COMMERCE DEPARTMENT

November 16, 2017

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 280
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G022/M-17-399

Dear Mr. Wolf:

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

A Request by Greater Minnesota Gas, Inc. (Greater Minnesota or the Company) for Approval by the Minnesota Public Utilities Commission (Commission) of a Change in Contract Demand Entitlement Units Effective November 1, 2017.

The filing was submitted on May 18, 2017. The petitioner is:

Kristine A. Anderson
Corporate Attorney
Greater Minnesota Gas, Inc.
202 South Main Street, P.O. Box 68
Le Sueur, Minnesota 56058

The Department recommends that the Commission:

- Approve Greater Minnesota's proposed level of demand entitlements as shown in the Company's *Petition*; and
- Allow Greater Minnesota to recover associated demand costs through the monthly Purchased Gas Adjustment effective November 1, 2017.

The Department also recommends that the Commission require Greater Minnesota to provide additional information in future demand entitlement filings, as detailed in the body of these *Comments*.

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

Sincerely,

/s/ ADAM J. HEINEN
Rates Analyst
651-539-1825

AJH/lt
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G022/M-17-399

I. BACKGROUND

On August 16, 2017, the Minnesota Public Utilities Commission (Commission) issued its Order in Docket No. G022/M-16-522 regarding Greater Minnesota Gas, Inc.'s (GMG, Greater Minnesota, or the Company) *Petition for Approval of Changes in Contract Demand Entitlements for the 2016-2017 Heating Season*. Through its 16-522 Order, the Commission:

1. Approved GMG's proposed level of demand entitlements and design-day requirements, as shown in GMG's October 27, 2016 Supplemental Filing.

2. Allowed GMG to recover associated demand costs, based on the information in its October 27, 2016 Supplemental Filing, through the monthly [Purchased Gas Adjustment] PGA effective November 1, 2016.

3. Required GMG to estimate its design day using data from multiple heating seasons when appropriate; if the results of these calculations are not acceptable, required GMG to fully explain its decision to use a shorter estimation period in its initial filing.

4. Required GMG to explore the use of separate regression analyses by service area, using area-specific weather stations (Mankato, Faribault, Shakopee, and Swanville, instead of just Minneapolis).

5. Required GMG to maintain its two-part design-day process involving both regression analysis and mathematical analysis based on its historical all-time peak-day send-out data.

6. Required GMG to file monthly customer-count updates in this docket.

II. SUMMARY OF PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2, Greater Minnesota) filed a *Petition for Approval of Changes in Contract Demand Entitlements for the 2017-2018 Heating Season* (*Petition*) on May 18, 2017. The Company proposed that the changes in its demand entitlements be effective on November 1, 2017. Greater Minnesota also proposed implementation of a Northern Natural Gas (Northern) storage contract beginning in June 2017. This storage contract does not impact the level of capacity deliverable on a peak day; therefore the Company proposes that these costs be recovered through the commodity portion of the monthly Purchased Gas Adjustment (PGA).

In its *Petition*, Greater Minnesota requested that the Commission accept the following changes in the Company's overall level of contracted capacity.

Greater Minnesota's Proposed Total Entitlement Changes	
Type of Entitlement	Proposed Changes Increase (decrease) (Dekatherms (Dth))
FT-A Capacity Release	(2,600)
FT-1 Viking	2,200

The Company's proposal would decrease the Company's proposed design-day (winter) capacity by 400 Dth/day from 13,009 Dth/day to 12,609 Dth/day.

The Company did not procure capacity specifically for non-peak periods (*e.g.,* summer months); however, the FT-1 contract that Greater Minnesota added is a 12-month contract, meaning these volumes are available for the entire calendar year, and the Company can call on these volumes to serve both peak and non-peak demand.

The Department discusses the various effects of the entitlement changes on the Company's rates for different customer classes below; however, Greater Minnesota's proposal would decrease capacity and decrease demand rates for residential heating customers by $3.44 for customers using 73 Dth per year.

The Department notes that Greater Minnesota typically recalculates the average consumption figure used to estimate the change in demand rates in each demand entitlement filing:

Docket	Average Residential Usage
G022/M-17-399	73
G022/M-16-522	68
G022/M-15-285	94
G022/M-14-651	101
G022/M-13-730	87

The Department noted the Company's practice in last year's demand entitlement filing and suggested that Greater Minnesota investigate basing this number on weather normalized sales figures in future demand entitlement filings. If the average consumption number is based on a fixed amount, it allows the Commission to track the impact to customers related strictly to changes in demand costs. The Department recommends that the Commission require Greater Minnesota, for the limited purpose of estimating the residential customer demand rate impact, to use a constant annual average usage estimate on a going-forward basis.

The Company described the factors contributing to the need for changing the level of demand entitlements as follows:

- Insure that the Company has sufficient reserve to meet its customers' need;
- Account for growth on the system; and
- Account for changes in the design-day calculation method.

The Department reviews Greater Minnesota's *Petition* in greater detail below.

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

The Department's analysis of the Company's request includes the following sections:

- compliance with the Commission's Order in Docket No. G022/M-16-522
- proposed overall demand entitlement level;
- design-day requirement;
- reserve margin; and
- Purchased Gas Adjustment (PGA) cost recovery proposal.

A. COMPLIANCE WITH THE COMMISSION'S ORDER

GMG's compliance with the Commission's directive to estimate its design day using data from multiple heating seasons when appropriate, and to fully explain a decision to use a shorter estimation period is addressed in section B.2 below.

In response to the Commission's directive to explore use of separate regression analyses by service area, using area-specific weather stations, Greater Minnesota indicated in footnote 4 of its *Petition* that:

> Although GMG historically assigned its town border stations geographically to a variety of weather sites, GMG now has multiple town border stations located in a variety of area across the state. Consequently, GMG predicated its modeling on weather conditions in Minneapolis. Similar methodology is employed by larger natural gas utilities with service throughout the state. GMG appreciates the Department's Comments last year that encouraged GMG to return to using multiple weather stations; and GMG agrees that doing so makes sense in the future. GMG's intent is to use multiple weather zones as soon as three solid years of regression data is available. Given new customer lag in conversion, the changing customer mix, and the fact that one of GMG's largest customers switched to transport service, using multiple weather stations for the current analysis would provide a nonsensical result lacking validity.

The Department does not oppose GMG's proposal.

GMG complied with the requirement to maintain its two-part design-day process involving both regression analysis and mathematical analysis based on its historical all-time peak-day send-out data. As more fully discussed below, the Department recommends that this requirement continue.

Finally, GMG filed customer count updates on September 14, 2017 and October 19, 2017, in compliance with the Commission's Order. The Company indicated that it had 7,651 firm customers and 79 interruptible customers as of August 2017. As of September 2017, GMG had 7,689 firm and 81 interruptible customers. The Department discusses the potential impact of over-estimating customer additions on GMG's demand entitlement levels in section B.2 below.

B. THE COMPANY'S DEMAND ENTITLEMENT LEVEL

1. Proposed Overall Demand Entitlement Level

As indicated in Department Attachment 2, the Company proposed to decrease its total entitlement level in Dth as follows:

Previous Entitlement (Dth)	Proposed Entitlement (Dth)	Entitlement Changes (Dth)	% Change From Previous Year
13,009	12,609	(400)	(3.07)

The Department analyzes below the proposed changes, the proposed design-day requirement, and the proposed reserve margin. The Department concludes that the Company's proposed recovery of overall demand costs is reasonable.

2. Design-Day Requirement

In past demand entitlement filings, Greater Minnesota employed a two-part design-day process to calculate its peak day sendout. In its 2015-2016 demand entitlement proceeding (Docket No. G022/M-15-285), the Department identified potential concerns with the Company's peak-day regression analysis. Specifically, the Department recommended that the Company maintain, on a going-forward basis, a two-part design-day process involving both regression analysis and a mathematical analysis based on the Company's historical all-time peak-day sendout until such time that Greater Minnesota has sufficient historical load data beyond the 2012-2013 heating season; and that the Company explore segregating its linear regression modeling into two components for large and smaller firm customers.

In its 2016-2017 heating season demand entitlement filing (Docket No. G022/M-16-522), Greater Minnesota employed an updated design-day estimation analysis. This updated analysis was based on three months of daily data from the 2015-2016 heating season and employed two separate regression models, one for residential customers and one for commercial customers. Greater Minnesota explained, in the 2016-2017 heating season demand entitlement docket, that it used a shorter data stream because its initial regression results, based on data from other heating seasons, were too low and relying on those results may harm firm ratepayers. The Company surmised that these low results were driven by the addition of higher use firm customers in recent years. The Department expressed concern with Greater Minnesota's design-day analysis in last year's demand entitlement filing but stated that its concerns would likely be alleviated over time as more data becomes available. The Department concluded that Greater Minnesota's new design-day analysis was acceptable at the time and would likely result in sufficient entitlements to serve firm customers on a peak day.

Greater Minnesota employed a design-day analysis in this filing similar to what it used in last year's demand entitlement filing. Specifically, Greater Minnesota based its design-day analysis on a two-stage process, one based on regression analysis and a second based on a mathematical calculation. The Company's regression analysis used separate residential and commercial firm customer models. Greater Minnesota noted that there was still insufficient data to rely on a three-year data sample; therefore, the Company determined that relying only on the most recent two years of usage and weather data in its regression analysis produced the result most likely to provide sufficient protection for its customers.

In terms of its statistical analysis, Greater Minnesota used Ordinary Least Squares (OLS) regression to calculate the projected design day for Greater Minnesota's service territory. Greater Minnesota conducted separate regression models for residential customers and commercial customers. The Company used daily weather data from Minneapolis, which is the same weather station it used in last year's demand entitlement filing, to estimate use per customer for each of its customer models. Given the data concerns discussed above, Greater Minnesota ultimately used historical daily consumption data from the 2015-2016 and 2016-2017 heating seasons in its analysis. Greater Minnesota explained in its *Petition* that its regression analysis is based on a 90 heating degree day (HDD) average design-day temperature for its planning objective. Greater Minnesota's regression models resulted in estimated design-day consumption for the 2017-2018 heating season, inclusive of customer additions, of 11,896 Dth/day.

In previous demand entitlement filings, the Department has discussed various concerns with the strict use of linear regression to estimate design-day consumption for the Greater Minnesota system. Greater Minnesota is a small gas utility and can be significantly impacted by customer growth and changes in the make-up of its customer base. These issues, both unexpected customer growth and changes in customer base, have occurred in the recent past; as such, the Department recommended, in last year's filing, that Greater Minnesota continue to include a mathematical design-day calculation in its demand entitlement analysis.

In the instance where the design-day regression methodology is changed, or has changed recently, which is the case in this proceeding, the use of a mathematical analysis as an accuracy check is important. The mathematical analysis uses firm use per customer on an all-time peak day multiplied by the projected number of firm customers in the upcoming heating season. As with any method of estimation, there are pros and cons to the mathematical approach. The mathematical method is simple, easy to calculate, and is based on an actual, historical events. However, since it is based on an actual event, temperatures on the all-time peak day might not correspond with an exceptionally cold day. Further, if the all-time peak day happened years in the past, consumption on a present peak day may not be the same due to changes in technology and other factors affecting energy use. Given that Greater Minnesota's all-time peak-day throughput happened during the last heating season (January 5, 2017), and its all-time peak-day consumption per customer occurred during the 2013-2014 heating season, the mathematical approach is acceptable since consumption characteristics are likely similar to what will be expected during the 2017-2018 heating season.

Using the use-per-customer from Greater Minnesota's all-time peak day use-per-customer (1.457 Dth/customer), adjusted for consumption on a 90 HDD planning objective and expected firm customer counts for the 2017-2018 heating season, the mathematical approach results in an estimated design-day of 11,821 Dth/day, which is 75 Dth/day, or 0.6 percent, less than Greater Minnesota's estimated result based on its regression analysis. This result supports the estimates from the Company's regression models. The result using the mathematical method is 788 Dth/day less than the proposed total entitlement procured by the Company, which suggests that the Company has sufficient entitlements to serve firm customers.

In recent demand entitlement filings, Commission Staff raised concerns regarding Greater Minnesota's actual customer additions relative to the forecasted customer additions included in the design-day calculations.[1] In particular, Commission Staff was concerned that the Company may have overstated its projected customer additions. If customer additions are over-projected, then it follows that a utility will over-estimate design-day requirements. To the extent that these customer additions are over-projected to a point where a utility must procure additional capacity, it will result in demand costs that are too high. Given these concerns, the Commission required Greater Minnesota to provide monthly compliance filings detailing customer additions.

In an effort to determine whether Greater Minnesota over-projected customer additions, the Department compared forecasted customer additions from last year's demand entitlement filing to actual customer additions provided in this demand entitlement. In last year's filing, Greater Minnesota forecasted customer additions during the 2016-2017 heating season of 839 which was 104 greater than actual additions of 735, which is approximately 12.4 percent lower than forecasted. Greater Minnesota forecasts adding 735 firm customers for the upcoming heating season. If an over-projection similar to last heating season were to occur, it would result in an over-estimation of approximately 91 additional firm customers during the upcoming heating season, which would result in the need for approximately 133 Dth/day of additional capacity on a peak day based on peak day use-per-customer of 1.457 Dth/customer. This would result in an effective reserve margin of 7.17 percent.[2] A 7.17 percent reserve margin is not unreasonable given GMG's expansion efforts. Although the possibility exists that Greater Minnesota has over-projected customer additions based on recent experience, the Department

---

[1] November 13, 2015 *Briefing Papers* in Docket No. G022/M-15-285 and July 31, 2017 *Briefing Papers* in Docket No. G022/M-16-522.
[2] (12,609 Dth -11,763 Dth)/11,763 Dth.

concludes that its impact on the estimated design-day requirements, and potential changes to the Company's procurement plan, are insignificant. Based on the size of the impact, and the fact that interstate pipelines sell capacity in chunks, the Department concludes that it is unlikely that a 12 percent over-estimation of firm customer additions would modify the Company's procurement plan and, therefore, costs charged to ratepayers.

After reviewing Greater Minnesota's design-day methodology, the Department continues to be concerned with the length of the estimation period used by Greater Minnesota. As required by the Commission's 16-522 Order, the Company explained why it employed a shorter estimation period. While the Department understands Greater Minnesota's decision in light of the under-estimation issues identified in previous demand entitlement filings, a two-heating-season estimation period may not be sufficient to ensure fully robust peak-day estimates. However, given the similarity between the regression and mathematical design-day estimates, the Department concludes that Greater Minnesota likely has sufficient entitlements, at this time, to serve firm customers on a Commission-prescribed peak day of 90 HDD. In addition, the Company's reasons for using a shorter timeframe, older data not including usage by new commercial customers, will likely diminish, or disappear, in future demand entitlement filings. The Department recommends that Greater Minnesota continue to estimate its design day with data from multiple heating seasons when appropriate. If the results of these calculations are not acceptable, the Department recommends that the Company continue to fully explain its decision to use a shorter estimation period in its initial filing.

Based on its analysis, the Department concludes that Greater Minnesota's design-day analysis is acceptable at this time and will likely result in sufficient entitlements to serve firm customers on a peak day. As noted above, the Department does have concerns with the Company's analysis but concludes that these concerns are not significant at this time.

3. *Reserve Margin*

As indicated in Department Attachment 2, the reserve margin, as proposed by the Company, is as follows:

Total Entitlement (Dth)	**Design-day Estimate (Dth)**	**Difference (Dth)**	**Reserve Margin %**	**% Change From Previous Year[3]**
12,609	11,896	713	5.99%	69.21%

The figures in the above table include design-day estimates from the Company's two customer-type (*i.e.,* customer class) regression models. The reserve margin is necessary since it provides an extra cushion that helps ensure firm reliability on a peak day; however, carrying too great a reserve margin results in customers paying higher demand costs than are necessary to provide reasonable service.

The Department has generally used a 5 percent reserve margin as an indicator of an adequate reserve margin, and the Company proposed a reserve margin that is above 5 percent. However; for Greater Minnesota, the Department has recommended, in previous demand entitlement filings, that the Commission accept higher reserve margins given the system dynamics, the higher level of growth experienced by this utility, and the fact that Greater Minnesota is a small utility with limited operational history. The Department concludes that the Company's proposed reserve margin is acceptable in this proceeding.

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 3. 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 4) and has issued a follow-up information request with the utilities to ask for updated information. The Department 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 may be occurring, 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

[3] The estimated reserve margin as approved in Docket G022/M-16-522 was 3.54 percent. The actual reserve margin for the 2016-2017 heating season was 20.25 percent. As shown on Department Attachment 2, the Company's average reserve margin since 1996 is 13.40 percent.

justified, and to continue monitoring the growing inter-relationship between the natural gas and electric industries.

C. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The demand entitlement amounts listed in Department Attachment 1 represent the demand entitlements for which the Company's firm customers will pay. In Attachment D Page 1 of 5 to its *Petition*, the Company compared its May 2017 PGA to its expected November 2017 PGA with the Company's proposed changes as a means of calculating the bill impact of its proposed changes. According to the Company, Greater Minnesota's demand entitlement proposal would result in the following annual rate impacts:

- Annual bill decrease of $3.44, or approximately 1.25 percent, for the average Residential customer consuming 73.0 Dth annually; and
- Annual bill decrease of $146.47, or approximately 1.25 percent, for the average Commercial and Industrial Firm customer consuming 3,106.5 Dth annually.

Given the time elapsed between the initial demand entitlement filing and the expected implementation of rates, the Department contacted Greater Minnesota regarding potential modifications to its procurement plan. Greater Minnesota confirmed that it made no changes to its initial demand entitlement proposal. The Department recommends that the Commission allow recovery of associated demand costs effective November 1, 2017 through the monthly PGA.

IV. THE DEPARTMENT'S RECOMMENDATIONS

The Department recommends that the Commission:

- Approve Greater Minnesota's proposed level of demand entitlements as shown in the Company's *Petition*; and
- Allow Greater Minnesota to recover associated demand costs through the monthly Purchased Gas Adjustment effective November 1, 2017.

The Department also recommends that the Commission require Greater Minnesota to undertake the following in future demand entitlement filings:

- Use a constant annual average residential usage estimate for the purpose of estimating rate impact on a going-forward basis;
- Perform separate regression analyses by service area, using area-specific weather

stations, as soon as there is sufficient consumption and customer data for the results to be relied upon;

- Estimate its design day using data from at least 3 heating seasons when appropriate. If the results of these calculations are not acceptable, the Department recommends that the Company fully explain its decision to use a shorter estimation period in its initial filing; and
- Maintain, on a going-forward basis, a two-part design-day process involving both regression analysis and mathematical analysis based on the Company's historical all-time peak-day sendout.

/lt

Department Attachment 1
Details of Greater Minnesota Gas's Demand Entitlements Historical and Current Proposal

Department of Commerce Attachment 1
Details of Greater Minnesota Gas' Demand Entitlements

2014-2015 Heating Season (November-January)	Quantity (Mcf)	Change in Quantity
TF-7 (Apr.-Oct.)	0	0
TF12 (Nov.-Oct.)	210	0
TFX-5 (Nov.-Mar.)	0	0
TFX-5 (Nov.-Mar.)	6,344	0
Viking Zone 1	2,000	0
Delivery Contract	950	0
TFX (Apr. and Oct.)	665	0
Viking Forward Haul	0	0
TF5 (Nov.-Mar.)	90	0
Viking Forward Haul/Emerson	1,400	100
SMS	2,000	700
Total Demand Entitlement	9,659	100
Total Transportation	11,659	100
Total Annual Transportation		0
Total Seasonal Transport	11,659	2,100
Percent Annual on Greater Minnesota System	0.00%	0.00%
Percent Seasonal on Greater Minnesota System	100.00%	17.30%

2014-2015 Heating Season (February-March)	Quantity (Mcf)	Change in Quantity
TF-7 (Apr.-Oct.)	0	0
TF12 (Nov.-Oct.)	210	0
TFX-5 (Nov.-Mar.)	0	0
TFX-5 (Nov.-Mar.)	6,344	0
Viking Zone 1	2,000	0
Delivery Contract	950	0
TFX (Apr. and Oct.)	665	0
Viking Forward Haul	1,200	1,200
TF5 (Nov.-Mar.)	90	0
Viking Forward Haul/Emerson	1,400	0
SMS	2,000	0
Total Demand Entitlement	10,859	1,200
Total Transportation	12,859	1,200
Total Annual Transportation		0
Total Seasonal Transport	12,859	1,200
Percent Annual on Greater Minnesota System	0.00%	0.00%
Percent Seasonal on Greater Minnesota System	100.00%	0.00%

2015-2016 Heating Season	Quantity (Mcf)	Change in Quantity
TF-7 (Apr.-Oct.)	0	0
TF12 (Nov.-Oct.)	210	0
TFX-5 (Nov.-Mar.)	0	0
TFX-5 (Nov.-Mar.)	6,344	0
Viking Zone 1	2,000	0
Delivery Contract	0	(950)
Non-Recallable Capacity Release	2,600	2,600
TFX (Apr. and Oct.)	665	0
Viking Forward Haul	1,200	0
TF5 (Nov.-Mar.)	90	0
Viking Forward Haul/Emerson	1,400	0
SMS	2,000	0
Total Demand Entitlement	12,509	1,650
Total Transportation	14,509	1,650
Total Annual Transportation		0
Total Seasonal Transport	14,509	1,650
Percent Annual on Greater Minnesota System	0.00%	0.00%
Percent Seasonal on Greater Minnesota System	100.00%	0.00%

2016-2017 Heating Season (FINAL)	Quantity (Mcf)	Change in Quantity
TF-7 (Apr.-Oct.)	0	0
TF12 (Nov.-Oct.)	710	500
TFX-5 (Nov.-Mar.)	0	0
TFX-5 (Nov.-Mar.)	6,344	0
Viking Zone 1	2,000	0
Delivery Contract	0	0
Non-Recallable Capacity Release	2,600	0
TFX (Apr. and Oct.)	665	0
Viking Forward Haul	1,200	0
TF5 (Nov.-Mar.)	90	0
Viking Forward Haul/Emerson	1,400	0
SMS	2,000	0
Total Demand Entitlement	13,009	500
Total Transportation	15,009	500
Total Annual Transportation		0
Total Seasonal Transport	15,009	500
Percent Annual on Greater Minnesota System	0.00%	0.00%
Percent Seasonal on Greater Minnesota System	100.00%	0.00%

2017-2018 Heating Season (FINAL)	Quantity (Mcf)	Change in Quantity
TF-7 (Apr.-Oct.)	0	0
TF12 (Nov.-Oct.)	710	0
TFX-5 (Nov.-Mar.)	0	0
TFX-5 (Nov.-Mar.)	6,344	0
Viking Zone 1	2,000	0
FT-1 Viking	2,200	2,200
Non-Recallable Capacity Release	0	2,600
TFX (Apr. and Oct.)	665	0
Viking Forward Haul	1,200	0
TF5 (Nov.-Mar.)	90	0
Viking Forward Haul/Emerson	1,400	0
SMS	2,000	0
Total Demand Entitlement	12,609	(400)
Total Transportation	12,609	(2,400)
Total Annual Transportation		0
Total Seasonal Transport	14,609	(400)
Percent Annual on Greater Minnesota System	0.00%	0.00%
Percent Seasonal on Greater Minnesota System	115.86%	15.86%

Department Attachment 2
Details of Greater Minnesota Gas's Demand Entitlements Historical and Current Proposal

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving			Reserve Margin
								+ Peak Shaving		
	(1)	(2)	(3)	(4)	(5)	(6)	2016-2017 Heating Season	(8)	(9)	(10)
Heating Season	Number of Design Day Customers	Change from Previous Year	% Change From Previous Year	Design Day (Mcf)	Change from Previous Year	% Change From Previous Year	Total Entitlement (Mcf)	Change from Previous Year	% Change From Previous Year	% of Reserve Margin [(7)-(4)]/(4)
2017-2018	8,113	735	9.96%	11896	1,078	9.96%	12,609	(400)	-3.07%	5.99%
2016-2017	7,378	735	11.06%	10,818	(308)	-2.77%	13,009	500	4.00%	20.25%
2015-2016	6,643	791	13.52%	11,126	2,157	24.05%	12,509	2,850	29.51%	12.43%
2014-2015	5,852	547	10.31%	8,969	52	0.58%	9,659	100	1.05%	7.69%
2013-2014	5,305	531	11.12%	8,917	3,953	79.63%	9,559	4,350	83.51%	7.20%
2012-2013	4,774	558	13.24%	4,964	514	11.55%	5,209	165	3.27%	4.94%
2011-2012	4,216	296	7.55%	4,450	0	0.00%	5,044	0	0.00%	13.35%
2010-2011	3,920	198	5.32%	4,450	239	5.68%	5,044	500	11.00%	13.35%
2009-2010	3,722	162	4.55%	4,211	(71)	-1.66%	4,544	300	7.07%	7.91%
2008-2009	3,560	182	5.39%	4,282	566	15.23%	4,244	244	6.10%	-0.89%
2007-2008	3,378	170	5.30%	3,716	166	4.68%	4,000	350	9.59%	7.64%
2006-2007	3,208	237	7.98%	3,550	583	19.65%	3,650	350	10.61%	2.82%
2005-2006	2,971	290	10.82%	2,967	270	10.01%	3,300	300	10.00%	11.22%
2004-2005	2,681	336	14.33%	2,697	697	34.85%	3,000	600	25.00%	11.23%
2003-2004	2,345	181	8.36%	2,000	(200)	-9.09%	2,400	(200)	-7.69%	20.00%
2002-2003	2,164	300	16.09%	2,200	400	22.22%	2,600	400	18.18%	18.18%
2001-2002	1,864	301	19.26%	1,800	400	28.57%	2,200	500	29.41%	22.22%
2000-2001	1,563	393	33.59%	1,400	300	27.27%	1,700	300	21.43%	21.43%
1999-2000	1,170	279	31.31%	1,100	250	29.41%	1,400	150	12.00%	27.27%
1998-1999	891	289	48.01%	850	350	70.00%	1,250	750	150.00%	47.06%
1997-1998	602	339	128.90%	500	200	66.67%	500	200	66.67%	0.00%
1996-1997	263	263		300	300		300	300		
Average Change Per Year:			19.81%			21.26%			23.22%	13.40%

Firm Peak Day Sendout

Heating Season *	(11) Firm Peak Day Send out (Mcf)	Change from Previous Year	% Change From Previous Year	Excess per Customer [(7) - (4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per DD Customer (7)/(1)	Peak Day Sendout per DD Customer (11)/(1)
2017-2018				0.0879	1.4663	1.5542	
2016-2017	9,246	(249)	-2.62%	0.2970	1.4663	1.7632	1.2532
2015-2016	9,495	1,126	13.45%	0.2082	1.6748	1.8830	1.4293
2014-2015	8,369	489	6.21%	0.1179	1.5326	1.6505	1.4301
2013-2014	7,880	2,855	56.82%	0.1210	1.6809	1.8019	1.4854
2012-2013	5,025	1,368	37.41%	0.0513	1.0398	1.0911	1.0526
2011-2012	3,657	(248)	-6.35%	0.1409	1.0555	1.1964	0.8674
2010-2011	3,905	251	6.87%	0.1515	1.1352	1.2867	0.9962
2009-2010	3,654	(374)	-9.29%	0.0895	1.1314	1.2208	0.9817
2008-2009	4,028	(72)	-1.76%	(0.0107)	1.2028	1.1921	1.1315
2007-2008	4,100	550	15.49%	0.0841	1.1001	1.1841	1.2137
2006-2007	3,550	738	26.24%	0.0312	1.1066	1.1378	1.1066
2005-2006	2,812	285	11.28%	0.1121	0.9987	1.1107	0.9465
2004-2005	2,527	185	7.90%	0.1130	1.0060	1.1190	0.9426
2003-2004	2,342	587	33.45%	0.1706	0.8529	1.0235	0.9987
2002-2003	1,755	747	74.11%	0.1848	1.0166	1.2015	0.8110
2001-2002	1,008	(180)	-15.15%	0.2146	0.9657	1.1803	0.5408
2000-2001	1,188	291	32.44%	0.1919	0.8957	1.0877	0.7601
1999-2000	897	95	11.85%	0.2564	0.9402	1.1966	0.7667
1998-1999	802	397	98.02%	0.4489	0.9540	1.4029	0.9001
1997-1998	405	233	135.47%	0.0000	0.8306	0.8306	0.6728
1996-1997	172	172		0.0000	1.1407	1.1407	0.6540
Average Change Per Year:			26.59%	0.1392	1.1451	1.2843	0.9972

Attachment 3 – 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 Natural Gas Utilities Date of Request: 11/8/2017
Type of Inquiry: General Response Due: 11/20/2017

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

Request Number: 22
Topic: Distribution Planning
Reference(s): Department Information Request No. 18

Request:

Please provide the above reference, including any and all subparts, updated to the most recent date available.

If this information has already been provided in the application or in response to an earlier Department-DER information request, please identify the specific cite(s) or Department-DER information request number(s).

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

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: