January 29, 2018

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

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G011/M-17-588

Dear Mr. Wolf:

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

> In the Matter of Minnesota Energy Resources Corporation's (MERC) Demand Entitlement Filing (Petition) for its Customers Served off of the Northern Natural Gas Company (NNG) System.

The Petition was filed on August 1, 2017 by:

> Amber S. Lee
> Regulatory and Legislative Affairs Manager
> Minnesota Energy Resources Corporation
> Suite 200
> 1995 Rahncliff Court
> Eagan, Minnesota 55122

On November 1, 2017, MERC submitted its *November Update* (Update).

The Department requests that MERC provide additional information in reply comments. The Department will offer additional comments and recommendations in subsequent response comments after it has reviewed the additional information. The Department is available to respond to any questions the Minnesota Public Utilities Commission may have on this matter.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

SS/ja
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G011/M-17-588

I. SUMMARY OF THE UTILITY'S PROPOSAL

Pursuant to Minnesota Rules part 7825.2910, subpart 2, Minnesota Energy Resources Corporation (MERC or the Company), filed a petition on August 1, 2017 with the Minnesota Public Utilities Commission (Commission or PUC) to change the levels of demand for natural gas pipeline capacity (Petition) for is customers served off of the Northern Natural Gas (NNG or Northern) System. The Petition is the first in which the Company's NNG and Albert Lea systems were combined based on the ruling in Docket No. G011/GR-15-736.[1] MERC requested that the Commission approve changes in the Company's recovery of overall level of contracted capacity.[2]

On November 1, 2017, MERC filed its *November 1 Update* (Update).

In terms of capacity, MERC proposed to maintain the same entitlement level as was in place last heating season, resulting in an estimated reserve margin of a negative 0.19 percent. However, MERC's Firm Deferred Delivery (storage) increased from a total Maximum Storage Quantity of 5,869,321 Dth[3] to 6,519,321 Dth as indicated on MERC's Attachment 7. This is an increase of 650,000 Dth or approximately 11.07% (650,000/5,869,321). Including the added storage, MERC's Firm Deferred Delivery makes up just over 30% of the anticipated usage for the upcoming winter (6,519,321 Dth /19,422,595 Dth or 33.57%).

[1] 1 In its December 21, 2012 Order in Docket No. G007,011/GR-10-977, the Commission approved consolidation of MERC's 4 Purchased Gas Adjustment (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." Pursuant to the Commission's Order in Docket No. G011/GR-15-736, the MERC-NNG and MERC NNG–Albert Lea PGAs were consolidated effective July 1, 2017. On August 1, 2017, MERC filed a demand entitlement request for MERC-Consolidated in Docket No. G011/M-17-587.

[2] MERC noted in its August cover letter that any updated information would be provided with the Company's November 1, 2017 filing.

[3] Dekatherms.

Using a similar design-day calculation methodology as has been used in the past, MERC proposed to increase its total design day by 7.25%.

The Company projected a negative 0.19% reserve margin for the upcoming heating season.

MERC estimated that its proposal would cause an increase in rates for residential customers of $0.0572 per Dth or approximately $5.03 per year for customers assuming an annual usage of 88 Dth.

The Minnesota Department of Commerce, Division of Energy Resources (Department) discusses below the various effects on the Company's rates for different customer classes.

MERC requested that the Commission allow recovery of the associated demand costs in the Company's monthly PGA for each district effective November 1, 2017.

In Section II below, the Department's analysis of the Company's request includes the following areas:

- changes to capacity;
- design-day requirements;
- reserve margins; and
- PGA cost recovery proposals.

II. THE DEPARTMENT'S ANALYSIS OF THE COMPANY'S 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[4] 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.[5]

[4] 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."
[5] See MERC Attachment 3.

On October 31, 2016, the Commission issued its *Findings of Fact, Conclusions, and Order* (October 2016 Order) in Docket No. G011/GR-15-736 (Docket 15-736) concerning the request by MERC to increase natural gas rates in Minnesota.

On February 13, 2017 the Commission issued its *Order* in Docket 15-736 approving MERC's proposed tariffs submitted in compliance with the October 2016 Order and directing the Company to implement final rates to bills effective March 1, 2017. As a result, the former MERC-Albert Lea PGA was combined into the MERC-NNG PGA effective July 1, 2017.

On September 29, 2017 in Docket No. G011/MR-17-564 (Docket 17-564) MERC requested that the Commission approve a new base cost of gas (BCOG) to coincide with the proposed January 1, 2018 implementation of interim rates requested in Docket No. G011/GR-17-563 (Docket 17-563). MERC filed its general rate case on October 13, 2017, two weeks later than its BCOG petition.

On October 23, 2017, the Department filed comments in Docket 17-564 recommending that the Commission approve MERC's BCOG petition and require MERC to provide updates to the base cost of gas in that proceeding as well as certain additional information in other dockets.

On December 5, 2017 the Commission issued its *Order Setting New Base Cost of Gas for Interim Rate Period* in Docket No. 17-564.

As indicated on page 1 of Department Attachments 1 and 2 that reflect the data from the Company's Attachments 1, 3 and 7, the Company proposed to change its entitlements by 14,190 Dth. However, MERC's Attachments (and page 1 of DOC Attachments 1 and 2) reflect only the data for MERC's former MERC-NNG PGA system prior to consolidation; MERC failed to include both the MERC-NNG and MERC-Albert Lea PGA systems' data. Page 2 of the Department Attachments 1 and 2 reflect both systems as consolidated. As indicated on page 2 of DOC Attachments 1 and 2, the Company in reality proposed to keep its total entitlement levels the same as the prior year. Table 1 below summarizes what is reflected in MERC's Petition and Update, and the Department's correction:[6]

[6] The Department's correction also reflects recognition of a reallocation of TF-12B and TF-12V services, as more fully explained below.

Table 1: MERC's NNG Total Entitlement Levels

Filing	Previous Entitlement (Dth)	Proposed Entitlement (Dth)	Entitlement Changes (Dth)	Change From Previous Year (%)
August 1, 2017	252,127	266,317	14,190	5.63%
November 1, 2017	252,127	266,317	14,190	5.63%
Department	266,317	266,317	0	0.00%

As noted above, MERC's Firm Deferred Delivery (storage) increased from a total Maximum Storage Quantity of 5,869,321 Dth to 6,519,320 Dth as indicated on MERC's Attachment 7.

In the Department's October 23, 2017 Comments in Docket 17-564, the Department stated the following:[7]

> In Docket 17-588 the Company stated the following regarding any changes to its design-day deliverability and other demand entitlement changes:
>
> > As shown in Attachment 3, MERC-NNG proposes no change in Design-Day Deliverability. The reserve margin for 2017-2018 is slightly negative. MERC will purchase city gate delivered supply to cover 0.19% of peak day throughput if necessary.
> >
> > … As shown in Attachment 3, MERC–NNG proposes no change in April/October Deliverability. However, MERC requests changes to increase Firm Deferred Delivery (storage) pipeline entitlements that are not included in peak day deliverability. MERC has increased the volume of capacity release NNG storage acquired from a total of 1,200,000 dth in 2016-2017 to 1,500,000 dth in 2017-2018 as discussed in the update filing for Docket No. G011/M-16-650. MERC will utilize this incremental storage to ensure supply price and reliability during the winter.

[7] See the Department's October 23, 2017 Comments in Docket 17-564 at pages 3-4.

> To ascertain if indeed there were no changes to MERC-NNG's PGA system demand entitlements other than changes to storage described above, the Department reviewed the Company's September 28, 2017 PGA filing in Docket No. G011/M-17-703 (Docket 17-703) describing MERC-NNG's PGA rates effective October 1, 2017. In Docket 17-703, Schedule A, MERC shows total demand costs of $22,303,099 for the MERC-NNG system. These demand costs from Docket 17-703 are approximately $113,372 higher than the demand costs shown in Docket 17-588, for MERC's proposed PGA rates effective November 1, 2017. For example, in Docket 17-588 MERC shows TF12B (Max Rate) Winter Units of 49,219 Dth whereas in Docket 17-703 MERC shows 42,983 Dth. Similarly in Docket 17-588 MERC shows TF12V (Max Rate) 5-month Units of 30,290 Dth yet in Docket 17-703 MERC shows 36,526 Dth. While the Department has not filed Initial Comments in Docket 17-588, the Department requests that MERC, in its November Update in Docket 17-588, reconcile its changes in Docket 17-588 described above to all the information in MERC's October 1, 2017 PGA filed in Docket 17-703.

Given that the Company's initial filing in this docket did not have any changes in design-day deliverability and subsequently no changes in the Company's overall demand entitlement, and considering that the MERC-Albert Lea PGA was combined with the MERC-NNG PGA effective July 1, 2017, it was expected that the demand costs and overall units would not be different between the October PGA filing in Docket 17-703, the BCOG petition, and the instant filing. However, the Department observed the above-referenced discrepancies and requested the above-referenced reconciliation.

In its *November Update*, the Company repeated the above-referenced information regarding changes to its design-day deliverability and other demand entitlement changes. Additionally, the Company provided the above-requested reconciliation and stated the following:[8]

[8] See the Company's November 1, 2017 update in the instant docket at pages 1-2.

> MERC responds that with respect to the requested reconciliation between the October 1 PGA and November 1 Demand Entitlement, the [sic] this docket are proposed effective November 1, 2017. Therefore, the changes would not be reflected in the October PGA. Additionally, however, MERC's August 1, 2017 Demand Entitlement filing schedules comparing the 2016-2017 demand costs to the proposed 2017-2018 demand costs only included the NNG costs for 2016-2017; whereas both the MERC-NNG and MERC-Albert Lea (now the consolidated MERC NNG PGA) costs were included in the 2017-2018 demand costs. The following updated comparison includes the total demand costs for the consolidated NNG PGA between 2016-2017 and 2017-2018.
>
> The former MERC-Albert Lea PGA was combined into the MERC-NNG PGA effective July 1, 2017. In order to provide an accurate comparison between the 2016 and 2017 Demand Entitlement filings, Attachment 8.1 was added to this filing to reconcile the differences between the combined PGA. This reconciliation is shown in the table below.
>
> … In review of this update, MERC also discovered an error in the storage cost calculation in the 2016-2017 Demand Entitlement. This error has been corrected in Attachment 8 and the new Attachment 8.1 to accurately reflect the change from 2016-2017 to 2017-2018.

The Commission in its December 5, 2017 *Order Setting New Base Cost of Gas for Interim Rate Period* in Docket No. 17-564, Ordering point 5 stated the following:

> MERC shall reconcile its demand costs in its November update in Docket Nos. G-011/M-17-587 and G-011/M-17-588 with the October 1 Purchased Gas Adjustment filed in Docket No. G011/AA-17-703. MERC shall explain any changes and provide this information as a supplement to Docket Nos. G-011/M-17-587 and G-011/M-17-588.

The Department concludes that MERC has complied with the December 5, 2017 Order issued in Docket No. 17-564 by providing the reconciliation in its *November Update* in the instant docket.

Table 2 below provides MERC's specific changes to its overall level of contracted capacity.

Table 2: A Comparison of MERC's Current and Proposed Entitlements

Filing	Type of Entitlement	Previous Entitlement (Dth)	Proposed Entitlement (Dth)	Entitlement Changes (Dth)
August 1, 2017 and November 1, 2017				
Attachment(s) 3	TFX 5 (month) (Max Rate)	108,701	109,501	800
	TF 5 (month) (Max Rate)	32,278	45,668	13,390
	Total Change			***14,190***
Attachment(s) 7	TFX 5 (month) (Max Rate	108,701	109,501	800
	TF 5 (month) (Max Rate)	32,278	36,275	3,997
	TF 12 (month) Base	45,026	54,419	9,393
	Total change			***14,190***
November 1, 2017				
Attachment 8.1	TF 12 (month) Base – Max rate Winter	42,983	49,219	6,236
	TF 12 (month) Variable – Max rate	36,526	30,290	(6,236)
	Total change			0

As shown above, given the discrepancies between Attachments 3 and 7 of MERC's Petition, the Department appreciates the reconciliation provided in Attachment 8.1 of MERC's *November Update*. While the Company reconciled its data, it failed to update its Attachments 3 and 7 of its *November Update* to properly reflect the corrected data reflected in Attachment 8.1. In addition, the Company failed to explain that it had updated its reallocation of TF-12B and TF-12V services.

In regards to NNG capacity, NNG's reallocation of TF-12B and TF-12V services are not known until the November update; typically, the changes are not significant. The changes are in accordance with NNG's tariff approved by the Federal Energy Regulatory Commission (FERC).[9] Usually there is no deliverability difference between TF-12B and TF-12V services, but TF-12B service is less expensive than TF-12V service. There was no change in the aggregate volume of NNG capacity year over year.

The Department analyzes below the proposed changes, the proposed design-day requirements, and the proposed reserve margin.

B. DESIGN-DAY REQUIREMENTS

As indicated in Department Attachment 2, 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 (%)
August 1, 2017	248,796	266,825	18,029	7.25%
November 1, 2017	248,796	266,825	18,029	7.25%
Department	262,324	267,783	5,459	2.08%

At page 2 of its Petition, MERC stated the following:

> The NNG Design-Day requirement has increased by 18,029 dekatherms (dth) from the November 1, 2016, filing. The larger than usual increase in Design-Day requirement is attributable to combining the MERC-Albert Lea PGA into the MERC-NNG PGA and new town growth load. The addition of MERC-Albert Lea alone accounts for 14,819 dth of the increase over the last heating season. For the Demand Entitlement filing effective November 1,

[9] Under its federally approved tariff, NNG is allowed to adjust a utility's assigned level of contracted capacity, based on the utility's usage of its NNG-based capacity over the previous five-month period (May through September).

> 2017, the total Design-Day requirement for MERC NNG is 266,825 dth (Attachment 1).

However, the design day requirement of 266,825 Dth is not supported by the Company's calculations as further explained below. Department's Attachment 2, page 2, correctly shows the proposed design-day requirement of 267,783 Dth.

MERC used a similar approach to what it used in last year's filing for its design-day analysis. As a result of MERC's telemetry program making it possible for all interruptible customers to have daily metered data, the Company no longer had to estimate interruptible customers' peak-day impact for the customers in the Company's former MERC-NNG PGA service area. However for the former MERC-Albert Lea service area, MERC had to estimate the interruptible customers' impact. The Company stated the following:[10]

> Finally, in its April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, the Commission directed MERC to work with the Department to develop an appropriate Design Day regression analysis methodology for its subsequent demand entitlement petitions until MERC has three years of daily interruptible data available for all interruptible for the consolidated (MERC-NNG and MERC-Albert Lea), NNG PGA area. MERC has worked with the Department to ensure its design day regression analysis for the NNG-PGA is reasonable. In particular, MERC has utilized daily telemetry data in its regression analysis for all of the MERC-NNG customers with adequate data available. MERC has completed installation of telemetry for its former MERC-Albert Lea customers and anticipates having sufficient data for these customers in approximately two years to utilize in MERC's Design Day analysis. Until that time, MERC intends to utilize the same methodology it had utilized prior to having telemetry equipment for its other interruptible customers.

MERC obtained the daily large volume transportation, interruptible and joint interruptible volumes by pipeline and weather station (Data A). In addition, MERC obtained the daily small volume interruptible volumes by pipeline and weather station (Data B). MERC calculated the daily firm volumes by subtracting both Data A and Data B from the total throughput volumes.

[10] *November 1, 2017 Update* at page 3.

In addition, MERC made some adjustments to its data, for example for the NNG pipeline, for its regression analysis. In its Petition MERC stated the following:[11]

> Review daily total metered throughput, Data A, and Data B and identify missing or bad reads, and to the extent possible, fix missing or bad reads. To the extent that the data could not be fixed, it was not included in the regressions.

In its Petition, MERC also stated the following:[12]

> Identify the coldest Adjusted Heating Degree Day (AHDD) for the time period January 1996-December 2016 for each weather station. Note, this is a change in practice from prior analysis that used a rolling 20-year period. The change was included because many weather stations experienced historically cold weather in the January/February 1996 time period and without inclusion of that additional data from January/February 1996, AHDD were materially lower and not reflective of MERC's capacity needs.

To the Department's knowledge, MERC's prior design-day analyses have relied on the coldest days from 1996. In any event, the Department agrees with MERC that it would not be acceptable to use a rolling 20-year weather period in the design-day calculations when planning for the Company's capacity needs in meeting the design-day.

The Commission's April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, at Order point 10, stated in part the following:

> Required MERC to verify its regression analysis results in future demand entitlement filings to ensure the results are consistent with the underlying theory the analysis attempts to explain.

In its Petition, MERC stated the following:[13]

> Order Point 10 of the Commission's April 28, 2016, Order in Docket No. G011/M-15-723 required that MERC verify its regression analysis results in future demand entitlement filings to ensure the results are consistent with the underlying theory the analysis

[11] August 1, 2017 Filing and the *November 1, 2017 Update*, Attachment 12 at page 4.
[12] August 1, 2017 Filing and the *November 1, 2017 Update*, Attachment 12 at pages 3-4.
[13] August 1, 2017 Filing and the *November 1, 2017 Update*, Attachment 12 at page 9.

> attempts to explain. MERC has carefully reviewed the results of its regression analysis and verified that the results are consistent with the underlying theory the analysis attempts to explain. Please see MERC's May 31, 2016, compliance filing in Docket Nos. G011/M-15-722, G011/M-15 723, and G011/M-15-724 for further discussion of this issue.

In MERC's analysis for Ortonville, the Company used a regression model with a negative intercept term. The Department concludes that, while MERC's use of a zero intercept in its Ortonville regression analysis is not ideal, our concerns remain somewhat mitigated as described in our previous comments.[14] Thus, MERC complied with the Commission's April 28, 2016 Order described above.

The Department notes that MERC appropriately corrected its models for autocorrelation, as required by the Commission's February 4, 2015 Order in Docket Nos. G011/M-12-1192, G011/M-12-1193, G011/M-12-1194, and G011/M-12-1195 wherein the Commission required that, in its future demand entitlement filings, MERC check the regression models it ultimately uses for autocorrelation and correct the model if autocorrelation is present.
Given the fact that MERC must plan for its design day, MERC's approach does not seem unreasonable. As a result, the Department recommends that the Commission approve the Company's peak-day analysis.

C. TELEMETRY

On April 28, 2016, the Commission issued its Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724 for the 2015-2016 heating season (2016 Order). In the 2016 Order, Ordering point 13 states:

> Requested the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions. This review should determine if similar interruptible service tariff language requiring telemetering is already in each natural gas utilities' tariff for interruptible and transportation service and, if so, whether data from telemetering is being used effectively, and, if not, should a telemetering requirement be incorporated into their tariffs, and this data be used to possibly reduce costs.

[14] Please see the Department's February 22, 2016 Response Comments in Docket No. G011/M-15-723 at pages 3-4.

On December 6, 2017, the Commission issued its Order in Docket Nos. G011/M-16-650, G011/M-16-651, and G011/M-16-652 for the 2016-2017 heating season (2017 Order). In the 2017 Order, Ordering point 4 states:

> Requested the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions.

1. Great Plains

Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc. (Great Plains) does not use interruptible data in the development of its design day requirements. In addition, the Department has previously discussed the above Commission requests in its November 29, 2017 Comments in Docket No. G004/M-17-521.

2. CenterPoint Energy

CenterPoint does not use interruptible data in the development of its design day requirements. In addition, the Department requested information from CenterPoint addressing the 2016 and 2017 Orders noted above. (See Department Attachment 6). In its response, CenterPoint stated the following:

> … All Dual fuel customers (including sales service and transportation service), all transport customers (both Firm and Dual Fuel), plus certain Firm-C sales customers are required to install telemetry. The Company estimates non-daily read firm sales by subtracting the Dual Fuel measured sales and transport volumes from the total TBS volumes. The Company must also remove firm transportation volumes for those customers who provide their own entitlement prior to determining its Design Day.
>
> - **Provide general discussion of telemetering requirements for interruptible customers;**
>
> As noted above, all dual fuel customers are required to have telemetered equipment.
>
> Tariffs requiring telemetry:
> Section V, Page 3, Large General Firm Sales Service

Section V, Page 4, Small Volume Dual Fuel Sales Service (see page 4.a under Special Conditions)
Section V, Page 5, Small Volume Firm / Interruptible Sales Service (see page 5.a)
Section V, Page 6, Large Volume Dual Fuel Sales Service (see page 6.a under Special Conditions)

Section V, Page 14, Small Volume Firm Transportation Service (see page 14 under Special Conditions)
Section V, Page 15, Large Volume Firm Transportation Service (see page 15 under Special Conditions)
Section V, Page 16, Small Volume Dual Fuel Transportation Service (under Special Conditions)
Section V, Page 18, Large Volume Dual Fuel Transportation Service (under Special Conditions)

- **Explain if the Company has any interruptible customers without telemetering and if so, provide the number of interruptible customers without telemetering and explain why this is the case;**

  The Company requires all interruptible customers to have telemetry.

- **Explain if the Company has reduced its design day and/or interstate pipeline demand entitlements in the prior five years as a result of having daily interruptible data.**

  The Company has not reduced its design day as a result of having daily interruptible data in the past five years. Telemetry for dual fuel customers has been required for over 30 years.

3. Xcel Gas

With regards to the Commission's request in the *April 28, 2016 and December 6, 2017 MERC Orders* above, for Northern States Power Company, doing business as Xcel Energy, please see the forthcoming Department Comments in Docket No. G002/M-17-586.

4. Greater Minnesota Gas

The Department has requested information from Greater Minnesota addressing the 2016 and 2017 Orders. (See Department Attachment 7). The Department will address Greater Minnesota's use of telemetry in developing its design-day requirements in Department Response Comments.

5. Observations

Typically, given the long-term nature and size of interstate pipeline contracts, it is not clear to the Department how use of telemetering would "reduce costs." For example, MERC stated the following:[15]

> It would be difficult or impossible to isolate the impacts of telemetry data on MERC's overall peak day analysis or the impact of MERC's ability to use daily interruptible data over time. While the incorporation of telemetry data in the 2014-2015 Demand Entitlement filings occurred at a time when MERC's peak day declined, MERC cannot reasonably or definitively correlate that impact of that data or other factors on the reduction to the peak day. Other factors affecting peak day include the potential impact of improved data over time, the timeframe of data analyzed and corresponding weather patterns during those times, changes in methodology related to weather aggregation, and customer changes from year-to-year. While MERC agrees with Commission staff that daily interruptible data availability has enhanced MERC's ability to more accurately calculate its design day requirements, MERC cannot reasonably correlate specific savings from reduced demand entitlements to the use of such daily interruptible data.
>
> In Docket No. 15-723, MERC did experience a reduction in the peak day forecast, which allowed MERC to forego the renewal of NNG contract 127852 in the volume of 14,383 dth/day for the 2015/16 winter season. This NNG contract was TFX-5 winter-only capacity at maximum tariff rates and had been contracted for beginning with the 2014/15 winter season.

[15] See Department Attachment 8 and MERC's response to Department Information Request (IR) No. 2.

In any event, once long-term capacity is acquired for its residential and firm class customers, that particular capacity cannot be reduced or increased on a permanent and annual basis. In addition, these changes would be subject to the prevailing conditions and availability on the particular interstate pipeline(s).

D. PROPOSED RESERVE MARGIN

As indicated in Department Attachment 2, page 2, the proposed reserve margin is (1,466) Dth, or (0.55) %, as follows:

Table 3: MERC-NNG Reserve Margin

Filing	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %	Percentage Point Change From Previous Year
August 1, 2017	266,317	266,825	(508)	(0.19)%	(1.53)%
November 1, 2017	266,317	266,825	(508)	(0.19)%	(1.53)%
Department	266,317	267,783	(1,466)	(0.55)%	(2.07)%

The proposed reserve margin of (0.19)% represents a decrease of 1.53 percentage points as compared to last year's reserve margin of 1.34%.[16] However as mentioned previously, the proposed reserve margin is incorrect. Thus, the corrected proposed reserve margin of (0.55)% represents a decrease of 2.07 percentage points as compared to last year's reserve margin of 1.52%.[17] Table 4 below lists MERC-NNG reserve margins for the past 6 years.

Table 5: MERC-NNG Proposed and Historical Reserve Margins

2017-2018	(0.55)%
2016-2017	1.52%
2015-2016	2.79%
2014-2015	2.44%
2013-2014	4.52%
2012-2013	3.50%

In the instant Petition the Company stated the following regarding any changes to its design-day deliverability and other demand entitlement changes:

[16] MERC Attachment 3.
[17] Department Attachment 3, page 2.

> As shown in Attachment 3, MERC-NNG proposes no change in Design-Day Deliverability. The reserve margin for 2017-2018 is slightly negative. MERC will purchase city gate delivered supply to cover 0.19% of peak day throughput if necessary. This reserve margin is appropriate because incremental NNG capacity will come on line in 2018 as a result of the Rochester expansion project.

While MERC-NNG's reserve margin has been below 5 percent in recent years, it is clear that a negative reserve margin is not reasonable. As a result, the Department asked MERC the following questions:

> Please provide further detail on how MERC will protect ratepayers in the upcoming winter from the risks of Northern Natural Gas (NNG) pipeline capacity not being available and/or the expense of capacity being purchased on short notice likely at a time when the NNG system is constrained. Please describe any plan(s) the Company has to purchase capacity for the months of highest risk within the winter season (e.g. December, January, and February).

In their response to Department IR No. 1, the Company stated the following:[18]

> MERC will continue to monitor weather forecasts and in the event of a potential peak day, will call upon all interruptible customers to curtail their usage and will purchase citygate delivered gas for the period such supplies are needed (i.e., likely over a short term during the peak day event). The Company will be proactive in its approach with the full understanding of the current capacity situation and that it must act in a conservative manner with respect to the timing and volume of such a purchase.
>
> The calculated negative reserve margin amounts to approximately 500 Dth. However, as discussed in MERC's response to Department Information Request No. 3, MERC utilized a conservative peak day estimate for the communities of Esko and Balaton for the 2017-2018 heating season; if MERC had utilized more moderate peak day estimates for these two new communities, the resulting reserve margin would have been slightly higher – closer to 0% but would

[18] See Department Attachment 8.

> not have affected the Company's contracted demand entitlements as filed.
>
> The alternative to proceeding with a very small negative reserve margin for the 2017-2018 heating season would have been to enter into a five year capacity contract with NNG at maximum tariffed rates. MERC concluded that in light of the calculated reserve margin and anticipated timing of additional Rochester capacity, entering into a five year contract for additional capacity would not be prudent or in the best interest of customers.

In its 2017 Order, Ordering point 3 states:

> Required MERC to submit an explanation regarding how MERC plans to mitigate the risk of being unable to secure incremental winter capacity on all pipelines through which MERC currently contracts for natural gas capacity, as a supplement to its change in demand entitlements filings for the 2017-2018 heating season, within 10 days of the date of this Order; and

In its December 15, 2017 Compliance Filing submitted in the instant docket, MERC stated in part the following:

> … In general, there is limited risk of MERC of being unable to obtain incremental winter capacity as needed, with the exception of situations of physical constraints where interstate pipeline upgrades are required to obtain additional capacity, in which case MERC would most likely know, and be able to plan in advance for such a situation.
>
> There are various alternative supply strategies that can be used when capacity is not available on an unconstrained pipeline. MERC has two main options for meeting its peak day requirements when capacity is not available: (1) purchase city gate delivered supply; and (2) purchase back-haul capacity. MERC has similar options on all pipelines it uses including Northern Natural Gas ("NNG"), Viking Gas Transmission Pipeline, Great Lakes Gas Transmission, and Centra. In cases where a physical inadequacy of capacity prevents MERC from effectively serving a peak load, upgrades to the pipeline must take place as in the case of the Rochester Expansion Project.

In addition, MERC essentially repeated the explanation it provided in its response to Department IR No. 1. As a result, the Department makes the following observations:

- Design Day assumes that interruptible customers, because they don't contribute to MERC's costs to reserve capacity on the interstate pipeline, will be required to discontinue gas use. In addition, the design day is an estimate of how much entitlement, or capacity, is needed on interstate pipelines to move all of the gas required by <u>firm</u> customers under design-day conditions that involves very cold temperatures. Interruptible customers are not part of the design-day estimates and as such the Company's response above is non-responsive to the question the Department asked of MERC.

- Given that MERC will have added capacity in the Rochester area in 2018 with flexibility for MERC to request alternative NNG delivery points, it makes sense that "The alternative to proceeding with a very small negative reserve margin for the 2017-2018 heating season would have been to enter into a five year capacity contract with NNG at maximum tariffed rates, and that entering into a five year contract for additional capacity would not be prudent or in the best interest of MERC's customers." However, that may not have been the only alternative.

- MERC has not explained whether it could have planned for and obtained capacity via NNG's Electronic Bulletin Board (EBB) for the typical months of highest risk within the winter season (e.g. December, January, and February).

- MERC has not explained why it was unable to plan for and obtain a 5-month contract similar to NNG contract 127852 in the volume of 14,383 Dth/day for the 2015/16 winter season that MERC did not renew. According to MERC, this NNG contract was TFX-5 winter-only capacity at maximum tariff rates and had been contracted for beginning with the 2014/15 winter season and as such spanned only one winter season.

- While it might be true that a less conservative design-day estimate for Balaton and Esko could increase the negative 0.55 percent reserve margin and bring it closer to zero, MERC has not explained whether there were other options for increasing the reserve margin, such as whether it could have planned for and purchased third-party delivered contract(s).

- Ultimately, MERC must plan for its design day and ensure that it reliably serves its firm customers under design-day conditions.

- Given the recent cold spell from approximately December 15, 2017 to January 20, 2018, MERC should provide information in its Reply Comments on how its system performed in terms of reliably serving its firm customers; what the associated weather was; how close it came to its design-day parameters; what the associated interstate pipeline operating conditions were – such as "operational flow orders," "constraints" et cetera; and if MERC had difficulty in securing gas supply for and/or reliably serving its firm customers.

In general, 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 intends to follow-up 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 justified, and to continue monitoring the growing inter-relationship between the natural gas and electric industries.

E. OTHER ISSUES

The Department makes the following observations with MERC's Petition:[19]

- This is the first Petition in which the Company was to reflect consolidation of its NNG and Albert Lea systems, as required by the ruling in Docket No. G011/GR-15-736. The Company failed to include or reflect all of the former Albert Lea PGA system data in some of its Attachments in its Initial August 1, 2017 filing;

- The Company failed to include or reflect all of the former Albert Lea PGA system data in its November Update even though it provided a reconciliation reflecting the Albert Lea data in its Attachment 8.1;

[19] See page 2 of Department Attachments 1, 2, and 3 wherein the Department has corrected some errors. MERC should confirm its agreement or in the alternative provide its "corrected" numbers along with the associated explanation of why their "corrected" numbers would be appropriate.

- MERC failed to update its comparison of costs in Attachment 3 to the October PGA in its *November Update* and kept it at the July 2017 PGA costs;

- The "number of firm customers" of approximately 187,194 does not appear to reflect the customers from its former Albert Lea PGA system and the Company should provide the correct number;

- In addition, the Company should explain if the "187,194" customers includes customers from Esko and Balaton; if they were excluded, MERC should correct for that discrepancy;

- The numbers in the "Commodity Cost" row in columns labeled "Demand Charge – Demand Filing November 1, 2016," "Most Recent PGA," and "Proposed Effective November 1, 2017" in Attachment 4 of both the initial August 1, 2017 Petition and *November Update* should be corrected;

- The numbers in the "Demand Cost" row in columns labeled "Demand Charge Demand Filing November 1, 2016," "Most Recent PGA," and "Proposed Effective November 1, 2017" in Attachment 4 of both the initial August 1, 2017 Petition and *November Update* should be corrected;

- The "Demand Costs" of "$27.6780" for the Small Volume Firm and Large Volume Firm customers in the columns labeled "Demand Charge Demand Filing November 1, 2016," "Most Recent PGA," and "Proposed Effective November 1, 2017" in Attachment 4 of both the initial August 1, 2017 Petition and *November Update* should be corrected;

- The "ANNUAL SALES -- As approved in Docket No. G011/MR-15-748" of 253,351,745 therms in Attachment 4 of both the initial August 1, 2017 Petition and *November Update* should be corrected;

- The "GS-NNG Sales as approved in Docket No. G011/MR-15-748" of 225,057,235 therms in Attachment 4 of both the initial August 1, 2017 Petition and *November Update* should be corrected;

- The Summer/Winter usage in MERC's Attachment 2 of both the initial August 1, 2017Petition and *November Update* appear to also reflect the data for MERC's former Albert Lea PGA system, however, it is unclear and as such MERC should explain if that is indeed the case. In addition, MERC should explain if these numbers reflect data for Esko and Balaton as well; and

- In its *November Update*, MERC stated the following:

> Attachment 8.1: Change in Entitlement Levels and Related Demand Costs (Including MERC-NNG and MERC-Albert Lea)[2]
>
> ___________________
>
> 2 MERC also identified an error in the storage cost calculation in its 2016-2017 Demand Entitlement. This error has been corrected in Attachment 8 and Attachment 8.1 to accurately reflect the 2016-2017 storage costs. There is no impact as a result of this correction to the proposed 2017-2018 storage costs.

In Docket No. 16-650, MERC filed a letter on May 31, 2017 on the modification of its Storage contracts effective June 1, 2017. The Department filed Supplemental Comments in Docket 16-650 on June 2, 2017 identifying concerns related to contracted rates for the NNG Storage that were above NNG's maximum tariffed rates. Thus, it is unclear whether the changes reflected in MERC's Attachment 8.1 in its *November Update* are as a result of correcting for the previous MERC-Albert Lea PGA system storage units, the modification of the Storage contracts, and correcting for the NNG Storage rates that were above NNG's maximum tariffed rates, or some combination of those 3 changes. The Department requests that MERC, in its Reply Comments, provide a detailed explanation for its "correction" referenced in its footnote 2 shown above.

F. THE COMPANY'S PGA COST RECOVERY PROPOSAL

In its Attachment 3 page 2, the Department compares MERC's October 2017 PGA to MERC's projected November 2017 PGA rates to highlight the changes in demand costs. According to the Department's calculations, the Company's demand entitlement proposal would result in the following annual demand cost impacts:

- annual bill decrease of $0.42 related to demand costs, or less than 0.07%, for the average General Service customer consuming 88 Dth annually;
- annual bill decrease of $1.30 related to demand costs, or approximately 0.01%, for the average Small Volume Firm customer consuming 5,110 Dth annually;
- annual bill decrease of $3.90 related to demand costs, or approximately 0.01%, for the average Large Volume Firm customer consuming 16,150 Dth annually; and
- no demand cost impacts related to MERC-NNG's interruptible rate classes.

III. THE DEPARTMENT'S RECOMMENDATIONS

The Department will provide its recommendations to the Commission in Response Comments, after MERC files Reply Comments.

The Department requests that MERC provide a detailed explanation on the following information:

- Other Issues – provide further details as requested herein on all the numbers and the Storage Contracts.
- Design-Day Analysis - the Department recommends that the Commission approve the Company's peak-day analysis.
- Reserve Margin – provide further information on the reserve margin as requested herein.

/ja

Department Attachment 1
Docket No. G011/M-17-588
MERC NNG Demand Entitlement Historical and Current Proposal
Prior to MERC - ABL Consolidation

	Historical Demand Entitlements				Proposed 11/1/17			
Contract Type	2013-2014 Quantity (Mcf)	2014-2015 Quantity (Mcf)	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	2017-2018 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
TF12B	49,153	55,019	45,026	45,026	45,026	0		
TF12V	26,926	21,060	30,290	30,290	30,290	0		
TF5	31,515	31,515	32,278	32,278	45,668	13,390		
TFX12	32,297	32,297	32,297	32,297	32,297	0		
TFX(5)	93,084	123,084	108,701	108,701	109,501	800		
TFX (April Only)*	2,000	2,000	2,000	2,000	2,000	0		
TFX (October Only)*	2,000	2,000	2,000	2,000	2,000	0		
Windom	2,500	2,500	2,500	2,500	2,500	0		
Northwestern Energy	910	910	1,035	1,035	1,035	0		
NNG Zone Delivery Call Option	20,000	0	0	0	0	0		
Bison**	50,000	50,000	50,000	50,000	50,000	0		
NBPL**	50,000	50,000	50,000	50,000	50,000	0		
Total Entitlement* **	**256,385**	**266,385**	**252,127**	**252,127**	**266,317**	**14,190**	**5.63%**	**7.25%**
Total Annual Transportation	**131,786**	**111,786**	**111,148**	**111,148**	**111,148**	**0**	**0.00%**	
Total Winter Only Transport	**124,599**	**154,599**	**140,979**	**140,979**	**155,169**	**14,190**	**10.07%**	
Percent of Winter Only Capacity	48.60%	58.04%	55.92%	55.92%	58.26%			

*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.
***The Entitlement increase of 14,190 Mcf is completely attributable to the combining of the MERC Albert Lea PGA into the MERC NNG PGA.
Source: MERC's Attachments 3 & 7

Department Attachment 1
Docket No. G011/M-17-588
MERC NNG Demand Entitlement Historical and Current Proposal
After MERC-ABL Consolidation

	Historical Demand Entitlements				Proposed 11/1/17			
Contract Type	2013-2014 Quantity (Mcf)	2014-2015 Quantity (Mcf)	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	2017-2018 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
TF12B	50,546	58,161	48,183	48,183	54,419	6,236		
TF12V	34,946	27,331	36,526	36,526	30,290	(6,236)		
TF5	35,521	35,521	36,275	36,275	36,275	0		
TFX12	32,297	32,297	32,297	32,297	32,297	0		
TFX(5)	93,884	123,884	109,501	109,501	109,501	0		
TFX (April Only)*	2,000	2,000	2,000	2,000	2,000	0		
TFX (October Only)*	2,000	2,000	2,000	2,000	2,000	0		
Windom	2,500	2,500	2,500	2,500	2,500	0		
Northwestern Energy	910	910	1,035	1,035	1,035	0		
NNG Zone Delivery Call Option	20,000	0	0	0	0	0		
Bison**	50,000	50,000	50,000	50,000	50,000	0		
NBPL**	50,000	50,000	50,000	50,000	50,000	0		
Total Entitlement* **	**270,604**	**280,604**	**266,317**	**266,317**	**266,317**	**0**	**0.00%**	**2.08%**
Total Annual Transportation	**141,199**	**121,199**	**120,541**	**120,541**	**120,541**	**0**	**0.00%**	
Total Winter Only Transport	**129,405**	**159,405**	**145,776**	**145,776**	**145,776**	**0**	**0.00%**	
Percent of Winter Only Capacity	47.82%	56.81%	54.74%	54.74%	54.74%			

*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.

***The Entitlement increase of 14,190 Mcf is completely attributable to the combining of the MERC Albert Lea PGA into the MERC NNG PGA.

Source: MERC's Attachments 3 & 7

Department Attachment 2
Docket No. G011/M-17-588
MERC NNG Demand Entitlement Analysis*
Prior to MERC - ABL Consolidation

	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)
2017-2018	187,194	2,617	1.42%	266,825	18,029	7.25%	266,317	14,190	5.63%	(508)	-0.19%
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)
2017-2018	unknown			-0.0027	1.4254	1.4227	unknown
2016-2017	212,653	8,209	4.02%	0.0180	1.3479	1.3660	1.1521
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

*Increases to the 2017-2018 Number of Firm Customers, Design-Day, and Total Entitlement were largley attributed the Albert Lea PGA.

**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 2
Docket No. G011/M-17-588
MERC NNG Demand Entitlement Analysis*
After MERC-ABL Consolidation

	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)
2017-2018	187,194	(8,117)	-4.16%	267,783	5,459	2.08%	266,317	0	0.00%	(1,466)	-0.55%
2016-2017	195,311	3,295	1.72%	262,324	3,248	1.25%	266,317	0	0.00%	3,993	1.52%
2015-2016	192,016	2,938	1.55%	259,076	(14,841)	-5.42%	266,317	(14,287)	-5.09%	7,241	2.79%
2014-2015	189,078	(176)	-0.09%	273,917	15,004	5.79%	280,604	10,000	3.70%	6,687	2.44%
2013-2014	189,254	1,709	0.91%	258,913	19,588	8.18%	270,604	22,900	9.24%	11,691	4.52%
2012-2013	187,545	1,655	0.89%	239,325	(8,657)	-3.49%	247,704	(15,771)	-5.99%	8,379	3.50%
2011-2012	185,890	(720)	-0.39%	247,982	13,075	5.57%	263,475	(15,690)	-5.62%	15,493	6.25%
2010-2011	186,610	799	0.43%	234,907	(9,694)	-3.96%	279,165	7,000	2.57%	44,258	18.84%
2009-2010	185,811	1,243	0.67%	244,601	(19,298)	-7.31%	272,165	4,227	1.58%	27,564	11.27%
2008-2009	184,568	1,854	1.01%	263,899	23,416	9.74%	267,938	0	0.00%	4,039	1.53%
2007-2008	182,714	7,073	4.03%	240,483	1,729	0.72%	267,938	2,036	0.77%	27,455	11.42%
2006-2007	175,641			238,754			265,902			27,148	11.37%
Average			0.60%			1.20%			0.11%		6.24%

	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)
2017-2018	unknown			-0.0078	1.4305	1.4227	unknown
2016-2017	212,653	(2,524)	-1.17%	0.0204	1.3431	1.3636	1.0888
2015-2016	215,177	10,612	5.19%	0.0377	1.3492	1.3870	1.1206
2014-2015	204,565	(19,471)	-8.69%	0.0354	1.4487	1.4841	1.0819
2013-2014	224,036			0.0618	1.3681	1.4298	1.1838
2012-2013				0.0447	1.2761	1.3208	
2011-2012				0.0833	1.3340	1.4174	
2010-2011				0.2372	1.2588	1.4960	
2009-2010				0.1483	1.3164	1.4647	
2008-2009				0.0219	1.4298	1.4517	
2007-2008				0.1503	1.3162	1.4664	
2006-2007				0.1546	1.3593	1.5139	
Average			-1.56%	0.0823	1.3525	1.4348	1.1188

*Design-Day, and Total Entitlement were largley attributed the Albert Lea PGA however MERC did not increase its 2017-2018 Firm Customers to incoporate the Albert Lea PGA numbers
**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-17-588
MERC NNG Rate Impacts

General Service-Residential	Base Cost of Gas Change G011/MR-15-748 7/1/16	Last Demand Change 11/1/2016	Most Recent PGA 07/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$4.3217	$3.2257	$3.0616	-5.09%	-29.16%	-5.09%	($0.1641)
Demand Cost	$0.9288	$0.9226	$0.9288	$0.9860	6.16%	6.87%	6.16%	$0.0572
Commodity Margin	$2.4116	$2.3980	$2.4116	$2.4116	0.00%	0.57%	0.00%	$0.0000
Total Cost of Gas	$6.5661	$7.6423	$6.5661	$6.4592	-1.63%	-15.48%	-1.63%	($0.1069)
Average Annual Use	88	88	88	88				
Average Annual Cost of Gas*	$577.82	$672.52	$577.82	$568.41	-1.63%	-15.48%	-1.63%	($9.41)

SV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 7/1/16	Last Demand Change 11/1/2016	Most Recent PGA 07/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$4.3217	$3.2257	$3.0616	-5.09%	-29.16%	-5.09%	($0.1641)
Commodity Margin	$0.9740	$0.9336	$0.9740	$0.9740	0.00%	4.33%	0.00%	$0.0000
Total Cost of Gas	$4.1997	$5.2553	$4.1997	$4.0356	-3.91%	-23.21%	-3.91%	($0.1641)
Average Annual Use	5,110	5,110	5,110	5,110				
Average Annual Cost of Gas*	$21,460.47	$26,854.58	$21,460.47	$20,621.92	-3.91%	-23.21%	-3.91%	($838.55)

LV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 7/1/16	Last Demand Change 11/1/2016	Most Recent PGA 07/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$4.3217	$3.2257	$3.0616	-5.09%	-29.16%	-5.09%	($0.1641)
Commodity Margin	$0.5329	$0.5007	$0.5329	$0.5329	0.00%	6.43%	0.00%	$0.0000
Total Cost of Gas	$3.7586	$4.8224	$3.7586	$3.5945	-4.37%	-25.46%	-4.37%	($0.1641)
Average Annual Use	16,150	16,150	16,150	16,150				
Average Annual Cost of Gas*	$60,701.39	$77,881.76	$60,701.39	$58,051.18	-4.37%	-25.46%	-4.37%	($2,650.22)

SV Firm Service	Base Cost of Gas Change G011/MR-15-748 7/1/16	Last Demand Change 11/1/2016	Most Recent PGA 07/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$4.3217	$3.2257	$3.0616	-5.09%	-29.16%	-5.09%	($0.1641)
Demand Cost	$27.6780	$10.1722	$27.6780	$10.1817	-63.21%	0.09%	-63.21%	($17.4963)
Commodity Margin	$0.9740	$0.9336	$0.9740	$0.9740	0.00%	4.33%	0.00%	$0.0000
Demand Margin	$3.0000	$2.7493	$3.0000	$3.0000	0.00%	9.12%	0.00%	$0.0000
Total Cost of Gas	$4.1997	$5.2553	$4.1997	$4.0356	-3.91%	-23.21%	-3.91%	($0.1641)
Total Demand Cost	$30.6780	$12.9215	$30.6780	$13.1817	-57.03%	2.01%	-57.03%	($17.4963)
Average Annual Use	5,110	5,110	5,110	5,110				
Average Annual Demand Units	25	25	25	25				
Average Annual Cost of Gas*	$22,227.42	$27,177.62	$22,227.42	$20,951.46	-5.74%	-22.91%	-5.74%	($1,275.96)

LV Firm Service	Base Cost of Gas Change G011/MR-15-748 7/1/16	Last Demand Change 11/1/2016	Most Recent PGA 07/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$4.3217	$3.2257	$3.0616	-5.09%	-29.16%	-5.09%	($0.1641)
Demand Cost	$27.6780	$10.1722	$27.6780	$10.1817	-63.21%	0.09%	-63.21%	($17.4963)
Commodity Margin	$0.5329	$0.5007	$0.5329	$0.5329	0.00%	6.43%	0.00%	$0.0000
Demand Margin	$3.0000	$2.7493	$3.0000	$3.0000	0.00%	9.12%	0.00%	$0.0000
Total Cost of Gas	$3.7586	$4.8224	$3.7586	$3.5945	-4.37%	-25.46%	-4.37%	($0.1641)
Total Demand Cost	$30.6780	$12.9215	$30.6780	$13.1817	-57.03%	2.01%	-57.03%	($17.4963)
Average Annual Use	16,150	16,150	16,150	16,150				
Average Annual Demand Units	75	75	75	75				
Average Annual Cost of Gas*	$63,002.24	$78,850.87	$63,002.24	$59,039.80	-6.29%	-25.12%	-6.29%	($3,962.44)

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	($0.1641)	$0.0572	($0.1069)	-1.63%	($9.41)
SV Interruptible Service	($0.1641)	$0.0000	($0.1641)	-3.91%	($838.55)
LV Interruptible Service	($0.1641)	$0.0000	($0.1641)	-4.37%	($2,650.22)
SV Firm Service	($0.1641)	($17.4963)	($17.6604)	-5.74%	($1,275.96)
LV Firm Service	($0.1641)	($17.4963)	($17.6604)	-6.29%	($3,962.44)

***** 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.

Department Attachment 3
Docket No. G011/M-17-588
MERC NNG Rate Impacts

General Service-Residential	Base Cost of Gas Change G011/MR-15-748 11/30/16	Last Demand Change 11/1/2016	Most Recent PGA 10/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$3.0682	$3.0658	$3.0658	-4.96%	-0.08%	0.00%	$0.0000
Demand Cost	$0.9288	$0.9319	$0.9376	$0.9328	0.43%	0.10%	-0.51%	($0.0048)
Commodity Margin	$2.4116	$2.3980	$2.4116	$2.4116	0.00%	0.57%	0.00%	$0.0000
Total Cost of Gas	$6.5661	$6.3981	$6.4150	$6.4102	-2.37%	0.19%	-0.07%	($0.0048)
Average Annual Use	88	88	88	88				
Average Annual Cost of Gas*	$577.82	$563.03	$564.52	$564.10	-2.37%	0.19%	-0.07%	($0.42)

SV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 11/30/16	Last Demand Change 11/1/2016	Most Recent PGA 10/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$3.0682	$3.0658	$3.0658	-4.96%	-0.08%	0.00%	$0.0000
Commodity Margin	$0.9740	$0.9336	$0.9740	$0.9740	0.00%	4.33%	0.00%	$0.0000
Total Cost of Gas	$4.1997	$4.0018	$4.0398	$4.0398	-3.81%	0.95%	0.00%	$0.0000
Average Annual Use	5,110	5,110	5,110	5,110				
Average Annual Cost of Gas*	$21,460.47	$20,449.20	$20,643.38	$20,643.38	-3.81%	0.95%	0.00%	$0.00

LV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 11/30/16	Last Demand Change 11/1/2016	Most Recent PGA 10/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$3.0682	$3.0658	$3.0658	-4.96%	-0.08%	0.00%	$0.0000
Commodity Margin	$0.5329	$0.5007	$0.5329	$0.5329	0.00%	6.43%	0.00%	$0.0000
Total Cost of Gas	$3.7586	$3.5689	$3.5987	$3.5987	-4.25%	0.83%	0.00%	$0.0000
Average Annual Use	16,150	16,150	16,150	16,150				
Average Annual Cost of Gas*	$60,701.39	$57,637.74	$58,119.01	$58,119.01	-4.25%	0.83%	0.00%	$0.00

SV Firm Service	Base Cost of Gas Change G011/MR-15-748 11/30/16	Last Demand Change 11/1/2016	Most Recent PGA 10/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$3.0682	$3.0658	$3.0658	-4.96%	-0.08%	0.00%	$0.0000
Demand Cost	$10.1448	$10.2670	$10.2337	$10.1817	0.36%	-0.83%	-0.51%	($0.0520)
Commodity Margin	$0.9740	$0.9336	$0.9740	$0.9740	0.00%	4.33%	0.00%	$0.0000
Demand Margin	$3.0000	$2.7493	$3.0000	$3.0000	0.00%	9.12%	0.00%	$0.0000
Total Cost of Gas	$4.1997	$4.0018	$4.0398	$4.0398	-3.81%	0.95%	0.00%	$0.0000
Total Demand Cost	$13.1448	$13.0163	$13.2337	$13.1817	0.28%	1.27%	-0.39%	($0.0520)
Average Annual Use	5,110	5,110	5,110	5,110				
Average Annual Demand Units	25	25	25	25				
Average Annual Cost of Gas*	$21,789.09	$20,774.61	$20,974.22	$20,972.92	-3.75%	0.95%	-0.01%	($1.30)

LV Firm Service	Base Cost of Gas Change G011/MR-15-748 11/30/16	Last Demand Change 11/1/2016	Most Recent PGA 10/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.2257	$3.0682	$3.0658	$3.0658	-4.96%	-0.08%	0.00%	$0.0000
Demand Cost	$10.1448	$10.2670	$10.2337	$10.1817	0.36%	-0.83%	-0.51%	($0.0520)
Commodity Margin	$0.5329	$0.5007	$0.5329	$0.5329	0.00%	6.43%	0.00%	$0.0000
Demand Margin	$3.0000	$2.7493	$3.0000	$3.0000	0.00%	9.12%	0.00%	$0.0000
Total Cost of Gas	$3.7586	$3.5689	$3.5987	$3.5987	-4.25%	0.83%	0.00%	$0.0000
Total Demand Cost	$13.1448	$13.0163	$13.2337	$13.1817	0.28%	1.27%	-0.39%	($0.0520)
Average Annual Use	16,150	16,150	16,150	16,150				
Average Annual Demand Units	75	75	75	75				
Average Annual Cost of Gas*	$61,687.25	$58,613.96	$59,111.53	$59,107.63	-4.18%	0.84%	-0.01%	($3.90)

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	$0.0000	($0.0048)	($0.0048)	-0.07%	($0.42)
SV Interruptible Service	$0.0000	$0.0000	$0.0000	0.00%	$0.00
LV Interruptible Service	$0.0000	$0.0000	$0.0000	0.00%	$0.00
SV Firm Service	$0.0000	($0.0520)	($0.0520)	-0.01%	($1.30)
LV Firm Service	$0.0000	($0.0520)	($0.0520)	-0.01%	($3.90)

* 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.
The BCOG column reflects MERC's 11-30-16 Compliance Filing and the Commision's *February 13, 2017 Order* in Docket No. G011/GR-15-736.
The 'Last Demand Change on 11/1/16' column reflects information from MERC's November 1, 2016 PGA filing in Docket No. G011/AA-16-879 and only reflects the previous MERC-NNG system.

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 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:

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G008/M-17-533	☐Nonpublic ☒Public
Requested From:	Marie Doyle, CenterPoint	Date of Request: 12/6/2017
Type of Inquiry:	General	Response Due: 12/18/2017

Requested by:	Sachin Shah/Michael Ryan/Adam Heinen
Email Address(es):	sachin.shah@state.mn.us , michael.j.ryan@state.mn.us & adam.heinen@state.mn.us
Phone Number(s):	651-539-1834 & 651-539-1825

Request Number:	DOC 001
Topic:	Demand Entitlement
Reference(s):	August 16, 2017 Public Utilities Commission (Commission or PUC) Staff Briefing Papers in Docket No. G011/M-16-650

Request:

On page 12 of the Briefing Papers, staff stated the following:

> If the Department has not begun the investigation, requested in Commission Order Point 13, in Docket Nos. 15-722, 15-723, and 15-724, into how other natural gas utilities acquire and use daily customer usage data:
>
> > 5. Request the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions. This review should determine if similar interruptible service tariff language requiring telemetering is already in each natural gas utilities' tariff for interruptible and transportation service and, if so, whether data from telemetering is being used effectively, and, if not, should a telemetering requirement be incorporated into their tariffs, and this data be used to possibly reduce costs.

The final order in Docket No. G011/M-16-650 has not been issued, but in the agenda meeting the Commission and staff expressed interest having the Department review the use of metered daily interruptible data. Based on this anticipated order, please:

- Provide general discussion on how interruptible customers and their data are incorporated into design-day analysis;

To be completed by responder

Response Date:	December 18, 2017
Response by:	Marie M. Doyle, CenterPoint Energy Minnesota Gas
Email Address:	marie.doyle@centerpointenergy.com
Phone Number:	612-321-5078

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G008/M-17-533	☐Nonpublic ☒Public
Requested From:	Marie Doyle, CenterPoint	Date of Request: 12/6/2017
Type of Inquiry:	General	Response Due: 12/18/2017

Requested by:	Sachin Shah/Michael Ryan/Adam Heinen
Email Address(es):	sachin.shah@state.mn.us , michael.j.ryan@state.mn.us & adam.heinen@state.mn.us
Phone Number(s):	651-539-1834 & 651-539-1825

- Provide general discussion of telemetering requirements for interruptible customers;
- Explain if the Company has any interruptible customers without telemetering and if so, provide the number of interruptible customers without telemetering and explain why this is the case;
- Reference and provide any tariff language that requires interruptible customers to have telemetering; and
- Explain if the Company has reduced its design day and/or interstate pipeline demand entitlements in the prior five years as a result of having daily interruptible data.

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

RESPONSE:

- **Provide general discussion <u>on how interruptible customers and their data are incorporated into design-day analysis;</u>**

The Design Day is an estimate of how much entitlement, or capacity, is needed on interstate pipelines to move all of the gas required by <u>firm</u> customers under extreme demand, usually driven by very cold temperatures. Design Day assumes that interruptible customers, because they don't contribute to the LDCs costs to reserve capacity on the pipeline, will be required to discontinue gas use.

CenterPoint Energy's daily dataset available to analyze includes daily usage data from all winter days for the past six heating seasons (November 2011 – March 2017). CenterPoint Energy's daily data is made up of total Company telemetered TBS Throughput and daily sales service and transportation volumes for customers who have daily-read telemetry. All Dual fuel customers (including sales service and transportation service), all transport customers (both Firm and Dual Fuel), plus certain Firm-C sales

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To be completed by responder

Response Date:	December 18, 2017
Response by:	Marie M. Doyle, CenterPoint Energy Minnesota Gas
Email Address:	marie.doyle@centerpointenergy.com
Phone Number:	612-321-5078

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G008/M-17-533	☐Nonpublic ☒Public
Requested From:	Marie Doyle, CenterPoint	Date of Request: 12/6/2017
Type of Inquiry:	General	Response Due: 12/18/2017

Requested by: Sachin Shah/Michael Ryan/Adam Heinen
Email Address(es): sachin.shah@state.mn.us , michael.j.ryan@state.mn.us & adam.heinen@state.mn.us
Phone Number(s): 651-539-1834 & 651-539-1825

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customers are required to install telemetry. The Company estimates non-daily read firm sales by subtracting the Dual Fuel measured sales and transport volumes from the total TBS volumes. The Company must also remove firm transportation volumes for those customers who provide their own entitlement prior to determining its Design Day.

For the 2017-2018 Heating season, the Company also captured the daily sales data for dual fuel customers who it expected to migrate to firm service. The Company performed regressions on the historical daily data to estimate a firm design day for that group of customers, and added it to the traditional design day estimate to estimate the total capacity required for the upcoming heating season.

- **Provide general discussion of telemetering requirements for interruptible customers;**

As noted above, all dual fuel customers are required to have telemetered equipment.

Tariffs requiring telemetry:
Section V, Page 3, Large General Firm Sales Service
Section V, Page 4, Small Volume Dual Fuel Sales Service (see page 4.a under Special Conditions)
Section V, Page 5, Small Volume Firm / Interruptible Sales Service (see page 5.a)
Section V, Page 6, Large Volume Dual Fuel Sales Service (see page 6.a under Special Conditions)

Section V, Page 14, Small Volume Firm Transportation Service (see page 14 under Special Conditions)
Section V, Page 15, Large Volume Firm Transportation Service (see page 15 under Special Conditions)
Section V, Page 16, Small Volume Dual Fuel Transportation Service (under Special Conditions)
Section V, Page 18, Large Volume Dual Fuel Transportation Service (under Special Conditions)

To be completed by responder

Response Date: December 18, 2017
Response by: Marie M. Doyle, CenterPoint Energy Minnesota Gas
Email Address: marie.doyle@centerpointenergy.com
Phone Number: 612-321-5078

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G008/M-17-533	☐Nonpublic ☒Public
Requested From:	Marie Doyle, CenterPoint	Date of Request: 12/6/2017
Type of Inquiry:	General	Response Due: 12/18/2017

Requested by: Sachin Shah/Michael Ryan/Adam Heinen
Email Address(es): sachin.shah@state.mn.us , michael.j.ryan@state.mn.us & adam.heinen@state.mn.us
Phone Number(s): 651-539-1834 & 651-539-1825

- **Explain if the Company has any interruptible customers without telemetering and if so, provide the number of interruptible customers without telemetering and explain why this is the case;**

The Company requires all interruptible customers to have telemetry.

- **Reference and provide any tariff language that requires interruptible customers to have telemetering; and**

Page 3 – Availability: "Customers must provide telemetering or agree to have telemetering installed at the customers' request."

Page 4.a – Special Conditions (continued):, 4) - "Customer is responsible for reimbursing CenterPoint Energy for all incremental on-site plant investments, including telemetry equipment, required by CenterPoint Energy for providing service to the customer. This investment shall remain the property of CenterPoint Energy."

Page 5.a – Special Conditions Firm and Interruptible - "Customer must install telemetry equipment. Customer is responsible for reimbursing CenterPoint Energy for all incremental on-site plant investments, including telemetry equipment, required by CenterPoint Energy for providing service to the customer. This investment shall remain the property of CenterPoint Energy."

Page 6.a - Special Conditions (continued):, 4) - "Customer is responsible for reimbursing CenterPoint Energy for all incremental on-site plant investments, including telemetry equipment, required by CenterPoint Energy for providing service to the customer. This investment shall remain the property of CenterPoint Energy."

To be completed by responder

Response Date: December 18, 2017
Response by: Marie M. Doyle, CenterPoint Energy Minnesota Gas
Email Address: marie.doyle@centerpointenergy.com
Phone Number: 612-321-5078

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G008/M-17-533	☐Nonpublic ☒Public
Requested From:	Marie Doyle, CenterPoint	Date of Request: 12/6/2017
Type of Inquiry:	General	Response Due: 12/18/2017

Requested by:	Sachin Shah/Michael Ryan/Adam Heinen
Email Address(es):	sachin.shah@state.mn.us , michael.j.ryan@state.mn.us & adam.heinen@state.mn.us
Phone Number(s):	651-539-1834 & 651-539-1825

Language on Pages 14, Special Conditions: 2)
Page 15, Special Conditions: 2)
Page 16, Special Conditions: 3) and
Page 18, Special Conditions: 3)

"Customer is responsible for reimbursing CenterPoint Energy for all incremental on-site plant investments, including telemetry equipment, required by CenterPoint Energy for providing transportation services to the customer. This investment shall remain the property of CenterPoint Energy."

- **Explain if the Company has reduced its design day and/or interstate pipeline demand entitlements in the prior five years as a result of having daily interruptible data.**

The Company has not reduced its design day as a result of having daily interruptible data in the past five years. Telemetry for dual fuel customers has been required for over 30 years.

To be completed by responder

Response Date:	December 18, 2017
Response by:	Marie M. Doyle, CenterPoint Energy Minnesota Gas
Email Address:	marie.doyle@centerpointenergy.com
Phone Number:	612-321-5078

COMMERCE DEPARTMENT

January 26, 2018

Kristine Anderson
Greater Minnesota Gas, Inc.
202 S. Main Street
Le Sueur, Mn 56058

RE: DOCKET NO. G022/M-17-399
NATURE OF DOCKET: Change in Contract Demand Entitlement for 2017-2018 Heating Season

Dear Ms. Anderson:

Enclosed please find the Department of Commerce information request number(s) **1** in the above cited docket number. Please send me and the requesting analyst(s) all responses in a text searchable PDF format. My email address is utility.discovery@state.mn.us. The appropriate analyst is listed on the questions page below and will be CC'd on this information request. If responding to more than one question, please make each response a separate file. If requested by the analyst to send something by CD-ROM please send it to me at the following address:

Connor Boler
Department of Commerce
85 7th Place East Suite 280
St. Paul, MN 55101-2198

Please indicate the above cited docket number, the corresponding request number, the requesting analyst, and the respondent's name and title on your response. If your response contains Trade Secret data, please include a public copy.

If you have any questions or problems providing information in the time specified, please contact me at (651) 539-1534 and I will direct you to the analyst requesting the information.

Respectfully submitted,

/s/Sharon Ferguson for Connor Boler
Regulatory Information Center

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G022/M-17-399	☐Nonpublic ☒Public
Requested From:	Kristine A. Anderson, Greater Minnesota	Date of Request: January 26, 2018
Type of Inquiry:	General	Response Due: February 5, 2018

Requested by:	Sachin Shah/Adam Heinen
Email Address(es):	sachin.shah@state.mn.us & adam.heinen@state.mn.us
Phone Number(s):	651-539-1834 & 651-539-1825

Request Number:	1
Topic:	Demand Entitlement
Reference(s):	August 16, 2017 Public Utilities Commission (Commission or PUC) Staff Briefing Papers in Docket No. G011/M-16-650 and December 6, 2017 PUC Order.

Request:

On page 12 of the Briefing Papers, staff stated the following:

> If the Department has not begun the investigation, requested in Commission Order Point 13, in Docket Nos. 15-722, 15-723, and 15-724, into how other natural gas utilities acquire and use daily customer usage data:
>
> 5. Request the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions. This review should determine if similar interruptible service tariff language requiring telemetering is already in each natural gas utilities' tariff for interruptible and transportation service and, if so, whether data from telemetering is being used effectively, and, if not, should a telemetering requirement be incorporated into their tariffs, and this data be used to possibly reduce costs.

Continued on next page

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: G022/M-17-399		☐Nonpublic ☒Public
Requested From:	Kristine A. Anderson, Greater Minnesota	Date of Request: January 26, 2018
Type of Inquiry:	General	Response Due: February 5, 2018

Requested by: Sachin Shah/Adam Heinen
Email Address(es): sachin.shah@state.mn.us & adam.heinen@state.mn.us
Phone Number(s): 651-539-1834 & 651-539-1825

The final order in Docket No. G011/M-16-650 has been issued, and requests the following:

> Requested the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions.

Based on this order, please:

- Provide general discussion on how interruptible customers and their data are incorporated into design-day analysis;
- Provide general discussion of telemetering requirements for interruptible customers;
- Explain if the Company has any interruptible customers without telemetering and if so, provide the number of interruptible customers without telemetering and explain why this is the case;
- Reference and provide any tariff language that requires interruptible customers to have telemetering; and
- Explain if the Company has reduced its design day and/or interstate pipeline demand entitlements in the prior five years as a result of having daily interruptible data.

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

RESPONSE:

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:	G011/M-17-588	☐Nonpublic ☒Public
Requested From:	Amber Lee, MERC	Date of Request: 11/8/2017
Type of Inquiry:	General	Response Due: 11/20/2017

Requested by: Sachin Shah/Michael Ryan
Email Address(es): Sachin.shah@state.mn.us & michael.ryan@state.mn.us
Phone Number(s): 651-539-1834 & 651-539-1807

Request Number: **1**
Topic: MERC-NNG Reserve Margin
Reference(s): MERC November 1 Update, Attachment C, Page 5.

Request:

The Minnesota Energy Resources' Corporation (MERC or Company) filing states the following in the reference above:

The reserve margin for 2017-2018 is slightly negative. MERC will purchase city gate delivered supply to cover 0.19% of peak day throughput if necessary. This reserve margin is appropriate because incremental NNG capacity will come on line in 2018 as a result of the Rochester expansion project.

Please provide further detail on how MERC will protect ratepayers in the upcoming winter from the risks of Northern Natural Gas (NNG) pipeline capacity not being available and/or the expense of capacity being purchased on short notice likely at a time when the NNG system is constrained. Please describe any plan(s) the Company has to purchase capacity for the months of highest risk within the winter season (*e.g*. December, January, and February).

If this information has already been provided in the application, written testimony or in response to an earlier Department information request (IR), please identify the specific testimony cite(s) or Department IR numbers(s).

Response:

MERC will continue to monitor weather forecasts and in the event of a potential peak day, will call upon all interruptible customers to curtail their usage and will purchase citygate delivered gas for the period such supplies are needed (i.e., likely over a short term during the peak day event). The Company will be proactive in its approach with the full understanding of the current capacity

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To be completed by responder

Response Date: November 20, 2017
Response by: Russell Laursen and Amber Lee
Email Address: ASLee@Integrysgroup.com
Phone Number: (651) 322-8965

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G011/M-17-588	☐Nonpublic ☒Public
Requested From:	Amber Lee, MERC	Date of Request: 11/8/2017
Type of Inquiry:	General	Response Due: 11/20/2017

Requested by: Sachin Shah/Michael Ryan
Email Address(es): Sachin.shah@state.mn.us & michael.ryan@state.mn.us
Phone Number(s): 651-539-1834 & 651-539-1807

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situation and that it must act in a conservative manner with respect to the timing and volume of such a purchase.

The calculated negative reserve margin amounts to approximately 500 Dth. However, as discussed in MERC's response to Department Information Request No. 3, MERC utilized a conservative peak day estimate for the communities of Esko and Balaton for the 2017-2018 heating season; if MERC had utilized more moderate peak day estimates for these two new communities, the resulting reserve margin would have been slightly higher – closer to 0% but would not have affected the Company's contracted demand entitlements as filed.

The alternative to proceeding with a very small negative reserve margin for the 2017-2018 heating season would have been to enter into a five year capacity contract with NNG at maximum tariffed rates. MERC concluded that in light of the calculated reserve margin and anticipated timing of additional Rochester capacity, entering into a five year contract for additional capacity would not be prudent or in the best interest of customers.

To be completed by responder

Response Date: November 20, 2017
Response by: Russell Laursen and Amber Lee
Email Address: ASLee@Integrysgroup.com
Phone Number: (651) 322-8965

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G011/M-17-588	☐Nonpublic ☒Public
Requested From:	Amber Lee, MERC	Date of Request: 11/8/2017
Type of Inquiry:	General	Response Due: 11/20/2017

Requested by: Sachin Shah/Michael Ryan
Email Address(es): Sachin.shah@state.mn.us & michael.ryan@state.mn.us
Phone Number(s): 651-539-1834 & 651-539-1807

Request Number: **2**
Topic: Demand Entitlement
Reference(s): August 16, 2017 Public Utilities Commission (Commission or PUC) Staff Briefing Papers in Docket No. G011/M-16-650

Request:

On page 8 of the Briefing Papers, staff stated the following:

> In Docket No. 15-723, PUC staff believed that the daily interruptible data availability enhanced MERC's ability to calculate its DD requirements, which led to an interstate pipeline capacity reduction, and saved MERC's ratepayers approximately $1.1 million in demand entitlement costs.[24]
>
> 24 Calculated by multiplying MERC's demand entitlement reduction of 14,383 Dth/day by 5 months by NNG's TFX-5 max rate of $15.1530 = $1,089,728.

Please provide and explain the following details related to the "14,383 Dth/day TFX-5" contract referenced above:

- relevant contract number(s);
- duration and associated size, terms, rates, agreements, et cetera of the Northern Natural Gas (NNG) Service;
- beginning and expiration date(s); and
- Fully explain MERC's reduction to NNG pipeline capacity referenced above.

Explain in detail any correlation between MERC obtaining daily interruptible data and the reduction to design day and demand entitlements in the prior five-year period (both MERC-NNG & MERC-CONS). Please indicate and explain if your response also includes the former MERC-Albert Lea service territory or if it only includes the former MERC-NNG service territory.

To be completed by responder

Response Date: November 20, 2017
Response by: Russell Laursen and Amber Lee
Email Address: ASLee@Integrysgroup.com
Phone Number: (651) 322-8965

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number: G011/M-17-588		☐Nonpublic ☒Public
Requested From: Amber Lee, MERC		Date of Request: 11/8/2017
Type of Inquiry: General		Response Due: 11/20/2017

Requested by: Sachin Shah/Michael Ryan
Email Address(es): Sachin.shah@state.mn.us & michael.ryan@state.mn.us
Phone Number(s): 651-539-1834 & 651-539-1807

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

Response:

It would be difficult or impossible to isolate the impacts of telemetry data on MERC's overall peak day analysis or the impact of MERC's ability to use daily interruptible data over time. While the incorporation of telemetry data in the 2014-2015 Demand Entitlement filings occurred at a time when MERC's peak day declined, MERC cannot reasonably or definitively correlate that impact of that data or other factors on the reduction to the peak day. Other factors affecting peak day include the potential impact of improved data over time, the timeframe of data analyzed and corresponding weather patterns during those times, changes in methodology related to weather aggregation, and customer changes from year-to-year. While MERC agrees with Commission staff that daily interruptible data availability has enhanced MERC's ability to more accurately calculate its design day requirements, MERC cannot reasonably correlate specific savings from reduced demand entitlements to the use of such daily interruptible data.

In Docket No. 15-723, MERC did experience a reduction in the peak day forecast, which allowed MERC to forego the renewal of NNG contract 127852 in the volume of 14,383 dth/day for the 2015/16 winter season. This NNG contract was TFX-5 winter-only capacity at maximum tariff rates and had been contracted for beginning with the 2014/15 winter season.

To be completed by responder

Response Date: November 20, 2017
Response by: Russell Laursen and Amber Lee
Email Address: ASLee@Integrysgroup.com
Phone Number: (651) 322-8965

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G011/M-17-588	☐Nonpublic ☒Public
Requested From:	Amber Lee, MERC	Date of Request: 11/8/2017
Type of Inquiry:	General	Response Due: 11/20/2017

Requested by:	Sachin Shah/Michael Ryan
Email Address(es):	Sachin.shah@state.mn.us & michael.ryan@state.mn.us
Phone Number(s):	651-539-1834 & 651-539-1807

Request Number:	3
Topic:	Demand Entitlement
Reference(s):	Docket No. G011/M-17-588

Request:

In the summary files for the 2017-2018 MERC peak day analysis that were provided by the company, MERC has included estimates for Esko and Balaton in its design-day analysis.

These projects were approved by the Minnesota Public Utilities Commission (PUC or Commission) in an Order dated February 9, 2017 in Docket Nos. G011/M-16-654 and G011/M-16-655. Please explain and provide in detail the following information related to these estimates for Esko and Balaton, namely:

- How these estimates included in the Company's peak day analysis were derived and calculated;
- As part of your response please explain the number of customers that were included in the calculation of the estimates;
- Please explain if these customers are firm and/or interruptible and whether they are residential, commercial (small or large) or large volume;
- Separately provide the various categories of customers that were included in the determination of the estimates; and
- Explain if the estimates of customers different from the respective dockets that the projects were approved in. If so, please explain the reason for the difference and the reasonableness of using different numbers.

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

To be completed by responder

Response Date:	November 20, 2017
Response by:	Russell Laursen and Amber Lee
Email Address:	ASLee@Integrysgroup.com
Phone Number:	(651) 322-8965

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G011/M-17-588	☐Nonpublic ☒Public
Requested From:	Amber Lee, MERC	Date of Request: 11/8/2017
Type of Inquiry:	General	Response Due: 11/20/2017

Requested by:	Sachin Shah/Michael Ryan
Email Address(es):	Sachin.shah@state.mn.us & michael.ryan@state.mn.us
Phone Number(s):	651-539-1834 & 651-539-1807

MERC Response

To serve Esko and Balaton, Town Border Stations were required to be built by Northern Natural Gas ("NNG"). MERC Engineering provided NNG with forecasted Peak Hour Delivery Service for each new community, which were based on the total potential customer pool as filed in Docket Nos. G011/M-16-654 and G011/M-16-655. This Peak Hour Delivery Service calculation was verified against other similarly sized communities served by MERC, and a 20% contingency was added to ensure adequate capacity would be available in each of these communities. NNG took MERC's stated information and designed Town Border Stations that would be able to deliver 1,500 and 1,000 dekatherms/day for Esko and Balaton respectively to meet MERC's projected needs. The Town Border Station delivery capabilities were then used in Gas Supply's Peak Day Demand forecast.

While the peak day estimates included for the communities of Esko and Balaton are likely conservative for the 2017-2018 winter heating season, these numbers did not impact MERC's proposed demand entitlements. If MERC had utilized more moderate peak day estimates for these two new communities, the resulting reserve margin would have been slightly higher – closer to 0% but would not have affected the Company's contracted demand entitlements as filed.

To be completed by responder

Response Date:	November 20, 2017
Response by:	Russell Laursen and Amber Lee
Email Address:	ASLee@Integrysgroup.com
Phone Number:	(651) 322-8965

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Comments

Docket No. G011/M-17-588

Dated this 29th day of January 2018

/s/Sharon Ferguson

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