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-16-650

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 Company (Northern or NNG) System Effective in the Purchased Gas Adjustment (PGA) on November 1, 2016.

MERC submitted its initial filing on August 1, 2016 (Petition). The Company filed an updated filing on November 1, 2016 (Update) 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

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

SUPPLEMENTAL COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE

DOCKET NO. G011/M-16-650

I. SUMMARY OF COMPANY'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2, Minnesota Energy Resources Corporation (MERC or the Company) filed a change in demand entitlement petition (Petition) on August 1, 2016 for its customers served off of the Northern Natural Gas Company (Northern or NNG) pipeline system.[1] MERC requested that the Minnesota Public Utilities Commission (Commission or PUC) approve recovery of costs associated with maintaining the existing level of contracted capacity, and increasing two storage contracts.[2]

On October 28, 2016 the Department of Commerce, Division of Energy Resources (Department) filed Comments requesting additional information regarding the Company's storage capacity additions, and asking MERC to reconcile the design-day regression data, and provide more information on the low reserve margin for the MERC-NNG PGA. Specifically, the Department requested:

- Storage Capacity Additions – provide further detail on the decision to add additional storage capacity;
- Design-Day Analysis - in sufficient detail to permit duplication, reconciliation of any and all difference(s) that are identified of discrepancies in the historical data for MERC's Rochester regression analysis. The Company should also explain if the reconciliation requested will impact the Company's design day analysis and/or Exhibits A through D filed by the Company on August 1, 2016. If so, the Department requests that MERC provide the corrected Exhibits and design-day analysis reflecting the Company's reconciliation; and

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[1] In its December 21, 2012 Order in Docket No. G007,011/GR-10-977, the Commission approved consolidation of MERC's 4 PGA systems effective July 1, 2013. MERC named the PGA for the NNG customers "MERC-NNG." At the time, MERC's only other PGA system was named "MERC-Consolidated." Effective May 1, 2015, MERC acquired Interstate Power & Light Company's Minnesota natural gas operations and customers. The Commission required MERC to maintain the transitioned customers on a separate PGA until MERC's next rate case. MERC named the PGA for the transitioned customers "MERC NNG-Albert Lea." On August 1, 2016, MERC filed a demand entitlement request for MERC-Consolidated in Docket No. G011/M-16-651 and MERC NNG-Albert Lea in Docket No. G011/M-16-652.

[2] MERC noted in its August cover letter that any updated information would be provided with the Company's November 1, 2016 filing.

- Reserve Margin – provide further information on the driver of the low reserve margin. Describe any actions that MERC may be contemplating to address the relatively low NNG reserve margin.

Because the natural gas heating season spans the 5-month period from November through March, the Company has the ability to secure capacity up until November 1st of each year. The Company provided an updated filing on November 1, 2016. Included with the Update, MERC provided information regarding the storage capacity additions, the low reserve margin, and indicated that they would provide the requested additional design-day data in subsequent Reply Comments.

On November 7, 2016 MERC filed its Reply Comments addressing the Department's design-day data reconciliation concerns.

On May 31, 2017, MERC filed a second Letter to provide notice that its contract demand would change effective June 1, 2017 due to the renewal of a storage capacity release at a greater volume than reported November 1, 2016. Because the change occurred June 1, 2017, it does not impact the design day analysis in this docket. The Company has confirmed that it will provide updated analysis in the 2017-2018 Demand Entitlement filing.

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

The Department's 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
- purchased gas adjustment (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 the same as the prior year as follows:

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[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.

Table 1: MERC's NNG Total Entitlement Levels

Filing	Previous Entitlement (Dth)	Proposed Entitlement (Dth)	Entitlement Changes (Dth)	Change From Previous Year (%)
November 1, 2016	252,127	252,127	0	0%

As discussed in the Department's October 28, 2016 Comments, MERC-NNG's proposed level of demand entitlement appears reasonable.

The Company also responded as follows to the Department's request for more information on MERC's addition of storage:[5]

> Without the increase in storage capacity, MERC would have had just under 30% of its forecast winter supply needs met by storage. With the increase, MERC is at 31.6% of forecast winter volume.

And;

> NNG storage has been difficult to procure in past years and firm storage (FDD) has not been available on the pipeline since March 4, 2013. MERC increased its storage capacity through a one-year capacity release with a third party that does not currently utilize its entire allotment of capacity. MERC has traditionally taken the entire volume this party offers because storage is otherwise unavailable. While slightly over its target of 30%, MERC's procurement allows the Company to maintain a relationship with a third party whereby future capacity can be procured at maximum tariff rates through release. In comparison, MERC pays nearly double maximum tariff rates for the portion of storage contract 118657 that was acquired through a storage expansion with NNG in 2008.
>
> The Department also requested that MERC address why the contracted rates are above the NNG maximum tariff rate of $1.7140/Dth and $0.3567 for Reservation and Storage Cycle, respectively. MERC responds that the pricing of storage contract number 118657 is based on a market-based expansion. Under this pricing, MERC pays maximum tariff rates plus the cost of the expansion over the term of the contract.

[5] MERC Update, November 1, 2016, pages 14-15.

> In previous years, the demand cost associated with physical call options has been high. The influx of Canadian gas into MERC's market area has made these physical options much more attractive, so MERC entered into a number of physical call options that will ensure the Company has increased certainty around meeting peak day requirements. The demand cost is shown in Attachment 4, page 2. The premiums paid range from $0.015-0.0425 dth/day.

The Department appreciates MERC's response and does not have any outstanding issues or questions.

2. *Design-Day Requirement*

As discussed in MERC's initial Petition and in the Department's initial Comments, the Company proposed to increase its total design day in Dth as follows:

Table 2: MERC's NNG Design Day Levels

Filing	Previous Design Day (Dth)	Proposed Design Day (Dth)	Design Day Changes (Dth)	Change From Previous Year (%)
November 1, 2016	245,263	248,796	3,533	1.44%

While not opposed to MERC's approach to its design-day analysis, the Department observed discrepancies in the historical data included in the Company's Rochester regression analysis.

In its Reply Comments, MERC stated the following[6]:

> Attachment 1 to these Reply Comments summarizes the total throughput and net throughput by gate station. The attachment also explains data differences for overlapping gate stations.
>
> **A majority of the difference between the two analyses is the geographic scope**. The demand entitlement peak day analysis used data from the gate stations in the vicinity of the Rochester weather station. The Docket G011/M-15-895 filing relates to a **smaller subset** of gate stations. The analysis provided in Docket G011/M-15- 895 also included Cannon Falls, which the demand entitlement peak day analysis placed in the Minneapolis region.

[6] MERC Reply Comments at page 2.

In addition, MERC had previously explained that when preparing the regression data and reviewing its daily total metered throughput, MERC, to the extent possible, had fixed missing or bad reads and where it was not possible to do so, the data was not included in the regressions. As previously stated by the Department, MERC's approach did not seem unreasonable.

In its Reply Comments, MERC had also stated the following[7]:

> These same adjustments were not made to the data utilized to complete the regression in Docket No. G011/M-15-895. Rather, MERC utilized the data that was available at the time that filing was compiled and did not conduct the same process to adjust missing or bad reads. Additionally, there were some reads in which interruptible customers were "netted out" of the throughput in the Docket G011/M-15-895 filing. For MERC's August 1, 2016 Demand Entitlement filing, this data was provided so that total throughput includes all volumes.

The Department reviewed MERC's calculations and explanations for the reconciliation provided in its Reply Comments, and concludes that they are acceptable.[8] As a result, the Department recommends that the Commission approve the Company's peak-day analysis.

3. Reserve Margin

As indicated in DOC Attachment 2, the proposed reserve margin is 3,331 Dth, or 1.34 percent, as follows:

Table 3: MERC's NNG Reserve Margin

Filing	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %	Percentage Point Change From Previous Year
November 1, 2016	252,127	248,796	3,331	1.34%	(1.46)%

The proposed reserve margin of 1.34 percent represents a decrease of 1.46 percentage points as compared to last year's reserve margin of 2.80 percent.[9] Table 5 below lists MERC-NNG reserve margins for the past 5 years.

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[7] MERC Reply Comments page 3.
[8] See MERC's Reply Comments, Attachment 1.
[9] MERC Petition, Attachment 3.

Table 4: MERC's NNG Proposed and Historical Reserve Margins

2016-2017	1.34%
2015-2016	2.80%
2014-2015	2.06%
2013-2014	4.27%
2012-2013	3.37%

In Reply Comments, the Company noted that Docket No. G011/M-15-895[10] is ongoing and has the potential to increase NNG capacity in the Rochester area and provide flexibility for MERC to alternative NNG delivery points. The Company also stated that given the potential for added capacity beginning 2018/2019, it makes sense to maintain a small reserve margin. The Department notes that the Commission approved MERC's petition in Docket No. G011/M-15-895 at its March 23, 2017 Agenda Meeting; therefore, the Department expects that capacity additions will be forthcoming in the near future. Given that the 2016-2017 heating season has concluded, the Department has no outstanding issue with the MERC-NNG's 2016-2017 reserve margin.

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 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 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.

B. THE COMPANY'S PGA COST RECOVERY PROPOSAL

In its Reply Comments, the Company compared its October 2016 PGA to its projected November 2016 PGA rates to highlight the changes in demand costs (MERC Attachment 4, Page 1 of 3). The Company's demand entitlement proposal would result in the following annual demand cost impacts:

- annual bill increase of $0.01 related to demand costs, or less than .02 percent, for the average General Service customer consuming 76 Dth annually;

[10] *In the Matter of a Petition by Minnesota Energy Resources Corporation for Project Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project*.

- annual bill increase of $0.05 related to demand costs, or approximately 0.02 percent, for the average Small Volume Firm customer consuming 4,508 Dth annually;
- annual bill increase of $0.15 related to demand costs, or approximately 0.02 percent, for the average Large Volume Firm customer consuming 12,372 Dth annually;
- no demand cost impacts related to MERC-NNG's 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, and allow MERC to recover the associated demand costs through the monthly PGA effective November 1, 2016.

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Department Attachment 1
Docket No. G011/M-16-650
MERC NNG Demand Entitlement Historical and Current Proposal

	Historical Demand Entitlements			Proposed 11/1/16			
Contract Type	2013-2014 Quantity (Mcf)	2014-2015 Quantity (Mcf)	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
TF12B	49,153	55,019	45,026	45,026	0		
TF12V	26,926	21,060	30,290	30,290	0		
TF5	31,515	31,515	32,278	32,278	0		
TFX12	32,297	32,297	32,297	32,297	0		
TFX(5)	93,084	123,084	108,701	108,701	0		
TFX (April Only)*	2,000	2,000	2,000	2,000	0		
TFX (October Only)*	2,000	2,000	2,000	2,000	0		
Windom	2,500	2,500	2,500	2,500	0		
Northwestern Energy	910	910	1,035	1,035	0		
NNG Zone Delivery Call Option	20,000	0	0	0	0		
Bison**	50,000	50,000	50,000	50,000	0		
NBPL**	50,000	50,000	50,000	50,000	0		
Total Entitlement	**256,385**	**266,385**	**252,127**	**252,127**	**0**	**0.00%**	**1.44%**
Total Annual Transportation	**131,786**	**111,786**	**111,148**	**111,148**	**0**	**0.00%**	
Total Winter Only Transport	**124,599**	**154,599**	**140,979**	**140,979**	**0**	**0.00%**	
Percent of Winter Only Capacity	48.60%	58.04%	55.92%	55.92%			

*Total entitlement is calculated during the heating season, which includes the five months of November-March. April- and October-only contracts do not meet this criteria.
**Entitlement for Bison and NBPL is not included in the total as it does not add incremental capacity due to the fact that NNG capacity would still be required.
Source: MERC's Attachments 3 & 7

Department Attachment 2
Docket No. G011/M-16-650
MERC NNG 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	184,577	3,251	1.79%	248,796	3,533	1.44%	252,127	0	0.00%	3,331	1.34%
2015-2016	181,326	2,938	1.65%	245,263	(15,739)	-6.03%	252,127	(14,258)	-5.35%	6,864	2.80%
2014-2015	178,388	(190)	-0.11%	261,002	15,124	6.15%	266,385	10,000	3.90%	5,383	2.06%
2013-2014	178,578	1,641	0.93%	245,878	19,995	8.85%	256,385	22,900	9.81%	10,507	4.27%
2012-2013	176,937	1,696	0.97%	225,883	(9,172)	-3.90%	233,485	(12,500)	-5.08%	7,602	3.37%
2011-2012	175,241	(786)	-0.45%	235,055	16,842	7.72%	245,985	(15,690)	-6.00%	10,930	4.65%
2010-2011	176,027	799	0.46%	218,213	(9,827)	-4.31%	261,675	7,000	2.75%	43,462	19.92%
2009-2010	175,228	1,266	0.73%	228,040	(19,148)	-7.75%	254,675	4,227	1.69%	26,635	11.68%
2008-2009	173,962	1,846	1.07%	247,188	23,434	10.47%	250,448	0	0.00%	3,260	1.32%
2007-2008	172,116	7,063	4.28%	223,754	1,635	0.74%	250,448	2,036	0.82%	26,694	11.93%
2006-2007	165,053			222,119			248,412			26,293	11.84%
Average			1.13%			1.34%			0.25%		6.83%

	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			0.0180	1.3479	1.3660	unknown
2015-2016	204,444	10,596	5.47%	0.0379	1.3526	1.3905	1.1275
2014-2015	193,848	(18,958)	-8.91%	0.0302	1.4631	1.4933	1.0867
2013-2014	212,806			0.0588	1.3769	1.4357	1.1917
2012-2013				0.0430	1.2766	1.3196	
2011-2012				0.0624	1.3413	1.4037	
2010-2011				0.2469	1.2397	1.4866	
2009-2010				0.1520	1.3014	1.4534	
2008-2009				0.0187	1.4209	1.4397	
2007-2008				0.1551	1.3000	1.4551	
2006-2007				0.1593	1.3457	1.5050	
Average			-1.72%	0.0893	1.3424	1.4317	1.1353

*Effective 7/1/13 MERC PGAs were consolidated from four down to two (NNG and Consolidated). Prior to 2013, no Peak-Day was calculated for only the NNG PGA.
Source: MERC's Attachment 1

Department Attachment 3
Docket No. G011/M-16-650
MERC NNG 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	$4.3217	$3.3879	$3.3533	$3.0682	-29.00%	-9.44%	-8.50%	($0.2851)
Demand Cost	$0.9226	$0.9003	$0.9317	$0.9319	1.01%	3.51%	0.02%	$0.0002
Commodity Margin	$2.1806	$2.1806	$2.3980	$2.3980	9.97%	9.97%	0.00%	$0.0000
Total Cost of Gas	$7.4249	$6.4688	$6.6830	$6.3981	-13.83%	-1.09%	-4.26%	($0.2849)
Average Annual Use	76	76	76	76				
Average Annual Cost of Gas*	$564.29	$491.63	$507.91	$486.26	-13.83%	-1.09%	-4.26%	($21.65)

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	$4.3217	$3.3879	$3.3533	$3.0682	-29.00%	-9.44%	-8.50%	($0.2851)
Commodity Margin	$0.8490	$0.8490	$0.9336	$0.9336	9.96%	9.96%	0.00%	$0.0000
Total Cost of Gas	$5.1707	$4.2369	$4.2869	$4.0018	-22.61%	-5.55%	-6.65%	($0.2851)
Average Annual Use	4,508	4,508	4,508	4,508				
Average Annual Cost of Gas*	$23,309.52	$19,099.95	$19,325.35	$18,040.11	-22.61%	-5.55%	-6.65%	($1,285.23)

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	$4.3217	$3.3879	$3.3533	$3.0682	-29.00%	-9.44%	-8.50%	($0.2851)
Commodity Margin	$0.4553	$0.4553	$0.5007	$0.5007	9.97%	9.97%	0.00%	$0.0000
Total Cost of Gas	$4.7770	$3.8432	$3.8540	$3.5689	-25.29%	-7.14%	-7.40%	($0.2851)
Average Annual Use	12,372	12,372	12,372	12,372				
Average Annual Cost of Gas*	$59,101.04	$47,548.07	$47,681.69	$44,154.43	-25.29%	-7.14%	-7.40%	($3,527.26)

SV Firm 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	$4.3217	$3.3879	$3.3533	$3.0682	-29.00%	-9.44%	-8.50%	($0.2851)
Demand Cost	$10.1722	$10.0707	$10.2650	$10.2670	0.93%	1.95%	0.02%	$0.0020
Commodity Margin	$0.8490	$0.8490	$0.9336	$0.9336	9.96%	9.96%	0.00%	$0.0000
Demand Margin	$2.5000	$2.5000	$2.7493	$2.7493	9.97%	9.97%	0.00%	$0.0000
Total Cost of Gas	$5.1707	$4.2369	$4.2869	$4.0018	-22.61%	-5.55%	-6.65%	($0.2851)
Total Demand Cost	$12.6722	$12.5707	$13.0143	$13.0163	2.72%	3.54%	0.02%	$0.0020
Average Annual Use	4,508	4,508	4,508	4,508				
Average Annual Demand Units	25	25	25	25				
Average Annual Cost of Gas*	$23,626.32	$19,414.21	$19,650.70	$18,365.52	-22.27%	-5.40%	-6.54%	($1,285.18)

LV Firm 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	$4.3217	$3.3879	$3.3533	$3.0682	-29.00%	-9.44%	-8.50%	($0.2851)
Demand Cost	$10.1722	$10.0707	$10.2650	$10.2670	0.93%	1.95%	0.02%	$0.0020
Commodity Margin	$0.4553	$0.4553	$0.5007	$0.5007	9.97%	9.97%	0.00%	$0.0000
Demand Margin	$2.5000	$2.5000	$2.7493	$2.7493	9.97%	9.97%	0.00%	$0.0000
Total Cost of Gas	$4.7770	$3.8432	$3.8540	$3.5689	-25.29%	-7.14%	-7.40%	($0.2851)
Total Demand Cost	$12.6722	$12.5707	$13.0143	$13.0163	2.72%	3.54%	0.02%	$0.0020
Average Annual Use	12,372	12,372	12,372	12,372				
Average Annual Demand Units	75	75	75	75				
Average Annual Cost of Gas*	$60,051.46	$48,490.87	$48,657.76	$45,130.65	-24.85%	-6.93%	-7.25%	($3,527.11)

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	($0.2851)	$0.0002	($0.2849)	-4.26%	($21.65)
SV Interruptible Service	($0.2851)	$0.0000	($0.2851)	-6.65%	($1,285.23)
LV Interruptible Service	($0.2851)	$0.0000	($0.2851)	-7.40%	($3,527.26)
SV Firm Service	($0.2851)	$0.0020	($0.2831)	-6.54%	($1,285.18)
LV Firm Service	($0.2851)	$0.0020	($0.2831)	-7.25%	($3,527.11)

* Average Annual Bill amount does not include customer charges.

Note: MERC updated Average Annual Use in the November 1 *Update* based on Annual Automatic Adjustment Report in Docket No. G999/AA-16-524.

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
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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-16-650

Dated this 2nd day of June 2017

/s/Sharon Ferguson

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