BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

In the Matter of a Rider for Large Power Demand Response

PUC Docket No. E-015/M-18-735

INITIAL COMMENT

The Large Power Intervenors ("LPI"), a continuing *ad hoc* consortium of large industrial end-users of electric energy in Minnesota served by Minnesota Power (also herein, the "Company"), submit the following Comment in support of the petition filed by Minnesota Power in the Matter of a Rider for Large Power Demand Response (the "Petition") in Minnesota Public Utilities Commission Docket No. E-015/M-18-735. LPI is comprised of the following individual members: ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Enbridge Energy; Hibbing Taconite Company; Sappi Cloquet, LLC; USG Interiors, LLC; United States Steel Corporation (Keetac and Minntac Mines); United Taconite, LLC; and Verso Corporation.

I. INTRODUCTION/BACKGROUND

LPI is grateful for the opportunity to comment on Minnesota Power's proposed Rider for Large Power Demand Response.[1] Demand Response (or "DR")[2] has potential to create significant system benefits for Minnesota Power and its customers while simultaneously providing an opportunity for participating large power customers to control their energy costs. LPI appreciates the Minnesota Public Utilities Commission's (the "Commission") support for expanding Minnesota Power's DR program in the Company's last Integrated Resource Plan ("IRP"), rate case, and the recent gas resource proceeding. LPI is also thankful for the

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[1] Petition for Approval (Dec. 7, 2018) (eDocket No. 201812-148328-01) (the "Petition").
[2] The Federal Energy Regulatory Commission defines DR as "[c]hanges in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." FERC, Reports on Demand Response & Advanced Metering, https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp (last accessed Feb. 6, 2019).

Company's efforts to work with LPI and engage other stakeholders to develop the proposals set forth in the Petition, which are a potential win-win-win for the Company, DR subscribers, and other customers.

LPI recommends approval of the Petition and Cost Recovery Method 2. While aspects of the proposal will not work for all LPI members and may be worth revisiting in the future, LPI believes Minnesota Power has created a strong framework for expanding industrial DR on its system in a way that will add value for the Company, participating customers, and all other ratepayers. Approval of the Petition and deployment of the new DR products – particularly the new Product B – will provide the Company, its customers, and other stakeholders with substantial knowledge that can be used to help fully realize DR as a system resource over the long term.

This Comment will address aspects of the Company's proposal that are most important from the perspective of large industrial customers. In general, agreeing to potential interruptions to electric service for an industrial customer means taking on substantial operational risk. Managing for that risk means making significant modifications to day-to-day operations to account and prepare for a potential interruption. In deciding whether to enroll in the DR program, customers will individually assess the operational risk of enrolling relative to the potential economic benefits.[3] But overall, LPI believes that Minnesota Power has struck an appropriate balance between benefits offered to enrolling customers and overall costs and cost allocation to other ratepayers. For the reasons set forth in more detail in this Comment, LPI respectfully requests that the Commission approve Product B and Cost Recovery Method 2.

A. Relevant Procedural History

LPI has been a proponent of expanding DR options for the last several years. Starting with Minnesota Power's 2015 IRP, LPI requested the Company analyze more demand-side resource options. In recognition of LPI's and other parties' positions on demand-side resources,

[3] As in other proceedings, LPI submits this Comment on behalf of itself as an ad hoc consortium only, and not on behalf of individual members of LPI. If the Petition is approved, individual members of the group will each make their own evaluation of the cost and benefits of enrolling in the expanded DR program. LPI as a group is supportive of approval of the Petition, but no individual member has made a firm commitment to enrollment.

the Commission ordered the Company to propose a DR competitive-bidding process within six months, and to include analysis of DR among potential alternatives to natural gas.[4]

Shortly after the conclusion of the Company's 2015 IRP, Minnesota Power filed a rate case in late 2016. Once again, through its final order, the Commission reiterated its commitment to a successful DR program by instructing the Company to do the following:

> The Company shall work with LPI and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, for submission to the Commission. The record to support the submission to the Commission may be developed in either Docket E015/AI-17-568 - OAH Docket 68-2500-34672 or a new miscellaneous docket. In the event the Company, LPI, and other stakeholders elect to proceed with a new miscellaneous docket filing, such filing shall be submitted for Commission approval within six months after the date of the final written order in this proceeding.[5]

The "final written order in this proceeding" was the Commission's order on reconsideration on May 29, 2018.

DR was analyzed again in the Company's Nemadji Trail Energy Center ("NTEC") docket, where Minnesota Power requested approval of certain affiliate interest agreements in connection with acquiring energy and capacity from a portion of a 525 MW natural gas combined-cycle facility in Wisconsin. In the NTEC order, the Commission confirmed its prior positions on DR, noting that "Minnesota Power, and other stakeholders should continue to develop a demand-response rider and corresponding methodology for cost recovery in a new miscellaneous-docket filing."[6] Pursuant to the Commission's direction, the Company submitted

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[4] *In the Matter of Minnesota Power's 2016-2030 Integrated Resource Plan*, PUC Docket No. E-15/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS at 8, 13 (July 18, 2016).

[5] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, PUC Docket No. E-015-GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 115 (Mar. 12, 2018).

[6] *In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*, PUC Docket No. E-015/AI-17-568, ORDER APPROVING AFFILIATED INTEREST AGREEMENTS WITH CONDITIONS at 23 (Jan. 24, 2019).

its Petition on December 7, 2018. The Petition contains multiple DR products and cost recovery method options, which are described below.

B. Product Offerings

In the Petition, Minnesota Power proposed three industrial DR product options. First, Product A is an emergency-only capacity product that is selected annually.[7] This product is similar to the currently-offered interruptible product for large industrial customers.[8] The Company contemplates the following conditions would apply for emergency capacity events: (1) a maximum number of five annual emergency events; (2) a maximum duration of four hours per emergency event; and (3) a minimum notice time of two hours prior to an emergency event.[9] During the initial year, the credit for Product A is anticipated to be approximately $.060 per kW of interruptible billing demand per month.[10] The Company contemplates that the amount of the credit may be updated annually based on current market price trends for short-term capacity.[11]

Second, Product B is a new long-term emergency capacity product offering that includes energy curtailment periods (referred to as "Firm Load Control") that may be called by Minnesota Power for economic purposes.[12] Participating customers are required to have an Electric Service Agreement ("ESA") in place with Minnesota Power for an initial period of 10 years.[13] The Petition argues that a 10-year commitment is required so Minnesota Power is able to plan for Product B in a fashion similar to a long-term supply-side resource.[14] Due to capacity need, the offering of Product B will be for 150 MW, and if customers desire more than 150 MW, the Company will allocate MW of the product based on expected peak energy usage.[15] The Petition contemplates the following conditions would apply for emergency capacity events: (1) a maximum of five annual emergency events; (2) a maximum duration of four hours per

[7] Petition at 16.
[8] *Id.*
[9] *Id.*
[10] *Id.*
[11] *Id.*
[12] *Id.* at 17.
[13] *Id.*
[14] *Id.*
[15] *Id.*

emergency event; and (3) a minimum notice time of two hours prior to an emergency event.[16] Product B also includes Firm Load Control periods for energy that can be called on by the Company for economic purposes. Effectively, customer energy can either be curtailed or the subscriber has the option to buy through the event at a higher cost. The following conditions apply for Firm Load Control periods: (1) a maximum of 600 hours of Firm Load Control per year; (2) a maximum of two Firm Load Control periods per day; (3) a maximum of 12 hours of Firm Load Control periods per day; (4) a maximum Firm Load Control duration of 12 hours per occurrence; (5) a minimum Firm Load Control duration of four hours per occurrence; (6) no more than four Firm Load Control periods in any seven days of the week; and (7) four hours of notice will be given either the day-ahead or real-time through an email notice.[17] Enrolled customers will receive a billing credit of $7.00 per kW-month. In recognition that large industrial operations require flexibility in their operations, Product B allows for subscribers to buy through Firm Load Control curtailment, with a charge based on the Company's incremental energy costs during the time of the sale plus a $5.00/MWh adder.[18] If customers reduce load during curtailment they will be paid a Physical Interruptible Energy Credit of $30.00/MWh.[19] Lastly, customers have the option to reduce MWs of Product B and convert them to firm service by submitting written notice to the Company and paying costs incurred by the Company associated with such conversion.[20]

Third, Product C is an emergency-only capacity product that can be used for excess capacity that does not fit into other DR products or needs of the Company.[21] The Company envisions Product C as an option for customers who seek a capacity product greater than the one-year term offered by Product A, but are unwilling to enter into a 10-year ESA (Product B).[22] The offering is open to those who have an ESA in effect that matches the terms of the Market Surplus Service as long as the customer has not served an ESA cancelation.[23] Under Product C,

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[16] *Id.*
[17] *Id.* at 17-18.
[18] *Id.*
[19] *Id.* at 18.
[20] *Id.*
[21] *Id.* at 19.
[22] *Id.*
[23] *Id.*

the Company and participating customer will work together to determine the specifics of emergency-only capacity offered as part of the subscription.[24]

C. Cost Allocation Methods

The Company's Petition requests cost recovery through its proposed Rider for Large Power Demand Response Service, and believes the Commission has authority to implement a rider pursuant to its general ratemaking authority and Minn. Stat. § 216B.05.[25] The Petition outlines the Company's two proposed cost allocation methods for the Commission's consideration.[26]

Cost Recovery Method 1 is a flat per kWh recovery from all firm customers.[27] Method 1 recovery is based upon the total demand credit for Product B and firm kWh sales to retail customers.[28] Cost Recovery Method 2 is a recovery based on the rate case apportionment of final rate increase.[29] This method allocates cost recovery based on the Commission's apportionment of the final rate case revenue deficiency by customer class.[30] Method 2 is consistent with apportionment of the final rate increase in Minnesota Power's recent rate case, and it also allocates more cost to the customer classes that benefit from peaking capacity products like DR.[31]

II. ANALYSIS

A. The Petition Appropriately Balances Compensation for Operational Risks and Value for the Utility's System

In Minnesota Power's recent rate case, LPI expert Robert R. Stephens provided testimony recommending a comprehensive suite of DR programs with a variety of term lengths and with

[24] *Id.*
[25] *Id.* at 24.
[26] *Id.*
[27] *Id.* at 25.
[28] *Id.* (for an example of Method 1 cost recovery see the Petition at 25).
[29] *Id.* at 26.
[30] *Id.*
[31] *Id.* (for an example of Method 2 cost recovery see the Petition at 26, Table 1).

credit values increasing in conjunction with the term length.[32] LPI made similar recommendations in MPUC Docket No. E015/AI-17-568 related to Minnesota Power's Energy*Forward* Resource Package.[33] In both dockets, LPI proposed five DR products (A-E) with a range of requirements for curtailment and interruptions.[34] While the Petition does not include as many products as LPI's proposal, LPI appreciates Minnesota Power's effort to provide multiple options for customers (Products A-C). Product A is similar to a current Company offering, while Product C is largely a framework for the Company to work with individual customers on more customized offerings. Product B is most similar to the type of product initially proposed by LPI and therefore will be the primary focus of this Comment.

Product B is well designed to address operational risk for subscribers in part because it permits subscribers to buy through during a curtailment. The Company's large power customers are part of global industries and face fierce international competition. Energy interruptions create a significant operational risk for these businesses, as noted by Karen Turnboom during a Minnesota Power stakeholder workshop:

> We take on many risks, including pricing, operational and safety risk. There is additional wear and tear on equipment each time you shut it down. Sometimes when you shut it down it doesn't come back up the same way. We also need to meet our own customer needs and deliver a product on time. We don't have a large, warehouse and we don't have big inventory, so most times we are manufacturing the product as it is ordered. There is also pricing risk – we have the cost of participation and then the cost of buying through an interruption, if needed. Finally, there is a safety risk to our employees when we have to shut down equipment with little notice and then start it back up again…[earlier in the stakeholder meeting, Ms. Turnboom described this complicated decision-making process by using] an analogy told to [her] by Minnesota Power's Dave Chura, if we are baking a dozen cookies, we will have to make a decision whether to shut off the oven before they

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[32] *See generally In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E015/GR-16-664, Direct Testimony of Robert R. Stephens (May 31, 2017) ("Stephens Rate Case Testimony").

[33] *In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*, MPUC Docket No. E015/AI-17-568, Direct Testimony of Robert R. Stephens (Jan. 19, 2018) ("Stephens NTEC Testimony").

[34] *See generally* Stephens Rate Case Testimony; Stephens NTEC Testimony.

> are ready and lose that batch of cookies, or pay more to keep the oven on to keep cooking them.[35]

Many companies may reasonably be able to accommodate an interruption much of the time, but still need to plan for rarer times when an interruption would compromise their ability to make a critical delivery, otherwise cause a serious loss, or create operational challenges depending on the time of year. Having the option to buy through an interruption – even at a premium – provides much more flexibility and makes participation in DR more feasible. Thus, the buy-through component of Product B is a necessary feature for managing the operational risk of potential interruptions.

In addition to working with the Company to include a buy-through option for economic curtailments, LPI worked with the Company to design other aspects of Product B to manage operational risk while maintaining overall value of the system. In particular, LPI appreciates that the terms of Product B clearly articulate matters such as the maximum number of annual emergency curtailments, maximum number of annual hours for economic curtailment, minimum notice periods, limits on the duration of each curtailment, and limits on clusters of economic curtailments. This clear framework allows customers to accurately model the potential impacts of enrolling the program on their operations and to plan for interruptions if they choose to participate. LPI appreciates that Minnesota Power incorporated substantial feedback from large power customers in designing these features. The balance struck in this proposal between the level of commitment required from customers relative to compensation provided likely will not be sufficient to induce all eligible customers to enroll. But Product B provides a strong framework for a modern DR program that may be attractive for some large power customers now and a basis for improvements and expansion in the future.

LPI's support for this Petition is based on the overall package proposed by the Company. Because participating in demand-side management programs is a significant operational risk for large industrial consumers, customers need to receive adequate compensation for that risk in order to induce them to actually enroll in the program. LPI believes the Company has made fair

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[35] Petition at Appendix A, pp. 4-5.

proposals for the monthly demand credit and physical interruptible credit that reflect the real value that DR would provide to the system and other ratepayers. But this balance is delicate. Even as is, some large power customers likely will determine that the operational risk of participating in Product B is too high relative to the benefits. If the Commission opts to order changes that would increase the operational risk (e.g., raise the total hours or number of curtailments), reduce the credit levels, or allocate more cost to the large power class this program is unlikely to be successful.

LPI members understand the important role they occupy on Minnesota Power's system and to the economy of Northern Minnesota generally, and LPI members appreciate that they have the ability to provide a significant benefit to the communities on Minnesota Power's system. The structure of DR Product B and Cost Recovery Method 2 together appropriately recognize the operational risks that potential customers will undertake to provide these benefits.

B. Product B Has the Potential to Provide Substantial Benefits to the Company's System

DR Product B is a modern DR product with potential to benefit the Company, subscribers, and non-subscribing customers on Minnesota Power's system. Importantly, Product B permits both emergency and economic curtailment, which together can provide substantial avoided energy and capacity benefits to the utility's system. The energy component of Product B permits up to 90,000 MWh to be curtailed annually.[36] In return, Product B subscribers receive a demand credit of $7.00 per kW-month plus a $30 credit for each MWh of energy actually curtailed during a Firm Load Control period.[37]

Minnesota Power explains in the Petition that the $7.00 per kW-month demand credit is competitive with the cost of building new peaking generation and calculates that Product B would provide all customers approximately $4.6 million in capacity savings over a 10-year

[36] *Id.* at 20.
[37] *Id.*

period.[38] Minnesota Power also identifies two additional key benefits to its system: (1) the $30/MWh physical interruptible credit is less expensive than dispatching peaking generation; and (2) there is a reduction in system emissions from displaced generation.[39] Essentially, when subscribers are curtailed, it avoids the need to generate energy or purchase energy from the market to meet the demand that would occur but for Product B. Minnesota Power contemplates implementation of Product B during periods of high demand or when intermittent renewable generation is unavailable.[40] Minnesota Power estimates the savings from avoided energy purchases to be approximately $10 million over a 10-year period.[41] LPI is supportive of Product B overall because of the overall benefits to the system, while also providing reasonable compensation for the operational risk undertaken by subscribing customers.

The system benefits of DR are not merely theoretical. Last month during a period of extreme cold weather, Minnesota Power called its current interruptible customers to curtail their load during the peak usage periods. The information request (LPI IR 1) attached to this Comment as Attachment A provides more detail about this event. According to Minnesota Power, 200 MW of large power load was shed during this emergency, which was approximately 85% of the total curtailed capacity. As demonstrated during this recent extreme weather event, large power interruptible load is already making a material contribution to reliability of the system. Approval of the Petition will enhance the Company's ability to further utilize DR for these types of emergency purposes, while also significantly enhancing the value of DR capacity by expanding the Company's ability to use it for economic purposes via the Product B Firm Load Control periods and for resource planning purposes based on the longer-term commitments required for Product B.

[38] *Id*. at 22. LPI is not opposing the credit calculated by the Company, but notes that its expert calculated and found justification for higher credit amounts for similar DR product proposals. For example, in exchange for a ten-year customer commitment, LPI proposed a credit of $9.00 per kW-month. *See* Stephens Rate Case Testimony at 9; Stephens NTEC Testimony at 21.
[39] *Id.* at 20.
[40] *Id.*
[41] *Id*. at 21.

C. LPI Supports Cost Recovery Method 2, Because It Is Consistent with the Commission's Rate Case Order and Accurately Apportions Costs in Accordance with Benefits

If the Commission approves Minnesota Power's Petition, LPI requests that costs for the program be recovered in accordance with the Company's proposed Cost Recovery Method 2. As noted in the Petition, Cost Recovery Method 2 is based on the Commission's approved apportionment of the final rate case revenue deficiency by customer class.[42] The Company filed this Petition in response to the Commission's order in the rate case and the record on DR and rate design issues developed in the rate case. As a result, choosing a cost recovery method that aligns with revenue allocation from the rate case would be fair and consistent with the Commission's order in that proceeding.

LPI is also supportive of Cost Recovery Method 2 because, compared to the alternative Cost Recovery Method 1, it allocates more cost to the customer classes that contribute more to the need for peaking capacity.[43] The Company notes that "[h]igh load factor customers like the Large Power class, utilize more energy relative to the required capacity, whereas lower load factor customers like residential and commercial customer classes require higher ratios of capacity relative to energy consumed to reliably serve their needs."[44] While Cost Recovery Method 1 is straightforward in application, it fails to reflect the traditional ratemaking principle of cost-causation. Cost Recovery Method 2, on the other hand, more appropriately allocates costs in accordance with who benefits from peaking capacity, thereby reflecting the principle of cost-causation.[45]

Finally, not only is Cost Recovery Method 2 fair overall, from a practical perspective, it is most likely to result in the new Product B being successful. As described above, the balance of risk and reward offered by Product B may already be too marginal for some eligible customers. Using a cost recovery method such as Cost Recovery Method 1, which would

[42] *Id.* at 26.
[43] *Id.*
[44] *Id.*
[45] The Company predicts that a typical customer will see an approximate 2.1% rate increase, while Large Power customers will receive an increase of 1.2%. *See* Petition at 27.

allocate more cost to the large power class, would further undermine the benefits of Product B to eligible customers and potentially put even a modest level of participation at risk. In determining whether it makes sense to participate, customers will consider the net costs and benefits to them – including their share of the cost of the product. Thus, over-allocating costs to the large power class would be a disincentive for customers to participate even nominally. LPI recommends Cost Recovery Method 2 because it is both analytically sound and less likely to discourage customer participation than other options.

D. DR Programs Must Continue to Improve to Fully Realize the Potential of Demand-Side Management

LPI supports approval of the Petition and appreciates the Company's efforts in this docket; however, it is important to note that certain aspects of the proposed DR products have room for continued growth and improvement.

As noted above, LPI's members operate in large, complex industries where operational flexibility is a key to continuing success. Under the current proposal, Product B is only offered for customers willing and able to subscribe for a 10-year term. LPI understands the Company's reasoning for this requirement and the value longer-term commitments have for resource planning purposes. However, a 10-year commitment will not be feasible for some large power customers who might otherwise be willing and able to offer more than the Product A annual commitment. In expert testimony in the rate case and NTEC proceedings, LPI proposed a suite of DR products ranging from one- to 12-year commitments, each with different pricing structures in recognition that shorter-term commitments may have lower value for resource planning purposes.[46] DR is not a one-size-fits-all resource. To unlock the full potential of DR on Minnesota Power's system, customers require a variety of options to allow them to select a plan to meet their specific needs. While Product C may provide a basis for developing alternative options, LPI ultimately would prefer there to be more options under the framework for Product B.

[46] *See* Stephens NTEC Testimony.

In addition to requiring a 10-year commitment, the currently proposed Product B requires a year-round commitment. During winter months, some customers have less flexibility to participate in DR programs based on heating needs or the time necessary to ramp down operations in response to a curtailment call. If Product B allowed for a summer-only commitment or commitment levels that vary by season (even if still spanning multiple years), more customers may be able to participate and more interruptible capacity could be available during summer months.

Minnesota Power limited its Product B proposal to 150 MW. Again, LPI understands the Company's reasoning and appreciates its commitment to studying higher levels in its next IRP. If the risk/benefit ratio is adequate, LPI believes that there is potential for significantly greater than 150 MW of industrial DR on Minnesota Power's system. Thus, LPI urges the Commission to include the Company's commitment to study expanding DR in its order approving the Petition. Further, the current proposal also only applies to the large power class. Other large industrial customers on Minnesota Power's system (i.e., members of the LLP class) could potentially participate in DR on similar terms and provide additional value.

Finally, if the Commission approves the Petition, LPI expects that all stakeholders will learn much through the implementation process. Future updates or clarifications to the DR program may be needed based on the level of enrollment, the experience of the Company and customers when curtailments are called, when and how often the Company calls for economic interruptions, the actual costs incurred by the Company and customers, future changes to MISO rules for load modifying resources, and other information gathered through experience. Thus, in addition to the above ideas for options to enhance the Company's DR offerings in the future, LPI expects that more experience will help optimize the value of DR for the system and customers over time. Thus, even if other stakeholders offer lists of potential improvements to this proposal as well, LPI would prefer to see the Petition approved and implemented expeditiously rather than being subjected to delays.

III. CONCLUSION

LPI is grateful for the opportunity to comment on this matter. DR has the potential to be a significant resource for Minnesota Power that benefits both the utility and customers moving forward. Minnesota Power's Petition is a positive step toward achieving this potential and approval would provide the necessary framework for future progress. Therefore, LPI respectfully requests that the Commission approve DR Product B and Cost Recovery Method 2.

Dated: February 20, 2019

Respectfully submitted,

STOEL RIVES LLP

/s/ Sarah Johnson Phillips

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ATTORNEYS FOR LARGE POWER INTERVENORS

Attachment A

LARGE POWER INTERVENORS

Utility Information Request

Docket Number: E-015/M-18-735

Requested From: Minnesota Power | Date of Request: February 6, 2019

Response Due: February 18, 2019

By: Large Power Intervenors (Andrew P. Moratzka, Sarah Johnson Phillips, Riley A. Conlin)

LPI IR 1

Re: Minnesota Power's Petition for Approval of an Industrial Demand Response Product.

Please provide details of any demand-side management interruptions called by Minnesota Power during the week of January 27, 2019 to February 2, 2019 including, to the extent possible:

a. information about the circumstances and conditions that caused Minnesota Power to call interruptions and which demand-side management programs were utilized;
b. the number of interruptible customers affected;
c. the total capacity of the called interruptions;
d. the percentage of total capacity curtailed provided by Large Power customers; and
e. the average duration of the interruptions.

RESPONSE:

a. Minnesota Power utilizes demand-side management programs to minimize cost for all customers when purchased power costs are above production costs, when Minnesota Power's system is short energy due to wind and solar being unavailable, when the company expects to incur a new system peak, at such times when in the company's opinion the reliability of the local system is endangered, or when the Midcontinent Independent System Operator (MISO) declares an emergency reliability event. On January 30th MISO issued a Maximum Generation Event EEA 2, Step 2B, which requires Local Balancing Authorities (LBAs) to reduce load from Load Modifying Resources (LMRs) as directed by MISO. To ensure reliability is maintained, MISO will continue through the Event Step process acquiring emergency resources until it reaches the final EEA 3 Event Step 5 where firm load is shed. Minnesota Power responded by initiating

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Response by: Jennifer Peterson
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List Sources of Information:

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the Replacement Interruptible and Curtailable Service products, which are registered with MISO as LMR Demand Response (DR), along with the Dual Fuel Interruptible rate.

In addition, to the actual demand side management implementation, Minnesota Power provided notifications to customers of a change in rates during the notification timeline to customers who subscribe to the Rider for Foundry, Forging and Melting, Large Light and Power/General Service Interruptible Rider, and the Pilot Rider for Residential Time-Of-Day Service products to give those customers price signals to give them the option to curtail usage during the notification time period to avoid high-priced market energy or to continue normal energy consumption.

b. **The following customers were affected by the interruptions:**
   a. **Replacement Interruptible and Curtailable Service:** MP notified 5 LP interruptible customers of the emergency event on January 30th, and based on notification time had to prepare to shed load down to the firm service level or keep load at or below the firm service level.
   b. **Dual Fuel Interruptible Rate:** MP notified approximately 8,000 customers on the dual fuel rate; about 7,500 residential and 500 commercial/industrial.
   c. **Price Recall:** MP notified 3 customers that are on the foundry rider.
   d. **Large Light and Power General Service Interruptible Rider:** MP notified 1 customer who is on the interruptible rider.
   e. **Pilot Rider for Residential Time-Of-Day Service:** MP notified approximately 400 residential customers who subscribe to the pilot rider.

c. Minnesota Power registered 230 MW of industrial Load Modifying-Demand Response resources with MISO, resulting in 264 MW of local Zonal Resource Credits (per MISO

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Module E rules, the Zonal Resource Credits for LMR DR is grossed up for transmission losses and planning reserve margin). Based on the time that Minnesota Power notified customers with scheduling instructions for Load Modifying-Demand Response interruptions, and by the time that MISO notified Minnesota Power of the cancelation of the emergency, Minnesota Power had approximately 200 MW of industrial demand response load offline. When emergency declaration was cancelled the industrial customers were still in the process of taking load offline. If the emergency declaration were to continue the full 230 MW of industrial Load Modifying-Demand Response would have been off-line.

The available curtailable Dual Fuel load in winter months depends on temperature and heating loads, mostly of residential customers. The Company estimates that approximately 30 MW of curtailable load would be available during a typical winter peak. Given the extreme temperatures experienced during the week of 1/27/2019, the average demand reduction for any particular hour was likely around 35 MW.

d. The percentage of total capacity taken off-line by Large Power customers based on the emergency event on January 30, 2019 was approximately 85% of the total capacity taken off-line (includes LMR and dual fuel demand-side management programs).

e. The average duration of interruptions during the week of January 27 to February 2, 2019 are:
   a. **Replacement Interruptible and Curtailable Service:** Minnesota Power first notified customers at 07:38, via an automatic message, of the potential for a LMR reduction and then at 10:15 a.m. provided specific scheduling instructions for the MISO emergency event. The scheduling instructions included what time the load needed to be off-line for the emergency that MISO declared from 10:00 a.m. to 7:00 p.m. At 12:27 p.m. MISO

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cancelled the emergency event, and customers were notified that they could bring load up to full production at 1 p.m. A fifth customer was still within the notification time period and had not curtailed the required demand-response load but had begun measures to reach their Firm Service Level.

b. **Dual Fuel:** Six interruptions were called for an average of 4 hours per interruption.
c. **Price Recall:** Three notification events were called for an average of 15 hours per event.
d. **Large Light and Power General Service Interruptible Rider:** Six notifications events were called for an average of 4 hours per event.
e. **Time-Of-Day:** Two notification events were called for an average of 3 hours per event.

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