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

REPLY 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") consisting of 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, submit this comment in reply to the initial comments submitted by the Department of Commerce, Division of Energy Resources (the "Department"), the Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG"), the Citizens Utility Board of Minnesota ("CUB"), the Advanced Energy Management Alliance ("AEMA"), and Fresh Energy in response to the Minnesota Public Utilities Commission's (the "Commission") Extended Notice of Comment Period on Minnesota Power's petition (the "Petition") for approval of a rider for Demand Response (or "DR") issued on January 2, 2019 in the above-titled Commission docket.[1]

I. INTRODUCTION

LPI appreciates the range of thoughtful opinions provided by stakeholders in their initial comments and offers this reply comment in response to several points raised by other parties. LPI maintains that the Company's proposed suite of DR products, especially Product B coupled with Cost Recovery Method 2, will provide significant economic and capacity benefits to Minnesota Power's system while simultaneously providing large power customers with an

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[1] Notice of Extended Comment Period (Jan. 2, 2019) (eDocket No. 20191-148808-01).

additional tool to control their electricity costs. As is traditionally true with new products and resources, LPI expects Minnesota Power's DR program to continue to be refined and improved in the future as the Company, customers, and other stakeholders gain experience with using DR in new ways. But as an important step toward realizing the potential of DR, LPI believes that the proposals in the Petition are well balanced to encourage both customer participation and ensure benefits to the system. Therefore, LPI reiterates its arguments made in initial comments and continues to support approval of the Petition and Cost Recovery Method 2.

II. ANALYSIS

A. Response to the OAG and CUB: The Need for DR Has Already Been Established and the Petition Directly Follows from Multiple Commission Orders.

Expanded DR will strengthen Minnesota Power's system. Despite the overall benefits of DR, the OAG and CUB criticize the Petition of Minnesota Power for not identifying a need for additional peaking resource and argue that the Petition should not be approved "without a demonstrated need for the resource."[2] These arguments ignore the Commission's direction to propose a new industrial demand response product and prior analysis performed by the Company that demonstrates a need for at least 150 MW of DR on its system.

The need for DR is not before the Commission in this proceeding. The Commission has continually instructed Minnesota Power to explore additional demand-side management options—including in the Company's 2015 integrated resource plan,[3] the Company's 2016 rate case,[4] and most recently in the Nemadji Trail Energy Center ("NTEC") proceeding.[5] In the rate case and NTEC proceedings, the Commission specifically directed Minnesota Power to "develop

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[2] Initial Comment by the OAG at 9 (Feb. 20, 2019) (eDocket No. 20192-150493-01) ("OAG Comment"); Initial Comments by the CUB at 4 (Feb. 20, 2019) (eDocket No. 20192-150494-01) ("CUB Comments").

[3] *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).

[4] *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) (the "Rate Case Order").

[5] *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) (the "NTEC Order").

a demand-response rider and corresponding methodology for cost recovery."[6] The Commission already recognized the value of and need for DR in these prior proceedings and the Petition is a direct response to the Commission's orders. Further, the proposed cap of 150 MW on the new Product B corresponds directly to the amount of DR modeled by the Company in the last resource plan and the NTEC proceeding.[7] While LPI advocated for a higher cap in prior proceedings and would like to see Product B expanded in the future, LPI also appreciates the Company's conservative approach and commitment to evaluating higher amounts of DR in the context of future resource plans.[8] Because the need for at least 150 MW of DR has been established in prior proceedings and the Commission specifically directed development of new DR product offerings, the question of need has already been resolved and there is no need to revisit that question in order to approve the Petition.

B. Response to the OAG and CUB: The Pricing for Product B Strikes an Appropriate Balance Between System Benefits and Compensating Subscribers for Additional Risk.

Both the OAG and CUB express concerns about the pricing of Product B relative to the anticipated benefits for other customers. LPI believes that the $7,000 per MW-month capacity price reflects a price that strikes a reasonable balance for compensating subscribers while not overburdening other ratepayers. As outlined in LPI's initial comments, subscribers take on substantial operational risks by allowing large portions of their load to be curtailed for either emergency or economic reasons.[9] For a DR program to be successful it is imperative for subscribers to be compensated at a level that elicits participation and recognizes the significant operational challenges presented by curtailment. While the OAG contends that $7,000 per MW-month is too high, arguing that it is a "*1,000 percent*" price increase compared to Minnesota Power's existing DR product,[10] LPI strongly disagrees with this position as it ignores that Product B also requires a 1,000 percent longer commitment of 10 years and an expectation of

[6] Rate Case Order at 115; NTEC Order at 23.
[7] Demand Response Petition at 11 (Dec. 7, 2018) (eDocket No. 201812-148328-01) (the "Petition").
[8] *Id.* at 11, 22.
[9] Initial Comment by LPI at 7-8 (Feb. 20, 2019) (eDocket No. 20192-150491-02).
[10] *See* OAG Comment at 10.

being called substantially more often than would be expected for existing DR programs.[11] And contrary to the OAG's assertion, LPI does not expect that it will typically be economically feasible for large power customers to terminate their participation in Product B early. As the Company explains in the Petition, exiting customers will be charged for any capacity or energy costs associated with converting interruptible to firm service such that other customers are held harmless.[12]

The Commission should avoid further delays in implementation. In initial comments, the OAG recommends a "Dutch auction concept" where the capacity price is set at a low number and incrementally increased every three months until customers subscribe.[13] The OAG then recommends the Dutch auction be capped at the currently proposed $7,000 per MW-month number.[14] This concept is unworkable for several reasons. First, as described in LPI's initial comment, $7,000 likely is the minimum level needed for many large power customers to justify the risk of participating in Product B and make the effort needed to adapt their operations. Thus, while the auction concept is creative, LPI does not believe it will be productive. Second, under the OAG's auction proposal, it will take almost two years to reach the current $7,000 amount. Since lower credit levels are very unlikely to yield participation, the effect will be to delay actual deployment of Product B. Updates to Minnesota Power's DR offerings have been under discussion across multiple proceedings since at least 2015. Delaying an additional two years to reach a price that LPI would consider near the floor of acceptability will unnecessarily delay implementation. Third, a delay in effective implementation will make it harder for Minnesota Power to evaluate additional DR in its next resource plan. As proposed, the new products could be approved and implemented in 2019, which would allow Minnesota Power to gauge interest levels and start to gain experience with Product B before filing its next resource plan in 2020.

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[11] Citing the Company's response to CUB Information Request No. 7, the DOC noted that the Company estimates that it would have called 595-600 hours of Firm Load Control Periods over each of the last five years. Initial Comment by the Department at 6 (Feb. 20, 2019) (eDocket No. 20192-150476-01) ("Department Comment"); Attachment 1.

[12] Petition at 18.

[13] OAG Comment at 13.

[14] *Id.* at 14. If the OAG truly seeks an open market solution for resolving the appropriate capacity price, LPI submits that the "Dutch auction concept" should not be capped at $7,000 if the OAG's motive is to see the price at which an appropriate level of DR is obtained.

The auction concept, in contrast, would leave pricing and subscription levels uncertain well into 2021 or beyond. Because DR has already demonstrated value and interruptible customers have worked with Minnesota Power to negotiate a fair price, LPI respectfully asks the Commission to approve Product B with the pricing proposed in the Petition.

C. Cost Recovery Method 2 Complies with the Commission's Rate Case Order and Does Not Overburden Other Customer Classes.

1. Response to the OAG: Contrary to the OAG, Cost Recovery Method 2 Fairly Allocates Costs.

First, the OAG generally objects to excluding interruptible customers from sharing in the costs of Product B. As the Company described in the Petition, DR provides benefits similar to a peaking resource and therefore program costs are comparable to cost of new generation infrastructure.[15] The pricing for Product B was determined on this basis and cost recovery should be determined on this basis as well. New generation resources would not typically be expected to share in their own costs and neither should DR resources that provide similar value to the system. The costs and benefits to interruptible customers of participating in DR are built into the pricing of Product B, and therefore this load should be excluded from the calculations for cost recovery from firm customers. It is also important to note that the Company has not proposed any cost recovery method that would exclude large power customers as a class. The exclusion narrowly applies to participating interruptible load.

Second, the OAG objects to Cost Recovery Method 2, arguing that it does not fairly represent the revenue apportionment ordered in the rate case. LPI disagrees with the OAG's reasoning and continues to believe that Cost Recovery Method 2 offers the fairest option for allocation of Product B costs. In particular, development of Product B was ordered in the rate case and much of the initial record in support of new industrial demand response products was developed in the rate case. Had Product B been approved in the rate case, the costs likely would have been addressed in the Commission's overall revenue apportionment decision. While class cost of service studies are not only performed on the revenue deficiency, the Commission's focus

[15] Petition at 24.

in a rate case is determining a fair allocation of the deficiency. The Commission's Rate Case Order addresses how to allocate the revenue deficiency, and Cost Recovery Method 2 follows that allocation.[16] Further, as reflected in the Rate Case Order, LPI does not consider the revenue apportionment decision in the rate case to have been favorable to large power or consistent with its recommendations in that case[17] and thus does not believe Cost Recovery Method 2 unduly favors the large power class.

Finally, from a practical perspective, the Commission should consider that the cost recovery method will have an impact on the net cost and benefits to a large power customer considering participation in Product B. Cost Recovery Method 2 together with the terms and conditions of Product B as set forth in the Petition may be sufficient as a package to incentivize some customers to subscribe. But as described above and in LPI's initial comment, there is limited, if any, margin for customers in that package. Eroding the potential benefits by allocating costs to interruptible customers or more costs to large power as a class risks upsetting this balance and little or no participation.

2. Response to the Department: Deferring Cost Recovery to a Rate Case Will Unnecessarily Delay Implementation.

The Company proposes that capacity costs associated with the new Product B be recovered through a new Rider for Large Power Demand Response service. In its initial comment, the Department criticized this proposal for not having adequate support and instead suggests that these costs be recovered via a general rate case.[18] LPI believes this proposal is contrary to the Commission's direction and is concerned that it would significantly delay implementation of Product B. As noted above, the discussion about enhancing the Company's industrial DR product offerings has been ongoing for several years and LPI objects to any further unnecessary delay.

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[16] Rate Case Order at 74-75.
[17] *Id.* at 75.
[18] Department Comment at 8.

First, in the Commission's NTEC Order, the Commission clearly directed stakeholders "to develop a demand-response rider and corresponding methodology for <u>cost recovery</u>."[19] LPI understands the Commission's order to contemplate that cost recovery should be addressed together with the proposed rider.

Second, waiting to determine cost recovery until the next general rate case will likely cause a significant delay in effective implementation of Product B. LPI also understands that the Company is considering filing a general rate case later this year. Such cases typically last for at least 10 months and often much longer. In other words, presuming the Company does file a general rate case later this year, it is reasonably likely that the case would not conclude until 2021. Even if the Commission approves the Petition in 2019 and the Company is willing to accept subscriptions prior to having certainty on cost recovery, customers are very unlikely to subscribe without knowing how the costs of Product B will be allocated. Large power customers will evaluate the full costs and benefits of Product B – including their share of the costs – in determining whether to participate. LPI expects the cost recovery method to have a material impact on this analysis and each customer's final decision. As a result, LPI believes customers are unlikely to subscribe to Product B without a final decision on cost recovery. For these reasons, any delay in approving a cost recovery mechanism will effectively delay implementation of Product B. LPI urges the Commission to approve Product B and Cost Recovery Method 2 simultaneously and without delay.

D. Response to AEMA.

LPI appreciates the participation of AEMA in this proceeding and the perspective it brings from its experience with a wide range of DR programs around the country. In its initial comment, AEMA recommended raising the cap for Product B to 400 MW and allowing customers to designate aggregators to manage participation. With respect to the cap, LPI is also interested in higher cap long-term and, as previously noted, appreciates the Company's commitment to studying higher amounts of DR in the future resource plans. With respect to the participation of aggregators, LPI is generally supportive of this concept. While participation of

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[19] NTEC Order at 23 (emphasis added).

aggregators may not be necessary in light of the long history of large power customers working collaboratively with Minnesota Power, additional options to help manage risk would be welcome.

E. Response to Fresh Energy.

LPI appreciates Fresh Energy's support for Product B and recognition of the value DR can provide to Minnesota Power's system. In its initial comment, Fresh Energy recommended a modest modification to the design of Product B that would eliminate the minimum four-hour duration of a Firm Load Control Period. LPI does not oppose this change, but offers a few caveats. It is important to note that most large power customers are not in a position to rapidly ramp up and down their operations. The minimum notice periods and other parameters of Product B that limit the frequency and duration of interruptions are critical for customers to prepare their facilities and manage the operational risk of participating in DR. Thus, while shorter interruptions are not necessarily problematic, more frequent or longer interruptions would not be welcome.

III. CONCLUSION

LPI respectfully recommends that the Commission approve Product B and Cost Recovery Method 2 of Minnesota Power's demand response proposal as soon as possible in order to expedite the process of bringing these valuable demand-side management resources to Minnesota Power's system.

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Respectfully submitted,

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