minn. Stat. § 216B.096 (the Cold Weather Rule) does not apply to vacant premises. However, out of an abundance of caution, we have not historically disconnected residential premises with unassigned accounts during the Cold Weather Rule period.

[10] We note that these types of disconnections, at a vacant premise and for non-credit reasons, were not subject to Minn. R. 7820.2500 requiring an in-person visit. The Commission granted the Company a temporary variance to that Rule in its March 22, 2023 Order in Docket No. E002/M-22-233.

2. *Evaluation Method*

The primary evaluation method for this benefit is the actual, total usage on unassigned accounts. Utilizing unassigned usage in kilowatt-hours (kWh), as opposed to a dollar value, is appropriate because this method excludes any effect of changing electric rates.

3. *Baseline and Interim Target Development*

To come to a single baseline value of 89,031,000 kWh for this metric, we reviewed actual annual residential UU usage from 2019 through 2022. We observed that 2022 was an unusually high year when comparing to previous years both pre-pandemic and pandemic. Annual 2022 UU consumption increased 16 percent compared to previous years. The increase was driven by an 8 percent increase in UU cases and an 8 percent increase in UU consumption per case. We assume these increases are the result of a greater number of customers moving post-pandemic. While we have based other metric baselines on pre-AMI and pre-pandemic data, we do not believe that would appropriate for this metric as we believe an increased level of customer moves will continue and we do not expect UU consumption values to fall below the 2019 to 2021 average until 2026 through UU remote disconnections. Therefore, it is appropriate to use 2022 actual UU consumption, adjusted to remove actual 2022 UU remote disconnections, as the baseline. Attachment A also includes 2019 through 2022 UU consumption.

To develop interim annual targets, based on the background information and data noted above, we assume a gradual decrease unassigned usage as AMI meter deployment continues, before reaching a 20 percent reduction – consistent with the CBA model assumption – from the baseline beginning in 2026.

E. Reduced Bad Debt Expense

Metric (Table 1)	$ of bad-debt write-offs
CBA Model Assumption	8% reduction in bad debt write-offs
Alternative Proposed Performance Metric	*# of days to complete credit disconnection*
Baseline	11.8 days
Interim Target - 2023	9.6 days
Interim Target - 2024	8.4 days
Interim Target - 2025	7.8 days
Interim Target – 2026-2028	7.1 days

1. Background

This benefit is realized through the ability to utilize the remote disconnection capabilities of AMI meters for credit-related purposes. With this capability, more meters can be disconnected (and reconnected) for credit more efficiently, which we expect will reduce bad debt expense over time. As discussed in the remote disconnect/reconnect proceeding and our July 31, 2023 PBR Comments, we expect a peak in the volume of disconnections to coincide with full deployment of AMI meters to occur in 2025 and into 2026, past the end of the 2026 CWR period. We estimate that 1.2 percent of our customer base could experience disconnections each month (during non-CWR months) at this initial peak. Using Salt River Project as a benchmark, after this peak, we anticipate up to a 25 percent reduction in the volume of customers experiencing a disconnection as behavior adjusts and customers understand it is important that they reach out to us for help with their bills prior to disconnection.[11] Using the Salt River Project as a guide, this has been shown to improve customer interactions, bring more resources to customers, and ultimately reduce their past due balances – and therefore bad debt expense.

That said, various factors outside the Company's control influence bad debt expense, including fuel costs and the health of the economy overall. For this reason, we offer an additional, alternative performance metric that isolates the AMI-related factor within the Company's control: *the time it takes to complete a credit disconnection for accounts with past-due balances of $1,000 or more*. We discuss this metric further below.

It is important to note that AMI's effect on bad debt expense is directly tied to an increased number and/or speed of credit disconnections. Disconnection is always a last resort, and we always want to work with our customers to help avoid disconnections when possible. We understand that incentivizing the Company to maximize the speed of disconnections may be counter to the priorities of customer advocates and the Commission. We intend to discuss this benefit and performance metric further with parties before bringing forward an associated PIM for this benefit in our forthcoming TCR petition.

For reference, Attachment A provides net write-off data for 2014 through 2022. In addition, Attachment A includes the average number of days to disconnect from 2019 through 2022.

2. Evaluation Method

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[11] *See* Attachment A to our April 14, 2022 Petition in Docket No. E002/M-22-233.

As noted above, factors that include the economy influence bad debt expense; therefore, bad debt expense will continue to be affected by events and influences outside the Company's control and due to factors wholly unrelated to AMI. The evaluation method for this metric, therefore, is three-fold:

1) *Reporting the average number of days to complete a credit disconnection compared to pre-AMI, for accounts with $1,000 or more past due*. We propose to use this evaluation method as the performance metric for this benefit.

   This average number of days will be weighted to reflect the Company's prioritization of credit disconnections. We mail a disconnection notice to an account when it reaches a threshold of $180 past due; however, we typically do not complete a disconnection until the account reaches $500 past due. Even with remote disconnection capabilities, we need to manage our disconnection volume to ensure we have adequate staffing levels at our contact centers to respond to customer calls. Therefore, we prioritize accounts with higher past-due balances and/or an older age of debt – both of which have a greater impact on bad debt expense. For this reason, we focus our performance metric on accounts with $1,000 or more past due.

   As remote disconnections increase and continue over time with AMI, we expect our overall age of debt and past-due amounts to decrease.

2) *Estimating the dollar value of AMI's effect on bad debt expense*. We can estimate the dollar value of AMI's effect on bad debt expense as follows.

   > Avoided bad debt expense = # of credit disconnections completed remotely × (Average # of days to complete credit disconnection pre-AMI - Average # of days to complete credit disconnection post-AMI) × Average kWh usage/day × Average $/kWh

3) *Reporting actual bad debt expense over time*. Although actual bad debt expense may or may not decrease and will change for reasons unrelated to AMI, actual bad debt expense may provide additional contextual information necessary for exploring new or updated baselines and targets in the future.

3. Baseline and Interim Target Development

To develop a single baseline value for this metric, we analyzed 2019 through 2022 data only. Ultimately, we did not consider 2020-2022 data in setting the baseline because of the global pandemic and its effects on our operations and our customers.

We halted all disconnections from March 15 to August 1, 2020. For the month of September and beginning October 1, with the start of the 2021-2022 Cold Weather Rule period, through April 30, 2022, our disconnection volume was also lower than normal. Therefore, the pre-AMI baseline is 11.8 days, which is the actual pre-AMI data from 2019.

A target based on the number of days to disconnect accounts with $1,000 or more past due is appropriate. Although we can calculate and report an illustrative approximation of *avoided* bad debt expense associated with a higher volume of and more efficient credit disconnections, using this approximation as a performance metric on which to set a target (and potentially a future PIM) is not appropriate. This illustrative avoided cost is an estimation that relies on numerous averages and assumptions. In addition, bad debt is affected by many factors, including many outside the Company's control.

By comparison, using our alternative number of days to disconnect as the performance metric, baseline, and target fits more appropriately within the Commission-approved Metric Design Principles:

- **Tied to a policy goal**. Using a days to disconnect metric balances the policy goals of maximizing AMI value without incentivizing higher volumes of disconnections.
- **Clearly defined**. Days to disconnect is easily defined and easily comparable pre- and post-AMI.
- **Sufficiently objective and free from external influences**. Days to disconnect measures behavior that is within the Company's control and excludes the effect of outside influences on bad debt expense overall, such as market forces.
- **Easily interpreted**. The direct effect of AMI on bad debt expense is difficult to measure on an ongoing basis and subject to interpretation, whereas days to disconnect is easily interpreted and digestible across time periods.
- **Easily verified**. A reduction in the days to disconnect is easy to tie more directly to AMI performance.
- **Should complement and inform evaluation of utility performance**. Days to disconnect is a new performance measure, whereas bad debt expense is tracked and reported in multiyear rate plans, and disconnection information is tracked and reported in multiple dockets for various purposes.

F. Reduced Theft/Meter Tampering

Metric (Table 1)	Increase in retail revenue

CBA Model Assumption	0.1% recovery of revenue lost for Residential 0.15% recovery of revenue lost for Small Commercial
Alternative Proposed Performance Metric	*# of theft/meter tampering cases completed*
Baseline	30 theft/meter tampering cases completed
Interim Target – 2023	34 cases completed
Interim Target – 2024	38 cases completed
Interim Target – 2025	42 cases completed
Interim Target – 2026	48 cases completed
Interim Target – 2027	54 cases completed
Interim Target – 2028	60 cases completed

1. *Background*

The AMI meters have built-in theft detection capabilities; while meter theft/bypasses are infrequent, when they do occur, they create danger to the public and property, and increase costs for all customers. This capability of the AMI meters allows the Company to systematically become aware of these circumstances and act more quickly to address theft, reducing costs.

After we identify an instance of theft or meter tampering, we perform a site visit to verify tampering and ensure the safety of the public and integrity of the meter. We may remotely disconnect the meter at that point if possible, or we may completely remove the meter. We then use historical average usage to bill the customer for an estimated amount of unmetered usage.

For reference, Attachment A provides the assumption for increases in retail revenues used in the CBA, we also provide data for 2019 through 2022. In addition, Attachment A includes the number of meter tampering cases completed 2018 through 2022.

2. *Evaluation Method*

Isolating AMI's direct effect on retail revenue due to improved theft and meter tampering detection is challenging in practice because we do not know the actual dollar amount lost to theft and tampering in a given year; when we bill a customer for unmetered usage, it is an estimate. Further, we cannot know exactly how much usage *would have* happened in the absence of AMI and improved detection abilities. Therefore, our evaluation method for this benefit is two-fold:
First, we can track and report on the number of meter tampering or theft cases completed (i.e., we conduct a site visit and bill the customer for an estimated amount of unmetered usage, as described above). We propose to use this as our performance

metric, as we discuss below. Although we do not necessarily expect the number of theft/tamper cases to increase, we expect to identify more of them, which in turn allows us to address more instances of theft and act more quickly to prevent further theft. We note that because we conduct an in-person site visit address instances of theft or meter tampering, resource constraints limit the number of cases we are able to complete.

As a secondary illustration of our performance with AMI, we can estimate the value of this benefit using the following calculation:

$$
\begin{aligned}
&Estimated\ avoided\ losses\ due\ to\ theft \\
&\qquad = \#\ of\ cases\ closed\ within\ 60\ days\ of\ identification \\
&\qquad \times preAMI\ duration\ of\ theft\ in\ days\ \times Average\ kWh\ per\ day \\
&\qquad \times Average\ \$\ per\ kWh
\end{aligned}
$$

This illustrative metric is an estimate based on numerous averages and assumptions, whereas using "the number of theft/meter tampering cases completed" as a performance metric is better aligned with the Commission's Metric Design Principles, discussed below.

3. *Baseline and Interim Target Development*

To develop a single baseline value for this metric, we analyzed 2018 through 2022 data. Ultimately, we did not consider 2020-2022 data in setting the baseline because of the global pandemic and its effects on our operations. As a baseline value for this metric, we use 30 cases of theft/meter tampering completed, which is the actual number of cases completed in 2018.

Our interim targets start at 34 meter tampering cases completed in 2023 and increase at approximately 12 percent per year. These interim targets assume we can utilize the built in theft detection capabilities to investigate and limit energy theft.

Using our alternative "number of theft/meter tampering cases completed" as the performance metric for this benefit is appropriate because it aligns with the Commission's Metric Design Principles:

- **Clearly defined** and **able to be quantified using reasonably available data.** Compared to the illustrative estimation of avoided cost, the number of meter tampering cases completed is straightforward and easily available, and contains fewer changing variables.

- **Sufficiently objective and free from external influences** and **easily interpreted**. The "number of theft/meter tampering cases completed" metric will be reflective of the Company's action: our ability to detect theft and meter tampering and address the theft. This value is easy to interpret and, unlike retail revenue, is not as heavily influenced by other factors and/or factors not squarely within the Company's control, such as electricity sales.
- **Easily verified**. "Number of theft/meter tampering cases completed" is easy to track and verify through existing reporting capabilities, and more effectively measures Company action related to AMI, as compared to retail revenue, which is affected by numerous variables unrelated to AMI.

G. Load Flexibility Benefits

Metrics (Table 1)	**Customer energy price savings due to time of use (TOU) rates**	**Avoided tons of CO_2 emissions due to TOU rates**	**Customer savings due to critical peak pricing (CPP)**
CBA Model Assumption	Starting in 2024, 269 GWh Shifted or $1.8M/year	45,000 tons/year	Starting in 2024, 245 MW Avoidance or $20M/year
Baseline	0	0	0
Interim Target	0	0	0

1. Background

The Company engaged The Brattle Group (Brattle) to model likely customer response to TOU and CPP rates. Brattle produced a study entitled "The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory" (the Brattle Study). The Brattle Study quantified benefits of potential TOU and CPP rates, which we incorporated into our CBA model. Further, the Company utilized information about shifting demand from on-peak to off-peak periods, resulting in energy price savings for customers and carbon reduction benefits. These benefits are realized through broad use of TOU and CPP rates.

To be clear, AMI meters alone do not enable customer bill savings or carbon emissions avoidance. TOU and CPP rates are generally enabled by the interval data capabilities of AMI meter technology, but bill savings or carbon avoidance are driven customer behavior, which is influenced by the specifics of the program and rate design. Therefore, evaluating the Company's ongoing AMI performance using TOU and CPP-related rates that do not exist would be improper. Evaluation of individual rates and programs, regardless of whether they are partly enabled by AMI or any other technology, should happen in the distinct dockets where the rate or program is proposed and approved. Currently, the Company does not have TOU or CPP rates broadly available in Minnesota, and the advanced rates that are available do not rely on the Itron AMI meters that we are currently deploying.

Attachment A does not include data for at least the three previous years pertaining to these three load flexibility metrics for two reasons: first, the CBA model was informed by a third-party study; and second, we do not have broad TOU or CPP rates enabled by the new AMI meters in place to inform baselines.

2. *Evaluation Methods*

As noted above, evaluation of individual rates and programs (regardless of whether they are partly enabled by AMI) should happen in the distinct dockets where they are proposed and approved. As required by the Commission's July 17, 2023 Order in our most recent electric rate case (Docket No. E002/GR-21-630), we are required to propose a permanent Residential Time-of-Use rate by December 31, 2023.[12] We expect and support a robust evaluation of any future advanced rate design proposal, including our forthcoming TOU proposal, as well as the program's performance once in place.

In addition, the PBR docket includes metrics related to the outcome "Cost Effective Alignment of Generation and Load." Commission-approved metrics reported for that Outcome are:

1. Demand response, including (1) capacity available (MW & MWh) and (2) amount called (MW, MWh per year).
2. Integration of customer loads with utility supply - Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns.
3. Integration of customer loads with utility supply - Amount of demand response that SHIFTS energy consumptions from times of high demand to times when there is a surplus of renewable generation.

4(a). Integration of customer loads with utility supply - Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events - for Available Load.

4(b). Integration of customer loads with utility supply - Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and

[12] Order Point 68.

supports the system in contingency events - for Actual Load Reduction Achieved.

4(c). Metrics that measure the effectiveness and success of items above, individually and in aggregate. (Load factor for load net of variable renewable generation.)[13]

The above metrics are appropriate and sufficient to evaluate the Company's performance in this area.

3. Baseline and Interim Target Development

AMI deployment is underway, and in the past three years, we have had no advanced rates that rely on AMI, nor do we currently offer TOU or CPP rates that rely on AMI. Therefore, a baseline of zero is appropriate for all three load flexibility metrics.

Similarly, zero is an appropriate interim target for these metrics, as no TOU or CPP rates relying on AMI exist.

H. Distribution Management Efficiency

Metric (Table 1)	**Capital and O&M $ spent on Asset Health and Reliability projects and Capacity Projects**
CBA Model Assumption	1% efficiency (capital)
Alternative Proposed Performance Evaluation Method	***Narrative description of the Company's use of AMI data to inform system investment plans***
Baseline	None
Interim Target	None

1. Background and Evaluation Method

First, we note that our CBA model assumed a one percent efficiency gain for capital spend in these categories, not O&M.

We clarify that this benefit is an efficiency, not a direct cost savings or net budget reduction. AMI provides the Company with information about the connectivity and workings of the distribution system. AMI data can be aggregated at varying levels of the distribution system including tap, transformer, and service lines amongst other distribution system equipment. The Company will be able to use this information to prioritize distribution grid improvements and more efficiently plan and design the

[13] In our July 31, 2023 Comments in the PBR docket, Docket No. E002/CI-17-401, we proposed removing this metric from future reporting.

system, for example, to refine the timing for installation and replacement of distribution assets, as well as inventory levels. While these efficiencies would be reflected in a lower cost of service over time, we do not anticipate our distribution capital spend to decrease due to AMI; rather, with AMI we expect our distribution capital spend will be lower than it otherwise may have been without AMI.

Even when we are able to leverage AMI data in planning, the efficiency gains will be realized through engineering judgment. For example, when AMI data is aggregated to the feeder level, it will provide a data set for evaluating overall feeder and distribution system loading. This data can then be used to compare with similar data provided by the Company's SCADA system. SCADA data often contains data anomalies due to operational switching and other abnormal conditions which make it difficult for Distribution Planning to interpret and determine the actual system loading. Further, SCADA data also represents net loading on the distribution system and includes the load-masking impact of distributed generation, whereas AMI data can be more easily aggregated to represent only the native loading on the distribution feeder. Therefore, AMI data will allow Distribution Planning to streamline the process of identifying historical daytime minimum load and peak load conditions on the distribution system. This will also allow Distribution Planning to more efficiently identify the need for system upgrades and initiate projects in the distribution budget. Further, the aggregated AMI data will clarify the existing system loading conditions and may lead to a project being deferred if it shows the effective system loading being significantly less than is represented by anomalous SCADA data.

Given the nature of this benefit and the need for at least two full years of AMI data to inform planning, there is currently no way to quantitatively measure or monetize the value of this efficiency. Further, we cannot predict precisely how AMI data will specifically inform planning for discrete investments, so we cannot develop a quantification method for use in the future. That said, we are committed to maximizing this benefit through effective use of AMI data. We understand the Commission wishes to hold the Company accountable, and we commit to providing narrative updates about our work to implement and utilize software and processes that leverage AMI data in Distribution Planning with future AMI Annual Reports. As we operationalize use of AMI data in planning, we will seek to find and develop methods to quantify this benefit.

For illustrative purposes, Attachment A presents present capital spending on Asset Health and Reliability and Capacity projects from 2014 through 2022. We present this information for illustration purposes only; we re-emphasize that we do not anticipate a reduction in spending in these areas.

III. COST OF ONGOING PERFORMANCE MEASUREMENT AND REPORTING

There is a substantial cost to the ongoing measurement and reporting discussed above, and we want to make sure the Commission and parties are aware to ensure the value of the tracking and reporting is commensurate with the cost. We are conducting internal analysis and refining our cost estimates, and we intend to provide further details in future filings.

IV. UPDATE ON AMI DEPLOYMENT

As of August 31, we have installed approximately 462,500 AMI meters. We began AMI deployment in Minnesota in Spring 2022 and expected deployment to be complete by the end of 2024. As we have conveyed previously, meter supplies have been challenged due to global supply chain constraints, and we now expect meter deployment will continue into 2025.

Xcel Energy entered into an agreement with Itron, Inc. in 2019 to supply and install electric AMI meters across Xcel Energy's enterprise. Under the agreement with Itron, Itron has full responsibility to supply and install AMI meters. Xcel Energy was notified by Itron in July 2021 that a force majeure event tied to global component shortages of key meter components had occurred. After a diligent review of Itron's force majeure claim, in September 2021 Xcel Energy acknowledged a force majeure event resulting from a global shortage of integrated circuits (semiconductors). It is important to note that semiconductor shortages were widely publicized and impacted a number of industries beyond meters, including the automotive, medical supply, consumer goods and electronics industries. It is also important to note that the component shortages impacting electric meters were industry-wide and were not limited to Itron.

Since the force majeure event, Xcel Energy has worked diligently with Itron to manage and mitigate the impacts of the meter shortages, to plan for the reduced meter availability, and to try to maintain the overall completion dates for the AMI deployment. This includes, but is not limited to, regular planning and forecasting meetings, supply chain meetings with Itron's operations and supply chain leadership where we assessed current market conditions and impacts on Xcel Energy's deployment, as well as other executive meetings including with Itron's CEO.

The forecasted supply chain recovery of semiconductors from Itron shifted from an originally forecasted recovery in 2022 to a forecasted recovery in the second half of 2023. Notwithstanding the foregoing, we have seen meter supply significantly improve from 2022 going into 2023, and as expected, meter deliveries further improved in August and are expected to slightly exceed the level Itron committed to earlier in 2023.

We now expect to complete meter deployment mid-2025. Table 2 provides the current deployment plan; however, we expect some uncertainty with regard to the specific meter volumes to continue.

Table 2: Latest Available Meter Deployment Schedule – Minnesota

Year	Meters Deployed Per Year (Actual)	Meters Deployed Per Year (Planned)
2022	127,991	127,991
2023	462,422*	545,000
2024	-	600,000
2025	-	127,360
Total	**590,413****	**Approx. 1.4 million**

*January 1–August 31, 2023.
**Through August 31, 2023.

We will provide further deployment updates in future filings.

CONCLUSION

This filing complies with Order Points 14 and 15 of the Commission's June 28, 2023 Order in the above-referenced docket. We are committed to maximizing the benefits of AMI for our customers and appreciate the Commission's and parties' desire to hold us accountable for the benefits laid out in our CBA model, which assumed full deployment of AMI and modeled the quantifiable value of benefits over the 20-year life of the meters. AMI meter deployment is ongoing, and we will need to continually evolve our operational capabilities as we gain experience with AMI functionalities and the data it provides. We have put forward, in good faith, evaluation methods, including, in some cases, appropriate alternative performance metrics; baselines; and interim targets that will provide the Commission and parties with ample opportunity to monitor the Company's performance in realizing the many benefits of AMI.

Dated: September 25, 2023

Northern States Power Company

Benefit
Avoided Meter Purchases

Metric	2014	2015	2016	2017	2018	2019	2020	2021	2022
Alternative Proposed Performance Metric: Meter Failure Rate	2.02%	2.04%	1.81%	1.82%	1.91%	1.93%	1.79%	1.38%	1.14%

Average 2019-2021
1.70%

Average 2014-2021
1.84%

Benefit
Outage Management Efficiency

Metric		2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital and O&M $ spent on storm recovery	Capital	$ 4,100,000	$ 7,800,000	$ 19,800,000	$ 15,500,000	$ 9,600,000	$ 23,500,000	$ 12,000,000	$ 11,000,000	$ 56,200,000
	O&M	$ 3,900,000	$ 2,600,000	$ 2,800,000	$ 1,100,000	$ 1,900,000	$ 6,900,000	$ 3,700,000	$ 7,100,000	$ 7,500,000

	Average 2014-2018
Capital	$ 11,360,000
O&M	$ 2,460,000

	Average 2019-2022
Capital	$ 25,675,000
O&M	$ 6,300,000

Benefit
Reduced Field and Meter O&M Expenses

Metric	2014	2015	2016	2017	2018	2019	2020	2021	2022
Field trips due to customer equipment damage	2,072	1,861	1,656	1,501	1,872	2,087	1,926	1,747	1,943
"Ok on arrival" outage field visits	6,168	6,809	8,585	8,015	7,662	8,635	8,762	8,243	9,418
Total Trips	8,240	8,670	10,241	9,516	9,534	10,722	10,688	9,990	11,361

Benefit

Reduced Field and Meter O&M Expenses

Metric

Percent of disconnects and reconnects done remotely

Reference Data	2014	2015	2016	2017	2018	2019	2020	2021
Credit Disconnections (AMR Meters)	23,311	24,473	19,262	18,180	16,635	15,255	2,939	6,152

Benefit

Reduced Consumption on Inactive Meters

Metric		CBA 2014-2018 Average	2019	2020	2021	2022
Usage on unassigned accounts		$ 6,450,000	$ 10,680,000	$ 10,362,000	$ 10,662,000	$ 13,876,000
	Reduction	$ 1,290,000	$ 2,136,000	$ 2,072,000	$ 2,132,000	$ 2,775,000

Reference Data	2019	2020	2021	2022
Unknown User kWh	78,017,000	75,635,000	76,595,000	89,409,000

Benefit
Reduced Bad Debt Expense

Metric		2014	2015	2016	2017	2018	2019	2020	2021	2022
$ of bad-debt write-offs	Total MN	$ 13,481,000	$ 16,141,000	$ 14,714,000	$ 13,023,000	$ 13,258,000	$ 13,442,000	$ 13,074,000	$ 10,630,000	$ 19,271,000
	Electric Share (80%)	$ 10,785,000	$ 12,913,000	$ 11,771,000	$ 10,418,000	$ 10,606,000	$ 10,754,000	$ 10,459,000	$ 8,504,000	$ 15,417,000

Metric
Alternative Proposed Performance Metric: Days to complete credit disconnection

	2019	2020	2021	2022
Days	11.8	11.4	12.5	12.0

Benefit

Reduced Theft/Meter Tampering

Metric		CBA 2014-2018 Average	2019	2020	2021	2022
Increase in Retail Revenue	Residential	$ 1,144,000	$ 1,165,000	$ 1,241,000	$ 1,291,000	$ 1,419,000
	Small C&I	$ 1,978,000	$ 1,980,000	$ 1,859,000	$ 2,103,000	$ 2,461,000

Metric

Alternative Proposed Performance Metric: Number of Meter Tampering Cases

2018	2019	2020	2021	2022
30	15	6	0	46

Benefit
Distribution Management Efficiency

Metric		2014	2015	2016	2017	2018	2019	2020	2021	2022
Capital spent on Asset Health and Reliability projects and Capacity projects	Asset Health	$ 28,221,000	$ 33,245,000	$ 50,007,000	$ 42,543,000	$ 48,227,000	$ 55,115,000	$ 81,674,000	$ 89,741,000	$ 115,861,000
	Capacity	$ 14,942,000	$ 10,708,000	$ 9,953,000	$ 6,169,000	$ 7,891,000	$ 12,288,000	$ 14,808,000	$ 17,926,000	$ 15,035,000
	Reliability	$ 14,405,000	$ 15,607,000	$ 20,182,000	$ 22,800,000	$ 24,363,000	$ 19,599,000	$ 29,857,000	$ 27,841,000	$ 51,374,000
	Total Capital	$ 57,568,000	$ 59,560,000	$ 80,142,000	$ 71,512,000	$ 80,481,000	$ 87,002,000	$ 126,339,000	$ 135,508,000	$ 182,270,000

CERTIFICATE OF SERVICE

I, Marie Horner, 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 NO. E002/M-21-814

Dated this 25th day of September 2023

/s/

____

Marie Horner
Regulatory Administrator

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