MINNESOTA DEPARTMENT OF COMMERCE

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June 2, 2017

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

RE: **Supplemental Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G011/M-16-652

Dear Mr. Wolf:

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

> A Request by Minnesota Energy Resources Corporation (MERC or the Company) for Approval of a Change in Demand Entitlement for its Customers Served off of the Northern Natural Gas-Albert Lea (NNG-ABL) System Effective in the Purchased Gas Adjustment (PGA) on November 1, 2016.

MERC submitted its initial filing on August 1, 2016. The Company filed an updated filing on November 1, 2016 and *Reply Comments* on November 7, 2016. The petitioner is:

> Amber S. Lee
> Minnesota Energy Resources Corporation
> 1995 Rahncliff Court, Suite 200
> Eagan, MN 55122

To ensure that the record is complete in this docket, the Department provides the following response to MERC's November 1, 2016 *Update* and November 7, 2016 *Reply Comments.* The Department recommends that the Minnesota Public Utilities Commission (Commission) **accept** the Company's proposed level of demand entitlement and allow MERC to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2016.

The Department is available to answer any questions that the Commission may have.

Sincerely,

/s/ MICHAEL RYAN
Rates Analyst

/s/ SACHIN SHAH
Rates Analyst

MR/SS/lt
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

SUPPLEMENTAL COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE

DOCKET NO. G011/M-16-652

I. SUMMARY OF COMPANY'S PROPOSAL

Effective May 1, 2015, Minnesota Energy Resources Corporation (MERC or the Company) acquired Interstate Power & Light Company's (IPL) Minnesota natural gas operations and customers. The Minnesota Public Utilities Commission (Commission) required MERC to maintain the transitioned customers on a separate Purchased Gas Adjustment (PGA) until MERC's next rate case.[1] MERC named the PGA for the transitioned customers "Northern Natural Gas-Albert Lea" (NNG-ABL).

Pursuant to Minn. R. 7825.2910, subpart 2, MERC filed a change in demand (capacity) entitlement petition (Petition) on August 1, 2016 for its customers served off of the NNG-ABL PGA system.[2] In its Petition, MERC requested no changes in the level of contracted capacity.

On October 28, 2016, the Department of Commerce, Division of Energy Resources (Department or DOC) filed comments requesting additional information regarding the following:

- The justification of its selection of data from the Rochester weather station in MERC-NNG-ABL's peak-day analysis; and
- As part of its justification, MERC should redo its design-day regression analysis with Albert Lea weather data and provide the results in its *Reply Comments.*

The Department stated that it would offer additional comments and recommendations after MERC filed its *Reply Comments*.

[1] See the Commission's December 8, 2014 *Order Approving Sale Subject to Conditions* in Docket No. G-001, G011/PA-14-107.
[2] In its December 21, 2012 Order in Docket No. G007,011/GR-10-977, the Commission approved consolidation of MERC's four PGA systems effective July 1, 2013. MERC named the PGA for the Northern Natural Gas customers "MERC-NNG." At the time, MERC's only other PGA system was named "MERC-Consolidated." On August 1, 2016, MERC filed a demand entitlement request for MERC-Consolidated in Docket No. G011/M-16-651 and MERC-NNG in Docket No. G011/M-16-650.

Because the natural gas heating season spans the five-month period from November through March, the Company has the ability to secure capacity up until November 1st of each year. On November 1, 2016, MERC submitted an update to its August 1, 2016, Demand Entitlement filing, stating it would provide the additional information requested by the Department regarding Albert Lea weather data in subsequent *Reply Comments*.

On November 7, 2016 MERC filed its *Reply Comments* addressing the Department's request described above. The Department discusses the responses below.

II. THE DEPARTMENT'S ANALYSIS OF THE COMPANY'S PROPOSAL

The Department analysis of the Company's request includes the following topics, which match the areas addressed in our initial comments:

- changes to capacity;
- design-day requirement;
- reserve margin; and
- PGA cost recovery proposal.

A. MERC'S PROPOSED CHANGES

1. Capacity

As an initial matter, the Department confirms that, as required by the Commission's Order Point 9[3] of its April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, MERC provided separate data on its summer and winter demand entitlements.[4]

As indicated in DOC Attachments 1 and 2, the Company proposed to keep its total entitlement level in Dth[5] the same as the prior year as follows:

Table 1: MERC's NNG-ABL Total Entitlement Levels

Filing	Previous Entitlement (Dth)	Proposed Entitlement (Dth)	Entitlement Changes (Dth)	Change From Previous Year (%)
November 1, 2016	14,190	14,190	0	0%

[3] Order Point 9 states, "Required MERC to separate its summer and winter demand entitlements as reflected in Attachment 4 of its petitions, rather than combining the data as reflected on Attachment 3 of its petitions."
[4] See MERC Attachment 3.
[5] Dekatherms

In addition to reviewing the proposed changes in demand, the Department also reviews other changes in non-capacity items in the demand change filings.[6] As in last year's filing, MERC was assigned 350,000 Dth[7] of Northern Natural Gas (NNG) Firm Deferred Delivery (FDD) storage and related reservation of 6,071 Dth from IPL. MERC also took assignment of 1,700 Dth of NNG's System Management Service (SMS), which provides additional tolerances for shippers, beyond the allowed five-percent tolerance.[8] MERC's proposed level of demand entitlement appears reasonable.

2. Design-Day Requirement

As discussed above, the Department filed comments on October 28, 2016 requesting additional information regarding the justification of MERC's selection of data from the Rochester weather station in the peak-day analysis and requested that MERC redo its design-day regression analysis with Albert Lea weather data.

With regards to the justification of Rochester weather station data, MERC stated the following:

> MERC responds that at the time of its August 1, 2016, filing, MERC did not possess the necessary Albert Lea weather data to utilize in its regression.
>
> … Because of the small size of the Albert Lea PGA and its proximity to MERC's existing weather stations, in particular, Rochester, MERC surmised that the use of historic weather data for Albert Lea would not significantly improve the quality of the design-day regression. Though MERC continues to believe the weather data relied upon for its initial design-day regression analysis was reasonable and appropriate, MERC has been able to obtain and verify adequate historical Albert Lea data to incorporate in the regression analysis at this time.[9]

In its *Comments*, the Department stated the following[10]:

> In the Department's December 31, 2015 Comments in Docket No. G011/M-15-724, at pages 4-5, the Department discussed how the Albert Lea Town Border Station (TBS) experienced the vast majority of the throughput used to serve MERC's (formerly IPL's) customers. In the Commission's April 28, 2016 Order in

[6] Minnesota Rule 7825.2910, subp. 2, requires that gas utilities file for a change to increase or decrease demand.
[7] This is the five-month Maximum Storage Quantity (70,000 Dth/month x 5 months).
[8] Storage and SMS costs are charged in the commodity portion of the PGA.
[9] MERC *Reply Comments* pages 1-2.
[10] Department *Comments* at page 4.

> Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M 15-724, Order Point 6 stated the following:
>
> > Accepted MERC-NNG-Albert Lea's peak-day analysis with the following caveat: Required MERC to fully justify its selection of the Rochester weather station as opposed to Albert Lea in its Design Day calculation in its next NNG-Albert Lea demand entitlement petition; and
>
> Even though MERC requested no changes in the level of contracted capacity, the Department recommends that MERC provide the justification of its selection of the Rochester weather station in its Reply Comments, and thus comply with the Commission's Order referenced above. In addition, the Department requests that as part of its justification, MERC redo its design-day regression analysis with Albert Lea weather data and provide the results concurrently with its *Reply Comments*.

According to MERC, "utilizing the Albert Lea weather data did improve the overall design-day regression models". MERC also provided a Table in its Reply Comments[11] showing the total design-day estimates and associated reserve margins and impact of using the Albert Lea weather data as follows:

Table 2: MERC's NNG-ABL Reserve Margin

Filing	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %
August 1, 2016	14,190	13,528	662	4.89
November 7, 2016	14,190	13,262	928	7.00

In its *Reply Comments*, MERC stated.[12]

> MERC notes that the change to the design day is only 266 Dth. Even if MERC had utilized the Albert Lea weather data in its original design-day regression analysis it would not have impacted MERC's proposed demand entitlements because MERC would not have been able to reduce its contract entitlements for the NNG-Albert Lea PGA by such a small increment.

[11] MERC's Nov. 7, 2016 *Reply Comments* page 2.
[12] MERC *Reply Comments* page 2.

The Department reviewed MERC's calculations provided in its *Reply Comments*, and concludes that they are reasonable, and that MERC has complied with the Commission's April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724. The Department agrees with MERC that the Company would not have been able to reduce its contract entitlements given that it inherited the contract as a result of its acquisition of Interstate Power & Light Company's (IPL) Minnesota natural gas operations and customers effective May 1, 2015.

The Department recommends that the Commission approve the Company's peak-day analysis as set forth in MERC's *Reply Comments.*

3. Reserve Margin

Table 3 and DOC Attachment 2 present MERC's proposed reserve margin in Dth as filed on August 1, 2016 and November 1, 2016 as follows:

Table 3: MERC's NNG-ABL Reserve Margin (Rochester Design-Day)

Filing	Total Entitlement (Dth)	Rochester Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %	Percentage Point Change From Previous Year
November 1, 2016	14,190	13,528	(662)	4.89%	2.16%

The proposed reserve margin of 4.89 percent represents an increase of 2.16 percentage points over last year's reserve margin of 2.73 percent.

On November 7, 2016, the Company provided updated design-day data using Albert Lea weather data instead of Rochester data as described above in the design-day section of comments. The updated design-day results in the following reserve margin:

Table 3a: MERC's NNG-ABL Reserve Margin (Albert Lea Design-Day)

Filing	Total Entitlement (Dth)	Albert Lea Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %	Percentage Point Change From Previous Year
November 7, 2016	14,190	13,262	(928)	7.00%	4.27%

The Department recommends that the Commission approve the Company's reserve analysis.

The Department notes that, in contrast to the electric utility industry, natural gas reserve margins are utility-specific rather than regionally specific, as more fully discussed in DOC Attachment 4. However, given Minnesota's efforts to expand natural gas use in under- and unserved areas, and the increasing use of natural gas for electricity generation, there is a growing need to more closely examine reserve margins and to integrate natural gas supply planning with electric resource planning. In light of this recognition, the Department has issued information requests (see DOC Attachment 5) and will review those responses, in addition to information provided in the annual service quality and annual automatic adjustment reports, to ascertain, among other things, the number and timing of interruptions (curtailments) that have occurred in the past 5 years, and the causes of those curtailments, as a first step in assessing whether the demand entitlements procured, including reserve margins in place at those times were sufficient or justified, and to begin monitoring the growing inter-relationship between the natural gas and electric industries.

C. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The Company's demand entitlement proposal would result in the following annual demand cost impacts as shown in detail in DOC Attachment 3:

- Annual bill increase of $0.00 related to demand costs for the average General Service customer consuming 76 Dth annually;
- no demand cost impacts related to MERC-ABL's Large General Service and interruptible rate classes.

III. THE DEPARTMENT'S RECOMMENDATIONS

Based on our review, the Department recommends that the Commission approve MERC's *Petition*, as modified in its November 1, 2016 *Update* and November 7, 2016 Reply Comments.

/lt

Department Attachment 1
Docket No. G011/M-16-652
MERC NNG-Albert Lea Demand Entitlement Historical and Current Proposal

			Proposed 11/1/16			
Contract Type	2014-2015 Quantity (Mcf)	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
TF12B	1,393	3,904	3,904	0		
TF12V	8,020	5,489	5,489	0		
TF5	4,006	3,997	3,997	0		
TFX(5)	800	800	800	0		
Total Entitlement	14,219	14,190	14,190	0	0.00%	-2.06%
Total Annual Transportation	9,413	9,393	9,393	0	0.00%	
Total Winter Only Transport	4,806	4,797	4,797	0	0.00%	
Percent of Winter Only Capacity	33.80%	33.81%	33.81%			

Source: MERC's Attachments 3 & 7

Department Attachment 2
Docket No. G011/M-16-652
MERC NNG-Albert Lea Demand Entitlement Analysis

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Heating Season	Number of Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dth)	Change from Previous Year	% Change From Previous Year	Total Design-Day Capacity (Dth)	Change from Previous Year	% Change From Previous Year	Reserve (7) - (4)	% Reserve [(7)-(4)]/(4)
2016-2017	10,734	44	0.41%	13,528	(285)	-2.06%	14,190	0	0.00%	662	4.89%
2015-2016	10,690	0	0.00%	13,813	898	6.95%	14,190	(29)	-0.20%	377	2.73%
2014-2015	10,690	14	0.13%	12,915	(120)	-0.92%	14,219	0	0.00%	1,304	10.10%
2013-2014	10,676	68	0.64%	13,035	(407)	-3.03%	14,219	0	0.00%	1,184	9.08%
2012-2013	10,608	(41)	-0.39%	13,442	515	3.98%	14,219	(3,271)	-18.70%	777	5.78%
2011-2012	10,649	66	0.62%	12,927	(3,767)	-22.56%	17,490	0	0.00%	4,563	35.30%
2010-2011	10,583			16,694			17,490			796	4.77%
Average			0.24%			-2.94%			-3.15%		10.38%

	Firm Peak-Day Sendout			Per Customer Metrics			
	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Heating Season	Firm Peak-Day Sendout (Dth)	Change from Previous Year	% Change From Previous Year	Excess per Customer [(7) - (4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak-Day Send per Customer (12)/(1)
2016-2017	unknown			0.0617	1.2603	1.3220	unknown
2015-2016	10,733	16	0.15%	0.0353	1.2921	1.3274	1.0040
2014-2015	10,717	(513)	-4.57%	0.1220	1.2081	1.3301	1.0025
2013-2014	11,230	1,318	13.30%	0.1109	1.2210	1.3319	1.0519
2012-2013	9,912	1,500	17.83%	0.0732	1.2672	1.3404	0.9344
2011-2012	8,412	(1,830)	-17.87%	0.4285	1.2139	1.6424	0.7899
2010-2011	10,242			0.0752	1.5774	1.6527	0.9678
Average			1.77%	0.1295	1.2914	1.4210	0.9584

Source: MERC's Attachment 1

Department Attachment 3
Docket No. G011/M-16-652
MERC NNG-Albert Lea Rate Impacts

General Service-Residential	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 10/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.6168	$2.8063	$3.1676	$3.0390	-15.98%	8.29%	-4.06%	($0.1286)
Demand Cost	$1.0379	$0.9194	$1.0379	$1.0379	0.00%	12.89%	0.00%	$0.0000
Commodity Margin	$2.3980	$2.1806	$2.3980	$2.3980	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$7.0527	$5.9063	$6.6035	$6.4749	-8.19%	9.63%	-1.95%	($0.1286)
Average Annual Use	76	76	76	76				
Average Annual Cost of Gas*	$536.01	$448.88	$501.87	$492.09	-8.19%	9.63%	-1.95%	($9.77)

Large General Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 10/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.6168	$2.8063	$3.1676	$3.0390	-15.98%	8.29%	-4.06%	($0.1286)
Demand Cost[1]	$1.0379	$0.9194	$1.0379	$1.0379	0.00%	12.89%	0.00%	$0.0000
Commodity Margin	$1.8232	$1.6579	$1.8232	$1.8232	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$6.4779	$5.3836	$6.0287	$5.9001	-8.92%	9.59%	-2.13%	($0.1286)
Average Annual Use	350	350	350	350				
Average Annual Cost of Gas[2]	$2,267.27	$1,884.26	$2,110.05	$2,065.04	-8.92%	9.59%	-2.13%	($45.01)

SV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 10/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.6168	$2.8063	$3.1676	$3.0390	-15.98%	8.29%	-4.06%	($0.1286)
Commodity Margin	$0.9336	$0.8490	$0.9336	$0.9336	0.00%	9.96%	0.00%	$0.0000
Total Cost of Gas	$4.5504	$3.6553	$4.1012	$3.9726	-12.70%	8.68%	-3.14%	($0.1286)
Average Annual Use	6,043	6,043	6,043	6,043				
Average Annual Cost of Gas*	$27,498.07	$22,088.98	$24,783.55	$24,006.42	-12.70%	8.68%	-3.14%	($777.13)

LV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 10/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.6168	$2.8063	$3.1676	$3.0390	-15.98%	8.29%	-4.06%	($0.1286)
Commodity Margin	$0.5007	$0.4553	$0.5007	$0.5007	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$4.1175	$3.2616	$3.6683	$3.5397	-14.03%	8.53%	-3.51%	($0.1286)
Average Annual Use	9,759	9,759	9,759	9,759				
Average Annual Cost of Gas*	$40,182.68	$31,829.95	$35,798.94	$34,543.93	-14.03%	8.53%	-3.51%	($1,255.01)

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	($0.1286)	$0.0000	($0.1286)	-1.95%	($9.77)
Large General Service	($0.1286)	$0.0000	($0.1286)	-2.13%	($45.01)
SV Interruptible Service	($0.1286)	$0.0000	($0.1286)	-3.14%	($777.13)
LV Interruptible Service	($0.1286)	$0.0000	($0.1286)	-3.51%	($1,255.01)

[1]The Department confirmed informally with MERC that Attachement 4 in the November 1 Update inadvertantly ommitted the demand cost for Large General Service. The demand cost is correctly stated in this attachment.

[2]Average Annual Bill amount does not include customer charges.

Prepared by the Minnesota Department of Commerce

Attachment 4 – Natural Gas Reserve Margins

Below is a brief summary of the differences between the electric and natural gas industries in terms of setting reserve requirements, and the factors impacting how natural gas reserve margins are developed.

A retail natural gas distribution utility acquires the product demanded by its customers through contracting with a natural gas transmission pipeline company for certain levels of product for specified time periods. A vertically integrated electricity provider supplies most of its own product (through owned generation or purchased power agreements), relying on the non-contractual market [for Minnesota, the Midcontinent Independent System Operator (MISO)] when consumption exceeds the levels planned or outages prevent supply at the planned levels. Thus, the electric industry structure requires interdependency among market participants, necessitating a common reserve margin to ensure balanced reliance on the larger system.

A major factor differentiating electricity and natural gas is a greater availability of storage options for natural gas as opposed to electricity. For example, if natural gas utilities are aware in advance of a cold snap in weather, they may use "line pack" as a way to "store" natural gas temporarily in the pipe for use during the cold snap. Further, when natural gas consumption exceeds the levels planned or pipelines are damaged causing a loss of supply, natural gas utilities may turn to their own storage resources, propane or liquefied natural gas peaking plant capabilities, curtail natural gas supplied to interruptible customers, or seek to procure capacity release opportunities, if any exist at that time and location.

Moreover, there is not an energy market or independent system operator to dispatch resources, as there is in the electric industry, in part because the natural gas systems are less interdependent on each other. Therefore, reserve margins on the natural gas system are utility-specific rather than regionally specific.

Natural gas reserve margins are not only utility-specific, but there may in effect be different levels of reserve margins in different places on the natural gas utility's system. That is, it may be misleading to consider one reserve margin as accurately reflecting the ability of the utility to supply natural gas. A utility may have what appears to be a reasonable overall reserve margin, but still experience curtailments at a certain Town Border Station (TBS) due to the inability to physically move available product to that location. Similarly, a utility may have what appears to be an unreasonably low reserve margin but still have large reserve margins at certain locations, with the flexibility (through a loop, for example) to move the excess gas to another location to avoid curtailments.

Appropriate natural gas reserve margins can be set using various methods. For instance, a natural gas reserve margin could be set equal to the output capability of a utility's propane or liquefied natural gas peaking plant because the function of that peaking plant is to provide product at times when demand exceeds pipeline supply. Therefore, it may be reasonable to set the reserve margin at the level of the peaking plant's capacity in order to ensure that peak demand is met should the peaking plant experience an outage. (This approach is called an "N minus one" approach.)

Natural gas utilities procure pipeline supply considering both minimum demand and peak demand. Minimum usage (minimum day load) on a winter day is estimated to ensure that base load gas acquired does not exceed the ability of the company to either use the gas for system load or to inject the gas into storage. The natural gas design-day calculation estimates the maximum firm demand anticipated under the most extreme weather conditions. The extent to which a utility procures entitlements in excess of its estimate of maximum firm demand may vary by utility depending on factors such as how much storage is in place, whether the utility has a peaking plant and the size of the plant, past experience, and expectation for load growth. Further, there may be a need to procure additional entitlements to meet design-day requirements, but the pipeline suppliers may not offer entitlements at the specific level needed. The excess amount procured could be considered, or proposed as, that utility's reserve margin, but the percentage represented by that reserve margin is not the result of a calculation; rather, it was dictated by the need to fulfill design-day needs. In other words, under certain circumstances a reserve margin may exceed the levels traditionally considered reasonable by the Commission, but be legitimately dictated by the availability of supply to meet the obligation to provide firm service.

At this time, the Commission should continue to determine the reasonableness of natural gas resources on a case-by-case basis.

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G999/AA-16-524	☐Nonpublic ☒Public
Requested From:	All regulated gas utilities	Date of Request: 3/10/2017
		Response Due: 3/20/2017

Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

Request Number: **18**
Topic: Distribution Planning

Request:

A. Please provide a detailed discussion of how the utility plans, constructs, and maintains its distribution system. As part of this response, include a discussion about how the utility decides to add capacity or expand in to new, or growing, service territory.
B. Please provide daily throughput data, by each individual Town Border Station (TBS) or delivery point, on the utility's system since November 1, 2012. If available, please provide these data divided by firm, interruptible, and transport load. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
C. Please provide the number of interruption days, by TBS or delivery point, by month since November 2012. To the extent possible, please identify the number of interruption days that are non-weather related (*e.g.,* reliability purposes). Please also provide these data in Microsoft Excel format with all links, and formulae intact.
D. Please provide, on a daily basis since November 1, 2012 by TBS or delivery point, the maximum deliverable throughput by customer type. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
E. Please provide, by TBS or delivery point, on a daily basis since November 1, 2012 the percentage of deliverable capacity subscribed by the utility. If applicable, please identify other parties, and their percentages of subscribed capacity, at the TBS. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
F. Please provide the following forecasted data, in Microsoft Excel format with all links and formulae intact, by TBS, or delivery point, for the next three heating seasons. If the utility expects daily fluctuation, please provide these data on a daily basis:
   a. Total utility throughput, if possible, divided by customer type (*i.e.*, firm, interruptible, transport); and
   b. Expected firm and total throughput available at the TBS or delivery point.
G. Please provide maps, by county, identifying the location (and name) of any, and all, TBSs or delivery points on the utility's system. If possible, please provide these maps in pdf and GIS executable formats.

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number: G999/AA-16-524 ☐Nonpublic ☒Public
Requested From: All regulated gas utilities
Date of Request: 3/10/2017
Response Due: 3/20/2017

Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

a. Please identify, by county, on the maps in Part F, the location of any, and all, transmission assets on the utility's system.
b. If the utility has an affiliate transmission or intrastate pipeline utility, please also identify these assets on the maps provided in Part F, by county.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

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
Supplemental Comments

Docket No. G011/M-16-652

Dated this 2nd day of June 2017

/s/Sharon Ferguson

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