PUBLIC VERSION

STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Dan Lipschultz	Vice Chair
Matt Schuerger	Commissioner
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John Tuma	Commissioner

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product

DOCKET NO. E015/M-18-735

COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL

The Office of the Attorney General—Residential Utilities and Antitrust Division ("OAG") submits the following Comments in response to Minnesota Power's ("MP") Petition for Approval ("Petition") of a new Large Power demand response ("DR") portfolio. The Commission should deny MP's Petition, unless significant changes are made to MP's proposal.

I. BACKGROUND.

MP proposes three new DR products, all with different characteristics. This Section will describe each product, and then describe MP's cost recovery proposal.

A. THE THREE DR PRODUCTS.

MP describes Product A as a "short-term emergency capacity product."[1] Product B is a "long-term emergency capacity curtailable with firm load control periods."[2] Product C is a "market service capacity product."[3]

1. Product A.

Product A appears to be mostly similar to a standard interruptible rate.[4] Large Power customers would agree on an annual basis to be subject to interruption during emergency

[1] Petition at 1.
[2] *Id.*
[3] *Id.*
[4] Petition at 16.

conditions triggered by MISO according to MISO Module E-1. Even when emergency conditions are triggered, there would be several limitations on when an interruption could be called. First, MP would need to provide at least 2 hours' notice before an interruption. Second, the duration of the interruptions could be no more than 4 hours. Third, MP could not call more than 5 interruptions during a year. In return for their agreement to interrupt during emergency conditions, Large Power customers would receive a credit of $0.60 per kW of interruptible billing demand per month. MP proposes to update the credit each year based on current market price trends. It is not entirely clear from the Petition how the pricing for Product A was developed, but presumably the Commission would have the opportunity to review any price changes. At its current price, MP estimates that Product A credits would be approximately $1.08 million if customers sign up to provide 150 MW of DR—the total cost would be more or less depending on how much customers offer.[5]

2. Product B.

Product B would be a new concept for MP.[6] The first distinction is that, while customers could decide to join or exit Product A each year, Product B would require a 10-year commitment. At the same time, customers who subscribe to Product B would be required to execute an Electric Service Agreement with a minimum duration of 10 years.

A second distinction is that the compensation for capacity interruption would be different. The emergency interruptions conditions would be exactly the same as for Product A,[7] but the price would be different. Customers on Product A would be compensated at $600 per

[5] OAG Information Request 11, Exhibit 1.
[6] Petition at 17.
[7] It appears that compensation would be different. While Product A would provide customers with discounts to billing demand in return for subscribing, it appears that there would be no compensation to Product B customers just for subscribing. It would be helpful for MP to clarify this point in response.

MW of interruptible billing demand per month;[8] customers on Product B would be provided with a demand credit of $7,000 per MW-Month. MP estimates that the credits of Product B capacity payments would be $12.6 million per year.[9]

The third distinction is that Product B would also allow MP to call for economic interruptions. MP could also call interruptions for economic reasons—referred to as Firm Load Control periods. Like the emergency interruptions, there would be limitations on when MP could call for economic interruptions, with significant limitations on how often and how much notice is required.[10] When MP decides to call a Firm Load Control period, a customer would have the choice to either 1) reduce their load as they agreed, or 2) "buy-through" the interruption. If a customer reduces their load as-agreed, they would be paid a Physical Interruptible Energy Credit of $30.00 per MWh. Essentially, customers who subscribe to Product B would not receive any payments unless and until MP calls an economic interruption. Buying through means that a customer would not reduce their load as they had agreed, and instead pay a penalty to MP. If the customer chooses to buy-through, they would pay an energy charge "based upon the Company's hourly incremental energy costs during the time of the sale," plus a $5.00/MWh adder. If customers are interrupted for 90,000 MWh, the maximum allowable amount, MP would issue credits of $2.7 million. If customers are interrupted but choose to buy through, then MP would collect some offsetting revenues for the added cost it incurred in the fuel clause.

[8] MP produces the price for Product A in $ / kW-month, but here it is converted to $ / MW-month to provide a direct comparison to the price for Product B.
[9] OAG Information Request 11, Exhibit 1.
[10] There are six limitations on when MP could call economic interruptions: 1) MP would have to give notice either day-ahead, or real-time with four hours advance notice; 2) MP could not call more than four periods in a calendar week; 3) MP could not call more than 2 periods in a single day; 4) MP could not control more than 12 hours in a single day; 5) periods that are called could not exceed 12 hours; and 6) MP could not call more than 600 hours in a calendar year.

A fourth difference is that customers on Product B can convert part of their Product B subscription back to firm service by providing notice to the Company.

A fifth difference is that Product B will be capped, and MP will accept no more than 150 MW of subscriptions. If customers requested more than 150 MW, MP states that it will apportion the available subscriptions proportionally.

3. Product C.

Product C is a "market surplus service." MP explains that it is an emergency-capacity available to "excess capacity that doesn't fit into other DR products."[11] MP states that it will work collaboratively with customers on how to offer their product to MISO. It appears, in some respects, that Product C would be MP acting as a middleman and helping customers to offer their own demand response into the MISO market—which customers are not currently permitted to do on their own.

B. MP's Cost Recovery Proposal.

MP proposes to recover the costs of Product A in the same way as its existing interruptible program, which was approved in its last rate case. MP does not appear to suggest any particular cost recovery proposal for Product C, which is somewhat speculative.

There are two types of costs for Product B. The first is the Physical Interruption Credits paid for economic interruptions, which MP proposes to recover through the fuel clause adjustment. The second is the estimated $12.6 million for demand credits. MP proposes to recover the demand credits through a new rider and presents two proposals for allocating the costs of the credits among customers. There are some similar characteristics for both of the demand credit proposals. First, MP proposes to recover the costs of Product B from only firm

[11] Petition at 19.

customers. Second, MP proposes to credit the DR cost recovery tracker for any Product A load that is lost from customers who choose to subscribe to Product B instead. Fourth, MP determines the jurisdictional portion of the Product B costs using the generation demand allocator (D-01) approved in its last rate case, leaving $10.6 million to allocate amongst its retail customers.

Cost Recovery Method 1 would recover the $10.6 million in costs using a flat per kWh from all firm customers. MP begins by providing the test year consumption from the last rate case, 8,864,975 MWh. MP then subtracts "the Large Power energy attributed to the participation in Product B."[12] The amount of Large Power energy subtracted is reduced by 25 percent, because MP assumes a load factor of 75 percent. This produces a total annual consumption of 7,879,475 MWh, which results in a per kWh charge of $0.001349 per kWh.

MP claims that Cost Recovery Method 2 would allocate the costs based on "the Commission's apportionment of the final rate case revenue deficiency by customer class,"[13] but the method does not actually calculate a different rate for each customer. Instead, it calculates a rate for Large Power customers, and a second rate for "all other customers." The Large Power rate would be $0.000792 per kWh, and the rate for "all other customers" would be $0.002126 per kWh—approximately 2.5 times as much as the rate for Large Power customers. MP estimates the following bill impacts to customers under the two options:

Chart 1
Bill Impacts for MP's Cost Recovery Proposals

	Option 1	Option 2
Residential	1.30%	2.10%
Large Power	2.00%	1.20%

[12] Petition at 25.
[13] Petition at 26.

These bill impacts would be related *only* to the demand credits from Product B. They do not include the Physical Interruption Credit costs, or any costs from Product A or Product C.

C. STANDARD OF REVIEW.

MP has not identified in its Petition any particular Minnesota Statute or Rule that provides an explicit standard of review. Typically, MP is required to identify a demonstrated need before acquiring a system resource like demand response, and demonstrate that its proposal is the lowest cost method for satisfying that need.[14] Further, in the absence of more specific guidance, the Commission always has the obligation to ensure that rates are just and reasonable, and to resolve doubts in favor of ratepayers.[15]

ANALYSIS

These Comments first discuss various concerns with the pricing and design of Product B in Section II. Section III discusses concerns with Product C. Section IV addresses MP's proposals for recovering the costs of the DR program.

II. CHANGES ARE REQUIRED TO ENSURE THAT THE PRICES AND DESIGN OF PRODUCT B ARE REASONABLE.

MP claims that Product B will produce two types of benefits for ratepayers. First, MP argues that ratepayers would receive a capacity-related benefit because the price of the Product B capacity—represented by the Demand Credit of $7,000 per MW-month paid to Large Power customers—is lower than the comparative price of a 228 MW CT unit. MP calculates that these capacity-related benefits are worth $4.6 million over a ten-year period. Second, MP argues that customers would receive two categories of benefits related to the economic curtailment component of Product B. MP argues that economic curtailment will produce up to $10 million

[14] Minn. Stat. § 216B.243.
[15] Minn. Stat. § 216B.03.

in avoided energy costs because the $30 per MWh price paid to Large Power customers is lower than the price of peaking generation. MP also argues that economic interruptions could avoid the emissions of 530,000 tons of CO_2 over a ten-year period.

This Section will first address concerns with the capacity-related benefits, and then address concerns with the energy-related benefits. This Section will conclude by summarizing the actions the Commission should take to ensure that rates are just and reasonable.

A. CAPACITY-RELATED BENEFITS.

MP claims that Product B would produce value for customers because the price they would pay for the 150 MW of capacity is lower than the price for a similar generation resource. MP will pay customers $7,000/MW-Month for their agreement to offer their DR into the MISO market, which MP states is lower than the cost of a new 228 MW combustion turbine. MP claims that the DR product would result in approximately $4.6 million of avoided investment over 10 years compared to the combustion turbine.

MP's analysis is flawed for two reasons. First, MP is overstating the benefits because it has not demonstrated that there is any need for the resources it seeks to acquire. Second, the price that MP is proposing to offer for Product B capacity is unreasonably high.

1. MP Has Not Demonstrated That There Is A Need For Additional DR Or Peaking Resources.

In general, MP's resources are approved in Integrated Resource Plans ("IRP") and Certificates of Need ("CN"), where MP is required to demonstrate that it has a need for the resources it seeks to obtain. The reason for these requirements is that it would not be reasonable for MP to acquire more resources that it needs to provide service to ratepayers. As MP explained in its Petition, Dr. Rakow from the Department recently testified that the first step for developing a DR product should be "identifying a need in the IRP."[16] These standards are at odds with MP's DR Petition. It does not appear that MP has demonstrated that there is any need for the resources it seeks to acquire, or that they would offset any other resources. In fact, it does not appear that MP has even attempted to demonstrate that there is a need for the resources in question.

In OAG Information Request 10, the OAG asked MP whether its last IRP indicated any need for peaking resources. MP's response did not identify any peaking generation resource. Instead, MP stated that the model included "150 MW of industrial demand response in the base case," and "did not indicate additional peak resources were required" above that amount.[17] This is problematic for MP's Petition, because the Petition states that its existing large industrial interruptible program has provided 100 MW to 260 MW of capacity over the last five MISO planning years.[18] Based on this information, it appears that MP's existing DR portfolio satisfies the identified need for DR and peaking resources in its most recent IRP. The new DR products that MP proposes do not appear to be necessary to serve an identified need for DR or other peaking generation resources. Similarly, MP has not identified any existing or planned generation investment that would be deferred or offset by the DR product. This raises some questions about the value of the DR products—it is not clear that a DR program could avoid $4.6 million in investments when the investments are not needed in the first place.

This is particularly concerning given the potential rate impact of MP's proposal. As discussed above, MP estimates that *only* the capacity costs of Product B would have a rate impact of between 1.2 percent and 2.1 percent for different customer classes under different cost

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[16] Petition at 11.

[17] OAG Information Request 10, Exhibit 2; *see also In the Matter of Minnesota Power's 2016–2030 Integrated Resource Plan*, Docket No. E-015/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS at 61 (June 18, 2016).

[18] Petition at 7.

recovery proposals.[19] To put that into context, MP's most recent rate case resulted in an overall rate increase of only 1.79 percent.[20] MP has not provided any justification for why it would be reasonable to increase rates by up to 2.1 percent for a DR product that it does not appear to be needed.

There may be a broader context to consider, given the number and complexity of dockets that have led to this DR proposal. That said, to the extent that MP is claiming that Product B will produce capacity benefits for the system and its ratepayers, MP should be required to clearly demonstrate what need those capacity benefits are satisfying, or what other resources the DR program would be replacing. MP accurately states that the Commission required it to provide DR proposal on this timeline, but that does not mean that the DR proposal should be approved without a demonstrated need for the resource.

2. MP's Proposal Creates A Significant Risk Of Overpricing For Product B Capacity.

MP proposes to set the price for the capacity portion of Product B at $7,000 per MW-month, a point which was developed by comparison to a 228 MW combustion turbine.[21] There are several problems with this proposal.

First, MP's proposal places significant pricing risk on ratepayers. According to MP's trade secret response to Fresh Energy Information Request 1, the **[TRADE SECRET BEGINS]**

[TRADE SECRET ENDS][22] It appears that the $7,000 per MW-month price was not calculated using a specific method, but was

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[19] Petition at 27.

[20] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-644, MP REVISED COMPLIANCE FILING, Schedule 5 (Dec. 3, 2018).

[21] Petition at 21.

[22] Fresh Energy Information Request 1, Attachment 1, Exhibit 3 (there are public and trade secret versions of this exhibit).

negotiated with the large power customers who found it "agreeable."[23] MP's argument appears to be that the $7,000 per MW-month price is reasonable because it is lower than the comparative price of the 228 MW CT. The problem with this argument is that it is **[TRADE SECRET BEGINS]**

[TRADE SECRET ENDS]

This calculation places much of the pricing risk for the DR program on MP's regular customers, who cannot participate in an industrial DR program. MP calculates that the capacity benefits will be $4.6 million over ten years—less than $500,000 per year. In order to capture those benefits, ratepayers would be required to pay $126 million to Large Power customers over the same period.[24] Paying $126 million to obtain $4.6 million in savings does not appear to be a good bet, especially when the "savings" will only happen if MP's price comparisons are accurate. If MP's price comparisons are off by only **[TRADE SECRET BEGINS]**

[TRADE SECRET ENDS], then ratepayers will not benefit. Large Power customers will win in every situation, though, because they will receive $126 million in capacity payments over ten years for a capacity resource that is not needed, and which is unlikely to ever be curtailed by MISO.[25]

Second, MP's calculations are questionable because of the comparison it used to set the DR capacity prices. The $7,000 per MW-Month demand credit prices are based on a comparison

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[23] CUB Information Request 5, Exhibit 4.
[24] Assuming that the program reaches its 150 MW cap.
[25] MISO has not called on MP's emergency response DR products *at all* in the last five years. *See* DOC Information Request 1, Exhibit 5.

to a 228 MW CT unit. As discussed above, though, MP does not own a peaking CT unit. Further, MP's most recent IRP does not indicate a need for any CT resources (or any incremental DR, for that matter). It is not reasonable to set the price for this DR product using a CT resource when MP does not own a CT unit and does not need one.

The proposed capacity price for Product B is also questionable compared to the capacity price for Product A. MP's currently approved interruptible tariff, which would be converted to Product A, pays customers $0.60 per kW-month.[26] Product B would pay customers a Demand Credit of $7.00 per kW-month,[27] *an increase of more than 1,000 percent*.[28] It is fair to recognize that there are differences between the two products. Customers in Product A would sign up for one-year agreements, while Product B would require ten-year agreements; and Product B would require customers to execute ten-year Electric Service Agreements with MP. It is not clear, though, that the value of these additional contract lengths is worth a 1,000 percent price increase. In fact, the value of the ten-year agreement is somewhat questionable because customers on Product B would have the opportunity to convert back to firm service at any time by giving only 90 days' notice.[29] The ten year agreements will only hold as long as they are convenient to the Large Power customers.

It is unreasonable for MP to set the prices for the DR product using a CT because MP neither has nor needs such a resource. The prices also do not make sense when compared to MP's other DR products. As OAG witness Mr. Ron Nelson explained in MP's most recent rate case, it can be very difficult to set prices for DR products in the absence of an obvious

[26] Petition at 1; *see also* OAG Information Request 11, Exhibit 1.
[27] *Id.* MP initially produced the information in MW-month numbers, but they are presented in kW-month here to provide a direct comparison to the Product A price.
[28] $7.00 / $0.60 = 11.666.
[29] *See* Petition at 18; OAG Information Request 5, Exhibit 6.

comparison, and without a market mechanism.[30] Doing so in this instance, particularly where there is no demonstrated need for DR resources, creates a significant risk of pricing the DR products too high and locking in those prices for ten years.

3. Product B May Not Actually Result In An Increase In Demand Response.

Comparing the prices for Product B to the prices for Product A raise one additional concern. As discussed above, Product A and Product B have the same emergency interruption triggers and limitations. Product B does require a longer contract period, but customers that are interested in providing DR to the system will likely be deciding whether they want to sign up for Product A or Product B. As discussed above, the prices for Product B are 1000 percent greater the prices for Product A, which looks like a relatively attractive offer. It is possible that all 150 MW of Product B will be filled by customers who transfer their DR product away from Product A. Creating 150 MW of Product B DR will not provide much benefit to the system if it means 150 MW less of Product A DR. In fact, that would harm ratepayers because the 150 MW of Product B would cost 1000 percent as much as 150 MW of Product A.

4. Potential Solutions To Demand Credit Price Concerns.

The simplest step to take in light of these concerns would be to reject MP's Petition because it has not demonstrated that the prices are reasonable. In the alternative, it may be possible to use administratively determined rates in a market-like system to reduce pricing risk, particularly in this context. When a rate is determined without complete information on the costs and benefits, there is always a risk that the price will be too high or too low. The risk of setting prices too high is that the system and its ratepayers will overpay, and some customers will

[30] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-015/GR-16-664, NELSON REBUTTAL at 42–44 (June 29, 2017). The relevant portion of this testimony is attached as Exhibit 7.

receive unreasonably large credits. The risk of setting prices too low is that customers will not provide the amount of DR that is efficient for the system. In this specific situation, though, the "low-price risk" is essentially zero. If the Commission sets the DR price lower than what MP has proposed, and no customers sign up for additional DR, then no harm will have occurred to the system—because MP has not demonstrated any need for additional DR.

Because there is no demonstrated need for the DR project, the Commission has the time and opportunity to employ a reverse Dutch auction concept. In a reverse Dutch auction, the buyer initially sets a low price, and then raises the price incrementally until a seller agrees to provide the services requested. There are many ways to design a reverse Dutch auction, and these Comments will provide one specific recommendation.

First, if the DR portfolio is approved, the Commission should set the initial capacity price for Product B at $3,500 per MW-month.[31] While this reduction may seem drastic, it is important to recognize that it would still be a 500 percent price increase over the capacity price for MP's existing DR product. MP would accept all bids from Large Power customers to provide Product B DR at the $3,500 per MW-Month price.

Second, the Commission should require MP to report on Product B subscriptions in three months.[32] When the Commission receives the report, it would determine whether the amount of DR provided by customers is sufficient. If it is sufficient, then the Commission would not need to take any action. If it is not, the price offered for Product B DR would be incrementally

[31] The $3,500 per MW-Month number is not based on a calculation, but is simply half of MP's proposed rate. For a reverse Dutch auction, it does not particularly matter what the initial price is set at, because the price will increase until sellers are satisfied.

[32] The Commission could select any period of time to require such a report and reset the pricing for the program, depending on how often it wishes to do so.

increased—perhaps to $4,000 per MW-Month.[33] Customers would then have three months to bid in Product B DR at the new price. This process could be repeated until the Commission is satisfied with the amount of DR that is obtained, or the price returns to $7,000 per MW-month.

Third, in order to make the mechanism function, the Commission would likely need to set a pre-determined threshold for the amount of DR to acquire. At this time, it would make sense to use the 150 MW threshold that MP has proposed. If the Commission later determines that more DR would be reasonable, it could release more capacity and start another reverse Dutch auction process.

This mechanism would replicate an open bidding market because the price for DR would respond to the supply and demand for the DR products, and because customers would have an incentive to compete on price to make sure their bids are accepted. It would provide a controlled method for testing whether MP can obtain DR at lower prices without requiring an RFP, which MP explained was not successful. The only potential downside of the method is that it may take some time to obtain the full amount of DR, but that is not actually a problem in this specific scenario because there is no immediate need to increase DR capacity. Even if the early phases of the auction do not result in DR bids, the price will rise until bids are received. That said, there is objective information suggesting that customers are willing to provide DR resources to MP at prices *far* lower than $7,000 per MW-month—MP's Petition indicates that it has received between 100 MW and 260 MW of DR agreements from customers at a price of $0.60 per kW-month. That context indicates that the Commission should find a way to learn whether customers would be willing to provide DR for lower prices than MP proposes—a level which was reached in a closed door negotiation with the Large Power customers themselves. This

[33] As with the item period for requiring reports, the Commission could select a different amount to incrementally increase the prices.

mechanism would substantially reduce the risk of overpaying for DR that the system does not currently require.

B. ENERGY-RELATED BENEFITS.

MP also claims that Product B would produce energy-related benefits. MP can curtail up to 90,000 MWh each year at a cost of $30/MWh. MP states that this energy credit is lower than dispatching peaking generation, and would also result in reduced system emissions.[34] MP argues that economic curtailments could result in $10.6 million in avoided energy costs over ten years.[35] It is important to recognize, however, that whether or not those benefits are produced depends entirely on MP's performance and its decisions about when to call for interruptions.

This section will first discuss concerns with MP's proposal, and then propose changes that can address those concerns.

1. Concerns With Avoided Energy Costs For Product B.

There are a few concerns with the avoided energy costs that MP claims will be produced by Product B. The $10.6 million avoided energy costs number is actually the maximum possible benefit. MP can interrupt *up to* 90,000 MWh per year. The amount of avoided energy costs actually achieved will be based on the amount of MWh that MP actually interrupts. Product B will only produce $10.6 million in avoided energy costs if MP interrupts the maximum 90,000 MWh each year, for ten years in a row.[36] There does not appear to be any particular reason to believe that MP will do so, which suggests that the actual avoided energy costs could be much lower than $10.6 million

[34] Petition at 20.
[35] OAG Information Request 7, Exhibit 8.
[36] The $10.6 million figure is also contingent on MP's assumptions about the cost of the resource that the Product B interruption would be offsetting. These Comments take no position on that assumption, except to state that it is an important assumption in the calculation, and that changing that assumption could change the results of the calculation.

In fact, MP would have relatively little incentive to call 90,000 MWh of economic interruptions each year. In response to OAG Information Request 29, MP confirmed that there are no tariffed triggers for the economic curtailment.[37] That means that when to call an economic interruption is entirely up to the Company's discretion. MP explained an economic interruption "could" be triggered when the forecasted incremental cost is higher than the Physical Interruptible Energy Credit of $30/MWh.[38] The tariff that MP has proposed, though, does not actually require MP to call for interruption when it would be cost effective to do so. In fact, if MP decided not to call an economic interruption, it would continue to recover the higher energy costs through the fuel clause adjustment. MP may face pressure, implicit or otherwise, to avoid interruptions of its largest customers whenever possible. The energy related benefits of Product B are not guaranteed, and MP has no clear incentives to capture them.

2. The Commission Should Require MP To Make Quarterly Compliance Filings.

In order to make sure that customers receive avoided energy costs from Product B, the Commission should require MP to make a quarterly report on its economic interruptions.[39] MP would indicate all of the times that it interrupted, energy market prices at the time, and provide the reasoning for its decision. MP would also be required to identify all of the times that energy market prices were higher than the $30 / MWh price of the interruptible credit, and demonstrate why it was reasonable to decline an interruption at the time.

The OAG is not aware of any other regulated utility in Minnesota that offers an economic interruption product, so it is important to increase familiarity with the first tariff to be offered. With a concept this new, and where the utility's incentives are questionable, it is important to

[37] OAG Information Request 29, Exhibit 9.
[38] *Id.*
[39] The quarterly report could be combined with the quarterly report on Product B bids, discussed above.

create a regulatory structure that captures value for ratepayers—the quarterly reporting requirement is intended to serve this purpose though close oversight. An alternative approach would be to create explicit incentives and penalties, such as a minimum interruption requirement. The quarterly reporting would be a balanced approach to ensuring that MP makes effective use of the economic interruption product, without placing specific restrictions on a program that has not yet been tested. MP claims that Product B will produce $10.6 million in avoided energy costs over ten years, but it has little incentive to actually capture these benefits. The economic interruption component of Product B will not produce any benefits for customers unless it is used effectively, and a quarterly reporting requirement is the minimum step necessary to ensure that MP is doing so.

C. RECOMMENDED CHANGES.

MP's proposal for Product B DR is not reasonable, and would not result in just and reasonable rates if approved without changes. In order to produce a just and reasonable rate, the Commission should:

- Require MP to demonstrate that there is a need for the DR resources it seeks to acquire, or that the DR resources would offset other, more expensive resources;
- Change the unreasonably high capacity price for Product B,
    - By reducing the demand credit to $3,500 per MW-Month initially,
    - Requiring MP to report on Product B participation quarterly,
    - Adjusting the MW-Month price upwards until 150 MW of Product B DR is provided, or the price reaches the $7,000 cap; and,
- Require MP to make quarterly compliance filing on the economic interruption product, including,
    - Identifying all the times that it interrupted, the prices at the time, and its reasoning for doing so; and

- Identifying all of the times that energy market prices were higher than the $30 / MWh interruptible credit, and demonstrating that it was reasonable not to call an interruption at the time.

These changes are necessary in order to make sure that Product B results in a just and reasonable rate. Without these changes, the OAG would recommend denial of MP's proposal for Product B.

The next Section will discuss MP's proposal for Product C.

III. PRODUCT C SHOULD BE DENIED, OR MODIFIED.

MP described Product C as a "market surplus service," but its proposal is unclear and ambiguous. It appears that Product C is designed to provide flexibility for MP to develop DR programs with its Large Power customers. Flexibility is often an important goal, but it must be balanced against the requirements that MP offer tariffed, non-discriminatory rates that are just and reasonable.[40] In this instance, MP has provided so little information about Product C that appropriately balancing these interests should lead to rejection.

MP has not provided any rates, costs, or terms for Product C. The proposed tariff for Product C states, "For each month that Market Surplus Service is provided and Minnesota Power has identified an option for customer's excess demand response capacity that results in revenue for the Company, the Customer shall receive a per kW Demand Charge Credit. Such credit shall be determined by the company and applied to Customer's demand charges billed under Schedule 74."[41] The tariff does not identify the price, which could conceivably allow MP to offer different prices to different Large Power customers. MP has not identified the cost to ratepayers, the savings that could result, or how it would track those revenues.

MP's proposal for Product C is not sufficiently clear or precise to result in a rate tariff. It also does not appear to be essential—Products A and B could move forward without Product C.

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[40] *See, e.g,* Minn. Stat. §§ 216B.03, .07, and .16.
[41] Petition, Rate Book Section V, Page 4.

There is no cap to the amount of DR that can be provided through Product A, meaning that any customer who would have offered DR through uncertain terms on Product C could make use of Product A. For that reason, the Commission should consider rejecting Product C or requiring MP to provide more information.

IV. MP'S PROPOSAL TO RECOVER THE COSTS OF PRODUCT B ARE UNREASONABLE.

Even if the Commission makes the changes described above, the Commission must make additional changes to MP's cost recovery proposals in order to produce a just and reasonable rate. MP proposals to recover the costs of Product B[42] continue the Company's track record of giving preferences to its largest, most influential customers at the cost of the smallest. The only costs in the Petition to dispute are from Product B, which has two different types of costs. One is the $30/MWh Physical Interruption Credit paid to customers when MP calls an economic interruption and customers curtail their load. If the Commission approves MP's proposal to recover the Physical Interruption Energy Credit through the Rider for Fuel and Purchased Energy Adjustment, the costs would be collected using the same per kWh rate for all customer classes, and there would be no dispute.[43] The other type of costs is demand discounts for participating Large Power customers. MP estimates that the maximum cost would be $12.6 million per year ($7.00/kw-month * 12 months * 150 MW).[44] The method for recovering this cost *is* in dispute, because neither of the methods that MP proposes is reasonable.

There are several flaws with MP's two proposed cost recovery methods.

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[42] The costs of Product A are not in dispute, because they would continue to be assigned in the same manner that was approved in MP's last rate case. There are no costs for Product C as yet, since MP has not explained what the costs would be or how the DR would be designed.

[43] Petition at 2. If the Commission approves the DR product but denies MP's request to recover the Physical Interruption Energy Credit through the FPEA, then the Commission will ultimately need to determine a different cost recovery method.

[44] Petition at 24.

A. THE COSTS OF THE DR PRODUCT SHOULD BE SHARED BY FIRM AND INTERRUPTIBLE CUSTOMERS.

Both of MP's proposals for recovery of demand discounts would allocate the costs of Product B only to firm customers, shielding interruptible customers—all of whom are Large Power customers—from the costs of the DR resource. MP's proposals do this in two steps. First, both proposals exclude the consumption from Large Power/Other customers.[45] Second, both of MP's proposals remove a portion of the consumption of Large Power customers who would participate in Product B when calculating the per kWh rate. These exclusions increase the rate paid by other customers, because they reduce the amount of consumption that the costs are spread over, and indicate that MP does not intend to charge Large Power/Other or Large Power Product B customers at all for the costs of Product B.

Either way, there is no reasonable basis for MP's proposal to exclude interruptible customers from the costs of Product B. MP argues that the purpose of the DR proposal is to replace the energy and capacity that would be produced by a new peaking generation resource.[46] In other words, without the DR proposal, MP argues that it may need to construct a peaking plant in the future.[47] If MP builds a peaking plant, all customer classes would be required to contribute to its costs—including interruptible customers.[48] The fact that MP seeks to fill this system need with DR rather than a peaking plant should not change which customers share in the cost—a fact that MP acknowledges, since the Petition specifically states, "All customers benefit from this

[45] *See* OAG Information Request 15, Exhibit 10 (stating that the "test year firm energy usage" includes all sales "with the exception of the Large Power/Other non-firm products).
[46] *See* Petition at 21–22.
[47] As discussed above, though, there is no demonstrated need for any generation resources.
[48] *See, e,g.*, OAG Information Request 16, Exhibit 11.

new industrial DR Product B as it is more economical than building a new peaking generation resource."[49]

Both of MP's cost recovery proposals are flawed because they do not spread the costs of the DR proposal among all customers. Cost Recovery Proposal 2 is flawed for additional reasons.

B. MP's Second Cost Recovery Proposal Is Unreasonable.

MP's second cost recovery proposal would allocate the costs of the DR program based on "the Commission's apportionment of the final rate case revenue deficiency by customer class."[50] This may appear to be the revenue apportionment that the Commission ordered in the rate case, but it is not. Instead, MP's proposal would allocate the DR costs based on only the incremental rate increase, not the actual revenue apportionment. The effect is a significantly lower assignment of costs to the Large Power customers, and a significantly higher assignment of costs to everyone else—a recurring theme in MP's regulatory filings.

To provide more context, the revenue apportionments ordered in the rate case are displayed in Figure 2, along with the apportionment of the revenue deficiency.

Figure 2
Comparison of Total Rate Apportionment to Revenue Deficiency Apportionment[51]

	Final Rate Revenue	Percentage of Total Rates		Revenue Deficiency Assigned	Percentage of Revenue Deficiency
Residential	$104,917,231	15.40%		$3,547,926	29.62%
General Service	$69,061,214	10.14%		$2,335,403	19.50%
Large Light & Power	$117,008,202	17.18%		$1,814,752	15.15%
Large Power	$350,067,353	51.39%		$4,094,217	34.18%
Lighting	$3,545,005	0.52%		$0	0.00%
Dual Fuel	$10,538,568	1.55%		$185,342	1.55%

[49] Petition at 22.
[50] Petition at 26.
[51] This information was drawn from Schedule 6 of MP's Revised Final Rates Compliance in Docket 16-664, filed on December 3, 2018.

Large Power Other	$26,073,817	3.83%	$0	0.00%
Total	$681,211,390		$11,977,640	

The apportionment of total rates was very different than the apportionment of the incremental increase due to the revenue deficiency. For example, the Residential class was apportioned 15.40 percent of total rates, but was assigned 29.62 percent of the revenue deficiency. Large Power was apportioned 51.39 percent of total rates, but only 34.18 percent of the revenue deficiency.

These differences are important because there is no reasonable argument to allocate *anything* using only the apportionment of the revenue deficiency. Neither MP, the OAG, nor any other party runs a Class Cost of Service Study ("CCOSS") on *just* the revenue deficiency—cost studies are run on all of the costs and revenues. The Commission does not set rates based only on the revenue deficiency—it determines a revenue apportionment for all of the utility's costs. MP has not provided any reason why it makes sense to allocate the costs of Product B in this way, which favors its largest customers, because there is none.

C. Reasonable Cost Allocation Method.

MP's first proposal was to use a flat, volumetric rate for all classes. The Commission has used a similar method for MP's EITE rider,[52] and for the gas utility rider recently approved for Minnesota Energy Resources Corporation.[53] In response to OAG Information Request 21, MP provided a spreadsheet which 1) included the Large Power/Other customers in the consumption

[52] *In the Matter of Minnesota Power's Revised Petition for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider*, Docket No. E-015/M-16-564, Order Approving Cost Recovery With Conditions at 6 (Apr. 20, 2017).

[53] The Order is not yet available for this decision. *See In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Gas Utility Infrastructure Cost Rider*, Docket No. G-011/M-18-281, Briefing Papers (Dec. 6, 2018).

calculation, and 2) did not exclude the Large Power Product B consumption from the calculation.[54] The results are presented in Figure 5.

Figure 5
Flat per kWh Rate Including Interruptible Customers[55]

Modified Method 1: Flat per kWh charge (LP DR energy included; LP Other energy included)			
Recovery target	$	12.6	million
Retail Recovery target (84.360%)	$	10.6	million
Test Year Usage (Firm)		8,864,975	MWh
Test Year Usage (LP/Other)		603,570	MWh
DR Billing units		9,468,545	MWh
Flat usage charge for all customers	**$**	**0.001123**	**per kWh**

This rate would correct MP's proposal to exclude the interruptible customers from sharing in the costs of the DR product, and has the effect of reducing the rate by approximately 20 percent.[56,57] If the Commission approves MP's DR proposal, and MP's proposal to recover the costs through a rider, the costs of the program should be allocated using this methodology. In the future, the Commission should direct MP to analyze whether the costs of the program should be rolled into base rates in the next rate case.

CONCLUSION

MP's proposal for a new DR program requires significant changes to produce a just and reasonable rate. In particular, the Commission should ensure that changes are made to the price

[54] OAG Information Request 21, Attachment 21.01, Exhibit 12.

[55] These calculations were taken from OAG Information Request 21 Attachment 21.01, although the table was reformatted slightly for appearance. The original version of the spreadsheet is attached as Exhibit 12.

[56] 0.00119 / 0.001349 = 82.9%.

[57] To the extent that there are concerns about including the Large Power/Other consumption in the calculation, excluding them and only including the Product B consumption would result in a rate of $0.001199 per kWh. OAG Information Request 19, Attachment 19.01, Exhibit 13.

of Product B capacity and the method for allocating Product B costs. Without making both of those changes, MP's proposal is unreasonable and should be denied. The Commission should take the following specific actions:

- Require MP to demonstrate that there is a need for the DR resources it seeks to acquire, or that the DR resources would offset other, more expensive resources;
- Change the unreasonably high capacity price for Product B,
  - By reducing the demand credit to $3,500 per MW-Month initially,
  - Requiring MP to report on Product B participation quarterly,
  - Adjusting the MW-Month price upwards until 150 MW of Product B DR is provided, or the price reaches the $7,000 cap; and,
- Require MP to make quarterly compliance filing on the economic interruption product, including,
  - Identifying all the times that it interrupted, the prices at the time, and its reasoning for doing so; and
  - Identifying all of the times that energy market prices were higher than the $30 / MWh interruptible credit, and demonstrating that it was reasonable not to call an interruption at the time.

The Commission should also require MP to allocate the costs of the DR proposal to all of its customers, using a flat per kWh rate. The OAG estimates that using this method would produce a per kWh rate of $0.001119.

The Commission should also deny the proposal for Product C without prejudice.

Dated: February 20, 2019

Respectfully submitted,

KEITH ELLISON
Attorney General
State of Minnesota

s/ **Joseph A. Dammel**
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ATTORNEYS FOR OFFICE OF THE
ATTORNEY GENERAL—RESIDENTIAL
UTILITIES AND ANTITRUST DIVISION

PUBLIC VERSION

OAG No. 11

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product

MPUC Docket No. **E015/M-18-735**

Requested from: Minnesota Power

By: Ryan Barlow
Telephone: (651) 757-1473

Date of Request: December 13, 2018
Due Date: December 26, 2018

What is the estimated total cost of the DR portfolio?

RESPONSE:

The estimated cost of Product A in the DR portfolio is estimated to be in the range calculated in the table below, but actual cost will be based on participation level.

KW (A)	Demand Credit / KW month (B)	Estimated Cost (A*B*12 months)
0	$0.60	$0.00
50,000	$0.60	$360,000
100,000	$0.60	$720,000
150,000	$0.60	$1,080,000
200,000	$0.60	$1,440,000

The estimated cost of Product B in the DR portfolio assuming full subscription of the 150 MW for the demand discount is shown in the table below.

KW (A)	Demand Credit / KW month (B)	Estimated Cost (A*B*12 months)
150,000	$7.00	$12,600,000

There are also Firm Load Control Periods where customers have the option to take their firm load off-line or buy-through. Based on the proposed Product B, if the customer physically interrupts load they will be paid a credit of $30/MWh, which is offset by lower costs in the Fuel Adjustment Clause. Assuming that customers interrupt load for 50% of the 600 hours the energy cost is shown in the table below.

Response by: Leah Peterson
Title: Supervisor – Customer Business Analytics
Department: Customer Experience
Telephone: 218-355-3014

PUBLIC VERSION

KWh/hour	KWh/hour (w/ 75% load factor energy) (A)	Physical Interruptible Credit /KWh (B)	Estimated Cost (A*B*300 hours)
150,000	112,500	$.03	$1,012,500

Response by: Leah Peterson
Title: Supervisor – Customer Business Analytics
Department: Customer Experience
Telephone: 218-355-3014

PUBLIC VERSION

OAG No. 10

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product	**MPUC Docket No.**	**E015/M-18-735**

Requested from: Minnesota Power

By:	Ryan Barlow	**Date of Request:**	December 13, 2018
Telephone:	(651) 757-1473	**Due Date:**	December 26, 2018

Reference: Page 22

Did MP's most recent resource plan indicate any peaking resources required over the planning period?

RESPONSE:

Minnesota Power's most recent resource plan (Docket No: E015/RP-15-690) included nearly 150 MW of industrial demand response in the base case. The model did not indicate additional peak resources were required above 150 MW of industrial demand response.

Response by:	Eric Palmer
Title:	Supervisor – Utility Planning
Department:	Strategy & Planning
Telephone:	218-355-3839

PUBLIC VERSION

Fresh Energy
Information Request

Docket No.:	E015/M-18-735		
Requestor:	Allen Gleckner		
Requested From:	Minnesota Power		
Date of Request:	December 19, 2018	Information Request No.	1
Response Due Date:	December 29, 2018		

Reference: Initial Filing

Please provide all workpapers and linked data used to inform Minnesota Power's Initial Filing including, but not limited to, pricing analysis, cost-effectiveness, and program parameter development (i.e. number of maximum events) for each product. Provide your response in live Excel spreadsheets with all links and formula intact.

Response:

Minnesota Power conducted extensive research, external sensing and stakeholder engagement that informed the Demand Response product development and initial filing. It's important to note that many of the program parameters, including the number of maximum events, were developed through an iterative and collaborative process with the large industrial customers who would be the participants of the program. Throughout the program development, Minnesota Power aimed to ensure that the agreed upon program parameters would provide benefits to all customers, which the analysis demonstrates.

Regarding the analysis that supported energy savings, avoided emissions, externalities values and capacity savings, the Company submits the attached TRADE SECRET excel workbook. This specific information request is very broad and Minnesota Power welcomes additional specific questions or data requests.

Preparer:	Eric Palmer
Title:	Supervisor – Utility Planning
Department:	Strategy & Planning
Telephone:	218-355-3839

PUBLIC VERSION

LIVE EXCEL WORKSHEETS FILED SEPARATELY

PUBLIC VERSION

CUB IR No. 5

Citizens Utility Board of Minnesota
Information Request

Date of Request: January 2, 2019

Requested By: Joseph Pereira
josephp@cubminnesota.org

Requested From: Minnesota Power

Request Due: January 12, 2019

In the Matter of the Petition for Approval of Minnesota Power's Industrial Demand Response Product **Docket No. E015/M-18-735**

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1. Minnesota Power proposes a demand credit for Product B of $7,000/MW-Month which will cost customers $12.6 million over 10 years, with Minnesota Power proposing $10.6 million to be recovered from retail customers. Minnesota Power projects approximately $4.6 million of avoided investment over 10 years due to this program.
   a. Could Minnesota Power please provide a walkthrough of the analysis and the assumptions used to determine a savings of $4.6 million of avoided investment over 10 years.
   b. Could Minnesota Power please provide a walkthrough of the analysis and the assumptions used to determine the $7,000/MW-Month proposed demand credit for Product B.

<u>RESPONSE</u>

a) Minnesota Power provided a TRADE SECRET workbook in response to Fresh Energy IR No. 1 that contains the analysis used to support the capacity savings values referenced above. A non-disclosure agreement (NDA) is required to access the data contained in the TRADE SECRET workbook. Parties who have signed a NDA should refer to that workbook – in particular – tab "Capacity" for the analysis results. The estimated $4.6 million in savings was calculated as the difference between the projected levelized revenue requirements for a new combustion turbine minus the capacity credit under Product B over the life of Product B. Please see cell B8 for the calculation.

Response by: Eric Palmer
Title: Supervisor – Utility Planning
Department: Strategy and Planning
Email Address: epalmer@mnpower.com
Telephone: 218-355-3839

b) Minnesota Power negotiated the value of capacity purchased under the framework for Product B to ensure it provided benefit to all customers and to participants of Product B. The value of capacity must properly compensate customers signed up for Product B for the energy curtailment risk they are taking on by participating. The value must also provide a net benefit to customers who pay and receive the capacity, energy and avoided emission benefits from Product B. The $7,000/MW-month value was agreeable to Minnesota Power's Large Industrial Customers. Furthermore, customers are receiving a peaking-like generation resource at a price slightly lower than to construct new large generation assets like a combustion turbine.

Response by: Eric Palmer
Title: Supervisor – Utility Planning
Department: Strategy and Planning
Email Address: epalmer@mnpower.com
Telephone: 218-355-3839

MINNESOTA DEPARTMENT OF COMMERCE
Division of Energy Resources
Information Request

Docket Number:	E-015/M-18-735	☐Nonpublic ☒Public
Requested From:	Minnesota Power	Date of Request: 1/3/2019
Type of Inquiry:	General	Response Due: 1/14/2019

Requested by: Michael Zajicek
Email Address(es): Michael.Zajicek@state.mn.us
Phone Number(s): 651-539-1830

Request Number: **1**
Topic: Demand Response Effectiveness
Reference(s): Initial Filing Page 7

REQUEST:

In its initial Filing Minnesota Power (MP or the Company) indicated that it currently offers several Demand Response (DR) products to various customer classes. For each offering where a customer's service might be interrupted please provide the following (this would **not** include Time of Day pricing where the customer's decision is strictly price based):

1. For each instance in which MP or MISO has called on MP's DR customers to reduce load in the past five years, please provide:
    a. the date(s) of the event or request,
    b. the amount of reduction expected or requested, and
    c. the amount of reduction achieved.
2. How many times each year for the past 5 years has a DR customer failed to reduce load when requested to by the Company or MISO? Please note any cases where any specific customer has failed to respond multiple times.
3. Please provide the data showing what percentage of DR customers have reduced power usage when requested to by the Company or MISO for DR purposes.
4. Please provide a narrative describing what happens if a DR customer fails to reduce load when requested.
5. Please indicate whether there are any differences in the consequences to a DR customer for failing to reduce load when requested under current DR tariffs, and under the proposed DR products, and provide a detailed explanation of the differences, if any.

Response by: Leah Peterson
Title: Supervisor – Customer Business Analytics
Department: Customer Experience
Email Address: lpeterson@mnpower.com
Telephone: 218-355-3014

PUBLIC VERSION

MINNESOTA DEPARTMENT OF COMMERCE
Division of Energy Resources
Information Request

Docket Number:	E-015/M-18-735	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	1/3/2019
Type of Inquiry:	General	Response Due:	1/14/2019

Requested by: Michael Zajicek
Email Address(es): Michael.Zajicek@state.mn.us
Phone Number(s): 651-539-1830

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6. Please describe the procedure for determining how much DR a Customer could provide in response to a request from the Company and if/how the Company confirms that the customer is capable of providing that much DR.

RESPONSE:

1. The current industrial demand response ("DR") product is an emergency capacity only product, and in the past five years the Midcontinent Independent System Operator ("MISO") or Minnesota Power has not called on Minnesota Power's DR customers to reduce load.

2. See response to Item 1.

3. See response to Item 1.

4. If an industrial customer fails to reduce load when requested for a MISO capacity emergency and such failure results in penalties being imposed upon Minnesota Power by MISO and/or financial damages resulting from non-completed or replacement wholesale sales or purchase, customer has to reimburse Minnesota Power the penalty or financial damages caused by failure to shed load. Also, if a customer does not shed load when called on for a MISO capacity emergency, MISO can disqualify the resource for the reminder of the planning year and/or disqualify for the next planning year. If a customer is disqualified their load cannot be accredited with MISO, and the customer would not be eligible to participate in Minnesota Power's suite of DR products.

5. The consequences under the current industrial DR product and the proposed industrial DR products is the same for MISO capacity emergency events. This applies to the proposed Product A and B. However, in the new suite of DR products, Product B, allows for Firm Load Control Periods of up to 600 hours per year when the customer can choose to shed load or buy-through. Firm Load Control Periods are an economic decision for participating and the consequence for not shedding load is that the customer would pay the incremental energy price plus an energy adder.

Response by: Leah Peterson
Title: Supervisor – Customer Business Analytics
Department: Customer Experience
Email Address: lpeterson@mnpower.com
Telephone: 218-355-3014

PUBLIC VERSION

MINNESOTA DEPARTMENT OF COMMERCE
Division of Energy Resources
Information Request

Docket Number:	E-015/M-18-735	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	1/3/2019
Type of Inquiry:	General	Response Due:	1/14/2019

Requested by: Michael Zajicek
Email Address(es): Michael.Zajicek@state.mn.us
Phone Number(s): 651-539-1830

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6. The procedure for to determine how much DR is available is the same for emergency events or economic curtailments ("Firm Load Control Period"). The procedure to determine how much DR a customer could provide in a request from Minnesota Power is calculated by taking the difference between the customer's MISO load (based on historical load at the time of MISO's peak) and Customer's firm service level. This difference represents the load reduction historically available during periods when the system could be stressed – this also is used in determining the accredited capacity level for industrial DR. The firm service level is the threshold the customer could reduce their load down to, and would be set in the customer's contract. Minnesota Power has systems that automatically tracks the customer's current load amount compared to the firm service level, which is used to determine how much energy is available for curtailment and used to track/confirm actual load during an emergency event. For emergency events customers are also able to receive a signal and command from the company to shed load, which can be done automatically. During a Firm Load Control period the customer has the option to shed load or buy-through the event at the incremental cost.

Response by: Leah Peterson
Title: Supervisor – Customer Business Analytics
Department: Customer Experience
Email Address: lpeterson@mnpower.com
Telephone: 218-355-3014

PUBLIC VERSION

OAG No. 05

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product	**MPUC Docket No.**	**E015/M-18-735**

Requested from: Minnesota Power

By:	Ryan Barlow	**Date of Request:**	December 13, 2018
Telephone:	(651) 757-1473	**Due Date:**	December 26, 2018

Reference: Page 18

Please explain in more detail what it would mean for a customer to "convert" "MWs of Product B" to "firm service." In what circumstance would a customer choose to do this? What impact would it have on the utility, including the impact on rider revenues or base revenues?

RESPONSE:

To convert MWs of Product B to firm service the customer must provide a written notice by October 1 of the year prior to the next MISO planning year. MP would then advise the Customer of any capacity or energy charge premiums the customer would have to pay to complete the conversion. The purpose of the energy charge premium would recover any cost that would otherwise be borne by non-participating customers due to converting MWs of Product B directly from the customer making the choice to convert the DR MWs to firm service. If the conversion to firm services is completed, the customer would no longer receive the capacity credit and MP would no longer be able to accredit Product B MWs as part of MISO's resource adequacy.

A customer may choose to convert "MWs of Product B" to "firm service" should their risk and reward tolerance change, or perhaps in circumstances in which the customer can no longer meet the Product B requirements. For example, higher than anticipated costs incurred by the customer from Firm Load Control Periods, or because of a change in customer operations that would prevent the customer from taking on the risk of having their energy curtailed. A customer may no longer be capable of meeting the requirements because of unforeseen changes in MISO Resource Adequacy or Energy Market rules.

The impact to the utility would be that MP may have to purchase replacement capacity and energy from a counterparty or the MISO energy and capacity market, or start the project development process to build a new asset, in order to accept the additional firm service requirements. The customer converting from Product B to firm service would need to directly support that cost premiums resulting from procuring or building capacity and from the need of replacing the energy that would have been curtailed. For capacity replacement, the premium would be based on the difference between the demand response capacity credit and cost of replacement capacity. For energy replacement, it would be based on the difference between the Physical Interruption Energy Credit and the cost of replacement energy. The revenue received from the premium would be passed through to the customer in the appropriate mechanism, which is discussed in more detail in the following paragraph.

Currently, Minnesota Power's most recent retail rate case test year does not have the demand response suite of products built in. Therefore, Minnesota Power is proposing the cost of the capacity credit would be recovered from customers through a new Demand Response Surcharge in the Rider for Large Power Demand Response Service and the Physical Interruption Energy Credit be recovered through the Fuel and Purchased Energy Rider. Revenue from the premium related to replacement capacity would be credited to the demand response rider tracker. Revenue from the premium related to replacement energy would be credited to the Fuel and Purchased Energy Rider. In subsequent rate cases, the treatment of the revenues from the premiums could be reconsidered. Rider revenue from other riders would be unaffected, as revenue booked is based on the associated revenue requirements of rider projects.

Q. Please respond to the Department concerns and recommendations.

A. I share the Department's concern that rider recovery may not be appropriate for the GRID Pilot. It is possible, however, that some of CUB's recommendations may lessen this concern. I also support the Department's recommendation that MP should be required to conduct a distribution study for distributed generation.

Q. Do you still recommend that the GRID Pilot be rejected by the Commission?

A. I will make my final recommendation in surrebuttal testimony after I have reviewed other intervenors arguments and responses.

E. INTERRUPTIBLE RATES LP AND LLP CLASSES

Q. What do you respond to in this section of your testimony?

A. I respond to the testimony of LPI witness, Mr. Robert Stephens, on the proposed demand response/interruptible service rider open to the Large Light and Power and Large Power Classes.

Q. In your own words, please summarize LPI's proposal.

A. For reliability and economic reasons, LPI proposed a suite of five options to provide demand response for large usage customers. Each demand response option is similar in that each allows customers to 1) "purchase power at elevated prices, rather than to interrupt," 2) "renew under the same interruptible option, at a level not-to-exceed the level of the current interruptible contract demand," 3) "have the option each year to modify their interruptible contract demand," and 4) allow customers to modify their interruptible demand, with 60 days' notice, if a material change in operations takes place.[62] The demand response options vary by a number of characteristics, including

[62] Stephens Direct at 9-10.

contract length, type of interruption (reliability and/or economic), frequency of interruptions, duration of interruptions, and notice required before interruptions. Based on the different contract characteristics, LPI claims that the demand charge discount for each option varies from $0.10 to $9.50 per kW-month.

Q. Do you have any concerns with LPI's proposal for a new demand response/interruptible tariff for large usage customers?

A. Yes. I have two primary concerns with LPI's proposal. First, I have concerns related to assumptions that LPI uses to estimate the value of interruptible capacity for the tariff. Second, there may be other more efficient approaches to procuring demand response and interruptible capacity for MP's large power customers. I address each of these concerns.

Q. What assumptions concern you with LPI's proposal?

A. LPI makes numerous assumptions, but I will focus on only one at this time. LPI estimates the value of its proposed tariff based on the avoided capacity cost of a new combustion turbine generation facility.[63] LPI did not, however, demonstrate that its proposed tariff would actually offset any new generation needs. Therefore, the estimated value may not be accurate.

Q. What other approaches could be used to procure demand response and interruptible capacity from MP's consumers?

A. A market-based approach could be used, but some current rules would likely need to be changed. For example, MP could put out a request for proposal to fulfill a general capacity and/or energy need, and third party aggregators of retail customers or other individual customers could respond with least-cost proposals. Currently, aggregators of

[63] Stephens Direct at 17-19.

retail customers are not allowed to operate in Minnesota. However, this is one example of how aggregators of retail customers could reduce costs for all ratepayers.

Q. Why could using a market based approach reduce costs for all ratepayers as opposed to adopting a plan similar to LPI's?

A. LPI's has created an administrative rate that is not based on the cost that consumers face when interrupting service. LPI's proposal is likely setting the capacity discount too high or too low to fill the proposed 300 MWs available to customers in the tariff. For example, if there was a need of 300 MWs and aggregators of retail customers were allowed in Minnesota, a process could be constructed where consumers would have to compete for the capacity discount, resulting in a more fair (i.e. market based) value paid to customers (and by customers in the form of revenue credits). Instead, LPI is asking residential customers to sign up to a twelve-year contract to pay Large Power customers for capacity using an administratively set rate. I have reservations with this approach because of the potential harm that this type of risky contract could have on residents and small businesses.

Q. Do you have any additional questions about LPI's proposal?

A. Yes. I appreciate the attempt to incorporate economic interruptions into MP's tariff because it has the potential to benefit all ratepayers. LPI does not, however, discuss how economic interruptions are triggered in testimony or in the proposed tariff. In addition, the value of economic interruptions is intricately linked to the probability of the interruption occurring, which again LPI was silent on. I request LPI fill in these gaps in surrebuttal testimony.

PUBLIC VERSION

OAG No. 07

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product

MPUC Docket No. **E015/M-18-735**

Requested from: Minnesota Power

By: Ryan Barlow
Telephone: (651) 757-1473

Date of Request: December 13, 2018
Due Date: December 26, 2018

Reference: Page 21

How much of the $10 million estimated energy value is obtained in each year of the ten-year period?

How much of the $10 million estimated energy value is related to the categories of fuel, variable O&M, and emissions reduction? Are there other categories included in the estimated value?

RESPONSE:

The Table below outlines how Minnesota Power calculated the total and annual energy savings value from the curtailment associated with Product B. Row E of the table below shows the estimated annual energy savings assuming that the maximum allowed annual curtailment of 90,000 MWh associated with Product B is utilized each year. It is important to note that the annual energy savings is the theoretical delta between the estimated costs to dispatch a modern combustion turbine (CT) and the $30 per MWh Physical Interruption Energy Credit paid to customer for interrupting energy under Product B.

Annual Estimated Savings by Year of Product B

Description	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Math
(A) Avoided Cost -- CT Dispatch Grossed up for Transmission Losses ($/MWh)	$37.56	$34.75	$34.58	$37.86	$40.90	$42.05	$44.14	$47.92	$49.23	$49.50	
(B) Physical Interruption Energy Credit ($/MWh)	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	
(C) Energy Cost Savings per MWh ($/MWh)	$7.56	$4.75	$4.58	$7.86	$10.90	$12.05	$14.14	$17.92	$19.23	$19.50	(A) - (B)
(D) Product B Maximum Annual Energy (MWh)	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	
(E) Annual Customer Savings ($)	$680,579	$427,622	$412,533	$706,994	$980,676	$1,084,778	$1,272,515	$1,612,456	$1,730,642	$1,754,854	(D) * (E)
(F) Total Customer Savings (10 years)	$10,663,650	∑ (E)									

Response by: Eric Palmer
Title: Supervisor – Utility Planning
Department: Strategy and Planning
Telephone: 218-355-3839

PUBLIC VERSION

The total dispatch costs for a theoretical CT used as the starting point for the annual energy savings calculation does include fuel costs, variable O&M, and transmission losses (shown as (A) in the table above), but they are not separately broken out. Because the total annual energy savings is based on a delta between such total CT dispatch costs and the Physical Interruption Energy Credit, breaking the savings down into individual components is not possible.

Externality costs for CO2 and criteria pollutants were not included in this calculation of annual energy savings. For more information on the cost impacts related to externalities and CO2, please see pages 20-22 and Figures 1 and 2 of the Petition.

Response by: Eric Palmer
Title: Supervisor – Utility Planning
Department: Strategy and Planning
Telephone: 218-355-3839

PUBLIC VERSION

OAG No. 029

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product	**MPUC Docket No.**	**E015/M-18-735**

Requested from: Minnesota Power

By:	Ryan Barlow	**Date of Request:**	December 18, 2018
Telephone:	(651) 757-1473	**Due Date:**	January 2, 2018

What are the economic triggers for Product B?

Under what conditions will MP trigger the economic curtailments?

RESPONSE:

The procedure for MP having an economic interruption will include comparing MP's forecasted incremental cost, including applicable real-time locational marginal prices for the Company's load zone, to the Physical Interruptible Energy Credit. If the estimated cost is expected to be higher for a four-hour period of time or longer, it could trigger an economic interruption or Firm Load Control Period, depending on whether Product B is the most economical resource for Minnesota Power customers at the time, and assuming that the other Firm Load Control period requirements are met (such as per day or per year limitations).

Response by:	Leah Peterson
Title:	Supervisor – Customer Business Analytics
Department:	Customer Experience
Telephone:	218-355-3014

PUBLIC VERSION

OAG No. 15

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product	**MPUC Docket No.**	**E015/M-18-735**

Requested from: Minnesota Power

By:	Ryan Barlow	**Date of Request:**	December 13, 2018
Telephone:	(651) 757-1473	**Due Date:**	December 26, 2018

Reference: Page 25

MP states that Cost Recovery Method 1 would apply a per kWh charge to "Firm Energy (All Customers)." Please identify all customer classes that are not included in "Firm Energy (All Customers)."

RESPONSE:

The test year firm energy usage of 8,864,975 MWh used in the calculation of Method 1, is from Minnesota Power's December 3, 2018 Revised Compliance Filing in Docket No. E015/GR-16-664, Compliance Schedule 10, page 2 of 47, line 11. It represents all retail energy with the exception of the Large Power/Other non-firm products that are based on market prices in part, with pricing determined separately from the rate case.

PUBLIC VERSION

OAG No. 16

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product	**MPUC Docket No.**	**E015/M-18-735**

Requested from: Minnesota Power

By:	Ryan Barlow	**Date of Request:**	December 13, 2018
Telephone:	(651) 757-1473	**Due Date:**	December 26, 2018

Reference: Page 25

Please explain how the costs of the following resources would be allocated, using the methodologies in the 2016 rate case:

- A peaking plant resource owned by MP;
- A thermal baseload resource owned by MP;
- A wind resource owned by MP; and
- Any of the above resources obtained through a 10-year or longer power purchase agreement.

Specifically identify whether the costs would be shared by Firm and non-firm customers, and whether there would be adjustments for the cost

RESPONSE:
Using the methodologies in the 2016 rate case, the costs of the above resources owned by MP would be allocated across jurisdictions and class using the Company's power supply production demand D-01/Peak & Average (P&A) allocation factors.

The costs of purchase power agreements are allocated according to the details of the contract: purchased capacity is allocated across jurisdictions and class using the Company's power supply production demand D-01/P&A allocation factors, and purchased energy is allocated across jurisdictions and class using the Company's power supply energy E-01/E8760 allocation factors.

Apart from typical revenue requirement adjustments (accumulated depreciation, accumulated deferred income taxes, depreciation expense, O&M, etc.), the costs would be allocated to and shared by all Firm customers, regardless of whether they also have non-firm products. The allocation factors are shown below.

Response by:	Michael A. Donahue
Title:	Cost and Pricing Analyst
Department:	Rates
Telephone:	218-355-3408

PUBLIC VERSION

Allocator Name	Minnesota Jurisdiction	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Light
Demand D-01/P&A	84.360%	10.655%	6.625%	14.604%	52.030%	0.193%	0.253%
Energy E-01/E8760	84.307%	11.182%	7.025%	14.877%	50.859%	0.176%	0.188%

Response by: Michael A. Donahue
Title: Cost and Pricing Analyst
Department: Rates
Telephone: 218-355-3408

PUBLIC VERSION

OAG No. 21

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product	**MPUC Docket No.**	**E015/M-18-735**

Requested from: Minnesota Power

By:	Ryan Barlow	**Date of Request:**	December 13, 2018
Telephone:	(651) 757-1473	**Due Date:**	December 26, 2018

Reference: Page 24–27

Recalculate the "Flat per kWh Recovery" method so that it (1) includes all Test Year Usage, without removing the Large Power DR Energy (75% LF) and (2) applies to all retail customers, not just Firm Energy customers.

RESPONSE:

Method 1 has been recalculated in OAG IR 21.01 Attach, applying the charge to the Large Power/Other category that is shown in Minnesota Power's December 3, 2018 Revised Compliance Filing in Docket E015/GR-16-664, Schedule 10, page 2 of 47, line 12, and including the Large Power demand response energy.

LIVE EXCEL WORKSHEETS FILED SEPARATELY

PUBLIC VERSION

OAG No. 19

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of Petition for Approval of Minnesota Power's Large Industrial Demand Response Product	**MPUC Docket No.**	**E015/M-18-735**

Requested from: Minnesota Power

By:	Ryan Barlow	**Date of Request:**	December 13, 2018
Telephone:	(651) 757-1473	**Due Date:**	December 26, 2018

Reference: Page 24–27

Recalculate the "Flat per kWh Recovery" method so that it includes all Test Year Usage, without removing the Large Power DR Energy (75% LF).

RESPONSE:

Method 1 has been recalculated in OAG IR 19.01 Attach without removing the Large Power demand response energy.

Response by: Michael A. Donahue
Title: Cost and Pricing Analyst
Department: Rates
Telephone: 218-355-3408

LIVE EXCEL WORKSHEETS FILED SEPARATELY