414 Nicollet Mall
Minneapolis, MN 55401

August 14, 2023

—Via Electronic Filing—

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

RE: REPLY COMMENTS
PERFORMANCE METRICS AND INCENTIVES
DOCKET NO. E002/CI-17-401

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply Comments pursuant to the Minnesota Public Utilities Commission's May 26, 2023 Notice of COMMENT PERIOD in the above-noted docket.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list. Please contact Bridget Dockter at bridget.dockter@xcelenergy.com or (612) 337-2096 or Taige Tople at taige.d.tople@xcelenergy.com or (612) 216-7953 if there are any questions regarding this submission.

Sincerely,

/s/

BRIDGET DOCKTER
MANAGER, POLICY & OUTREACH

Enclosure
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 THE COMMISSION INVESTIGATION TO IDENTIFY AND DEVELOP PERFORMANCE METRICS AND POTENTIALLY, INCENTIVES FOR XCEL ENERGY'S ELECTRIC UTILITY OPERATIONS	DOCKET NO. E002/C-17-401 **REPLY COMMENTS**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission these Reply Comments in response to the Commission's May 26, 2023 Notice of Comment Period (Notice) in the above-referenced docket.

REPLY COMMENTS

We would like to again express our appreciation to parties for their willingness to meet prior to submitting Comments and discuss positions, as well as opportunities for collaboration. The Company values the feedback provided by stakeholders and appreciates the opportunity to respond to Comments.

I. STAY THE PROCESS

The Center for Energy and Environment (CEE) and Fresh Energy (FE) as Joint Commenters, recommend the Commission take no action now on setting baselines, targets, and benchmarks (PIM's) until parties understand the impacts of significant newly enacted policies at the federal and state level. Further, they recommend the Company report its 2023 Annual Report as usual, and after the 2023 report is filed, the Commission should consider if it is appropriate to move toward setting baselines or targets. Also, after the filing of our 2023 Annual Report, the Joint Commenters recommend that parties, including the utility, complete a full review of the current metrics to determine if any changes are necessary as a result of the recent policy changes. Other parties also acknowledge the potential impacts to the existing metrics in light of the recent policy changes.

The Company supports the Joint Commenters recommendations and suggests a similar approach in our filed Comments, the only difference being that we proposed to provide an initial assessment of the policy changes in our 2023 Annual Report filing.

II. ACCEPTING 2021 & 2022 ANNUAL REPORT

The Commission sought input on future metrics, a utility dashboard, and upstream methane emissions. While commenting parties expressed individual items of interest, all supported the approval of our filed 2021 and 2022 Annual Reports. No party objected to our proposed reporting of the future metrics $MAIFI_E$ and Power Quality, nor did they object to removing the Workforce Transition Plan reporting from this proceeding and only reporting within its assigned Integrated Resource Plan (IRP) docket. We address the Public Facing Dashboard next.

III. PUBLIC FACING DASHBOARD

In our Comments, we relayed the stakeholder process and consensus of those attending the meeting. The stakeholder group recommended that if the Commission wished to pursue a dashboard, it should be a stationary one, updated with each Annual Report, consisting of primary metrics and/or targets. The stakeholder group also recommended the appropriate balance of cost to develop the dashboard with how much the data may be utilized and by who.

The Department now fully supports the development of a dashboard and continues to recommend it be stationary, updated once per year. The Department also indicates its support of four of the five metrics used in the sample dashboard, including average monthly bill for residential customers, system average interruption duration index (SAIDI), total carbon emissions by (1) utility-owned facilities and PPAs and (2) all sources, and demand response, including available capacity (MW and MWh).

Environmental Law and Policy Center/Vote Solar (ELPC/VS) recommend we establish a comprehensive dashboard for all metrics and underlying data, update it quarterly or semi-annually, and provide it in a more user-friendly format for stakeholders.

We agree a public facing dashboard would be beneficial for stakeholders and regulators to easily review this information. However, consistent with our position to wait until we have the necessary information to assess the impacts of recent legislative policy changes on the approved metrics, we do not believe it is appropriate to establish a dashboard at this time. If the Commission decides it would like the Company to develop a dashboard in the future, we recommend it contain a small amount of high interest targets – not metrics – that should be identified once targets are developed. Consistent with the Department, we agree a dashboard should be stationary and updated annually.

The Commission has previously required annual reporting of approved metrics. Providing data updates more frequently is out of the scope of the process stakeholders agreed to during metric development. ELPC/VS provides no support as to why they recommend shorter reporting durations. Reporting quarterly or semi-annually for a dashboard requires data gathering and verification an additional two to four times per year. This data gathering and verification is performed once each year specifically to meet our annual PBR reporting requirements and includes extensive detail of the relevant data. We do not house the relevant information separately such that we could update it and provide links to the supporting data. As such, we do not support EPLC/VS's recommendation as this additional reporting is onerous, was not supported by the stakeholder group, and is not required by the Commission in this docket.

IV. EXISTING QSP TARIFF TARGETS

The Department noted the Commission may want to ask the Company for a proposal for the future of the QSP tariff and how the Commission might incorporate the targets for the metrics identified in that tariff in its 2024 Performance Based Ratemaking (PBR) filing. As we have stated in our initial Comments, we do not support moving the current targets within our Service Quality tariff to this PBR proceeding. The currently established process has proven to be effective. Re-establishing the current service quality tariff targets under the PBR proceeding would be time consuming without any significant benefit.

We remind the Commission that the Company is the only Minnesota utility that currently has targets and penalties associated with its Service Reliability Service Quality (SRSQ) metrics. If the Commission believes opening the SRSQ targets under the current tariff for review and assessment is productive, we recommend it open an "all utility" docket to assess the impacts of targets and PIMs on SRSQ.

V. AFFORDABILITY OUTCOME

A. Bills and Rates

The Department and Office of Attorney General – Residential Utilities Division (OAG) each recommend that the Commission set targets for the currently reported metrics of rates per KWh and average monthly bills. Targets would be set at five percent below an Energy Information Agency (EIA) baseline. To support this proposal, these parties reference Minn. Stat. § 216C.05, Subd 2 (4). The Department also requested that the Company discuss the potential to utilize EIA National data as a baseline for average residential customer bills.

The Company disagrees with this proposal for several reasons. First, the rates that the Company charges to customers are reviewed and approved by the Commission based on the Company's prudent costs of providing safe and reliable service. Minn. Stat. § 216B.16, Subd. 19(d) states: "Rates charged under the multiyear rate plan must be based only upon the utility's reasonable and prudent costs of service over the term of the plan." The Company is required to charge its customers the rates established by the Commission through its rate cases and rider proceedings, in which the Commission routinely balances a variety of competing policy concerns. While the Company can advocate for what it believes to be the appropriate rates based on its prudently incurred costs in those proceedings, it cannot unilaterally control the rates that it charges.

The proposal by the Department and the OAG would also subject the Company to a target that is dictated by commissions in *other states*. Specifically, the Company would be encouraged to target rates based on the average rates charged in other states. This is problematic because the rates of utilities operating in different states are determined by those states' policies, goals, and commission orders, which can and often do differ significantly from the policies in Minnesota. For example, in North Dakota, under Section 49-02-23 of the North Dakota Century Code, the Public Service Commission is expressly precluded from considering environmental externalities in resource planning, while Minn. Stat. Section 216B.2422, Subd. 3, requires the opposite. It would be unreasonable to establish a target—and possibly a future financial incentive—for achieving an outcome that the Company cannot control, especially when it could encourage the Company to act in ways that conflict with the State's other policy goals.

Second, the proposal by the Department and the OAG unreasonably focuses on one of several state energy policy goals that the Minnesota Legislature has codified, some of which can be in tension with each other. The Commission has the authority and responsibility to balance these goals when they conflict. However, the proposal here, could impact the Company's ability to achieve other state policy goals.

For instance, while the Department and OAG refer to the policy goal provided in Minn. Stat. § 216C.05, Subd. 2 (4), they do not mention the policy goals provided in Minn. Stat. § 216C.05, Subd. 2 (1)-(3). Those policy goals focus on increasing conservation, reducing fossil fuel usage, and increasing the percentage of renewable resources used to serve customers. These goals can be in tension with the goal of maintaining low "rates". As an example, increased conservation efforts are specifically designed to reduce consumption, which, unless offset by other forms of load growth, will result in the need for the utility to increase rates. As we indicated in our Comments, Statutory changes in 2021, such as the Energy Conservation and Optimization (ECO) Act enabling "efficient fuel-switching" as part of the Company's demand-side management efforts, as well as the Natural Gas Innovation Act (NGIA), may enable future electrification. In addition, Inflation Reduction Act (IRA) Home Energy Rebates, which will be made available by the Department of Energy later this summer, will further enable the adoption of electrification technologies. These can have varying impacts on higher rates but lower customer bills or higher electric bills and lower natural gas bills.

Other state policy requirements and Commission orders can impact the rates that the Company must charge to recover its reasonable costs of providing service. For instance, the Company is the only Minnesota utility obligated to accept all community solar gardens (CSGs) without limitations.[1] Our mandated CSG program has a material impact on customer bills. With over 30,000 active subscribers, we reported in our 2022 Annual Community Solar Garden Program Compliance Report[2], the non-economic costs of current legacy CSG systems, alone, have increased average residential customer bills by $3.70 per month (or $44 per year) since the inception of the program in 2015. While subscribers to CSGs receive varying degrees of a credit to their bill, both participants and non-participants are experiencing the increased cost of the required program.

Third, the proposal of the Department and OAG does not directly address the policy goal that they seek to promote—ensuring that our customers receive "affordable" electric service. While the Company acknowledges that lower rates can, in the most general sense, promote greater affordability, the connection is tenuous. Many of our Commercial and Industrial and wealthier residential customers can easily afford our

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[1] H.F.2310 adjusted this language to end this practice on January 1, 2024 closing the legacy program and limiting CSGs moving forward under specific caps. This will not adjust the current customer impact resulting from active community gardens but will begin to limit the upward trajectory.
[2] Filed under DOCKET NO. E002/M-13-867 on March 31, 2023, Pages 14 & 15

current rates and could likely afford rates much higher. Yet, it is undeniable that a subset of our customers—particularly low-income residential customers—struggle to pay their bills and would likely continue to struggle with even much lower rates. The Company is committed to ensuring that our rates are affordable for all customers and is open to measures that track our ability to achieve this goal.

For this reason, we continue to support a target, and, eventually a potential PIM, focused on reducing customer disconnections once a baseline can be established after full AMI deployment. This target should consider our efforts to successfully reach out to our customers to connect them with resources and energy assistance options. We believe this target better promotes the goal that the Commission seeks—ensuring affordable service for our customers who otherwise cannot afford those costs. We are open to other possible metrics but believe that setting a target based on our overall rates is not appropriate.

Fourth, it is not clear how the Commission could ultimately create an incentive mechanism for a target based on the rates we charge. Specifically, we continue to believe—consistent with recent Commission discussions—that the appropriate design for any PIMs based on targets established in this proceeding should be symmetrical and include "deadbands." Such a design for PIMs provides the most effective and fair incentive for the Company and is consistent with PIM structures established in other states. Applying a financial incentive to a rate target makes no sense. Presumably, if the Company needed to charge rates above a particular target to recover its costs, it could be penalized, potentially resulting in a regulatory "taking" as the Company would be improperly denied an appropriate opportunity to recover the costs of its service and earn a reasonable return, as required under Minn. Stat. § 216B.16, Subd. 6. Conversely, if the Company were to charge rates below a target, it would, somewhat perversely, receive the "reward" of being able to charge higher rates than otherwise authorized by the Commission. Neither situation provides a reasonable outcome for the Company or our customers.

Finally, we have concerns with potentially using EIA National data as a baseline for residential rates. The different utilities reporting to EIA may not have the same rate or program options available, creating fundamental differences in what is reported. For this reason, we believe it is not possible to provide accurate comparable rates and bills with the precision needed to accurately determine whether the Company has met a "target" of maintaining rates of five percent below the national average. While this data may be a helpful general guidepost to the Commission in a rate proceeding, it is not appropriate to use as a firm benchmark upon which to measure utility performance.

For these reasons, the Company disagrees with the proposal by the Department and the OAG to establish a target based on the rates the Company charges its customers. Instead, the Commission should focus on metrics that are better designed to promote customer affordability that do not conflict with the State's other policy goals or the needs of the utility.

As indicated in the approved *Metric Design Principle* two below, our rates and bills include effects outside of our control. We are unsure how we would extrapolate the effects of mandated federal and state policies and Commission Orders to offer a comparison on a rate or bill level nationally.

> 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 across time and utilities.*

For these reasons, we believe it is not possible to provide accurate comparable rates and bills. Establishing a target and potentially a PIM could lead to the Company incurring a penalty for implementing a required state policy or Commission Order. As indicated in our Initial Comments, we firmly agree affordability for our customers, especially those most in need, is very important. We continue to support a future target and potentially PIM focused on reducing customer disconnections once a baseline can be established after full AMI deployment. This target will consider our efforts to successfully reach out to our customers to connect them with resources and energy assistance options.

If the Commission ultimately believes a target and PIMs should be established for these two metrics, we recommend a similar methodology to other future targets with a deadband and symmetrical PIMs. We also ask to be provided the opportunity to discuss these further at that time.

R Street proposed a new metric, designed around rate increases due to generation fuel increases. As the Department indicated in its Reply Comments the Commission has directly addressed this issue in Docket No. E999/CI-03-802, resulting in a new fuel clause adjustment process on January 1, 2020. This new process includes an annual forecast and a true-up process for all utilities. We do not support adding a separate process within the PBR docket.

B. Disconnections & Arrearages

The impacts of the COVID-19 pandemic were felt by all of us beginning in 2020 and continue to this day. CEE/FE, the Department, CUB, and the OAG discuss the impacts of COVID-19 in their Comments.

Utilities across the country experienced many changes to their business during the pandemic. Among those changes was a change in customers' behavior as they struggled with the pandemic and subsequent economic challenges. Our customers are still trying to recover. In Minnesota, this can be seen in the utilities respective Residential Customer Status Reports that are filed weekly during the Cold Weather Rule (CWR) and monthly thereafter.[3] We saw a dramatic increase in customer arrearages resulting first from disconnection moratoriums that began in early 2020 and lasted through the CWR in May of 2022. Throughout this time, the Company has worked diligently with the Department of Commerce to actively expand LIHEAP enrollment, worked with Minnesota Housing Finance on their Rent Help program that offered utility assistance, and performed significant additional outreach efforts to engage our customers in the most need to make them aware of resources available to them. These efforts are explained in our most recent Electric Low Income Discount Annual Report.[4] We did propose a possible future target and methodology measuring the effectiveness of our efforts to help customers avoid disconnections in our Comments. However, due to the pandemic and because we are in the midst of our AMI implementation that will likely change the baselines for both customer disconnections and arrearages, we recommended waiting until after full AMI deployment to establish a target for customer disconnections. We support CUB's position to not set a target and PIM on lowering arrearages. Instead, CUB recommends additional reporting to study the effectiveness of our payment plans.

If the Commission and parties find that reporting the three additional metrics requested by CUB valuable in helping to determine the effectiveness of our payment plans, we support adding these to our Annual Reports. As CUB noted, prior to submitting Comments, the two organizations discussed CUB's request and we can provide the information they are seeking. This includes:

- The number of customers (and the percentage of all residential customers) who were under one or more payment plans during the reporting period;
- The percentage of payment plans that ended in a default that then prompted a disconnection; and

[3] Utility reports are filed under Docket No. E,G999/CI-YY-02

[4] 2022 ANNUAL REPORT ELECTRIC LOW INCOME ENERGY DISCOUNT PROGRAM DOCKET NOS. E002/M-04-1956 AND E002/M-10-854

- The average percent reduction in arrears per customer participating in a payment plan during the reporting period.

In their Reply Comments, the Department indicated we have requested a new metric in the Affordability Outcome titled: "Decreasing Customer Disconnections in Identified Areas of Concentrated Poverty". For clarification, the Company is not proposing a new metric, only proposing to utilize the existing disconnection metric to establish a future target and potentially a PIM focused on decreasing customer disconnections, once our AMI deployment is complete.

VI. RELIABILITY OUTCOME

A. Average System Availability Index (ASAI)

The Department recommends the Company calculate a baseline and target for ASAI. The Department's recommended baseline for ASAI includes converting the IEEE SAIDI benchmark results, then the Commission adopt the same adjusted target that is used for SAIDI. Alternatively, the Company recommended an ASAI baseline using a three-year rolling average approach but did not recommend a target. The Company believes the baseline for reliability performance should be aligned with current performance that is within the Company's control. While the Company does participate in the annual IEEE Distribution Reliability Working Group (DRWG) benchmarking survey, the quartile results are a representation of the industry, and not specifically viewing the Company's performance. Additionally, the IEEE benchmark quartiles change annually, thus if the Commission were to implement the Department's recommendation for the ASAI baseline, the baseline would change annually.

The Company does not agree a target associated with ASAI is appropriate. ASAI is redundant information to SAIDI, and we already have an established target and underperformance penalty associated to SAIDI in the Service Quality Tariff. SAIDI is the number of minutes of interruption per year, and ASAI is the fraction of time service is available in a year, including an adjustment on leap years. The Department is correct in that the published IEEE benchmark SAIDI data could be converted into ASAI performance. However, the ASAI data is more difficult to distinguish good versus poor performance because of the way ASAI is reported, specifically that the differences get buried in the decimal. For example, ASAI of 99.9649% vs. 99.9752% is equal to a SAIDI of 170 minutes versus 96 minutes. Also, IEEE does not benchmark using ASAI data. Creating a target utilizing ASAI is duplicative of the same data.

B. Reliability Outcome Targets and Penalties

The OAG recommends establishing targets and penalties for the six metrics under the Reliability Outcome, SAIDI, SAIFI, CAIDI, CELID, CEMI, and ASAI. The Company currently has established underperformance penalties within our Service Quality Tariff for four of the six metrics: SAIDI, SAIFI, CELID, and CEMI. Our annual performance information related to these targets is filed at the end of each April.[5] The Company reports CAIDI in our Annual SRSQ filings utilizing the IEEE benchmarking target. Specifically, Order Point 10 in Attachment B of the Commission's January 28, 2020 Order in Docket No. E002/M-19-261 requires the Company to provide "IEEE Benchmarking results for SAIDI, SAIFI, CAIDI, and MAIFI from the IEEE benchmarking working group." The Company agrees with the OAG that the CAIDI and ASAI baselines should use the three-year rolling average approach. However, we do not agree that CAIDI and ASAI should be assigned a target or penalty. A system level CAIDI target does not add value in addition to the established SAIDI and SAIFI targets and underperformance penalties. CAIDI often conflicts with improvements to SAIFI, since CAIDI is a ratio of SAIDI and SAIFI. Thus, CAIDI can be misleading on a system level if SAIDI and SAIFI are reduced, which is improving the overall system reliability, but CAIDI could increase. The Company's view of assigning an ASAI target was discussed above.

C. Locational Reliability

ELPC/VS requests the Commission re-establish the Locational Reliability within the PBR proceeding. In compliance with the Commission's May 18, 2023 Order[6], we are currently conducting an analysis that examines whether there is a relationship between poor performance on the five identified metrics displayed on the interactive map and equity indicators. If any disparities are found, we are required to identify preliminary steps we could take to correct them and if Commission approval is required, where and when it would expect to file solutions in our next Service Reliability Service Quality Plan filed April 1, 2024. At this time, it is unclear what metric would be used for Locational Reliability. If the Commission approves moving Locational Reliability back into the PBR proceeding, we ask that when the Commission determines it is

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[5] 2022 ANNUAL REPORT SERVICE QUALITY PLAN DOCKET NOS. E,G002/CI-02-2034 AND E,G002/M-12-383

[6] n the Matter of Xcel Energy's Annual Report on Safety, Reliability, and Service Quality and Petition for Approval of Electric Reliability Standards In the Matter of a Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations, Docket Nos E-002/M-20-406 E-002/CI-17-401; May 18, 2023

appropriate to move forward in this docket, parties be provided the opportunity to give feedback on this metric.

VII. CUSTOMER SERVICE QUALITY OUTCOME

A. Customer Satisfaction

The Department recommends a 50th percentile be used as a baseline for customer satisfaction measurement. Instead, the Company proposes to use a three-year rolling average to set a baseline for this metric. We believe this will more accurately account for industry trending as well as gage our customer satisfaction. One factor to consider when utilizing comparative ranking is not all peer utilities in the group are a combination gas and electric, like Xcel Energy. A review of the peer combination gas and electric utilities within the JD Power Study shows that they have average percentile rankings below the 50th percentile historically. The high cost of gas the past couple of years will contribute to customers' perceptions of cost and value. Additionally, customers are increasingly dissatisfied in repeated or extended outages related to an increase in storms and other weather effects. Immediate impacts of weather-related outages are outside of our control. We agree with the Department that a target is not appropriate for this metric. Unlike some of the other metrics, customer satisfaction includes elements that fall outside the approved *Metric Design Principles,* these include: clearly defined, sufficiently objective and free from external influences, and easily interpreted. This leaves the comparative customer satisfaction information imprecise, and a target should not be established around it.

B. Call Center Response Time, Billing Invoice Accuracy, & Customer Complaints

The OAG recommends additional targets to exceed the current Service Quality Tariff targets with associated underperformance penalties for Call Center Response Time, Billing Invoice Accuracy, and Customer Complaints. The targets and underperformance penalties established in the Service Quality Tariff is a form of Performance Based Ratemaking with the underperformance penalty established as an asymmetrical only PIM. This is similar to the State of Minnesota's Energy Conservation and Optimization asymmetrical incentives under Minn. Stat. 216B.241 We oppose setting multiple underperformance targets for a metric. We believe it is confusing, unnecessary, and overly punitive.

VIII. ENVIRONMENTAL PERFORMANCE OUTCOME

A. Methane Emissions

As indicated in our Comments, the tracking and reporting of methane emissions focused on our gas distribution and supply would be more appropriately managed in our upcoming Gas Integrated Resource Plan (IRP). We understand the original interest from parties to track and report on methane emissions. However, we now have dockets open regarding Gas IRP and the Future of Gas, which will be more appropriate places to incorporate methane tracking. PBR is an electric-based docket and methane reporting should be moved to a gas-based docket. The Department appears to indicate its support for this move on [page 11] of its Comments stating, *"While the Department recognizes the Commission's desire to quantify the volumes and calculate the costs associated with those upstream emissions as quickly as possible, the Department suggests that the determination of those values may be better suited for a natural gas integrated resource plan proceeding, In support of this suggestion, the Department notes it recommended emissions targets for carbon dioxide and the criteria pollutants based on information provided in the Company's electric IRP."*

While acknowledging our position on where future methane emission discussions should lie, we respond to additional related questions from the Department. The Department correctly identified the metric design principle we cited *"Sufficiently objective and free from external influences. Metrics should seek to measure behaviors that are within the utility's control and free from exogenous influences, such as weather or market forces"* in regard to reporting only on methane emissions from our own gas distribution system.

The Department also requests the Company discuss the availability of data from other gas local distribution companies (LDC's). As noted, we are not recommending methane targets related to upstream or our LDC be set in this electric PBR but discussed that if targets were set, it would only be appropriate for our LDC system that we control. It is not clear for what purpose the Department is seeking data from other LDCs, as it would pertain to recommending a potential methane target for our LDC system. We do not have access to LDC data beyond what would be publicly available through EPA reporting.

The Department requests the Company incorporate a discussion of how the proposed methane emission fee from the Inflation Reduction Act of 2022 (IRA) can be reconciled with the calculation of upstream emissions of methane on a utility-specific basis across the entire fuel cycle.

We have not yet proposed a methodology to calculate upstream methane emissions as sufficient data is not yet available, which the Department has verified. The methane fee may not directly impact calculation of upstream methane emissions. However, the IRA Methane Emissions Reduction Program[7] also directs EPA to update GHG Reporting Protocol regulations for petroleum and natural gas systems (Subpart W) Subpart W reporting to include empirical data and provides technical and financial assistance, which could increase the accuracy of upstream emissions data available in the future. However, updates to Subpart W were just proposed last month (July 2023) and are not yet final. Implementation of IRA will take time, and other barriers to tracking emissions associated with gas supply across utility-specific supply chains in the market still exist. Certified natural gas will likely still play an important role. The Company has requested methane emission reporting be moved to an appropriate gas-based docket, like the Gas IRP. However, if the Commission retains the methane emission reporting in this electric docket, we will report our re-evaluation of data availability for the 2023 PBR Annual Report (filed in 2024), as required. Although with the current timeline, it does seem likely sufficient data may not yet be available. Sufficient data must be available before the Company would propose a methodology for calculating upstream methane emissions.

B. Carbon Emission Reductions

As most parties have noted, the newly passed federal and state legislative policy changes may impact many of the metrics in this docket. They will likely impact those within the Environmental Outcome the most. Minnesota's 100% Carbon Free Energy by 2040 (CFS) standard does not specifically consider emissions. However, the carbon emission metrics in this proceeding should be consistent with that law. The Commission has opened an investigation docket to set definitions, reporting requirements, etc., and that is the appropriate place to discuss such topics.[8]

The Department recommends utilizing three-year averages of the reported data to establish baselines and targets utilizing the annual emissions calculated as part of our most recently approved IRP for the first four metrics and sub-metrics in this Outcome. The State of Minnesota's CFS requirements, for which compliance methods have yet to be fully developed, may help inform the target setting process. However, we note that the CFS is not a mass-based carbon reduction requirement,

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[7] Methane Emissions Reduction Program | US EPA

[8] Docket No. E999/CI-23-151, In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon Free Standard under Minn. Stat. § 216B.1691.

rather a requirement to generate increasing amounts of carbon-free energy relative to our Minnesota electricity demand. It is not yet fully clear how the CFS and mass-based carbon reduction will relate to one another. As such, and as indicated in our Comments, for the mass-based carbon targets considered in PBR, we believe a single baseline year taken from our most recent approved IRP is more appropriate. Specifically, we recommend using the base year of each approved IRP to establish a baseline. For example, our most recent IRP used 2020 as a base year. Furthermore, it is not appropriate to set carbon emission reduction targets linearly, year over year. As we have seen in our IRP, the largest magnitude carbon reductions occur when coal-fired units are retired, and due to the sometimes inconsistent nature of in-servicing new carbon-free resources, there may be interim years where mass-based carbon emissions do not decline substantially for reasons outside the Company's control. Consistent with our recommendation to perform a federal and state policy review for the next PBR Annual Report filed in April 2024, we will propose five-year target increments, based on the most recent approved IRP emission reduction actual calculations, to potentially begin in 2025.

IX. COST EFFECTIVE ALIGNMENT OF GENERATION AND LOAD OUTCOME

A. Demand Response

The Department recommends a baseline of capacity for demand response utilizing the Commission's Order in Docket No. E002/RP-15-21 requiring the Company to acquire an additional 400 MW by 2023.[9] The Company does not believe this is an appropriate baseline in this proceeding and continues to recommend the use of our proposed baseline of a three-year rolling average; or as suggested by Parties, wait until 2024 to establish baselines.

There are two reasons the Company does not believe the additional 400 MW established under Docket No, E002/RP-15-21 is an appropriate baseline of capacity for demand response in PBR. First, the PBR proceeding is Minnesota-specific and, as a result, the reported Minnesota controllable load is specific only to Minnesota. In contrast, the cited additional 400 MW Order is an established requirement applicable to the Northern States Power Company - Minnesota integrated system and includes: Minnesota, Wisconsin, North Dakota, South Dakota, and Michigan.

[9] See ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Minnesota Public Utilities Commission, Docket No. E002/RP-15-21, January 11, 2017, Order Point 10.

Second, the Order in Docket No. E002/RP-15-21 established a requirement for demand response. It has not yet been determined whether the Company is able to meet this requirement as customers begin to choose which program best meets their need or determine that other opportunities are more impactful to their business. While the Company continues to actively pursue our requirements under that docket and is optimistic about customer response to our newer programs. The Company is committed to the long-term growth of demand response and will report our results in the February 1, 2024 filing in Docket No. E002/M-20-421.

R Street recommends an extension of Docket E999/CI-22-600 to include targets for Shed, Shape, and Shift, utilizing Third Party Aggregators. The Company agrees with the Department that the current Demand Response Pilot program underway will inform the markets ability to contribute to our demand response efforts. We do not believe any action should be taken at this time.

B. New Demand Response Efforts Towards Shape and Shift

In Attachment A of their Comments, the Department requested further information regarding calculation of Shape and Shift resources. The Company has limited shifting resources at this time, including customers signed up for the Peak Flex Credit Pilot. To date, there is less than one year of data regarding these customers as the program was launched in December 2022. Additionally, we have proposed load shifting measures as part of our 2024-2026 ECO Triennial plan in Docket No. E002/CIP-23-92; these measures have not yet been approved by the Department. We do not anticipate having a data set to begin to analyze for load shifting until 2025 at the earliest.

The Company analyzed shaping resources as part of our residential time-of-use program. The results of the pilot showed modest impacts on participant energy usage patterns and minor effects on total customer bills. On average, participants in the pilot reduced their summer On-Peak demand by up to 1.6 percent.[10] On average, annual energy consumption increased by 0.2 percent to 0.5 percent, corresponding to an annual increase in energy consumption of 30 kWh or less on average. We did see that a small, highly engaged subset of participants accounted for a disproportionate share of estimated on-peak reductions. Those high-impact customers on average showed summer on-peak demand reductions of greater than 10 percent of their baseline usage.

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[10] Impacts did vary by study area and year.

C. Load Net of Variable Renewable Generation

The majority of Parties recommended to wait to establish further documentation around Load Net of Variable Renewable Generation rather than remove the metric at this time. As a result, the Company agrees to continue monitoring these details and looks forward to furthering stakeholder discussion regarding how to update this metric for more effective outcomes.

As noted in our Annual Report, the metric itself has proven less effective than hoped in measuring the effectiveness of demand response efforts due to the rapid adoption of variable renewable generation. As renewable efforts have ramped up, the energy used for the factor calculation has been reduced. To show a load factor reduction, because of demand response, would require a peak reduction beyond the potential of demand response. R Street suggested in Comments that targets should be set for metrics 1-3, 4(a) and 4(b). These metrics concern the achievement of demand response broken down into the shed, shape and shift components. The potential of demand response will be determined in the Company's next Upper Midwest IRP, and demand response scenarios will be modeled to determine the cost-effective achievable potential of demand response. The Company suggests that targets should not be set until this cost-effective achievable potential is determined. This reduction is not a result of less demand response, but instead, a result of less energy in the system.

We continue to recommend an alternative methodology for showing how demand response can illustrate effectiveness, especially as we begin to focus on demand response efforts that do not impact peak reduction – such as load flexibility. As suggested by parties, including the Department, we look forward to working with stakeholders to "re-evaluate" this measure and help establish the most appropriate methodology.

CONCLUSION

The Company appreciates the opportunity to provide this response to filed Comments.

In summary, we support:

- Waiting to establish baselines, target, and PIMs until such time as parties fully understand the impacts of newly passed federal and state policies on approved metrics.

- The Company completing an initial assessment of current metrics as they relate to newly passed federal and state policies and including it in our 2023 Annual Report filed in April 2024.
- The Commission opening a process for parties to perform a full review and response after the Company files it 2024 Annual Report. We recommend that because these will be in-depth reviews, comment periods extend longer than normal.
- Adopting a three-year rolling average baseline for ASAI and CAIDI, but not a target.
- Establishing a baseline for Rates and Bills utilizing the Commissions most recent approved rates.
- Discontinue reporting of the Workforce Transition Plan in this proceeding but continue in IRP docket.
- Discontinue reporting ACSI.
- Re-evaluating Load Net of Variable Renewable Generation in the future.
- Developing of a stationary Public Facing Dashboard reporting key targets that are identified once parties agree enough information from sources such as federal and state policy changes and AMI implementation is available.
- Utilizing a three-year rolling average for a Customer Satisfaction baseline.
- Reporting three additional payment plan related metrics as requested by CUB.
- Shifting methane related reporting to an appropriate gas docket such as the Gas IRP.
- Setting mass carbon emission targets on a single year from our most recent approved electric IRP.
- Setting a three-year rolling baseline for demand response capacity.

We do not support:

- Establishing targets or PIM methodologies for Rates and Bills.
- Establishing a target or PIM associated with arrearage levels.
- Targets and potentially PIMs that are in addition to and extend beyond current Service Quality Tariff targets with associated underperformance penalties for Call Center Response Time, Billing Invoice Accuracy, and Customer Complaints.
- Creating a new metric related to fuel costs
- Establishing targets and PIMs for demand response that includes third party aggregator actions.

At this time, the Company takes no position on Locational Reliability.

Dated: August 14, 2023

Northern States Power Company

Certificate of Service

I, Christine Schwartz, 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/CI-17-401

Dated this 14th day of August 2023

/s/

Christine Schwartz
Regulatory Administrator

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