COMMERCE DEPARTMENT

February 20, 2019

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E-015/M-18-735

Dear Mr. Wolf:

Attached are the Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> Minnesota Power's (MP or the Company) Petition for Approval of an Industrial Demand Response Product in Minnesota.

The Application was filed on December 7, 2018 by:

> Jennifer J. Peterson
> Manager – Regulatory Affairs
> Minnesota Power
> 121 7th Place East, Suite 350
> St. Paul, MN 55101-2147

The Department recommends that the Commission **approve with reporting requirements** MP's proposed Industrial Demand Response Product options **but will provide final recommendations on cost recovery after reviewing MP's reply comments**.

Sincerely,

/s/ MICHAEL N. ZAJICEK
Rates Analyst

MNZ/jl
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

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

I. BACKGROUND

In the Minnesota Public Utilities Commission's (Commission) July 18, 2016 ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS in Docket No. E-015/RP-15-690, the Commission stated the following regarding procurement of replacement generation due to the retirement of Boswell 1 and 2 and Taconite Harbor 1 and 2:

> The Commission agrees with the Clean Energy Organizations and the Large Power Intervenors that Minnesota Power's evaluation of replacement generation should not be limited to one resource. At the same time, the Commission does not wish to foreclose the Company's exploration of efficient combined-cycle generation as part of a portfolio of resources to replace its small coal-fired generators. The Commission will therefore allow Minnesota Power to continue pursuing its RFP to investigate the possible procurement of combined-cycle natural gas generation to meet its energy and capacity needs in the absence of Boswell 1 and 2 and Taconite Harbor 1 and 2.
>
> Acceptance of the RFP establishes no presumption that any or all of the generation identified in that bidding process will ultimately be approved. Moreover, to ensure that a wide variety of replacement options is considered in the next resource plan, the Commission will require that the plan include a full analysis of all alternatives to natural gas, including renewables, energy efficiency, distributed generation, and demand response, for providing the energy and capacity sufficient to meet the Company's needs.
>
> …
>
> The Commission agrees with the Department and the Large Power Intervenors that verifying the energy savings of Minnesota Power's CIP-exempt customers could present practical and legal challenges. However, the Commission also agrees with the Clean Energy Organizations that the Company should pursue

> conservation measures in which its CIP-exempt customers may participate voluntarily.
>
> Accordingly, the Commission will require Minnesota Power to (1) propose a demand-response competitive-bidding process within six months of the date of this order and (2) investigate the potential for an energy-efficiency competitive-bidding process and summarize its investigation and findings in the next resource plan. These measure hold the potential both to promote state policy favoring energy savings and to benefit large customers competing in global markets.

On January 18, 2017, MP filed a compliance filing in the Resource Plan docket indicating that it had issued an RFP for "Up to 300 MW of Large Customer Demand Response Resources" on August 6, 2016. On July 28, 2017 MP filed its *Petition for Approval of the Energy Forward Resource Package* (Docket No E-015/AI-17-568), within which it indicated that it had received only one response to its RFP; the single response was for 96 MW of demand response available during MISO system emergencies or MP local system emergencies. MP's analysis indicated that the proposal was not a least-cost alternative for customers.

In the Minnesota Public Utilities Commission's (Commission) March 12, 2018 FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota* (Docket No E-015/GR-16-664), the Commission required Minnesota Power (MP or the Company) "to develop a demand response rider and corresponding methodology for cost recovery, based on stakeholder input, for submission to the Commission."

In Docket No. E-015/AI-17-568 (*In the Matter of Minnesota Power's Petition for Approval of the EnergyForward Resource Package*), Large Power Intervenors (LPI) proposed a demand-response rider for up to 300 MW of interruptible load. In the Commission's January 24, 2019 ORDER APPROVING AFFILIATED INTEREST AGREEMENTS WITH CONDITIONS, the Commission directed MP, LPI, and other stakeholders to continue their efforts to develop a demand-response rider and corresponding methodology for cost recovery.

On December 7, 2018, MP submitted a *Petition for Approval of Minnesota Power's Industrial Demand Response Product* (Petition) to the Commission. The Company is requesting approval of new Demand Response (DR) product options for its large industrial customers that would offer special rates in exchange for those customers reducing energy usage when requested by the Company for emergency or economic purposes.

II. SUMMARY OF MP'S FILING

The Company's Petition seeks approval for three DR products and recovery of the costs associated with implementing these products. The three DR products were created in response to the Commission including 150 MWs of DR in the Company's last Integrated Resource Plan (IRP)[1] and after a stakeholder process including large industrial customers. The Company proposes the following products to be implemented via new or amended Electric Service Agreements (ESA):[2]

- Product A: a *Short-Term Emergency Capacity Product* that offers customers a credit of $0.60 per kW of monthly interruptible billing demand, to be updated annually;
- Product B: a *Long-Term Emergency Capacity Curtailable with Firm Load Control Periods Product* that offers a $7 per kW-month capacity credit for up to 150 MW of capacity. This product also provides a $30 per MWh Physical Interruption Energy Credit for customers who interrupt operations for economic purposes. Customers would have the option to buy-though a control period at the Company's incremental energy price, plus an [$5 per MWh] adder.
- Product C: a *Market Surplus Service Capacity Product* that allows Minnesota Power to work with a participating customer to identify options for any excess capacity that does not fit into other DR products or current needs of the Company for Resource Adequacy. [Any negotiated agreements related to this product would require Commission approval.]

MP is requesting that the $30 per MWh Physical Interruption Energy Credit be recovered through the existing Rider for Fuel and Purchased Energy Adjustment. The Company is also requesting a Demand Response Surcharge be added to customers' bills via a new Rider for Large Power Demand Response to recover the costs of the expanded DR program, consisting of the costs resulting from the $7 per kW-month capacity credit and any costs created from Product C.

III. DEPARTMENT ANALYSIS

The Department analyzed each of the Company's proposed products and the Company's proposed cost recovery options. The Department generally supports the use of DR to offset the need for additional resources being built and for the purposes of energy conservation.

[1] Docket No. E015/RP-15-690
[2] Petition, page 1.

A. PRODUCT A: SHORT-TERM EMERGENCY CAPACITY CURTAILABLE WITH FIRM LOAD CONTROL PERIODS

MP's proposed Product A is essentially the interruptible product the Company currently offers to its large industrial customers that was approved by the Commission. Product A would provide a credit of $0.60 per kW of interruptible billing demand per month; the price would be updated annually based on the current market price trends for short-term capacity. Product A would strictly be for emergencies, as called by the Midcontinent Independent Systems Operator (MISO) and would require that the customer meet the requirements for MISO DR accreditation in accordance with Module E-1 of the Business Practices Manual for Resource Adequacy. Product A has a maximum of 5 events annually, with required notification for the customers of 2 hours prior to an event and each event would last no more than 4 hours. The Company notes that Product A is currently available to industrial customers as a single-year commitment, and thus there are no additional costs for rate payers resulting from this product.

The Department notes that the inclusion of Product A in this filing is essentially just to list all the Company's DR products in one filing so as to provide context for the analysis of the Company's proposed new products. As such the Department recommends that the Commission approve the Companies proposed Product A and require the Company to include an analysis for updating the Product A credit per kW in an annual compliance filing each year for Commission approval.

B. PRODUCT B: LONG-TERM EMERGENCY CAPACITY CURTAILABLE WITH FIRM LOAD CONTROL PERIODS

MP's proposed Product B is a new long-term product of up to 150 MW that requires a ten-year ESA and includes both emergency response, with the same requirements as Product A, and economic Firm Load Control periods. The Firm Load Control periods have the following restrictions:

- Maximum of 600 hours Firm Load Control per year;
- Maximum of 2 Firm Load Control periods per day;
- Maximum of 12 hours of Firm Load Control periods per day;
- Each Firm Load Control period can last a minimum of 4 hours up to a maximum of 12 hours;
- No more than four Firm Load Control periods can be called in any seven days of the week (Sunday-Saturday); and
- Notice must be given either the day ahead or in real time with four hours advanced notice through an e-mail notice.

Customers would have the option to buy though a Firm Load Control period and/or reduce their load. Customers would be paid a Physical Interruptible Energy Credit of $30.00/MWh for load curtailed, and customers would pay the Company's hourly incremental energy cost (the cost the Company incurs to purchase energy at that time) plus a $5.00/MWh adder for load not curtailed.

MP states that its cost of energy from peaking generation is projected to be $41/MWh, which is greater than the $30.00/MWh curtailment credit. As such the Company projects that MP is saving rate payers around $11/MWh with the Product B. If a participating customer buys though the event, then other customers are not harmed because the $30.00/MWh is not paid to the participating customer plus the customer pays the cost MP incurs to acquire peaking energy from the market as well as the $5/MWh adder. The Company states that they expect to save ratepayers approximately $10 million in avoided energy costs.

Customers can reduce the MWs of Product B and add more firm service through a written notice to the Company no later than October 1 of the year prior to the next MISO planning year. The Department requests that the Company explain in reply comments if the $5/MWh would be retained by the Company or returned to customers via the Fuel and Purchased Energy Adjustment.

MP indicates that Product B would also provide participating customers an avoided capacity benefit (demand credit) of $7,000/MW-Month. The Company states that this amount is less than the Company would pay for a competitive new peaking generator such as a new 228 MW combustion turbine. The Company believes that paying this amount to participants still provides ratepayers with an approximately $4.6 million benefit of avoided investment over 10 years. Overall the Company states that combining this and savings from avoided energy costs would give rate payers approximately $15 million in benefits over the next 10 years. MP calculates that at full participation of 150 MW the program would cost ratepayers $12.6 million ($7.00/kW-month x 12 months x 15- MW), which would result in approximately $2.4 million in net savings for rate payers from Product B, although MP assumes that participation will likely not be exactly 150 MW.

The Company also notes in its Petition that DR resources would substantially reduce emissions of various pollutants that would be emitted by peaking generators. The Company estimates the value of this reduced pollution at $6,670,457 to $30,160,275 depending on whether low or high externalities are used. The Department notes, however, that if customers buy though or replace the energy they would obtain from MP via self-generation then these pollution benefits could be lost, with the possibility of pollution actually increasing if the market energy or self-generation energy is more pollution intensive than that of a potential peaking plant that MP might have built instead of using DR.

The Department notes that it is possible that all participants in Product B could choose to buy through a particular economic event. However, as long as MP can purchase power from the market to account for the 150 MW of potential buy-through during an economic event, non-participating ratepayers would not necessarily be harmed by missing out on the capacity benefits associated with Product B since the Company is still avoiding a capacity addition. The Department requests that the Company discuss in reply comments whether there is significant risk of there being an economic event where the Company is not able to purchase enough energy from the market to account for customers buying though the Firm Load Control Period.[3]

The Department also notes that issues could occur if the Company fails to call Firm Load Control Periods when the conditions for calling these periods are present. The Company provided in response to Citizens Utility Board information request 7 a calculation of the number of hours of Firm Load Control Periods the Company would have called under the proposed Product B. The Company indicated that it would have called 595 to 600 hours of Firm Load Control Periods over each of the last 5 years.[4] If the Company actually calls a similar amount of Firm Load Control Periods in the future then it is expected that the Company's other customers would receive benefits from the DR products. The Department concludes that Product B will provide the Company with DR resources that will benefit all customers, thus the Department recommends that the Commission approve the Company's proposed Product B. The Department also recommends that the Company file an annual compliance report including at least the following information:

- the number of Firm Load Control Periods,
- the number of hours per period that the Company called,
- how many periods met the criteria for the Company to call a Firm Load Control Period but a Firm Load Control Period was not called, and an explanation for why each period was not called,
- how many customers responded to each event called,
- the amount of curtailed energy,
- how many customers bought though each period,
- how many emergency events were called,
- customer response rates to each emergency DR request, and
- any other data the Commission determines would be useful.

C. PRODUCT C: MARKET SURPLUS SERVICE CAPACITY PRODUCT

MP's proposed Product C is an emergency-only capacity product for excess capacity that a customer has that does not fit with other DR products or current resource adequacy needs of MP. Product C would be a flexible product allowing longer contracts than Product A, but shorter contracts than entering into the ten-year ESA associated with Product B. Product C

[3] Since customers are not able to buy thought emergency events the Department is not concerned about MISO emergency events as any failure to curtail power would result in the customer being disqualified from the program, consistent with MP's current DR program.

[4] See DOC Attachment 1

would be available to customers that currently have an ESA that matches the terms of the Market Surplus Service. The Customer and MP would negotiate the quantity of emergency-only capacity to be offered as part of Product C and a negotiated per-kW-month demand discount would be passed through to the customer providing the capacity on their monthly bill. MP indicated that if non-participating customers are impacted by Product C, the Company would seek Commission approval to pass any costs or benefits to those customers. Product C must meet the MISO accreditation requirements in MISO Module E-1 of the Business Practices Manual for Resource Adequacy.

The Department examined the Company's proposal and concludes that offering a flexible option to obtain additional emergency-only DR is reasonable since any negotiated contract must be approved by the Commission prior to implementation. Therefore the Department recommends that the Commission approve the Company's Product C.

D. COST RECOVERY

The Company is requesting to recover the costs associated with Product B[5] through MP's existing Rider for Fuel and Purchased Energy (FPE Rider). MP states that implementation of Product B is in compliance with the Commission's directives in prior proceedings and that a DR product without cost recovery would be contradictory to those dockets.[6] MP is proposing to recover the cost of the $30 per MWh Physical Interruptible Energy Credit though the FPE Rider.

Minnesota Rules, parts 7825.2390 through 7825.2920 enable regulated utilities "to adjust rates to reflect changes in the cost of energy delivered to customers from those costs authorized by the commission in the utility's most recent general rate case." The adjustment per Kwh is calculated by subtracting the base electric cost (cost of fuel consumed in the generation of electricity and purchased power that is set in a rate case) per Kwh by the current period cost of energy purchased and fuel consumed per Kwh. The cost of energy purchased is defined as "the cost of purchased power and net interchange defined by the Minnesota uniform system of accounts, … account 555 and purchased under federally regulated wholesale rates for energy delivered through interstate facilities." As noted above, the Commission directed MP to develop and propose a demand response rider and corresponding cost recovery mechanism, but did not indicate any presumptively preferred cost recovery method. The Department agrees that, to the extent DR Product B would reduce the amount of energy delivered to customers, recovery through MP's FPE Rider appears to be logical; however, Minnesota Rules governing the Company's FPE Rider do not appear to allow recovery of a payment to a

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[5] The costs associated with Product A are already being recovered and Product C would require subsequent Commission approval before the rates and terms of any Product C ESA is implemented.

[6] See the Commission's Order regarding Minnesota Power's 2015 Integrated Resource Plan dated July 2016 in Docket No. E015/RP-15-690 and Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package, July 28, 2017, Docket No. E015/M/AI-17-568.

customer participating in a demand response program. The Department requests that MP provide further support for its proposal, including justification for any rule variance that may be required in order to allow use of the FPE Rider to recover the Physical Interruptible Energy Credit of Product B.

The Company proposes to recover DR Product B's Avoided Capacity Benefit payments though a new Rider for Large Power Demand Response Service. The Company states that it believes the Commission has the authority to approve a rider under its general ratemaking authority and Minn. Stat. §216B.05.[7]

The Department does not believe this is adequate support for the creation of a new rider to recover costs. In Minnesota, capacity costs are recovered through base rates set in a general rate case. In MP's recent EnergyForward resource acquisition proceeding noted above, the Commission adopted the Department's recommendation to not allow MP to recover capacity costs outside of a rate case. The Department recognizes that due to the uncertainty as to the actual cost of DR Product B, the Company would prefer to recover the capacity costs through a rider, at least until those costs become somewhat predictable, however best practices would suggest that these costs should be recovered in a rate case to ensure that MP has the incentive to implement DR product B in a way that reduces costs between rate cases. In general, rate riders are extraordinary recovery mechanisms, each of which have a specific statutory basis. In general, current rider mechanisms were put in place to remove disincentives to investing in certain public policy goals. As noted in the Commission's June 2010 *Utility Rates Study*, trackers could reduce regulatory scrutiny in evaluating cost prudence:

> Moreover, making certain cost categories subject to automatic recovery removes them from inclusion in the overall review of costs (those that decrease as well as those that increase) when a general rate case is ultimately filed. It effectively takes them "off the table" in a rate case review and thereby constricts the Commission's rate-making authority. And while special recovery will have the effect of dampening the magnitude of rate requests that utilities make when

[7] MN Stat. § 216B.05, subd. 1 states that "Every public utility shall file with the commission schedules showing all rates, tolls, tariffs, and charges which it has established and which are in force at the time for any service performed by it within the state, or for any service in connection therewith or performed by any public utility controlled or operated by it." MN Stat. § 216B.05, subd. 2 states that "Every public utility shall file with and as a part of the filings under subdivision 1, all rules that, in the judgment of the commission, in any manner affect the service or product, or the rates charged or to be charged for any service or product, as well as any contracts, agreement, or arrangements relating to the service or product or the rates to be charged for any service or product to which the schedule is applicable as the commission may by general or special order direct; provided that contracts and agreements for electric service must be filed as required by subdivision 2a [(regarding electric service contracts)].

> they do ultimately file a rate case petition, the reality is this effect merely masks the full rate implications for ratepayers.

It is the Department's understanding the Minnesota Power is likely to file a general rate case before the end of 2019. In order to discourage the proliferation of rate riders to ensure the Commission is able to fully assess the Company's capacity costs, the Department does not support MP's proposal to create a new rate rider for the capacity costs associated with DR Product B.

MP proposed two cost recovery allocation methods for recovering the capacity payments through the proposed rider. Although the Department does not support establishing a new rider, we provide the following analysis of the two methods should the Commission approve the rider.

As an initial matter, the Company proposes to use the generation demand allocator for the DR program Avoided Capacity Benefit costs to allocate costs between wholesale and retail since the product is essentially serving as a replacement for new generation infrastructure. Since the proposed Product B is open to a maximum of 150 MW of participation, the maximum cost for implementing Product B is $12.6 million.[8] The Department agrees with MP that the Company's approved generation demand allocator (D-01) from MP's 2016 rate case would be reasonable to use to allocate costs to retail customers. Using this allocator the Company would aim to recover up to $10.6 million from retail customers if Product B is fully subscribed.[9] The Company then proposes two options for allocating the $10.6 million among the retail customers.

a. Cost Recovery Method 1: Flat per-kWh Charge From All Firm Customers

The first cost recovery method the Company proposes is a flat per-kWh charge for all firm customers regardless of class. Using the 2017 Test Year energy usage and the expected Large Power energy savings attributed to Product B participation, the Company estimates that the maximum per-kWh charge for all firm customers using this method would be $0.001349/kWh assuming maximum Product B participation. Table 1 below shows the Company's calculations.

Table 1: Cost Recovery Method 1:

Test Year Usage (Firm)	8,864,975 MWh
Less Large Power DR Energy	(985,500 MWh)
Demand Response Billing Units	7,879,475 MWh
Retail Recovery Maximum	$10.6 million

[8] $7000/MW-month * 12 Months * 150 MW = $12.6 million
[9] $12.6 million * 84.360% = $10.6 million

Per kWh charge on Firm Energy	$0.001349/kWh (max)

Cost recovery allocation method 1 would result in a maximum monthly bill increase for a residential customer of $1.01, or 1.3% and about a 2% increase for Large Power Customers.

b. Cost Recovery Method 2: Recovery based on Rate Case Apportionment of Final Rate Increase

MP's second cost recovery allocation method is allocating costs between industrial and other customers based on the Commission-approved revenue apportionment from the Company's last rate case.[10] Table 2 below shows the Company's cost recovery method 2 proposal which would result in a rate of $0.000792/kWh for Large Power Customers and $0.002126/kWh for all other customers.

Table 2: Cost Recovery Method 2:

	Large Power	All Other Customers
Allocation (as % of Retail)	34.182%	65.818%
Maximum Target Recovery	$3.6 million[11]	$7.0 million[12]
Test Year Firm Energy	5,574,721 MWh	3,290,254 MWh
Minus Large Power DR Energy	(985,500 MWh)	
Total Billing Units	4,589,221 MWH	3,290,254 MWh
Rate	$0.000792/kWh	$0.002126/kWh

Cost recovery method 2 would result in a maximum monthly bill increase for residential customer of $1.59, or 2.1% and about a 1.2% increase for Large Power Customers.

The Company stated that both methods 1 and 2 result in a net benefit for MP's customers as this represents a cheaper way to obtain peaking energy than building a new generator. Method 1 lessens the impact to residential customers and therefore lessens the impact on customers on a fixed income and low-income customers. Method 2 meanwhile lessens the impact on Industrial customers who have historically been allocated more costs than the class cost of service study in most rate cases suggests they should, however these customers would also be the most likely to benefit from subscribing to Product B. Further, Large Power customers include those that have access to the Company's Energy Intensive Trade Exposed (EITE) pricing. The Department believes either pricing option has merit, and will make its final recommendation after reviewing the comments of other parties. The Department requests that the Company provide in reply comments a discussion of the rate impacts for a customer if

[10] Docket No. E015/GR-16-664
[11] $10.6 million * 34.182%
[12] $10.6 million * 65.818%

they are under both EITE pricing and one of the Company's DR products, particularly Product B. Additionally the Department requests that the Company clarify in reply comments whether customers participating in Product B would be charged the applicable fee associated with whichever cost recovery might be implement.

IV. RECOMMENDATIONS

The Department recommends that the Commission:

- approve the Company's proposed Product A;
- require the Company to include an analysis for updating the Product A credit per kW in an annual Compliance Filing each year for Commission approval;
- approve the Company's proposed Product B;
- require the Company file an annual compliance report including at least the following information:
    - the number of Firm Load Control Periods the Company called,
    - the number of hours per period that the Company called,
    - how many periods met the criteria for the Company to call a Firm Load Control Period but a Firm Load Control Period was not called, and an explanation for why each period was not called,
    - how many customers responded to each event,
    - the amount of curtailed energy,
    - how many customers bought though each period,
    - how many emergency events were called,
    - customer response rates to each emergency DR request, and
    - any other data the Commission determines would be useful; and
- approve the Company's proposed Product C.

The Department also requests that the Company provide the following in reply comments:

- explain if the $5/MWh would be retained by the Company or returned to customers via the Fuel and Purchased Energy Adjustment;
- discuss if there is significant risk of there being an event where the Company is not able to purchase enough energy from the market to account for customers buying though the Firm Load Control Period when MISO is NOT in an emergency condition;
- a discussion of the rate impacts for a customer if they are under EITE pricing and one of the Company's DR products, specifically Product B;
- further support for its proposal to recover the Physical Interruptible Energy Credit of Product B through MP's FPE, including justification for any rule variance that may be required; and

- clarification as to whether customers participating in Product B would be charged the applicable fee associated with whichever cost recovery might be implement.

The Department will provide a final recommendation on cost recovery after reviewing comments from other parties in the instant docket and after reviewing the Company's reply comments.

/jl

Citizens Utility Board of Minnesota Information Request

Date of Request:	February 1, 2019
Requested By:	Joseph Pereira josephp@cubminnesota.org
Requested From:	Minnesota Power
Request Due:	February 11, 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. Please provide the number of Firm Load Control periods Minnesota Power would have called as well as the number of MWhs that would have been curtailed on a monthly basis for the past 5 years had Product B been in place.
2. Please provide the estimated number of Firm Load Control periods Minnesota Power expects to call well as the expected number of MWhs curtailed on a monthly basis over the next five years.

RESPONSE:

1. Below are two table summarizing the Firm Load Control periods (Table 1) that could have called by Minnesota Power over the past five years and the associated industrial energy that might have been curtailed by customers (Table 2).

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

Table 1: Firm Load Control Periods (Hours)

Month	2014	2015	2016	2017	2018
1	189	45	26	61	91
2	143	111	0	0	4
3	35	25	0	46	0
4	23	12	0	30	37
5	89	43	5	34	69
6	35	50	66	58	32
7	4	112	114	126	50
8	4	147	179	56	78
9	0	52	37	25	36
10	52	0	73	46	74
11	16	0	14	64	100
12	5	0	86	49	28
Total	**595**	**597**	**600**	**595**	**599**

Table 2: Potential Energy Curtailments by Industrial Customers

Month	2014	2015	2016	2017	2018
1	28,350	6,750	3,900	9,150	13,650
2	21,450	16,650	0	0	600
3	5,250	3,750	0	6,900	0
4	3,450	1,800	0	4,500	5,550
5	13,350	6,450	750	5,100	10,350
6	5,250	7,500	9,900	8,700	4,800
7	600	16,800	17,100	18,900	7,500
8	600	22,050	26,850	8,400	11,700
9	0	7,800	5,550	3,750	5,400
10	7,800	0	10,950	6,900	11,100
11	2,400	0	2,100	9,600	15,000
12	750	0	12,900	7,350	4,200
Total	**89,250**	**89,550**	**90,000**	**89,250**	**89,850**

2. For the next five years Minnesota Power expects the Firm Load Control periods and associated potential MWhs curtailed will be similar to the historical shown in the tables above. Where the Firm Load Control Periods will likely be concentrated during the peak winter and summer months.

   The proposed Industrial Demand Response product is flexible on when the Firm Load Control Periods can be called. Giving Minnesota Power the capability to adjust when the Firm Load Controls periods are called to align with the changing market dynamics due to the evolving power supply and customer

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

usage patterns. Minnesota Power will manage this proposed demand response product to maximize the value of the energy curtailments for customers.

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

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E015/M-18-735

Dated this 20th day of February 2019

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_18-735_M-18-735
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_18-735_M-18-735
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_18-735_M-18-735
Celine	Carpenter	celine.carpenter@state.mn.us	Department of Transportation	MN Dept of Transportation 395 John Ireland Blvd St. Paul, MN 55155	Electronic Service	No	OFF_SL_18-735_M-18-735
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-735_M-18-735
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-735_M-18-735
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_18-735_M-18-735
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_18-735_M-18-735
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_18-735_M-18-735
Barbara	Gervais	toftemn@boreal.org	Town of Tofte	P O Box 2293 7240 Tofte Park Road Tofte, MN 55615	Electronic Service	No	OFF_SL_18-735_M-18-735

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Janice	Hall	N/A	Cook County Board of Commissioners	411 W 2nd St Court House Grand Marais, MN 55604-2307	Paper Service	No	OFF_SL_18-735_M-18-735
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-735_M-18-735
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_18-735_M-18-735
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-735_M-18-735
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-735_M-18-735
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_18-735_M-18-735
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Electronic Service	No	OFF_SL_18-735_M-18-735
Marion Ann	McKeever	N/A	Satellites Country Inn	9436 W Hwy 61 Schroeder, MN 55613	Paper Service	No	OFF_SL_18-735_M-18-735
Herbert	Minke	hminke@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_18-735_M-18-735

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_18-735_M-18-735
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-735_M-18-735
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_18-735_M-18-735
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_18-735_M-18-735
Thom	Petersen	Thom.Petersen@state.mn.us	MN Department of Agriculture	625 North Robert St Saint Paul, MN 55155	Electronic Service	No	OFF_SL_18-735_M-18-735
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_18-735_M-18-735
Britt	See Benes	britt@ci.aurora.mn.us	City of Aurora	16 W 2nd Ave N PO Box 160 Aurura, MN 55705	Electronic Service	No	OFF_SL_18-735_M-18-735
John Linc	Stine	john.stine@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd Saint Paul, MN 55155	Paper Service	No	OFF_SL_18-735_M-18-735
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_18-735_M-18-735
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_18-735_M-18-735